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Think Corner Research Note

The Impacts of Raising the Energy Price Cap in ERCOT[1]

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Abstract

In order to ensure resource adequacy, the Public Utility Commission of Texas (PUCT) proposes to raise the energy price cap (system wide offer cap) from the current level of $3,000/MWh to $9,000/MWh gradually by 2015; PUCT approved an increase to $4,500/MWh starting August 1, 2012. We evaluate the impacts of the approved and proposed increases using an economic dispatch model, AURORAxmp, compared to a scenario of keeping the price cap at its current level. Importantly, we assume a high demand scenario taking the summer 2011 peak demand as our baseline to establish boundary conditions. The price cap increases have an impact on new builds in the near future (13% increase between 2013 and 2015); net capacity additions (after retirements) are 15% higher during the 2013-15 period and 8% higher in the long-run under the $9,000 scenario. The actual peak reserve margins are higher under the $9,000 case but still significantly lower than the target reserve margin of 13.75%. The average wholesale price rises about 9% although there are years when it is lower under the price cap increase scenario. Given this average price increase effect, it is important to note that clearly communicated commitment to price cap increase is paramount to eliminate any doubts about regulatory uncertainty on the part of investors as well as lenders.

To improve our analysis, we will next evaluate the value of securing different levels of demand response (DR) in terms of grid reliability. Already, the comparison of demand curtailment amounts between the two scenarios analyzed in this paper provides a sense of what value the consumers might assign to DR. We also plan to run a scenario with the 13.75% target reserve margin as a mandate to estimate the cost of achieving that target. Comparing results from DR and 13.75% reserve margin runs will improve our understanding of consumers' willingness to participate in DR programs at different price levels as well as the appropriateness of the 13.75% reserve margin as an indicator of optimal reliability.

It is important to recognize that the changes to the price cap will not occur in isolation from changes to environmental regulations, fuel prices, and renewables policies. In a previous paper, we evaluated the combined impact of EPA CSAPR, EPA MATS, natural gas price volatility, renewables subsidies, and a CO_2 penalty.[2] We also plan to incorporate changes in cost structure of renewable generation technologies. We will evaluate the impact of proposed price cap changes, demand response and mandated 13.75% reserve margin in a more complete setting that takes into account all of these factors.

Problem Statement

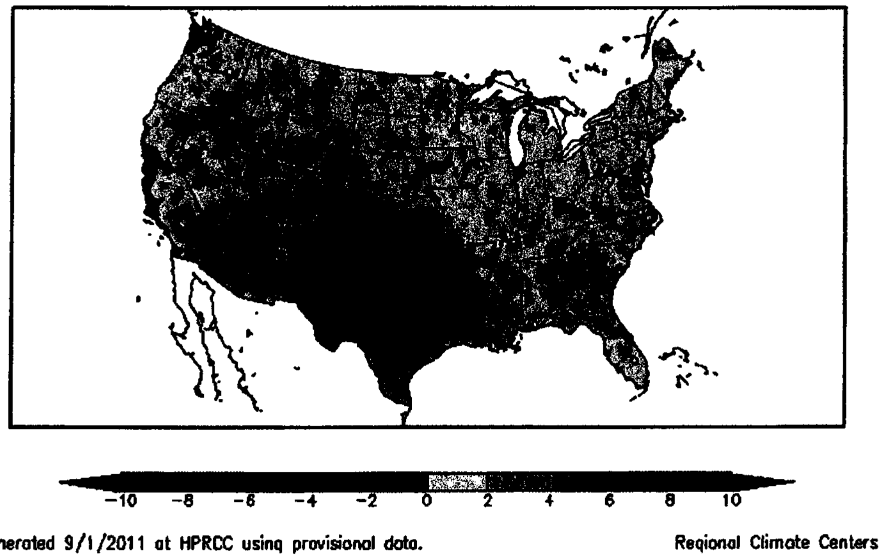
After the summer heat wave in 2011 forced the Electricity Reliability Council of Texas (ERCOT) to declare an Energy Emergency Alert (EEA) in order to meet system demand,[3] the concerns about whether there will be sufficient generation capacity going forward to meet growing demand in Texas' energy-only market have increased. This concern about resource adequacy, though, is not solely based on the fear of cyclical summers of above normal temperatures. Without a doubt, the ERCOT region experienced

[2] For details, please see "U.S. Gas-Power Linkages: Building Future Views" by Gülen et al at http://www.beg.utexas.edu/energyecon/thinkcorner/Think%20Corner%20Gas-Power%20Linkages.pdf. It is also important to revisit assumptions about availability and price of natural gas going forward: see "The Outlook for U.S. Gas Prices in 2020: Henry at $3 or $10?" by Foss at http://www.oxfordenergy.org/2011/12/the-outlook-for-u-s-gas-prices-in-2020-henry-hub-at-3-or-10/.

[3] See ERCOT Press Release "ERCOT in level 1 emergency; Consumers asked to conserve 3-7 p.m. today" on August 4th, 2011.

one of the hottest summers in history, setting records in August 2011 (Figure 1); but there are other reasons for being concerned about resource adequacy.

