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Scenarios of Resource Adequacy in ERCOT: Mandated Reserve Margin, Impact of Environmental Regulations and Integration of Renewables

Among four different scenarios that were evaluated relative to a reference case using an economic dispatch model, the one mandating a 13.75 percent reserve margin leads to the lowest average wholesale price of electricity, even with the estimated cost of capacity payments added. However, design details of a capacity market can certainly lead to higher prices and inadequate capacity at times. The environmental regulations cause significant retirements and uncertainty in the market, resulting in low reserve margins and high prices. If all built, planned renewables capacity will help resource adequacy, especially if peak contribution improves.

Gürcan Gülen and David K. Bellman

I. Introduction

In order to ensure resource adequacy in the ERCOT market, the energy price cap is being raised gradually from $3,000/MWh to $9,000/MWh by 2015.[1] Gülen and Soni (2013) discuss the concerns about development of new generation capacity falling

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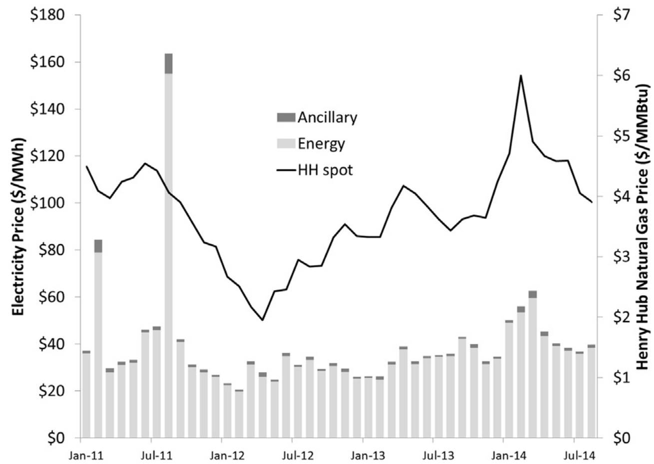

Figure 1: Average Price of Electricity in ERCOT
Source: On the basis of data from Independent Market Monitor reports.

behind the growing demand and market design changes under consideration to address the resource adequacy issue; and evaluate the impacts of raising the price cap. Some of the changes might already be working, as the ERCOT experienced significantly fewer tight market conditions in each of 2012, 2013, and 2014, as evidenced by much lower average prices than in 2011 (Figure 1). Despite low natural gas prices (roughly $4/MMBtu), the electricity price averaged $48/MWh in 2011 owing to spikes in February and August. Low natural gas prices ($2.75/MMBtu) and a mild summer led to an average electricity price of $28/MWh in 2012. The recovery in the price of natural gas to $3.73/MMBtu in 2013 pushed the average electricity price to above $33/MWh in 2013 despite another mild summer. In the first eight months of 2014, the Henry Hub price averaged $4.68/MMBtu and the ERCOT average electricity price followed an upward path to $44.5/MWh. Excluding the price spike of August 2011, the correlation between the natural gas price and ERCOT electricity price is high at 0.8.

The resource adequacy concerns in ERCOT are temporarily eased partially owing to low electricity prices, which can primarily be explained by low natural gas prices and mild summers. However, these low prices could undermine incentives to build new generation capacity in ERCOT's energy-only market. With load expected to grow, the fundamentals for resource adequacy remain at a delicate balance. At the same time, the evaluation criteria are evolving. Newell et al. (2014) estimate the economically optimal reserve margin in ERCOT as 10.2 percent and ERCOT has been revising its demand forecast downward, leading to reserve margins in excess of 16 percent until 2018 in some studies.[2] ERCOT (2014) predictions are significantly lower but still higher than the target 13.75 percent between 2014 and 2017.

