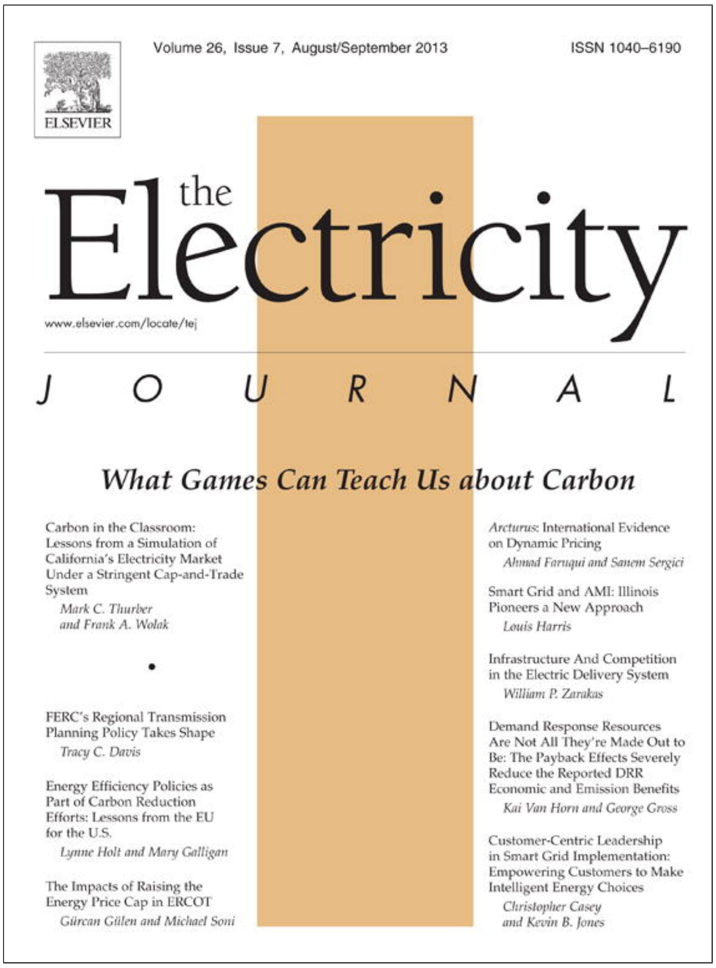

Volume 26, Issue 7, August/September 2013 ISSN 1040–6190

ELSEVIER

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What Games Can Teach Us about Carbon

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The work discussed in this article was supported by funding from BEG's State of Texas Advanced Oil & Gas Resource Recovery (STARR) program, a revenue-neutral initiative. STARR support for energy economics research at BEG is under direction of principle investigator Dr. Michelle Michot Foss, CEE program manager. The authors thank David Bellman for his advice and EPIS staff for its assistance with the model details, but note that all remaining errors are solely theirs.

The Impacts of Raising the Energy Price Cap in ERCOT

In order to ensure resource adequacy, the Public Utility Commission of Texas raised the energy price cap from $3,000 per MWh to $4,500 starting Aug. 1, 2012, and decided to gradually increase it to $9,000 by 2015. An economic dispatch model is used to evaluate the impacts of the price cap increase.

Gürcan Gülen and Michael Soni

I. Problem Statement

After the summer heat wave in 2011 forced the Electricity Reliability Council of Texas (ERCOT) to declare energy emergency alerts (EEA) in order to meet system demand, 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 summers of above-normal temperatures becoming the norm. The ERCOT region experienced one of the hottest summers in history, setting records in August 2011 (**Figure 1**), but these extreme conditions are often seen as one-in-100-years types of occurrences based on historical weather data.[1]

Demand for electricity has been growing fast along with the population and economy of Texas; total consumption of electricity in Texas has grown about 1.5 percent per year on average over the past decade. More importantly, peak demand has increased more than 10 GW between 2002 and 2012 but net operational capacity declined by over 7 GW over the same time period (**Figure 2**). Electricity prices reflected the tight

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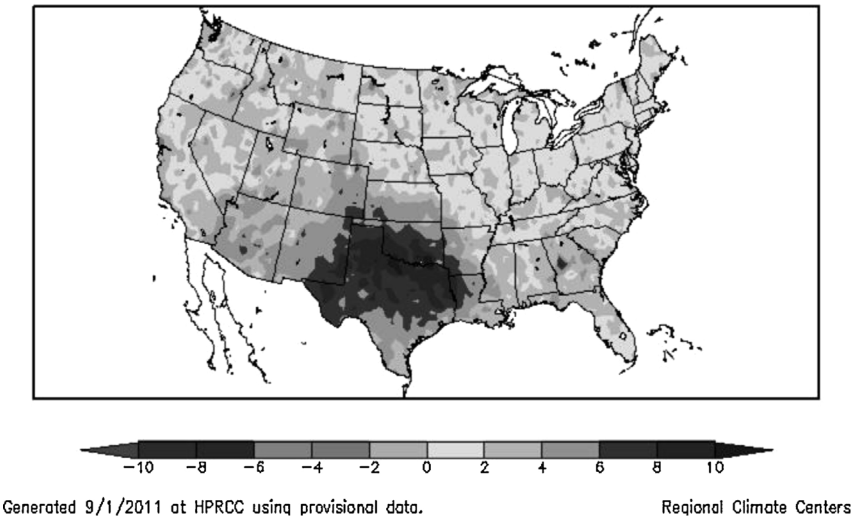

Figure 1: Departure from Normal Temperature (F) 8/2/2011–8/31/2011
Source: National Weather Service.

conditions in the market, hitting the $3,000 price cap for 17 hours during August 2011[2] and averaging, in load-weighted terms, about $160/MWh in August 2011 as compared to the annual average of $53/MWh (**Figure 3**). Not load-weighted, the average price in August 2011 was about $127/MWh. Historically, electricity and natural gas prices have been highly correlated in the ERCOT market (0.95 for the 2002–2012 period in Figure 2), which kept the margins of gas-plant operators tight in the environment of lower gas prices since late 2008. This correlation was broken in 2011 mainly due to high prices caused by extreme weather in February and August 2011 but was re-established in 2012 in the absence of such extreme weather events.