Figure 1. Departure from normal temperature (F) 8/2/2011 – 8/31/2011



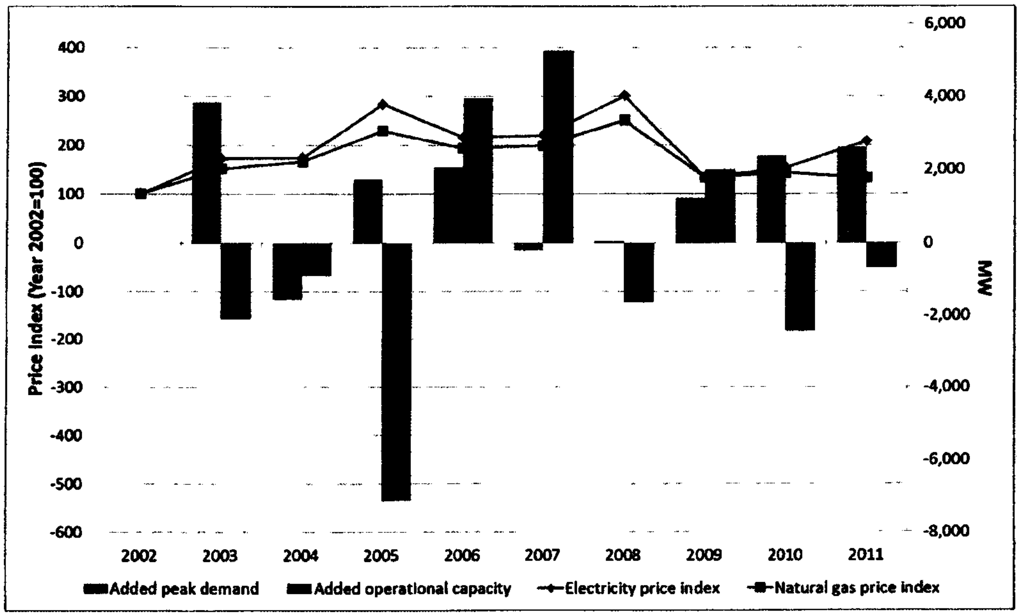
Source: National Weather Service

Demand for electricity has been growing fast along with population and economic growth in Texas; total consumption of electricity in Texas has grown about 2% per year on average between 1990 and 2010; and 3.8% in 2010. More importantly, peak demand has increased more than 12 GW between 2002 and 2011 but net operational capacity declined by 3.7 GW over the same time period (Figure 2). Among the potential reasons for investment falling behind demand growth are the low level of price caps in an energy-only market combined with the infrequency of scarcity periods; and the low price of natural gas, which keeps electricity prices and margins low in Texas' competitive market with a low market heat rate. Wind energy supplied to market at negative prices at times also contributes to keeping average wholesale prices low; the frequency of negative bids have been quite high since 2007 and will probably continue at least until the CREZ lines are completed.

Also, the recession triggered by the financial sector crisis in 2008 raised uncertainty regarding demand growth and caused generation investors to be more cautious. Given the difficulties of the financial sector, the lending practices have also become more rigorous with increasing cost of borrowing for some investors, especially smaller ones. The fact that electricity demand in Texas grew faster than predicted since 2009 probably surprised both investors and lenders.

There is not much that can be done about the weather or the price of natural gas but it is possible to modify the market design to create additional incentives for generation investment and demand response. Although initiatives on demand response are limited at this time, there are potentially significant changes to encourage more supply. In addition to some adjustments in ancillary services, the Public Utility Commission of Texas (PUCT) proposes to raise the energy price cap (also referred to as the system wide offer cap) from the current level of $3,000/MWh to $4,500/MWh[4] starting in August 2012 and gradually rising to $9,000/MWh by 2015 if approved in a pending Commission rulemaking.[5]

Figure 2. ERCOT added peak demand and operational capacity, natural gas and electricity prices



Sources: capacity and demand from http://www.eia.gov/electricity/annual/ (except for 2011 data, which is from ERCOT); price of natural gas delivered to power plants from http://www.eia.gov/dnav/ng/hist/n3045us3a.htm and ERCOT wholesale electricity prices from http://www.potomaceconomics.com/index.php/documents/C6.

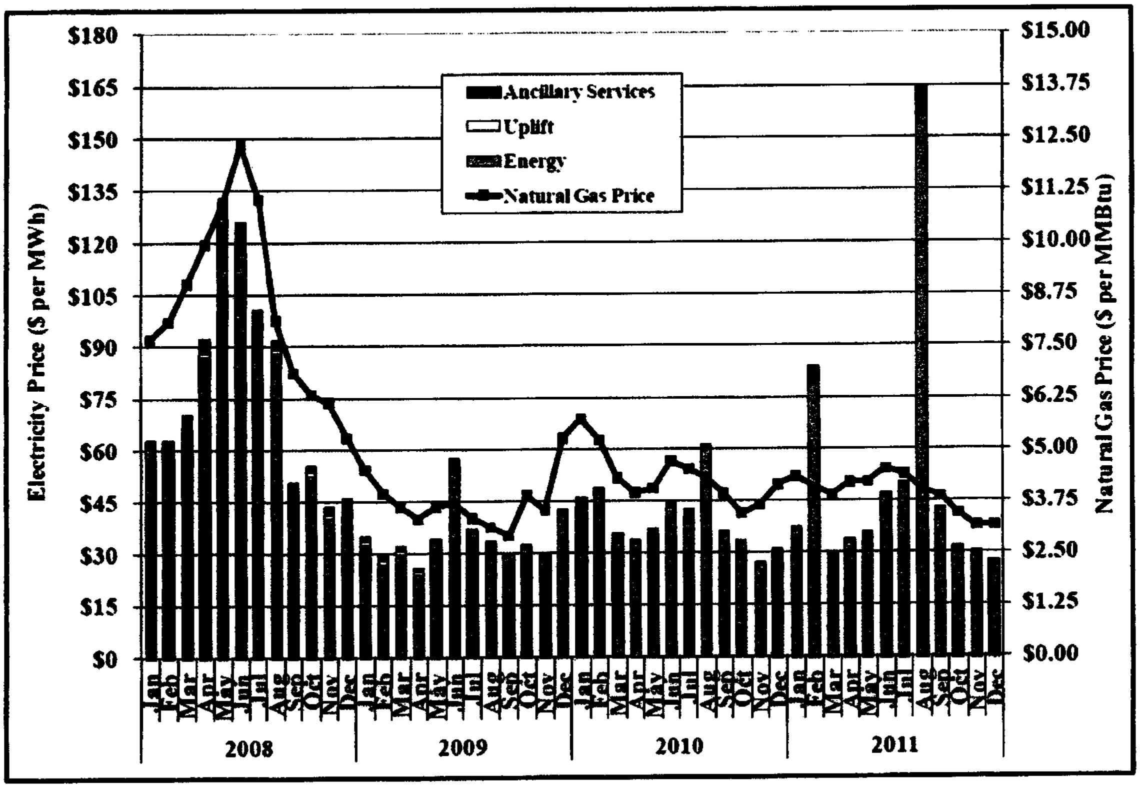
Electricity prices reflected the tight conditions in the market, hitting the $3,000 price cap for 20 hours during August of 2011[6] and averaging about $160/MWh in August 2011 as compared to the annual average of $53/MWh (Figure 3). Historically, electricity and natural gas prices have been highly correlated in the ERCOT market (Figure 2), which kept the margins of gas-plant operators tight, especially in the environment of lower gas prices since late 2008. This correlation was broken in 2011 but will most likely be re-established in the absence of a large number of scarcity periods and/or higher price caps.

