POTOMAC ECONOMICS

Report to the

Texas Senate Committee on Business & Commerce

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Potomac Economics

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Introduction

Potomac Economics, the Independent Market Monitor ("IMM") for the wholesale markets in the Electric Reliability Council of Texas, Inc. ("ERCOT") region, specializes in providing expert economic analysis and is charged with monitoring wholesale market activities so as to: (1) detect and prevent market manipulation strategies and market power abuses; and (2) evaluate the operations of the wholesale market with the current market rules and proposed changes to the market rules, and recommend measures to enhance market efficiency.

The purpose of this testimony is to brief the Committee on the state of the ERCOT wholesale market, specifically with regard to the following areas:

- Demand and Supply;
- Generating Resources;
- Wind Output;
- Reliability Commitments; and
- Resource Adequacy

This testimony is also intended to identify historical trends and indicators within those areas and provide perspective on future wholesale market outcomes.

Demand and Supply

The changes in overall load levels from year to year can be shown by tracking the changes in average load levels. This metric tends to capture changes in load over a large portion of the hours during the year. Separately evaluating the changes in the load during the highest-demand hours of the year is also important. Significant changes in peak demand levels play a major role in assessing the need for new resources. The level of peak demand also affects the probability and frequency of shortage conditions (i.e., conditions where firm load is served but minimum operating reserves are not maintained). The expectation of resource adequacy is based on the value of electric service to customers and the harm or inconvenience to customers that can result from interruptions to that service. Hence, both of these dimensions of load are key system attributes.

Total ERCOT load was 357.4 million megawatt-hours (MWh) in 2017, an increase of 1.9% from 2016. All zones showed an increase in average real-time load in 2017, with the West zone having the largest average load increase at 8.3%.

Summer conditions in 2017 produced a peak load of 69,512 megawatts (MW) on July 28, 2017. This was less than the ERCOT-wide coincident peak hourly demand record of 71,110 MW set on August 11, 2016. Further, demand did not ever exceed 70,000 MW in 2017, compared to five separate hours in 2016.

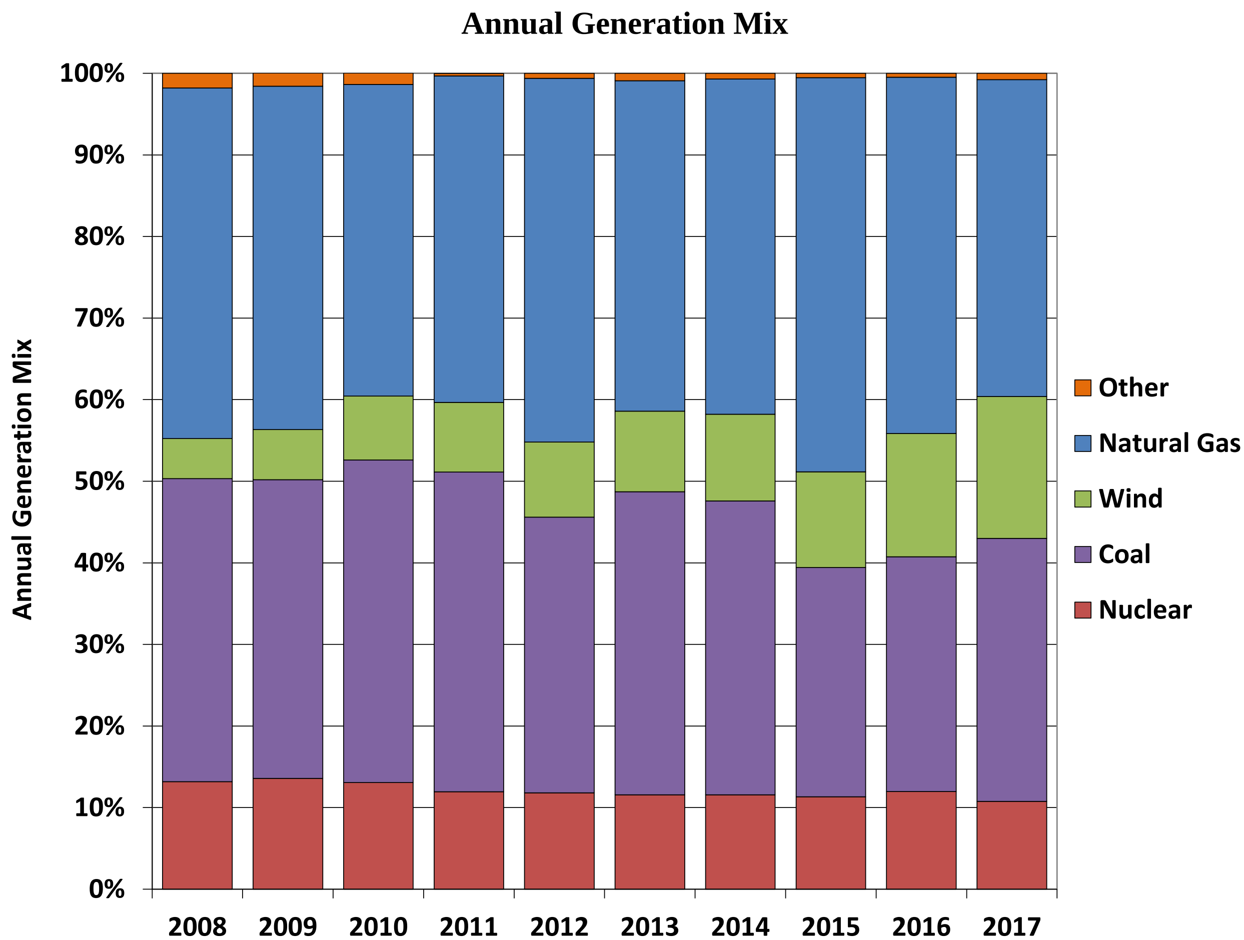
In each zone, as in most electrical systems, peak demand significantly exceeds average demand. The North zone is the largest zone (with about 36% of the total ERCOT load); the South and Houston zones are comparable (27%) while the West zone is the smallest (10% of the total ERCOT load).[1]