Industry analysts have concentrated on several factors that could explain generation investment falling behind demand growth. Low natural gas prices leading to low electricity prices may have squeezed profit margins; although a benefit of competition for consumers, this squeeze also hurt annual revenues for generators. In addition, the low level of price caps in an energy-only market combined with the infrequency of scarcity periods did not allow for sufficient revenue generation during

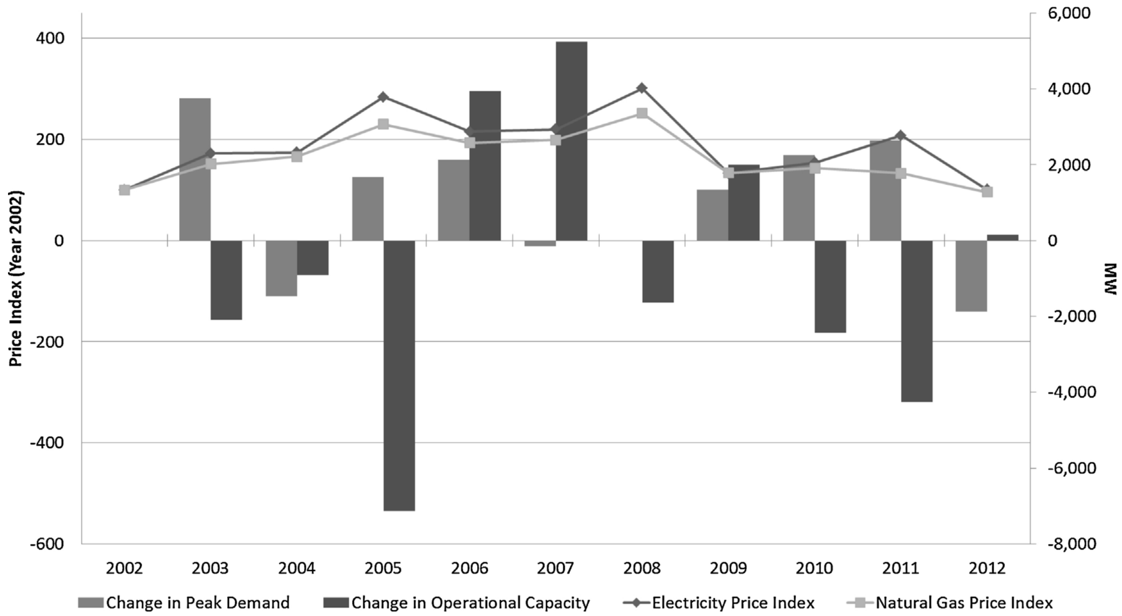

Figure 2: Year-on-Year Changes in Peak Demand and Net Operational Capacity; and Natural Gas and Electricity Price Indexes in ERCOT.
Sources: capacity and demand from EIA Electric Power Annual (January 2013 release) except for 2012 data, which are from ERCOT; price of natural gas delivered to power plants from http://www.eia.gov/dnav/ng/hist/n3045us3a.htm and ERCOT wholesale electricity prices from http://www.potomaceconomics.com/index.php/documents/C6 except for 2012, which is calculated based on the ERCOT hourly data.

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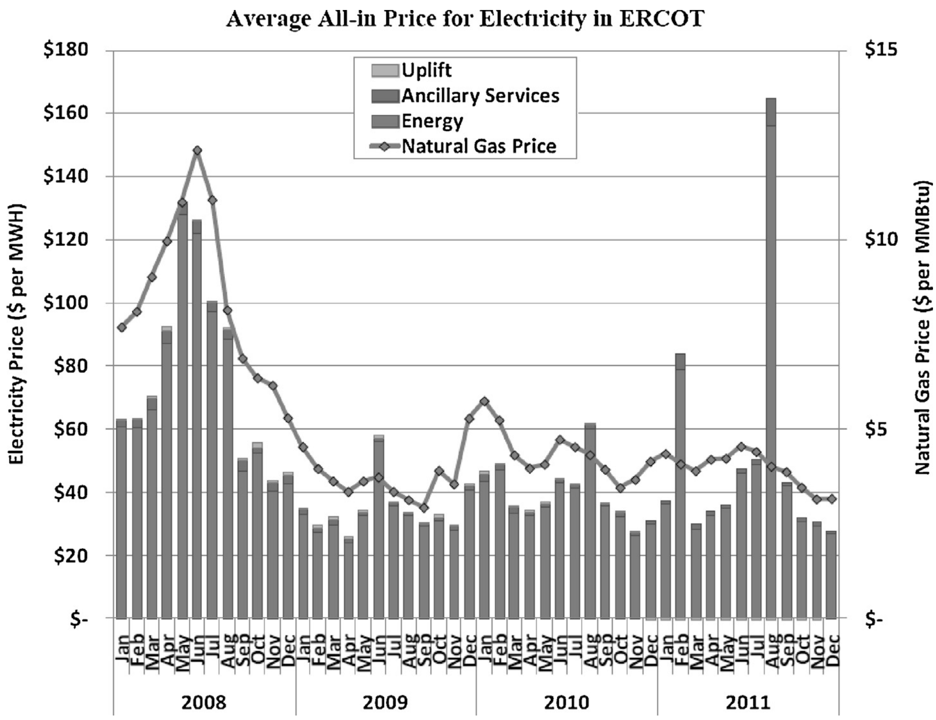

Figure 3: Load-Weighted Electricity Prices in ERCOT, 2008–2011
Source: See page iii in [12].

summer peak hours, except for 2011.[3] Finally, wind energy from West Texas has been supplied to the market at negative prices, mainly in order to collect federal tax credits.[4] The frequency of negative bids has been high since 2007 and might continue at least until the Competitive Renewable Energy Zone (CREZ) transmission lines are completed.

It is also possible that 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 many expected after the 2008 crisis probably surprised both developers and lenders.