The actual observed reserve margin during the August 2011 peak was 7% as compared to 17.5% predicted by ERCOT in May 2011.[7] ERCOT expects reserve margins to steadily decline through the decade based on current demand projections and resource additions.[8] ERCOT reports in its 2012 long-term outlook that, by 2022, summer peak load in ERCOT territory will be larger than total resources (unless new generation capacity is built, additional demand response is procured or a combination of both). In these annual reports, ERCOT can only include planned units with signed interconnection

[4] Similar price/offer cap ($4,500/MW) also applies on capacity obtained for ancillary services.
[5] See http://www.puc.state.tx.us/industry/projects/rules/40268/40268.aspx and http://www.puc.state.tx.us/industry/projects/rules/37897/37897.aspx.
[6] http://www.directenergybusiness.com/energy-insights/texas-regulatory-update.php.
[7] See ERCOT's *2011 Report on the Capacity, Demand, and Reserves in the ERCOT Region* (http://www.ercot.com/content/news/presentations/2011/ERCOT_2011_Capacity,_Demand_and_Reserves_Report.pdf).
[8] See ERCOT's *2012 Report on the Capacity, Demand, and Reserves in the ERCOT Region* issued in May 2012 (http://www.ercot.com/content/news/presentations/2012/CapacityDemandandReserveReport-2012.pdf).

agreements and in the case of thermal units those with air permits. By definition, these numbers will be conservative but as shown in Figure 2, net additions has slowed down considerably in recent years while Texas' population and electricity demand continued to rise.

Figure 3. Load-weighted electricity prices in ERCOT, 2008-2011



Source: Independent Market Monitor report to ERCOT Board of Directors Meeting, February 21, 2012. (http://www.ercot.com/content/meetings/board/keydocs/2012/0221/Item_07_-_IMM_Report_(Feb_2012_ERCOT_Board_Meeting).pdf)

ERCOT assumes about 4-5% load growth from 2013 to 2014, and from 2013 to 2014 and about 2% annual growth until 2022. To secure availability of resources during summer 2012, 10 mothballed units are brought online to add nearly 2,000 MW of capacity.[9] Given these concerns, PUCT decided to raise price caps from the current level of $3,000/MWh to $4,500/MWh effective on August 1, 2012. While three different higher price cap scenarios are proposed, the highest proposed increases for future years are $5,000 in 2013, $7,000 in 2014 and $9,000 in 2015 forward. Before we present the results of our analysis of the impact of these price cap increases, it is useful to remind ourselves of the resource adequacy considerations.

The Resource Adequacy Debate

The competitive electricity market in ERCOT is an energy-only market but the scarcity price mechanism is currently capped at $3,000/MWh (high system wide offer cap, or HCAP) and there is limited demand

[9]See ERCOT presentation "Mothballed Units: Current Status for 2012 Summer" (http://www.ercot.com/content/news/presentations/2012/Mothballed_Units_Status_4-27-12.pdf).

side participation, without which meeting reliability targets such as the 13.75% reserve margin focuses on the supply side, i.e., adding more generation. Over the last several years, net capacity additions failed to keep up with rapidly growing demand. The lack of certain profits causes investors and lenders to be hesitant about constructing new plants.

In relation to raising the HCAP, a couple of other mechanisms are under revision: Peaker Net Margin (PNM) and low system wide offer cap (LCAP). The PNM is an instrument to prevent unusually high single year wholesale electricity prices. According to ERCOT, the accumulated PNM is the operating margins of a gas combustion turbine (CT) with a heat rate of 10 MMBtu/MWh. For illustration purposes, let us assume that the marginal cost of a CT is $100/MWh. Every time the market clearing price of electricity (MCPE) in the ERCOT system exceeds $100/MWh, the PNM is calculated as the difference of MCPE and $100. Over the year, the cumulative PNM continues to increase every time MCPE exceeds $100/MWh. If the cumulative PNM reaches $175,000 within a year, then the offer cap is lowered from the $3,000 HCAP to the LCAP. The LCAP is a price that is the greater of (1) the operating cost of a gas fired unit with a heat rate of 50 MMBtu/MWh or (2) $500/MWh.