In this article, we simulate the impact of mandating the current target reserve margin of 13.75 percent. However, the resource adequacy should not be discussed in a vacuum. There are several Environmental Protection Agency (EPA) regulations that could force some plants to retire (especially older coal and simple-cycle gas units) and/or influence the dispatch order. Accordingly, we also evaluate the impacts of new environmental regulations. There is also a large amount of renewables projects, especially wind, either under construction or scheduled to be built by 2017. The model does not build as much renewable capacity (especially wind) despite providing credits. Accordingly, in one scenario, we impose about 8.7 GW of new wind and about 900 MW of new solar capacity between 2014 and 2017 (based on ERCOT (2014) and the SNL database) in order to study their impact on retirements and new builds of other fuels. We believe that these considerations provide a more complete picture of the future market conditions, within which to discuss resource adequacy.

The results from different scenarios should be evaluated relative to the reference case. The absolute MWs of retirements and new builds are on the basis of certain assumptions on demand growth and natural gas prices in addition to more detailed

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operational details in the model. Changes in any combination of these assumptions would lead to different results in terms of MWs; but we keep these foundation assumptions constant across scenarios to focus on relative changes in key metrics such as average reserve margin and average wholesale price across the scenarios.

II. Simulation Description

We evaluate four cases in addition to the reference scenario:

- **Reference** — there are three key assumptions for the reference case: the $9,000/MWh price cap, natural gas price and basis forecasts from IHS and SNL, and ERCOT (2014) demand growth. Also, roughly 2,100 MW of gas-fired, 300 MW of wind, and 150 MW of solar capacity that came online in 2013 or 2014, or is expected to come online in late 2014 or early 2015, are included in the starting resource database.
- **Mandated Reserve Margin (MRM)** — in addition to assumptions in the Reference Case, current target reserve margin of 13.75 percent is imposed on the model as a mandate to force the simulation to delay retirements and/or build new capacity to ensure that reserve margin is maintained around 13.75 percent. This case represents a more regulated structure as simulated capacity payments undermine the relevance of wholesale prices in the competitive market.
- **Regulations** — in addition to assumptions in the Reference case, we assigned to each unit in the ERCOT system the incremental cost of complying with the following EPA regulations: Mercury and Air Toxic Standards (MATS), Cross State Air Pollution Rule (CSAPR) or Clean Air Interstate Rule (CAIR), Clean Water Act Section 316 (b), and Coal Combustion Residuals Disposal. Although these rules have been evolving and CSAPR was stayed by a federal court in 2012 and reinstated by the Supreme Court in 2014, we are testing the case of their implementation and represent the potential retrofit costs using estimates for units operating in ERCOT as provided in ERCOT (2011). The incremental cost for some units is zero, as they are assessed as already complying with these regulations.

The resource adequacy concerns in ERCOT are temporarily eased partially owing to low electricity prices.

- **Renewables** — using data from ERCOT (2014) and SNL, wind and solar capacity that are either under construction or scheduled to come online through 2017 are inputted in the starting resource database. In addition to the capacities hardwired in the Reference case, about 8.4 GW of wind and about 750 MW of solar capacity are added. Despite the fact that the model includes a credit of roughly $28/MWh to represent the benefits of federal tax credits as well as trading of renewable energy certificates, the model does not build as much renewable capacity as in reality, especially in the early years. We have observed this gap in different model runs since late 2011. Many of these facilities are getting built on the basis of long-term power purchase agreements (PPAs) with utilities; there are also some local tax benefits. We believe the inability to incorporate these details into our model is the main reason for the gap.
- **Regulations and Renewables (RR)** — combination of the previous two cases.

We follow peak demand growth levels of ERCOT (2014), which average about 1.3 percent per year between 2015 and 2024 as compared to 1.5 percent in ERCOT (2013). More importantly, the growth is fairly flat in ERCOT (2014) whereas it starts at a faster rate in ERCOT (2013): 3.2 percent from 2014 to 2015 and 2.9 percent from 2015 to 2016.

However, the coincident peak demand and energy demand growth are implemented by weather zone following **Tables 1 and 2**. This regional approach allows us to capture different demand patterns across ERCOT.

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Table 1: ERCOT Weather Zone Coincident Peak Forecast (MW).