Work is under way 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 changes to encourage more supply. The Public Utility Commission of Texas (PUCT) raised the energy price cap (the ''high system-wide offer cap,'' or SWOC, also known as HCAP) from $3,000/MWh to $4,500/MWh[5] starting on Aug. 1, 2012. In October 2012, the Commission approved gradually increasing the system-wide offer cap to $5,000/MWh in 2013, $7,000/MWh in 2014, and $9,000/MWh in 2015.[6] In late 2012, the Commission raised the low system offer cap (LCAP) to $2,000/MWh or 50 times the daily Houston Ship Channel gas price index of the previous business day, and the peaker net margin (PNM) to $300,000 from $175,000.[7] The PNM is the accumulation of 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. Brattle Group [2] concludes that, 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

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to be about three times of CONE to attract investment.[8] If the cumulative PNM reaches $300,000 within a year, then the offer cap is lowered from the HCAP to the LCAP. There have also been changes to ''scarcity pricing threshold'' with ERCOT increasing required amount of responsive reserves and the price floor for dispatch of regulation-up services. All of these changes are targeted to allow scarcity pricing signals to be stronger.[9]

II. Reserve Margin Predictions and History

The electricity industry has generally followed the reliability standard of one loss-of-load event (LOLE) every 10 years, which can lead to prices in the range of $3,000-$20,000/MWh depending on target LOLE and cost of a combustion turbine. Ideally, the price cap should be set at this value of lost load (VOLL). Given ERCOT's interpretation of the reliability standard as one loss-of-load event, which is more stringent than one day in 10 years interpretation used by other entities responsible for grid reliability elsewhere, one generator reported $26,000/MWh[10] for ERCOT. Sener [13] offers $100,000 as implied VOLL but price caps of $15,000 to $20,000/MWh to achieve CONE. Prior to 2011, the LOLE standard led ERCOT to calculate 13.75 percent as the target reserve margin given historical weather and load patterns. The inclusion of 2011 weather indicates an increase in target reserve margin to at least 16 percent to maintain the 1-in-10 criteria [3].[11]

Since 2005, ERCOT has been releasing the *Report on the Capacity, Demand and Reserves in the ERCOT Region* (from here on, CDR), which includes a forecast of the reserve margins in future years. These forecasts are based on demand growth projections and expected resource additions.

The combination of conservative estimates for new generation capacity and the high-demand-growth assumption leads to a forecast of declining reserve margins.

In these annual reports, ERCOT only includes planned units with signed interconnection agreements and in the case of thermal units those with air permits. By definition, these numbers will be conservative.

Demand growth assumptions are often based on high-growth scenarios for the Texas economy. For example, in May 2012 CDR [7], peak load growth was assumed at about 4.4 percent from 2013 to 2014, 4.9 percent from 2014 to 2015, 3.3 percent from 2015 to 2016, and 2.1 percent from 2016 to 2017 before falling below 2 percent based on a high-economic-growth scenario for the Texas economy provided by Moody's.

As a result, the combination of conservative estimates for new generation capacity and the high-demand-growth assumption leads to a forecast of declining reserve margins. However, reserve margins have remained mostly above predictions and above the target of 13.75 percent as more resources came online and/or demand fell short of the peak forecasted, except for 2011 (**Figure 4**).

During the resource adequacy project of the PUCT, several updates were filed. The alternative estimates were based on a lower-demand-growth scenario and/or additional resources (either new or mothballed). The December 2012 CDR [8] report predicts higher reserve margins than the May 2012 CDR report for both of these reasons but still follows a declining trend. In between these two reports, ERCOT filed an update of its May 2012 estimates at the request of the Commission under Project 40000 on Oct. 22, 2012 (Update 1 in Figure 4). This update includes generation additions announced since the release of the May 2012 CDR and assumes the low-growth scenario from Moody's. Commissioner Anderson provides an estimate that includes additional resources and 1,786 MW of mothballed capacity that can return to service in less than six months (Update 2 in Figure 4). Clearly, assumptions about growth scenarios, new and mothballed resources are crucial

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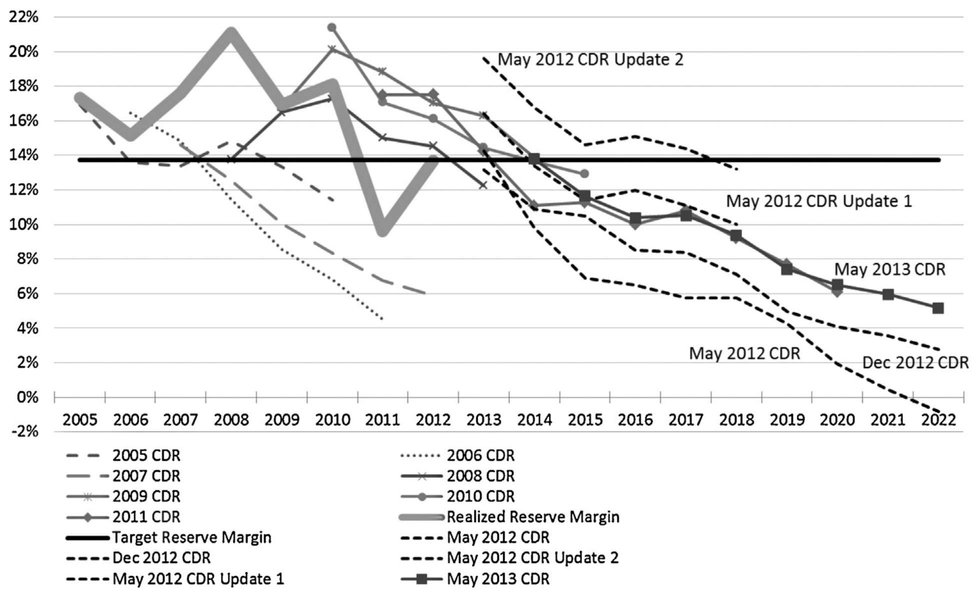