The Brattle Group report concludes if price spikes occurred once every five years and energy margins in non-scarcity years are half of the cost of new entry (CONE), the PNM in a year of price spikes would need to be about three times of CONE to attract investment.[10] The LCAP is also relevant because it is the offer cap enforced after the PNM is exceeded. An LCAP priced too low will cause market inefficiencies by not allowing peaking generators from being dispatched. PUCT proposed raising the PNM threshold and LCAP to $262,500 and $2,000, respectively, in order to attain a more favorable market environment and attract sufficient investment into the grid.[11]

A method to examine the reliability of an electricity grid is the Loss of Load Probability (LOLP). The LOLP is the probability that a system peak demand will exceed total system capacity, usually expressed as a number of days, or hours, over an extended period of time. For example, the LOLP can be defined for an expected load loss of 1 day every 10 years. The LOLP can provide insight to stakeholders on what price wholesale electricity must be to attract additional investment into the market. In the instance where LOLP is based on 1 day every 10 years, prices in the range of $10,000-$15,000/MWh may be needed. These values can also be seen as representing the value of lost load (VOLL), or the amount that customers would be willing to pay to avoid a disruption in their electricity service, and may even be higher; the residential users would theoretically have the lowest VOLL, the industrial users would have the highest, and the commercial users would be somewhere in between. The product of the two (LOLPxVOLL) would be a good estimate of the system cost of low reserve margin periods. An economically efficient approach would be to set the energy price cap at the VOLL. A detailed and robust analysis of VOLL in the ERCOT market will help the discussion on setting the right price cap, identifying DR potential and determining the optimal reliability targets greatly.

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[10] See page 82 in "ERCOT Resource Adequacy Review" by the Brattle Group (http://www.ercot.com/content/news/presentations/2012/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf).

[11] See http://www.puc.state.tx.us/industry/projects/rules/40268/40268.aspx and http://www.puc.state.tx.us/industry/projects/rules/37897/37897.aspx.

Generators may prefer a capacity market similar to the one that exists in the PJM territory and elsewhere. PJM's capacity market, also referred to as the Reliability Pricing Model (RPM), is based on making capacity commitments three years in advance to create long term price signals. PJM's energy market functions as an exchange, using supply and demand to match participants with price. Supporters of capacity markets argue that the resource adequacy capacity target is clearly defined by regulators, and capacity markets reduce market volatility. Energy-only markets appear to be more volatile than capacity markets, which mean they might require a higher projected return for investors. Capacity markets may not always provide the desired results either. The Brattle Group reports: "...in our recent review of PJM's forward capacity market, we heard many similar concerns about capacity price volatility and uncertainty."[12] At this point, a capacity market is not considered for ERCOT but further modeling is necessary to compare pros and cons of all options.

The Proposed Solution by PUCT

In June 2012, the Public Utility Commission of Texas (PUCT) decided to raise the system-wide offer cap to $4,500/MWh starting August 1, 2012. The Commission also suggests gradually increasing the system-wide offer cap to $5,000 MWh in 2013, $7,000 MWh in 2014, and $9,000 MWh in 2015 in order to attract new generation capacity.[13] In addition, the amendment proposes increasing the high and low system offer caps as well as the PNM. PUCT staff has determined that, for each year the changes are in effect, there will be no fiscal implications for state or local government as a result of enforcing the amendments and that for each of the first five years the amendments are in effect, "the public benefit expected as a result of the amendments is greater assurance of resource adequacy in the ERCOT wholesale electricity market."[14] How much incremental new capacity would be built under the proposed conditions? What kind of capacity can be expected to be built? Will this additional capacity improve reserve margins to desired levels? What impact will the increased price caps have on the average wholesale price? These are the questions we will try to answer in the rest of this paper.

Evaluating the Impact of Higher Price Caps

By running a scenario where the price cap remains unchanged ($3,000/MWh) and comparing it to a case where the price cap is escalated to $9,000 in 2015 as proposed, we can determine the effect of the price cap proposal over the coming years. Note that we do not impose the target reserve margin (13.75%) but rather let the model yield actual peak reserve margins under the two scenarios. We assume that electricity demand will grow at about 2% a year through 2025; this rate is consistent with ERCOT CDR assumptions. Note, however, that ***we take the 2011 summer demand as our baseline – the extreme weather of 2011 may not repeat but this assumption helps us establish an upper boundary on the impacts***. We use the natural gas price forecast from the Annual Energy Outlook 2011 (Figure 4).

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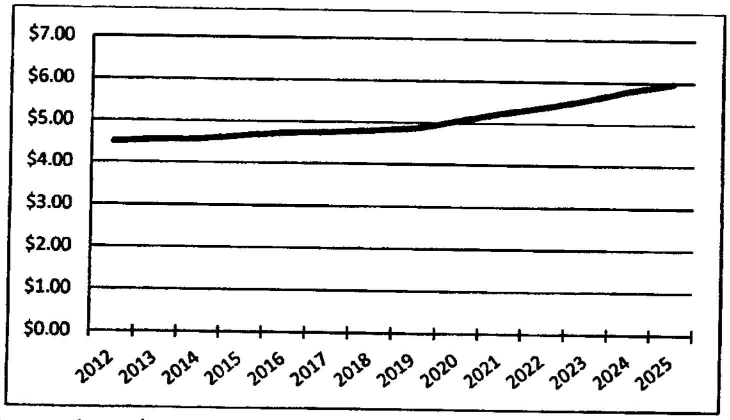
[12] See page 44 in "ERCOT Resource Adequacy Review" by the Brattle Group (http://www.ercot.com/content/news/presentations/2012/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf).

[13] There are two alternative cases under consideration in PUCT Project 40268, both with lower price caps. See "Proposal for Publication of Amendments to §25.505" (http://www.puc.state.tx.us/industry/projects/rules/40268/40268pub.pdf). By testing the highest price caps, we establish an upper boundary.

[14] See PUCT document "Proposal for Publication of Amendments to §25.505" (http://www.puc.state.tx.us/industry/projects/rules/40268/40268pub.pdf).