	North	North Central	East	Far West	West	South Central	Coast	South	ERCOT
2014	1,546	24,605	2,390	2,430	1,851	11,420	18,341	5,512	68,096
2015	1,536	24,963	2,396	2,551	1,871	11,507	18,533	5,699	69,057
2016	1,526	25,321	2,402	2,672	1,891	11,592	18,725	5,885	70,014
2017	1,516	25,670	2,409	2,791	1,912	11,588	18,916	6,070	70,871
2018	1,507	26,014	2,415	2,910	1,932	11,669	19,108	6,252	71,806
2019	1,497	26,353	2,422	3,029	1,952	11,750	19,424	6,433	72,859
2020	1,487	26,691	2,428	3,148	1,972	11,829	19,617	6,612	73,784
2021	1,477	27,030	2,434	3,266	1,993	11,908	19,809	6,792	74,710
2022	1,468	27,366	2,441	3,385	2,013	11,987	20,001	6,970	75,631
2023	1,458	27,699	2,447	3,503	2,033	12,066	20,194	7,150	76,550
2024	1,449	28,032	2,453	3,622	2,053	12,145	20,387	7,330	77,471

Source: http://www.ercot.com/gridinfo/load/forecast/Docs/Summer_CP_forecast_by_weather_zone_090514.xls (accessed 29.10.14).

For example, the oil and gas industry activities from upstream drilling to gas processing, refining, and petrochemicals are expected to continue to grow and intensify in the next several years, fueling the Texas economy via multiplier effects. A lot of these activities are growing in the Permian Basin (Far West) and Eagle Ford (South). Accordingly, those are the regions where peak demand grows fastest: more than 4 percent in Far West and more than 3 percent in South for next four years, whereas average growth for ERCOT is about 1.3 percent for the same period.

We use the natural gas price forecast from SNL's forward curves (downloaded in June 2014) for the first couple of years of data, and forecasts from IHS Monthly Gas Briefing (June 2014) for the remainder of the time horizon of interest (**Figure 2**). Note that this price outlook is significantly different than the EIA (2014), in which real prices in 2012 dollars increase from \$3.7 in 2015 to \$6.9 in 2035 fairly monotonously. We consider the cyclical forecast a more realistic representation of how demand and supply of natural gas have behaved in the past; the future will likely follow a similar path although an increase in real price might not be ruled out. We use capital and operating cost assumptions from EIA (2013) to decide on new builds. We use

Table 2: ERCOT Weather Zone Energy Forecast (MWh).

	North	North Central	East	Far West	West	South Central	Coast	South	ERCOT
2014	7,889	113,381	12,430	13,258	9,403	56,094	94,811	29,072	336,339
2015	7,968	115,440	12,639	13,444	9,500	57,404	96,743	29,760	342,899
2016	8,044	117,599	12,829	13,684	9,609	58,602	98,662	30,411	349,440
2017	8,116	119,701	13,060	13,882	9,734	59,856	100,485	31,088	355,922
2018	8,200	121,730	13,304	14,067	9,869	61,097	102,311	31,760	362,338
2019	8,311	123,743	13,598	14,278	10,055	62,286	103,954	32,477	368,702
2020	8,419	125,746	13,898	14,478	10,244	63,398	105,699	33,152	375,034
2021	8,531	127,836	14,186	14,699	10,435	64,513	107,321	33,847	381,369
2022	8,640	130,011	14,481	14,916	10,618	65,536	108,968	34,506	387,676
2023	8,746	132,135	14,774	15,128	10,798	66,595	110,545	35,161	393,961
2024	8,853	134,283	15,069	15,341	10,979	67,656	112,069	35,822	400,247

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Figure 2: Real Henry Hub Price of Natural Gas ($2012)

AURORAxmp, an economic dispatch model, to run these scenarios.[3]

III. Simulation Results

A. Retirements

Environmental regulations lead to the highest level of retirements among all scenarios at 13.3 GW between 2015 and 2024, or about 4 GW more than the Reference case (**Table 3**). The mandated reserve margin delays retirements, as units remain operational to take advantage of capacity schemes. Only 475 MW are retired in the MRM case, lowest among all scenarios. There will be over 9 GW of retirements under the Reference and Renewables cases.