Figure 4: Forecasts of Reserve Margins
All forecasts are from ERCOT's CDR reports except the following: May 2012 CDR Update 1 is done by ERCOT at the request of the Commission to capture additional resources and using Moody's 2011 low-economic-growth forecast (filed under PUCT Project 40000); May 2012 CDR Update 2 is from a presentation by Commissioner Anderson, capturing mothballed units (http://www.puc.texas.gov/agency/about/commissioners/anderson/pp/ANALYSIS_ERCOT_CAPACITY_RESERVE_MARGIN.pdf).

for forecasting future reserve margins. Given the wide range of these estimates, in mid-December 2012 the Commission decided to open a rulemaking on what inputs should go into the CDR Report.[12]

In ERCOT [9], seven additional economic growth scenarios developed by Moody's are evaluated; the low scenario was selected for the long-term demand and energy forecast. The CDRs released in December 2012 and May 2013 use lower-growth scenarios. We use the lower-demand-growth scenario from the December 2012 CDR in our baseline case, and analyze the higher-demand-growth scenario of the May 2012 CDR in an alternative scenario (Figure 5).

The observed reserve margin during the August 2011 peak was 7 percent. The margin would be 9.6 percent if we consider 1,612 MW of load resources (LRS), emergency response service (ERS) and energy efficiency programs to consistently compare to 17.5 percent predicted by ERCOT in May 2011.[13] To secure availability of resources during the summer of 2012, mothballed units were called upon to add nearly 2,000 MW of capacity.[14] In contrast to 2011, the 2012 summer was milder than feared and the ERCOT grid met all summer demand without the need of any emergency procedures.[15] As a result, ERCOT decided that several units did not need to be classified as RMR and could consequently be mothballed or retired.[16] The reserve margin in 2012 was 13.7 percent when 1,577 MW of LRS, ERS and energy efficiency resources from ERCOT [5] are accounted for (Figure 4), and 11 percent without those resources, which is significantly better than it was on Aug. 3, 2011.

Hence, the long-term concerns regarding resource adequacy remain. Under Project 40000, PUCT is considering two main options: (1) enhancements to the energy-only market, including the promotion of demand response to support price cap increases; and (2) establishment of a capacity market. These options are based on a study by The Brattle Group commissioned in early 2012 and feedback to that study and recommendations by market participants.[17]

III. Evaluating the Impact of Higher Price Caps

We evaluate the impacts of increasing price caps on net capacity additions, reserve

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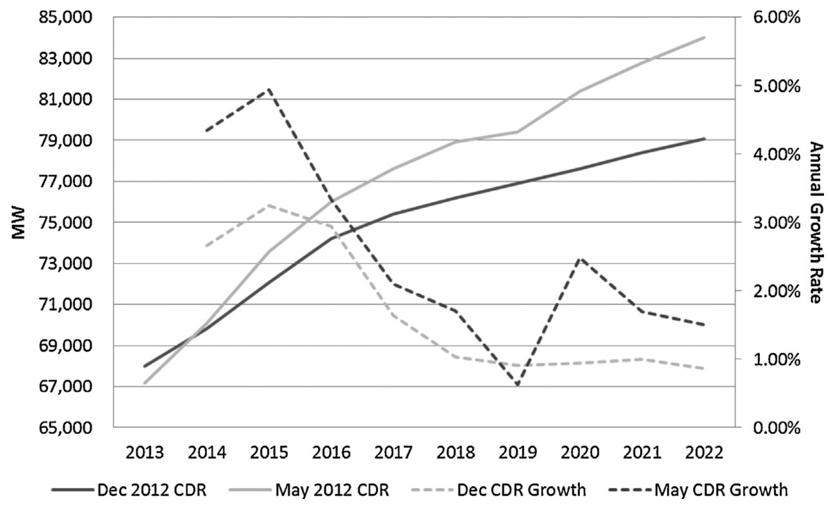

Figure 5: ERCOT Peak Demand Growth Scenarios

margins, average prices, and demand curtailments among other market and reliability indicators. We run two scenarios: the previous price cap ($3,000/MWh), and the future price cap ($9,000/MWh).[18] We do not impose the target reserve margin (13.75 percent) but rather let the model yield actual peak reserve margins under these scenarios. We assume electricity peak demand growth levels of December 2012 CDR. For base load, we assume 1.5 percent annual growth based on the average electricity consumption growth in Texas over the last 10 years. We use the natural gas price forecast from the Annual Energy Outlook 2012 (**Figure 6**). We also evaluate the sensitivity of the results to assuming the higher-demand-growth scenario of the May 2012 CDR and an alternative gas price scenario based on Foss [11], CEE in Figure 6.

We use AURORAxmp, an economic dispatch model, to run these scenarios on an hourly basis. Because 2011 was an extreme year, we first calibrated the model to reproduce the actual 2011 conditions of 17 price cap hits ($3,000/MWh), the monthly wholesale price average of $127/MWh, and the reserve margin of 7 percent in August 2011 (without accounting for LRS, ERS and energy efficiency). The model produced 17 price cap hits, a monthly wholesale price of $122/MWh, and a reserve margin of 6.7 percent in August 2011. Also, the model's average annual wholesale price for 2011 is $41/MWh as compared to $53/MWh in the actual market. The actual wholesale price is higher than the model's price due to the unexpected outage of several generating facilities that occurred during an extremely cold day in February 2011, which led to the price cap being hit six additional times.[19] We do not model this February outage since such winter outages are very infrequent and unpredictable. More importantly, we focus on peak demand growth in summer months as the period of concern for the resource adequacy debate. 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 10 years.