We use AURORAxmp, an economic dispatch model, to run these scenarios on an hourly basis from January 1, 2012 until December 31, 2025. We first calibrated the model to reproduce 2011 conditions. In August 2011, there were reportedly 20 hours in which the price cap of $3,000/MWh was reached. When running the model in the 2011 scenario, price spikes are seen in August in a total of 19 hours. The model also yields fairly close estimates for actual observed reserve margin and wholesale prices in 2011. The model yields a reserve margin of 6.7% for the peak in August 2011 as compared to 7% we calculated for the actual peak on August 3, 2011. The model's average wholesale price for 2011 is $45/MWh as compared to $53/MWh in the actual market; but note that we did not incorporate the February peak of 2011 (Figure 3) and that the model average is significantly higher than $39/MWh in 2010, reflecting the summer 2011 conditions. Hence, we feel confident of the model's robustness to capture ERCOT market developments as accurately as possible over an extended period of more than ten years.[15]

Figure 4. Natural gas price through 2025 ($/MMBtu)



Source: Annual Energy Outlook 2011, Energy Information Administration

Retirements, new builds, net capacity additions

Since the model is based on economic dispatch, it is also reporting the retirement of units that will not be competitive going forward (Figure 5). Between 2013 and 2023, there will be about 11 GW of retirements under the $3,000 scenario as compared to 8.8 GW under the $9,000 scenario. It seems that some units will find it profitable to operate when scarcity prices are higher.

About 1 GW of additional new generation capacity is expected to be built under the $3,000 scenario relative to the $9,000 scenario (26 GW versus 25 GW) between 2013 and 2023 (Figure 6). This may appear counter-intuitive but note that this additional new capacity is not sufficient to compensate for the additional retirements expected under the $3,000 scenario (2.2 GW). Also important to note that more combined cycle capacity will be built under the $9,000 case (17.2 GW versus 16.4 GW) – see next section below for more.

[15] As an additional check on model robustness, we ran two alternative scenarios: $1,000/MWh and $13,000/MWh price caps. All results are directionally consistent with results reported in this paper, increasing our confidence in the model outputs.

Figure 5. Retirements (MW)

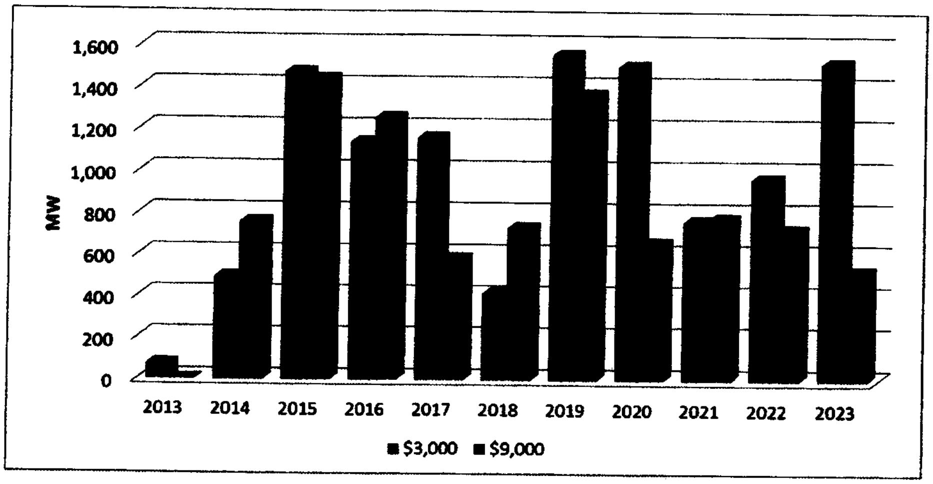
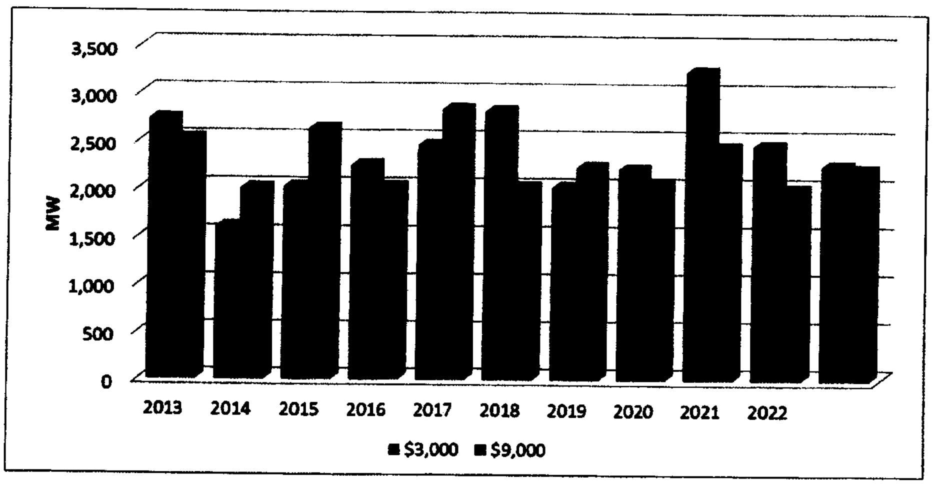
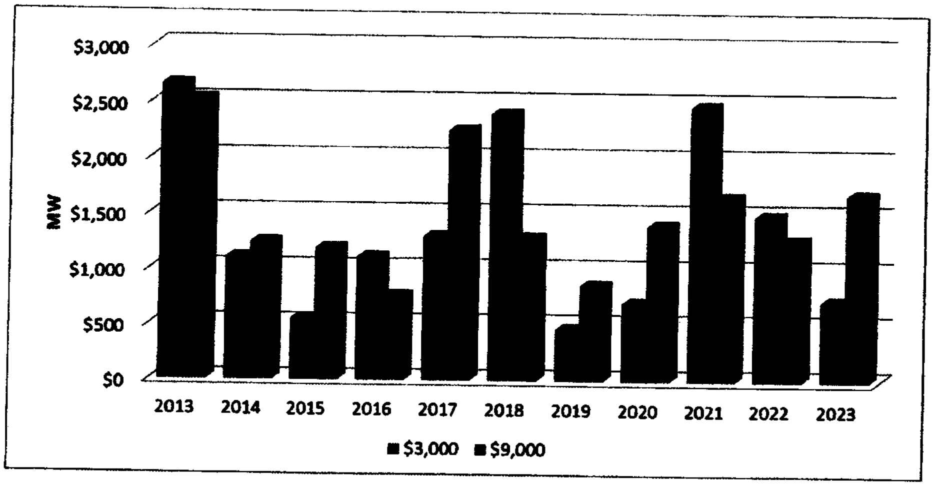