Generating Resources

The distribution of capacity among the four ERCOT geographic zones is similar to the distribution of demand with the exception of the large amount of wind capacity in the West. In 2017, generation located in the North zone accounted for approximately 33% of capacity, the South zone 29%, the Houston zone 18%, and 20% in the West zone. Excluding mothballed resources and including only the fraction of wind capacity available to reliably meet peak demand, the North zone accounts for approximately 38% of capacity, the South zone 33%, the Houston zone 20%, and the West zone 9%.

[1] For purposes of this discussion the four Non-Opt In Entity (NOIE) Load Zones have been aggregated with the proximate geographic zone; San Antonio, Austin, and LCRA into the South and Rayburn into the North.

The shifting contribution of coal and wind generation is evident in the figure below, which shows the percentage of annual generation from each fuel type for the years 2008 through 2017.



The generation share from wind has increased every year, reaching 17% of the annual generation requirement in 2017, up from 5% in 2008 and 15% in 2016. While the percentage of generation from coal had declined significantly between 2014 and 2015, its share has increased the last two years, reaching 29% in 2016 and 32% in 2017. Natural gas declined from its high point of 48% in 2015 to 44% in 2016 and 39% in 2017.

Wind Output

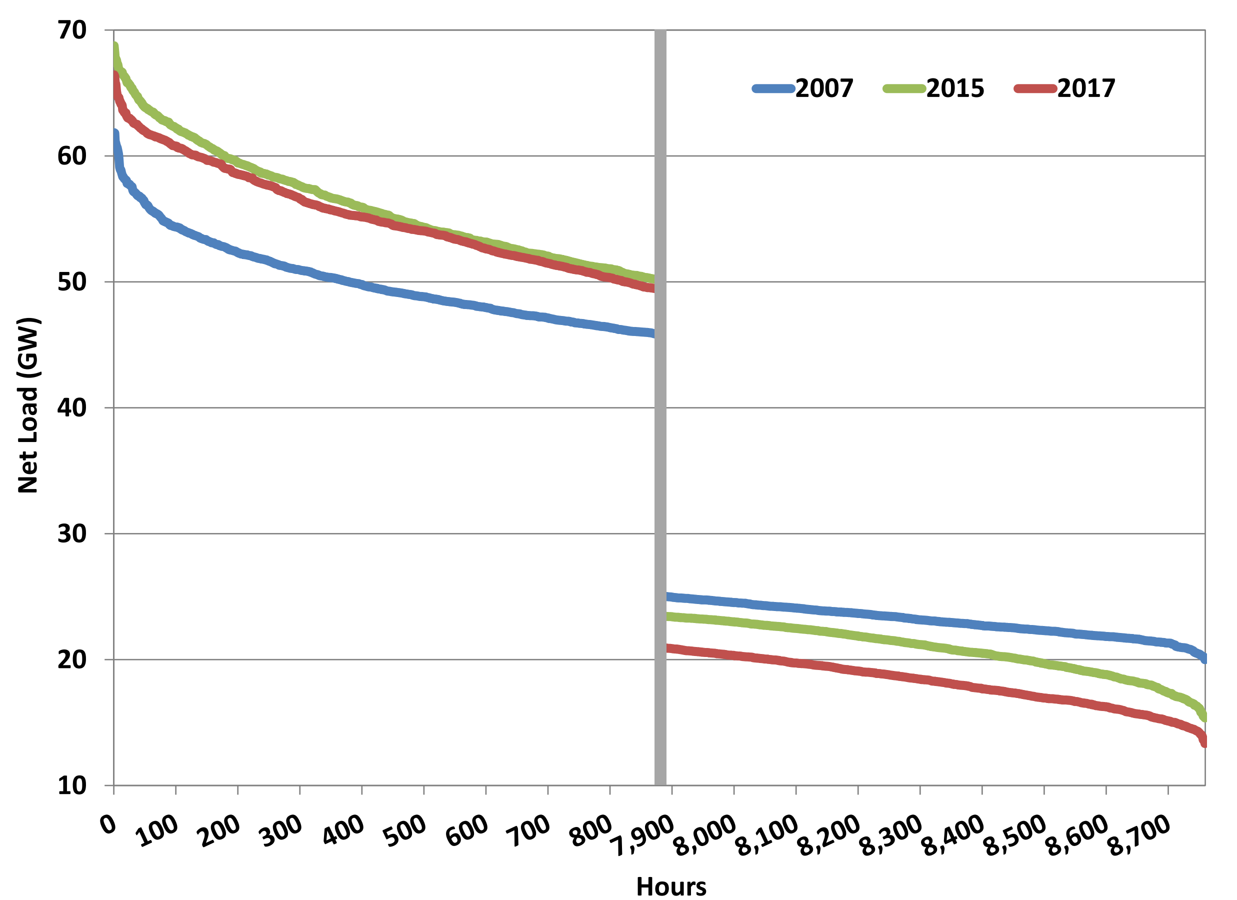
ERCOT continued to set new records for peak wind output in 2017. On November 17, 2017, wind output exceeded 16 GW, setting the record for maximum output and providing nearly 42 percent of the total load[2]. Increasing levels of wind resources in ERCOT have important implications for the net load duration curve faced by the non-wind fleet of resources. Net load is

2 The maximum hourly wind generation has since been surpassed in February 2018.

defined as the system load (total customer demand for electricity) minus wind production. The figure below shows lowest and highest net load hours.

In the hours with the highest net load (left side of the figure above), the difference between peak net load and the 95th percentile of net load has averaged 12.3 thousand-megawatts or gigawatts (GW) the past three years. This means that 12.3 GW of non-wind capacity is needed to serve load less than 440 hours per year.

Top and Bottom Ten Percent of Net Load



In the hours with the lowest net load (right side of the figure), the minimum net load has dropped from approximately 20 GW in 2007 to below 13.3 GW in 2017, even with the sizable growth in annual load that has occurred. This trend has put operational pressure on the almost 25 GW of nuclear and coal generation that were in-service in 2017. This operational pressure was certainly one of the contributors to the recent retirement of more than 4 GW of coal.

Thus, although the peak net load has been and is projected to continue to increase, creating an ever larger need for non-wind capacity to satisfy ERCOT's reliability requirements, the non-wind fleet can expect to operate for fewer hours as wind penetration increases. This outlook further reinforces the importance of efficient energy pricing during peak demand conditions and other times of system stress, particularly in the context of the ERCOT energy-only market design.