A. Extreme prices

There are more extreme price instances under the lower price cap (**Table 1**). This is likely due to the fact that investors realize more potential revenue under the higher price cap; even when the price cap is not hit, the market experiences prices between $3,000 and $9,000 under the higher-price-cap scenario. Thus, generators are more inclined to

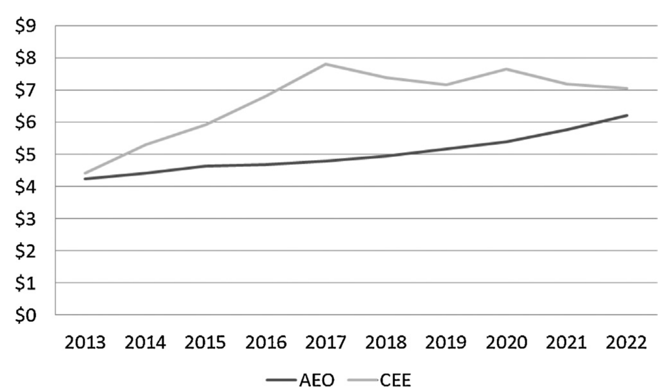

Figure 6: Nominal Natural Gas Price through 2022($/MMBtu)
Source: Annual Energy Outlook 2012, Energy Information Administration.

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Table 1: Extreme Price Hours by Year.

AEO	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
$3,000 Cap	1	–	1	8	2	1	–	–	–	–
$9,000 Cap	–	–	1	2	–	–	–	–	–	–

invest in generation, particularly in the earlier years. Overall, though, there are not many extreme price periods in either case, probably because we are analyzing a low-demand-growth scenario.

B. Retirements, new builds, net capacity additions

Between 2013 and 2022, there will be about 9.6 GW of retirements under the $3,000 scenario and 10 GW of retirements under the $9,000 scenario (**Figure 7**). The retirements pick up in later years because demand growth slows down in that period (Figure 5) and more generation would have been built by then (**Figure 8**).

About 24.2 GW of additional new generation capacity is expected to be built under the $3,000 scenario and roughly 24.8 GW new generation capacity is expected under the $9,000 scenario between 2013 and 2022 (Figure 8).

Through 2022, we can expect 14.8 GW of net capacity additions under the $9,000 scenario and 14.7 GW of net capacity additions under the $3,000 scenario (**Figure 9**). Although there are fluctuations from year to year, the higher price caps will lead to more new builds in the near future (Figure 8); between 2013 and 2016, 8.4 GW is expected to be built under the $9,000 scenario, and 7.3 GW is expected under the $3,000 scenario. When retirements are taken into account, between 2013 and 2016, there would be roughly 740 MW of additional net capacity additions under the $9,000 scenario relative to the $3,000 scenario. When comparing the $9,000 and $3,000 scenarios, we determine that the price cap increase would lead to a 12 percent increase in net capacity in the short run (2013–2016) but only a 1 percent increase in the long run (2013–2022).

C. Type of new builds

Combustion turbine (CT) plants appear immediately in 2013 under both scenarios; close to 1,700 MW of CT capacity is built under the $9,000 case as

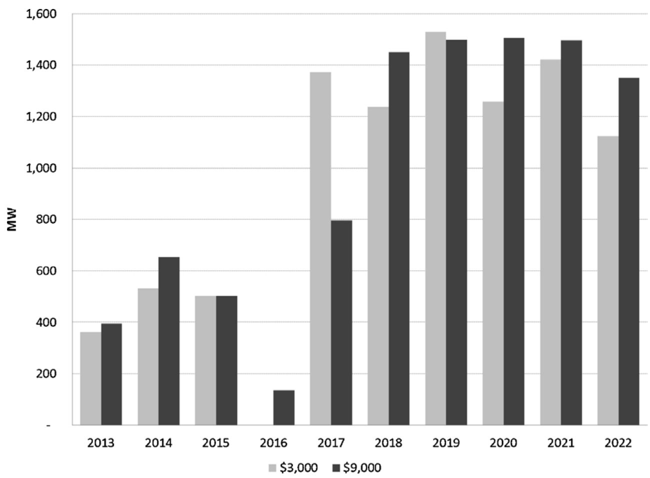

Figure 7: Retirements (MW)

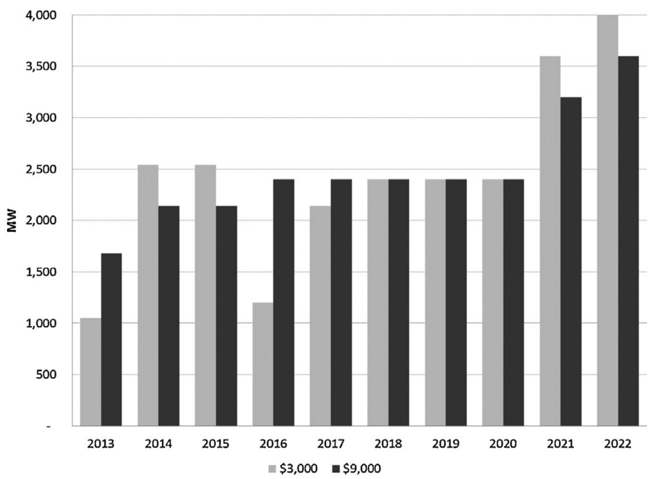

Figure 8: New Generation Capacity (MW)

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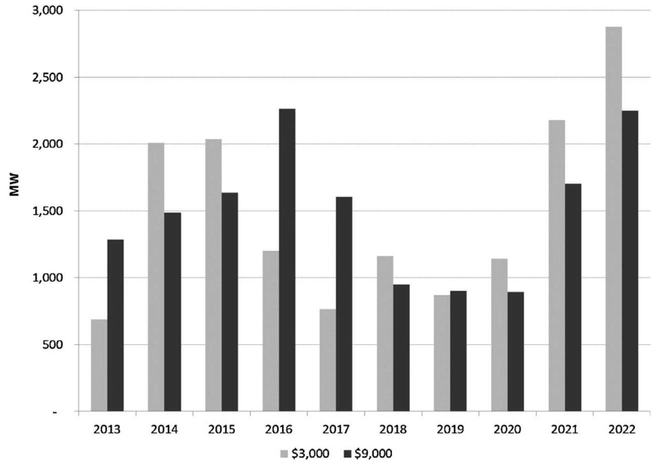

Figure 9: Net Capacity Additions (MW)

compared to about 1,000 MW in the $3,000 case. 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. There will be significantly more CT capacity built in the long run to replace retiring units and to meet growing market demand not just peak demand.