Figure 6. New generation capacity (MW)



We can expect 1,160 MW of net capacity additions under the higher price cap scenario (Figure 7). Although there are fluctuations from year to year, the higher price caps will lead to more new builds in the near future (Figure 6); between 2013 and 2017, an additional 1,000 MW is expected to be built under the $9,000 scenario relative to the $3,000 scenario. Between 2013 and 2015, there would be 640 MW of additional net capacity builds under the increased price cap scenario. Overall, we determine that the price cap increase would lead to a 15% increase in net capacity in the short run (2013-2015) and almost 8% increase in the long run (2013-2023).

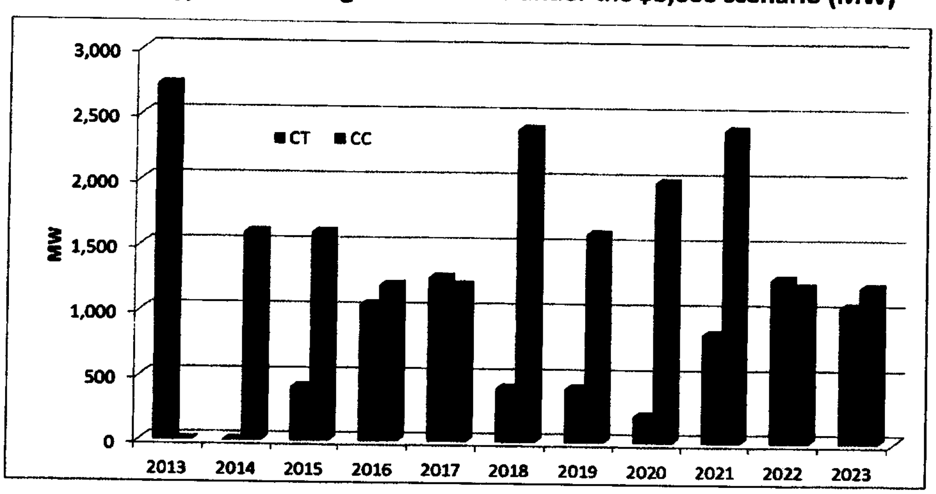
Figure 7. Net capacity additions (MW)



Type of new builds

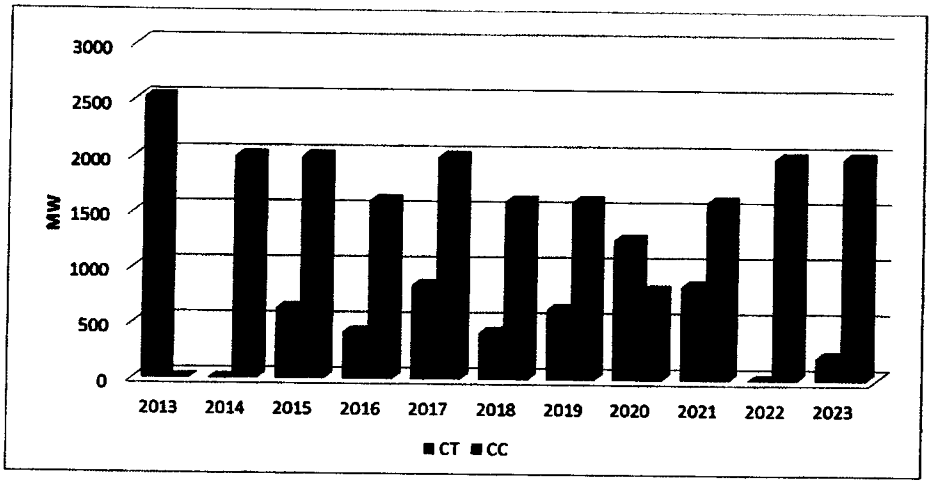
All of the capacity builds are natural gas plants.[16] Combustion turbine (CT) plants appear immediately in 2013 under both scenarios. In both instances, the capacity of CTs built in the first year exceeds 2,500 MW. The current issue with the ERCOT grid resides in meeting load during summer peak hours; it is not surprising that CTs are built first to address this market need since advanced CT plants are cheaper than advanced combined cycle (CC) plants to build and operate.[17] However, there will be significantly more CC capacity built in the long-run to replace retiring units and to meet growing market demand not just peak demand.

Figure 8. Type of natural gas new builds under the $3,000 scenario (MW)



[16] We are not assuming any incentive programs for renewables such as production or investment tax credits; nor do we assume any significant improvements in costs of renewables.
[17] See *Updated Capital Cost Estimates for Electricity Generation Plants*, November 2010 (http://www.eia.gov/oiaf/beck_plantcosts/index.html).