Reliability Commitments

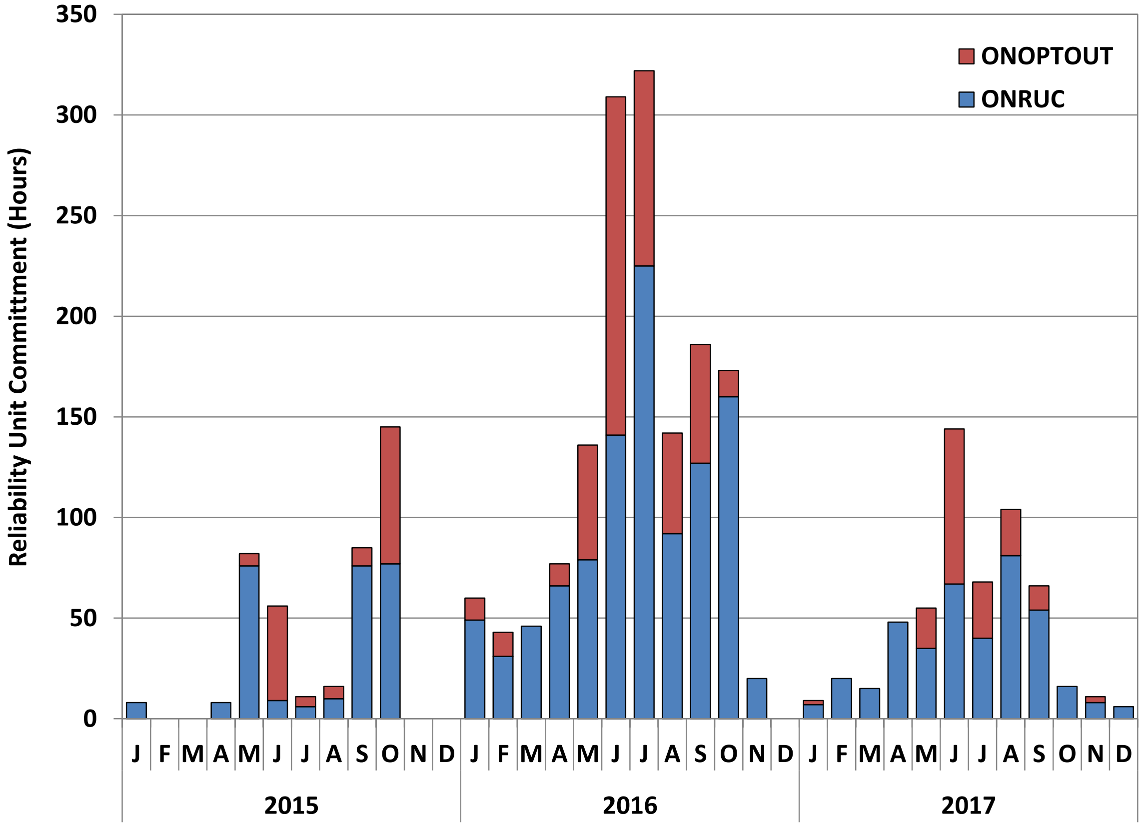
One of the important characteristics of any electricity market is the extent to which it results in the efficient commitment of generating resources. Under-commitment can cause apparent shortages in the real-time market and inefficiently high energy prices; while over-commitment can result in excessive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

The ERCOT market does not include a mandatory centralized unit commitment process. The decision to start-up or shut-down a generator is made by the market participant. ERCOT's day-ahead market outcomes help to inform these decisions, but ERCOT's day-ahead market is only financially binding. That is, when a generator's offer to sell is selected (cleared) in the day-ahead market there is no corresponding requirement to actually start that unit. The generator will be financially responsible for providing the amount of capacity and energy cleared in the day-ahead market whether or not the unit operates.

ERCOT continually assesses the adequacy of market participants' resource commitment decisions using a reliability unit commitment (RUC) process that executes both on a day-ahead and hour-ahead basis. Additional resources may be determined to be needed for two reasons – to satisfy the total forecasted demand, or to make a specific generator available resolve a transmission constraint. The constraint may be either a thermal limit or a voltage concern. When a participant receives a RUC instruction, it may "opt-out" of the instruction by voluntarily starting its unit and receiving the real-time market revenue. If the supplier does not opt-out, it is eligible to receive a make-whole payment to cover its cost, but will relinquish the market revenues in excess of its cost through a "clawback" provision.

The figure below shows how frequently these reliability unit commitments have occurred over the past three years, measured in unit-hours. The total number of RUC commitments in 2017 dropped considerably from 2016.