D. Impact on average prices

One of the concerns about raising the price cap is the impact on wholesale (and, indirectly, retail) electricity prices. 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 several years in our model runs that are consistent with this latter interpretation (Table 1). Overall, the average wholesale prices remained roughly the same over the years for both scenarios (**Figure 10**); the 2013–2022 average wholesale electricity price is roughly $49 for both cases. Note that the electricity price is highly correlated with the natural gas price and increases in parallel to the increase in the natural gas price (Figure 6). The model does not provide results on retail prices but given that the average wholesale prices are basically the same in both cases, we can safely assume that raising the price cap will not impact retail prices.

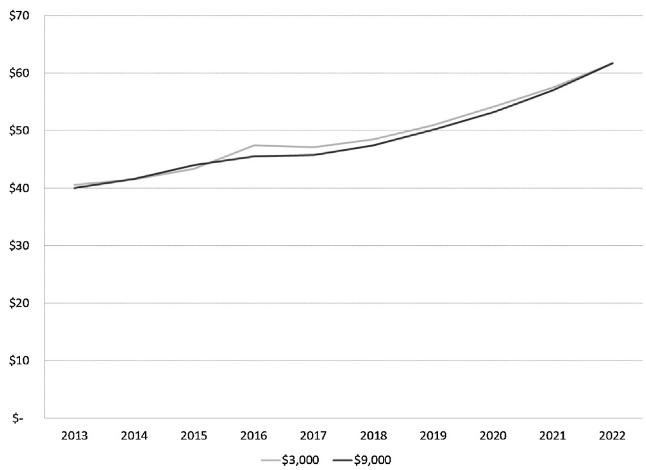

Figure 10: Average Wholesale Electricity Prices ($/MWh)

E. Demand curtailment

The model indicates that the more involuntary demand curtailment will occur under the $3,000 than the $9,000 case; total MWh curtailed in each year under both scenarios are reported in **Figure 11**. The most curtailment occurs in 2016, probably because demand growth was very high in the 2013–2016 period (Figure 5) and net builds were not sufficient to keep up with it (Figure 9). Nevertheless, curtailment amounts represent a very small percentage of the load; electricity consumption in the ERCOT market was 335,000,000 MWh in 2011 and will grow going forward.

F. Reserve margin

Overall, the peak reserve margins are higher under the $9,000 price cap for almost every year during the 2013–2022 period. The average reserve margins (adjusted for LRS, ERS and energy efficiency from CDR to compare with ERCOT CDR forecasts) are 13.0 percent under the $3,000 cap

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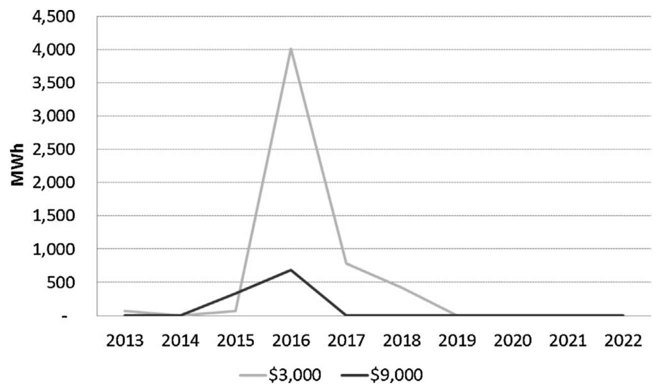

Figure 11: Total Demand Curtailment (MWh)

and 14.1 percent under the $9,000 cap. Without adjustments, reserve margins would average 8.8 percent and 9.8 percent for the $3,000 and $9,000 cases, respectively. These numbers can be compared to 6 percent ($3,000) and 10 percent ($9,000) estimates reported in page 3 of Brattle Group [2]. It is noteworthy that our estimates for the 2014–2016 period overlap with ERCOT [10]; the model continues to build new capacity afterwards, leading to higher reserve margins than ERCOT [10], which can only count new capacity with interconnection agreements and air permits (Figure 12).

Overall, our modeling exercise suggests that the price cap increase will help raise the reserve margin by an average of 1 percent over the long term without much impact on the average prices while eliminating most of involuntary demand curtailment, which is not large even in the $3,000 case. However, this analysis is based on a docile natural gas price path and low-demand-growth assumptions. It would be beneficial to evaluate the sensitivity of the results to changing some of these assumptions.

IV. Alternative Scenarios

We ran a combination of other scenarios using higher demand growth from the May 2012 CDR and a different natural gas price scenario (CEE) (Table 2). The AEO scenario is our base case discussed above.

The number of extreme price hours under each scenario can be seen in Table 3. In general, over the course of the next 10 years, the model does not yield too many extreme prices. The lack of extreme prices explains the low differentiation in wholesale average prices under each cap. If prices are only reaching the cap a couple of times per year, we would expect the yearly wholesale prices to be roughly the same over the long term. The AEO natural gas price scenarios seem to experience more extreme price instances than the CEE cases; a possible explanation is that higher natural gas prices in the CEE scenario allow for higher electricity prices and revenues for generators in the shorter term.