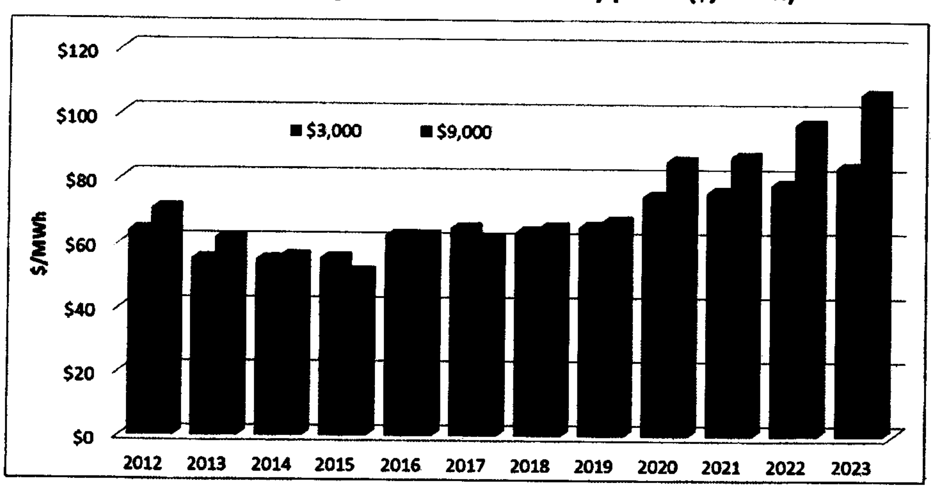
Figure 9. Type of natural gas new builds under the $9,000 scenario (MW)



Impact on average prices

One of the concerns about raising the price cap is the impact on wholesale (and, indirectly, retail) electricity prices; many are concerned that consumers will end up paying higher prices for their electricity. For the same number of scarcity events, the higher price caps will lead to higher average prices; but it is also possible that there will be a larger number of scarcity periods going forward, at least in some years, under the $3,000 scenario since there may not be enough new builds to increase the reserve margin. There seems to be a couple of years in our model runs that are consistent with this latter interpretation: the average wholesale price is higher under the $3,000 scenario in 2015 and 2017 (**Error! Not a valid bookmark self-reference.**). Note that in these two years net capacity additions under the $3,000 case are significantly less than those in the $9,000 case (Figure 7).

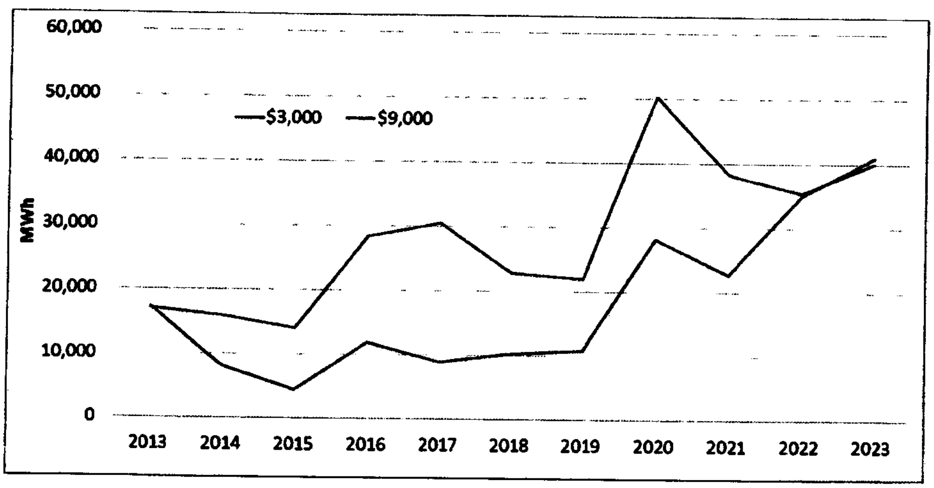
Figure 10. Average wholesale electricity prices ($/MWh)



For other years, however, the average wholesale electricity price is higher under the $9,000 scenario (except for 2016, when prices of two scenarios are basically equal). The average increase in wholesale prices due to increasing energy price cap is about 9% between 2012 and 2023; but the range is wide: the average wholesale price under the $9,000 scenario is 27% higher than the average wholesale price under the $3,000 scenario in 2023 but it is 7.8% lower in 2015. Note that the model seems to be picking up the increased price cap of $4,500 to be implemented starting in August 1, 2012 with the average price being almost 11% higher; the further increase to $5,000 in the summer of 2013 also seems to have a relatively significant impact (close to 12% higher). Remember, however, that we are assuming summer 2011 as our baseline, which is likely to increase the number of scarcity events going forward. Such extreme weather conditions are not expected to repeat every year; as such, the 9% increase in average wholesale price should be seen as the maximum possible increase due to the rise of energy price caps. Also worth noting is that the natural gas price increases only about 50 cents over eight years from $4.50/MMBtu in 2012 to $5.00/MMBtu in 2020; but picks up speed and rises 60 cents in three years to $5.60/MMBtu in 2023 (the gap between the $9,000 scenario prices and $3,000 scenario prices is highest in the 2020-23 period).

The model does not provide results on retail prices but given the competitive market in ERCOT, we can speculate that retailers may not be able to pass on these wholesale price increases to customers fully or quickly; for example, long-term contracts with fixed rates may offer customers some protection. On the other hand, higher price caps may increase credit requirements for retail electricity providers (REPs) and would necessitate better price risk management practices by REPs. Long-term contracts with customers, especially those with fixed prices, may become too costly to maintain for some REPs. These risks to REPs need to be monitored.

Figure 11. Demand curtailment (MWh)