Frequency of Reliability Unit Commitments

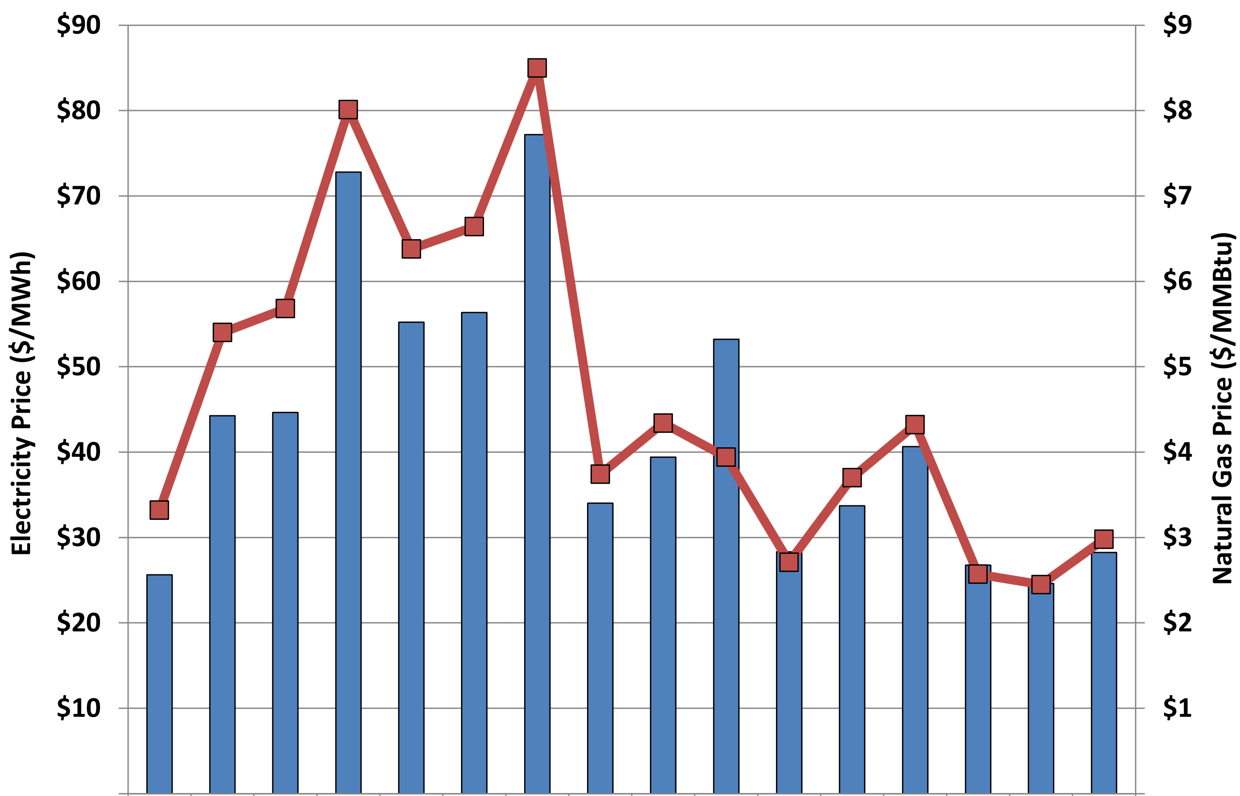


Resource Adequacy

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 have been and are expected to continue to increase, 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-shortage, energy prices during shortage and capacity payments. The only capacity payments generators receive in ERCOT are related to the provision of ancillary services, which to-date have been a small source of revenue, approximately $5 per kW-year. Setting ancillary service payments aside, generator revenue in ERCOT is overwhelmingly derived from energy prices under both shortage and non-shortage conditions. The figure below shows that electricity prices are highly correlated to natural gas prices and have been relatively low in recent years.

Price Comparisons



	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
ERCOT	25.64	44.26	44.64	72.79	55.22	56.35	77.19	34.03	39.40	53.23	28.33	33.71	40.64	26.77	24.62	28.25
Gas	3.32	5.40	5.68	8.01	6.38	6.64	8.50	3.74	4.34	3.94	2.71	3.70	4.32	2.57	2.45	2.98