The net capacity additions of each scenario and price cap are compared in Figure 13. In each case, the increased price cap leads to more net builds. The higher demand scenarios experience substantially more net builds to keep up with demand; the AEO high demand scenario saw an 11 percent increase in the $3,000 case and a 12 percent increase in the $9,000 case in comparison to the AEO baseline

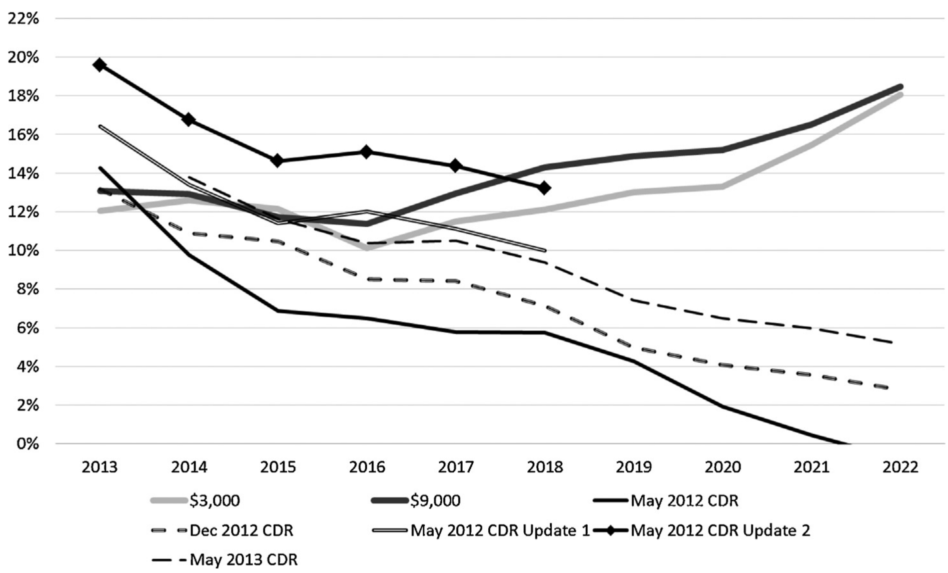

Figure 12: Actual Peak Reserve Margins from the Model

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Table 2: Higher-Demand-Growth Scenarios.

Scenario	Natural Gas Price	Demand Growth
AEO	AEO 2012	ERCOT Low Demand
AEOHD	AEO 2012	ERCOT High Demand
CEE	CEE*	ERCOT Low Demand
CEEHD	CEE	ERCOT High Demand

* Based on Foss [11].

Table 3: Extreme Price Hours under All Scenarios.

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
AEO	$3,000 Cap	1	–	1	8	2	1	–	–	–	–	13
	$9,000 Cap	–	–	1	2	–	–	–	–	–	–	3
AEOHD	$3,000 Cap	–	–	4	3	2	2	2	2	1	–	16
	$9,000 Cap	–	–	1	1	1	2	1	2	1	–	9
CEE	$3,000 Cap	1	–	1	2	–	–	–	–	–	–	4
	$9,000 Cap	1	–	1	3	–	–	–	–	–	–	5
CEEHD	$3,000 Cap	–	–	3	2	2	–	–	1	1	–	9
	$9,000 Cap	–	–	1	–	–	–	–	–	–	–	1

scenario. Likewise, the CEE high demand scenario also had more net builds than its lower demand counterpart, with a 14 percent increase in both the $3,000 and $9,000 cap.

The average yearly wholesale prices are shown below for each scenario under the two cases (Figures 14 and 15). Over the long run, the wholesale prices of the AEO and AEOHD scenarios are nearly identical; the same observation is made between the CEE and CEEHD scenarios. However, the prices between the AEO natural gas scenarios and the CEE scenarios are widely different. Given the high correlation between electricity and natural gas prices, CEE scenarios lead to higher prices. Overall, the CEE scenario saw an increase of 29 percent in the $3,000 case and a 31 percent increase in the $9,000 case as compared to the AEO scenario. The CEEHD scenario experienced a 29 percent increase in the $3,000 case and a 26 percent increase in the $9,000 case.

Reserve margins for each scenario under both price caps are displayed Figures 16 and 17. Under each of the four scenarios, the average reserve margin increased when the price cap was raised to $9,000, sometimes by more than a percentage point. Under the $3,000 and $9,000 cases, the lower-demand-growth scenarios both have significantly higher reserve margins, particularly after 2019; as demand growth slows in the later years, reserve margins reach 18 percent. One might question

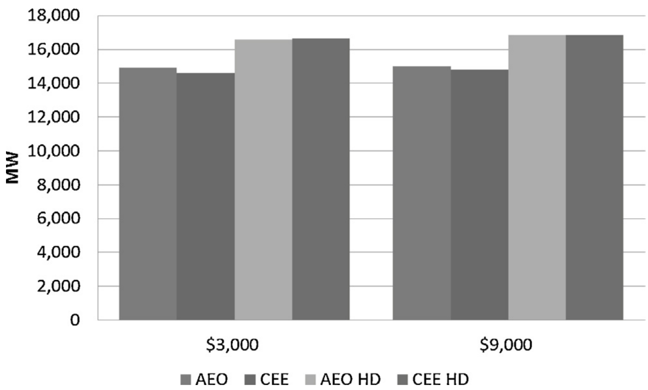

Figure 13: Net Capacity Additions (2013–2022)

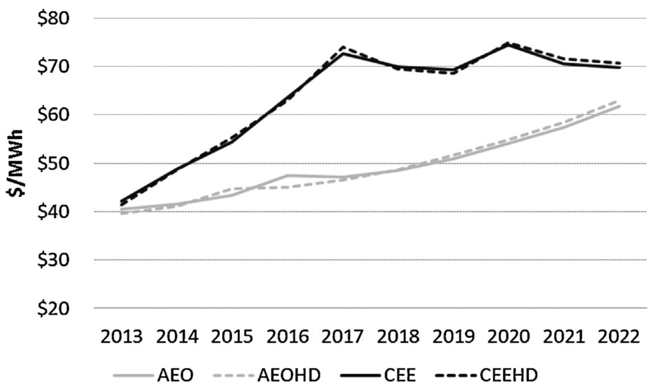

Figure 14: $3,000 Cap Wholesale Price

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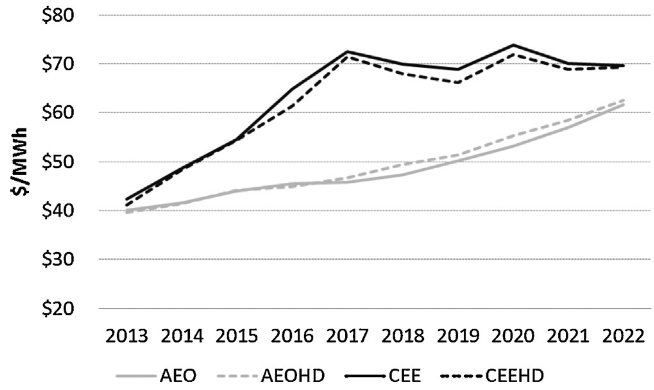