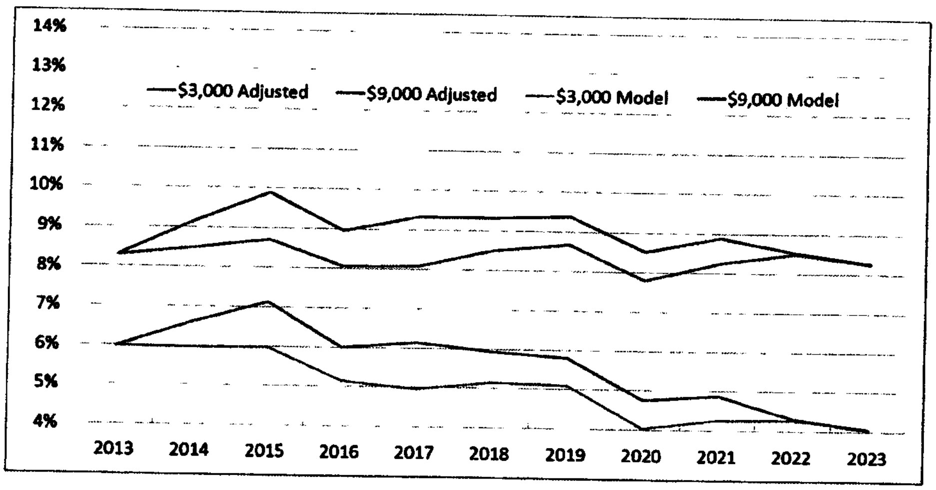
Demand curtailment

The model indicates that there will more demand curtailed under the $3,000 case for most of the time period under analysis; total MWh curtailed in each year under the two scenarios are reported in Figure 11. In many years, curtailment occurs only in peak hours of August and in some years it occurs in July and August. Electricity consumption in the ERCOT market was 335,000,000 MWh in 2011 and will grow going forward; curtailment amounts represent a small percentage of the load. Peak curtailment ranges between 2,444 MW in 2015 and 3,697 MW in 2020 in the $3,000 case; and 1,634 MW in 2015 and 3,656 MW in 2023 in the $9,000 case. Although not a perfect comparison, note that demand curtailment figures are higher than ERCOT CDR load response assumptions in all years of the $3,000 case. In contrast, except for 2013 and 2014, the $9,000 case demand curtailment estimates and ERCOT CDR load response assumptions are mostly within 10% of each other.

Impact on the actual peak reserve margin

The desired benefit of increasing the price cap is to ensure resource adequacy. In Figure 12, we report two sets of reserve margins: those reported by the "model" and those "adjusted" by the load response figures assumed in ERCOT CDR to approximate CDR's "firm load" figures.[18] Overall, the adjusted peak reserve margins are higher under the higher price cap scenario except for three years (2013, 2022 and 2023) but the enhancement is not large: the 2013-2023 average adjusted reserve margin rises from 8.3% under the $3,000 cap to 9% under the $9,000 price cap.[19] There are years when improvements are more significant. For example, in 2015 and 2017, the difference is about 1.2%; 8.7% versus 9.9% in 2015, and 8.1% versus 9.3% in 2017.

Figure 12. Actual peak reserve margins from the model



Our work suggests that the price cap increase will help raise the reserve margin; but also that it will not be enough to achieve the ERCOT target reserve margin of 13.75%. However, the model does not indicate significant demand curtailment (relative to total demand) but the amounts curtailed may be sufficient to maintain a reserve margin of around 9% that could be economically efficient. Perhaps, a revisiting of the target reserve margin based on VOLL and cost of ancillary services used to meet reliability goals could be useful. We will explore the role of demand response, optimal values for it and reserve margin from an economic perspective in future analysis.

[18] We extrapolate 2023 since ERCOT CDR estimates end with 2022. We implement this adjustment because the model reserve margin is based on the actual peak demand, which is calculated based on our assumption of 2011 summer peak as baseline and 2% annual growth, and actual peak capacity, which is calculated based on the economic dispatch algorithms of the model. Neither one includes demand response figures. Demand curtailment figures reported above are not appropriate because they represent all curtailment in addition to DR. In future analysis, we will try to incorporate DR scenarios into the model setup.

[19] The actual observed reserve margin on August 3, 2011 was 7%. Also, these numbers can be compared to 6% ($3,000) and 10% ($9,000) estimates reported in page 3 of the "ERCOT Resource Adequacy Review" by the Brattle Group (http://www.ercot.com/content/news/presentations/2012/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf).

Conclusions and Further Research

Through this exercise, we have tried to quantify the effects of the proposed PUCT policy to raise the price ceiling by examining the increase in new builds, the average price of wholesale electricity and the peak reserve margin. The proposal to raise price caps has an impact on new capacity builds in the near future (13% increase in 2013-15); net capacity additions (after retirements) are 15% higher during the 2013-15 period and 8% higher in the long-run under the $9,000 scenario. Although still lower than the target reserve margin of 13.75%, the "adjusted" peak reserve margins are higher under the $9,000 case with an average of 9%, which is also higher than the August 2011 actual observed reserve margin of 7%.

Wholesale electricity prices rise about 9% on average between 2012 and 2023 although there will be years when the average wholesale price is lower under the $9,000 price cap scenario. Nevertheless, given that there is already criticism of the competitive market and the proposed increase in price caps on the basis of higher energy costs, it is important to communicate clearly the benefits of reliability improvements that can be achieved by higher scarcity pricing and that the proposed levels may not be sufficient subject to definition of reliability, which also needs to be clearly communicated. During times of changes, regulatory certainty is even a more important signal to investors and lenders.

Demand response is an important part of reliability considerations, which does not seem to have received enough attention; we will evaluate the value of securing different levels of demand response in terms of grid reliability. Demand curtailment estimates from the current runs, and in particular, the comparison of the amounts between the two scenarios provide a sense of what value the consumers might assign to demand response services. We also plan to run the model imposing the 13.75% target reserve margin as a mandate; the results from this run should be informative about the cost of achieving that target. Comparing results from demand response runs and mandated 13.75% reserve margin will help us improve our understanding of consumers' willingness to participate in demand response programs at different price levels.

Finally, it is important to recognize that competitive electricity markets such as that in ERCOT are complex; and that energy and environmental policies that can impact these markets are numerous and inherently unpredictable. For these reasons, this analysis provides a gauge for the expected results, but should not be considered a forecast. The changes to the price cap will not occur in isolation of other developments such as environmental regulations, changes in fuel prices, and renewables policies. In a previous paper, we evaluated the combined impact of EPA CSAPR, EPA MATS, natural gas price volatility, renewables subsidies, and a CO_2 penalty. We also plan to incorporate changes in cost structure of generation technologies, especially for solar which is expected to decline. In future analyses, we will evaluate the impact of proposed price cap changes, demand response and mandated 13.75% reserve margin in a more complete setting that takes into account all of these factors.