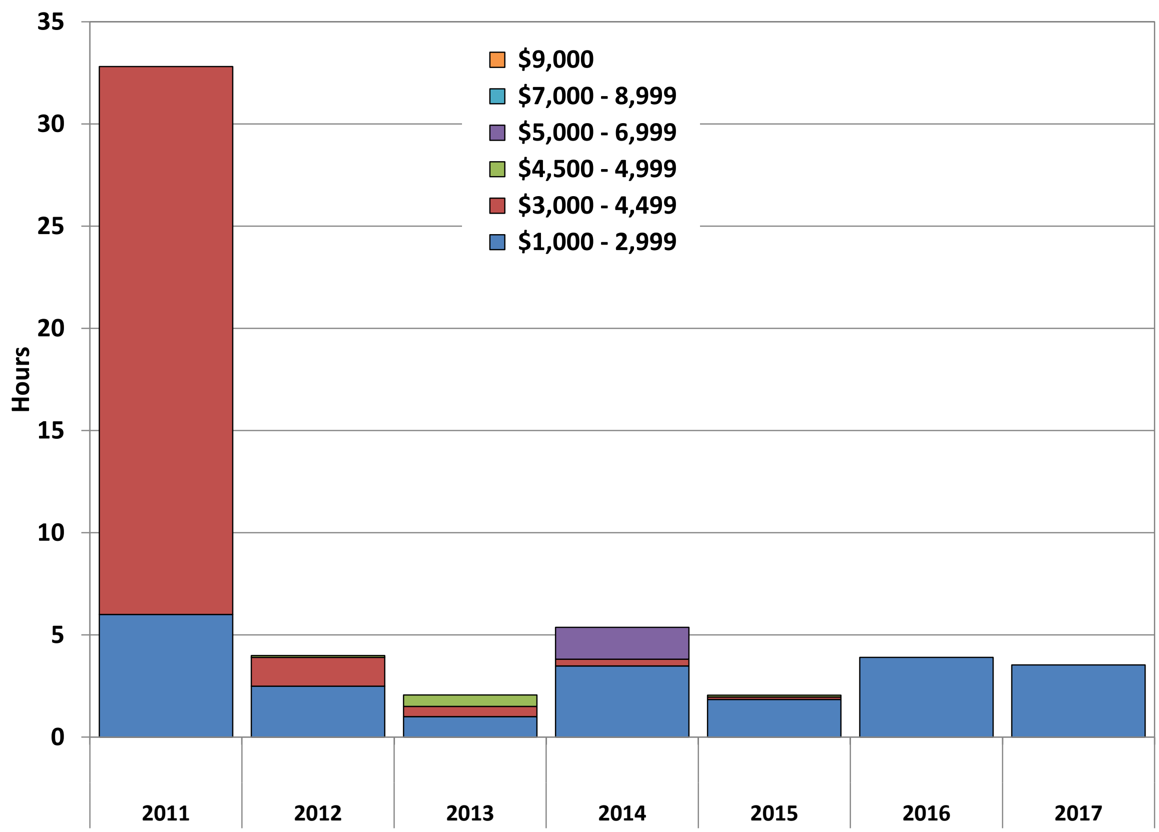
Expectations for energy pricing under non-shortage conditions are the same regardless of whether payments for capacity exist. In ERCOT, with no capacity payments available, the amount a generator may receive from energy pricing under shortage conditions must be large enough to provide the necessary incentives for new capacity additions. This will occur when energy prices are allowed to rise substantially during 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” (not serving) load multiplied by 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 not include enough capacity to meet a specified target for planning reserves.

Faced with reduced levels of generation development activity coupled with increasing loads that resulted in falling planning reserve margins, in 2012 and 2013 the PUCT devoted considerable effort deliberating issues related to resource adequacy. In September 2013 the PUCT Commissioners directed ERCOT to move forward with implementing Operating Reserve Demand Curve (ORDC), a mechanism designed to ensure effective shortage pricing when operating reserve levels decrease. Over the long term, a co-optimized energy and operating reserve market will provide more accurate shortage pricing. Planning reserves should continue to be monitored to determine whether shortage pricing alone is leading to the desired level of planning reserves.

The PUCT also adopted revisions to 16 Tex. Admin. Code § 25.505 in 2012 that specified a series of increases to the ERCOT system-wide offer cap under the Scarcity Pricing Mechanism (SPM) provision. The last step went into effect on June 1, 2015, increasing the system-wide offer cap to $9,000 per MWh.