Figure 15: $9,000 Cap Wholesale Price

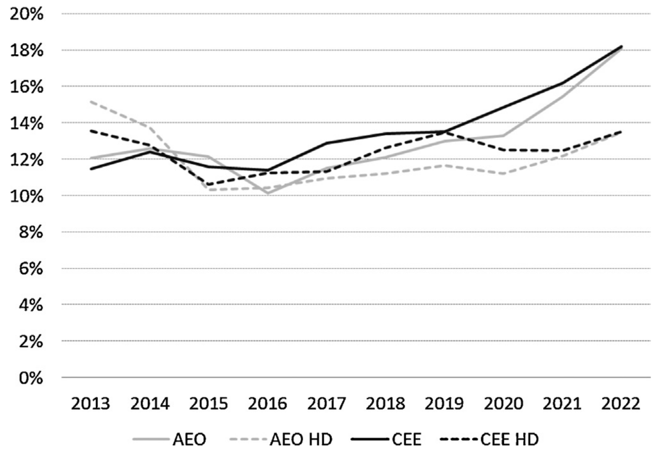

Figure 16: $3,000 Cap Reserve Margin

why the reserve margins initially are higher in the higher-demand-growth scenarios; this is because in the December 2012 CDR (low demand growth), demand is forecasted to be higher in the preliminary years, before slowing down relative to the May 2012 CDR (high demand growth) forecast.

V. Conclusions

We estimate the effects of increasing the price cap, or SWOC, to $9,000 from $3,000/MWh in ERCOT's energy-only market. Importantly, in our base case, we assume the demand growth scenario from ERCOT [9] rather than the higher-demand-growth scenario used in ERCOT [7]. Our modeling exercise suggests that the price cap increase will help raise the reserve margin by an average of 1 percent over the long term from 13 percent to 14 percent if one takes into account LRS, ERS, and energy efficiency services accounted for in ERCOT CDR reports. This increase would be sufficient to meet the current target reserve margin on average over the next 10 years, albeit not every year; but the 10-year average reserve margins would be less than 16 percent or higher that is implied in ECCO International [3], which takes into account 2011 summer weather. The raising of the price cap would not have much impact on the average prices and would eliminate most of involuntary demand curtailment, which is not large even in the $3,000 case. Assuming higher demand growth leads to a slightly higher average price, but this effect is not visible under a higher-natural-gas-price path scenario. There is more demand curtailment and reserve margins are lower on average with higher demand growth unless the natural gas price also follows a higher price path, in which case $9,000 leads to an average reserve margin of 14.7 percent, the highest level in all of our scenarios.■

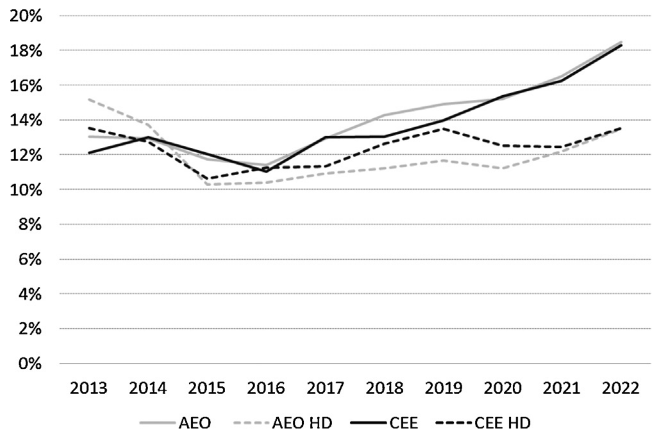

Figure 17: $9,000 Cap Reserve Margin

  http://dx.doi.org/10.1016/j.tej.2013.07.002

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Endnotes:

1. See U.S. Experiences Second Warmest Summer on Record; Texas Has Warmest Summer on Record of Any State, Press Release, National Oceanic and Atmospheric Administration (NOAA), at http://www.noaanews.noaa.gov/stories 2011/20110908_auguststats.html.

2. Potomac Economics [12], vii.

3. *Id.*, at xxii.

4. See Baldick [1].

5. Similar price/offer cap ($4,500/MW) also applies on capacity obtained for ancillary services.

6. See http://www.puc.texas.gov/industry/projects/rules/40268/40268adt.pdf.

7. See http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.505/25.505.pdf.

8. Brattle Group [2] at 82.

9. See Sener [13] for a more detailed discussion of these and other changes.

10. Heard by the authors at the GCPA Fall Conference in Austin, TX, Oct. 2–3, 2012.

11. Also, the authors use higher effective load carrying capability (ELCC) ratios for wind (14.2 percent for the West, 32.9 percent for Coastal relative to 12.2 percent from the 2010 loss-of-load analysis); and state that the target reserve margin would fall to 15.3 percent if they were to use 12.2 percent for ELCC.

12. Project No. 41060: Proceeding to Examine the Inputs Included in the ERCOT Capacity, Demand and Reserves Report.

13. See ERCOT [4].

14. See ERCOT [6].

15. See presentation by Commissioner Anderson at the Gulf Coast Power Association Fall Conference on Oct. 2, 2012, at http://www.puc.texas.gov/agency/about/commissioners/anderson/pp/GCPA_100212.pdf).

16. These changes can be seen on page 6 of ERCOT [9].

17. See Brattle Group [2] and filings under Project 40000.

18. Note that we ignore the transition period with intermediate price caps and assume $9,000 price cap to become active in 2013 in order to capture full impact of price cap changes in the long term.

19. Potomac Economics [12] at 15.

 1040-6190/$–see front matter http://dx.doi.org/10.1016/j.tej.2013.07.002