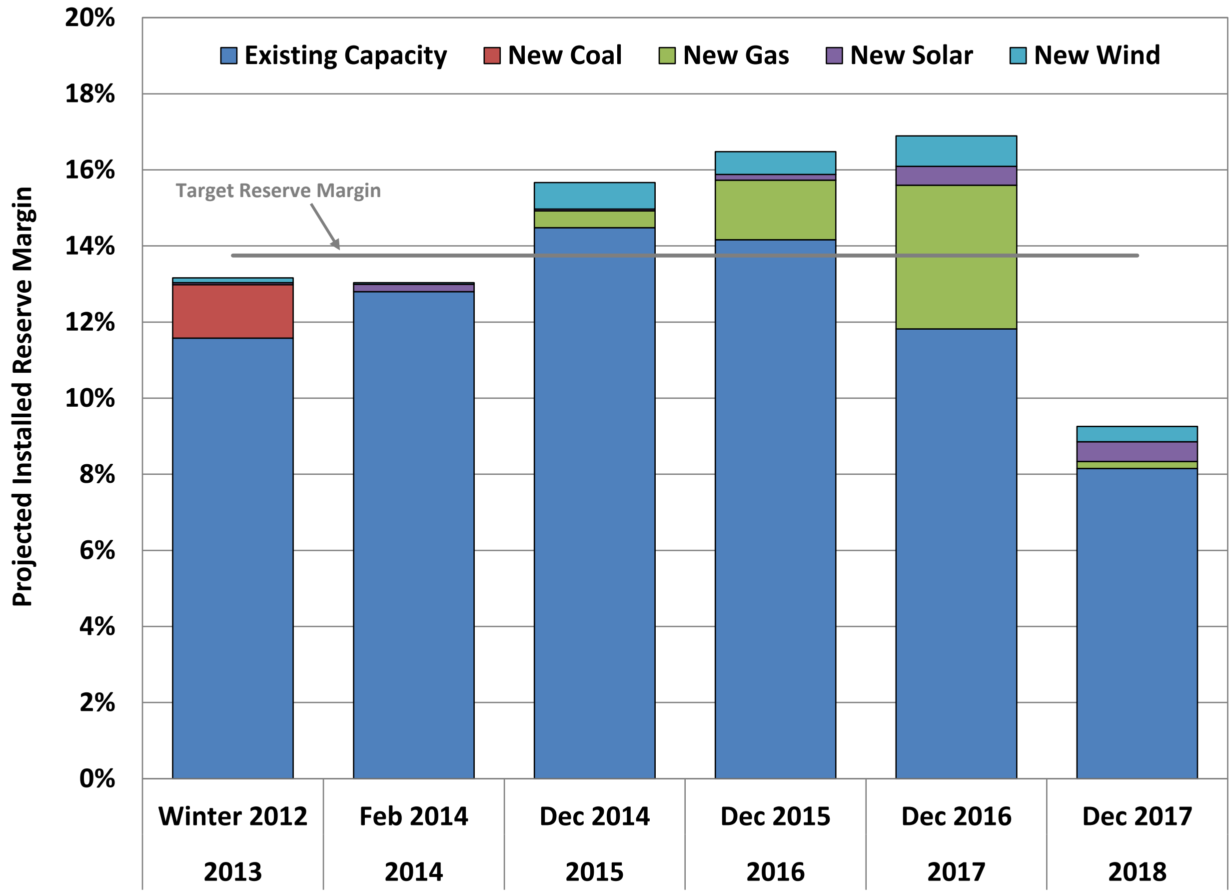
Duration of High Prices



The figure above summarizes the accumulated length of time that real-time electricity prices exceeded $1000 per MWh, for each year since 2011. 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, and none since 2015.[3] The large number of hours in 2011 with price greater than $3,000 per MWh (the system-wide offer cap in effect at the time) were primarily due to higher than expected load due to extreme weather conditions that year.

The next figure compares the expected installed reserve margins for the past several summers, as calculated from ERCOT's Capacity Demand Reserve (CDR) report generated in the prior winter. It shows ERCOT's current projection that the region will have a 9.3% percent reserve margin heading into the summer of 2018. This is noticeably lower than expectations for the previous several years, due in large part to the approximately 5 GW of capacity that has been recently retired.

Projected Planning Reserve Margins

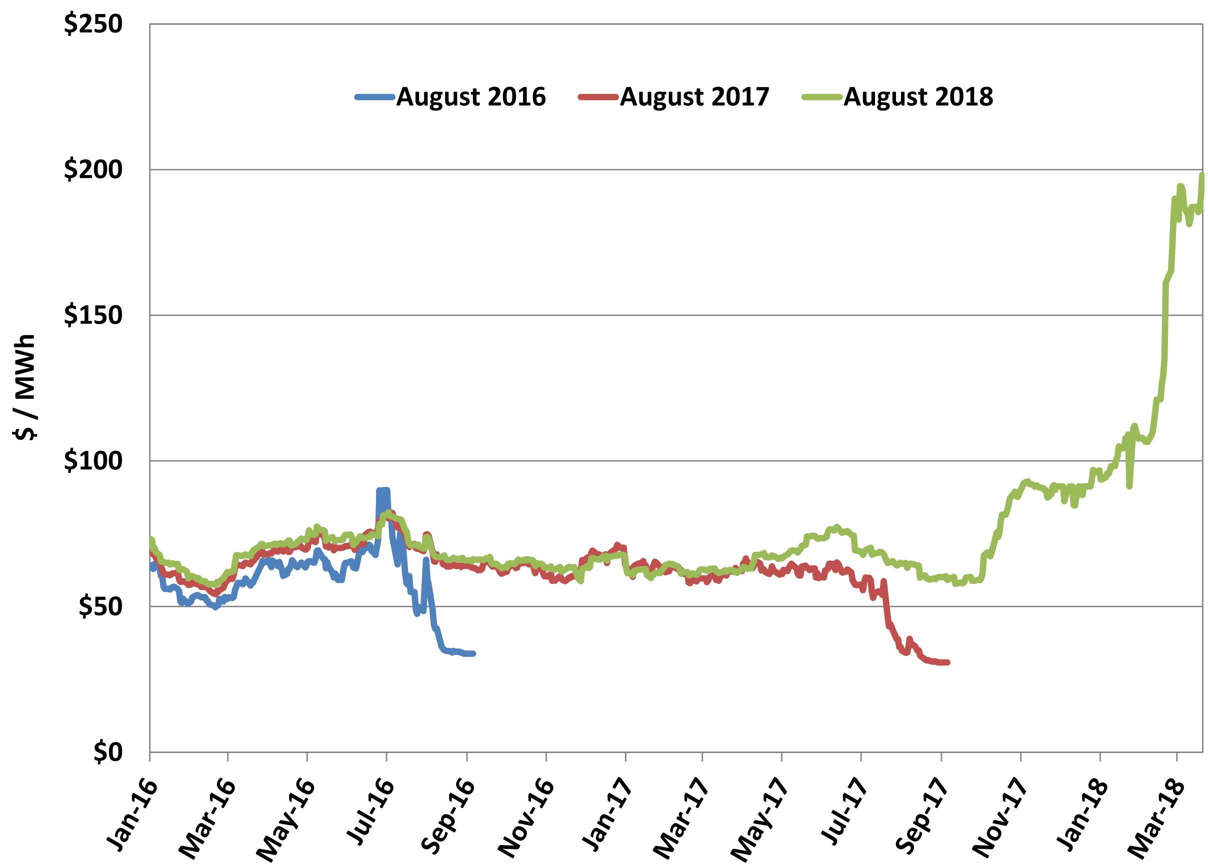


3 Prices in ERCOT's real-time energy market were $9000 per MWh for two-five minute intervals on the morning of January 23, 2018.

The response by market participants to the lower reserve margin projections has been evident in forward prices. The figure below shows the forward prices for electricity delivered to the North Hub during on-peak hours of August 2016, 2017 and 2018.

Starting in January 2016, prices for August 2016 and 2017 varied in a small range between $50 and $70 per MWh, until converging with the actual price, which was between $30 and $35 per MWh for both years.

North Hub Forward Prices



However, forward prices for August 2018 have risen to much higher levels, starting in the fall of 2017 when they increased to almost $100 per MWh shortly after the announcements that Luminant would retire more than 4,000 MW of capacity. Since the beginning of 2018, on-peak prices for August steadily increased to almost $200 per MWh.

The current projection of planning reserve margin combined with expected shortage pricing during the summer of 2018 after years of higher reserve margins and lower prices demonstrates that the market is functioning properly. That is, less efficient, uneconomic units are being retired in times of relatively low prices and the resulting absence of pricing signals incentivizing new generation. How investors in new generation respond to these market signals will be monitored closely throughout 2018. It is entirely possible that actual planning reserve margins may be somewhat higher than forecasted in the figure above as forward prices rise.

To date, ERCOT's energy only market design has attracted sufficient investment in new resources. Going forward, it will be important to monitor whether renewable resources will be sufficient to meet growing demand and if additional investment in thermal (gas) units will be forthcoming.