The retirements are fairly constant across the years in the Regulations case at about 1,300 MW (**Figure 3**). Despite the hardwiring of significant wind capacity in the early years of our study period, roughly the same pattern manifests in the RR case, reflecting the dominant impact of environmental regulations that force the retirement of 4.4 GW of older, steam turbines that ran on gas and about 8.7 GW of coal units as compared to 5.5 GW of gas units and 7.8 GW of coal units in the Regulations case. Retiring coal units in both scenarios are the same units except for one more unit retiring in the RR case. Out of 14 coal units retiring in the RR scenario, eight started operating in the 1970s, five in the early 1980s, and the youngest in 1988. In contrast, most of the gas units (4.9 GW) also retire but only 4.3 GW of coal units retire in the Reference case.

For a comparable case, ERCOT (2011), the source of retrofit costs used in our analysis, reports 9.8 GW of gas-fired and 1.2 GW of coal retirements. Most of the retirements in ERCOT (2011) are due to closed-loop cooling tower requirements. More recently, the Current Trends scenario analyzed by the Regional Planning Group of ERCOT, which is probably closest to our Regulations scenario, predicts 10 GW of retirements by 2024 strictly on the basis of unit age.[4] The Regulations case results in more retirements overall, but

Table 3: Total Retirements 2015–2024 (MW).

Reference	MRM	Regulations	Renewables	RR
9,232	475	13,288	9,517	13,060

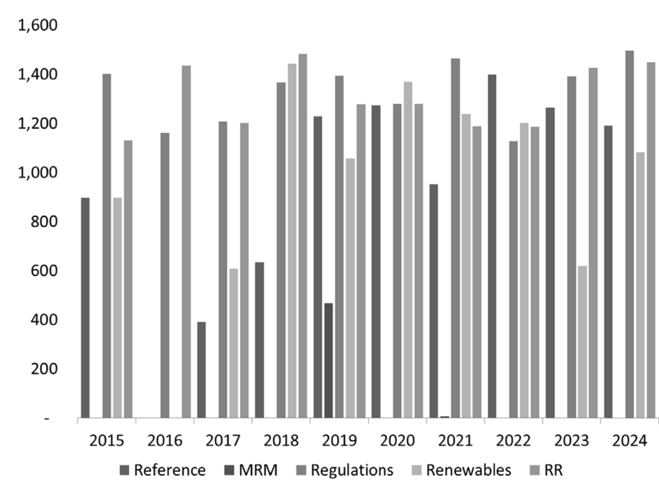

Figure 3: Retirements 2015–24 (MW)

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much more coal and less gas units relative to ERCOT (2011). This discrepancy can probably be explained by differences in assumptions on operating costs and constraints, efficiencies, and the financial analysis criteria.

Investigating the impact of the same set of four environmental regulations as ERCOT (2011), Brattle Group (2010) estimates 9–12 GW of coal capacity at risk of retirement in ERCOT by 2020. Brattle Group (2014) provides a more nuanced view, reflecting changing market conditions and the importance of assumptions on future coal and gas prices as well as the details of how regulations will be implemented. Only 0.4 GW of coal and 1–2 GW of gas capacity are at risk of retirement before 2020 in their reference case, assuming a natural gas price in the range of $4 to $4.25/MMBtu until 2020. In a low gas price scenario ($3–3.5/MMBtu), up to 6 GW of coal capacity could retire. In addition, 5–10 GW of gas/oil capacity are found to be at risk of retirement if cooling towers are required. This last case is closest to the Regulations case in this study, in which 5.5 GW of gas units are retired—low end of the range in Brattle Group (2014) case.

Scenario 1 in EEI (2011) covers the same set of regulations, albeit with different assumptions in how they are implemented, and is estimated to cause 2.3 GW of coal and about 2 GW of gas-fired capacity retirements. Relative to other studies, gas retirements are much lower whereas coal retirements are mostly consistent. The main difference seems to be relaxed timeline (10 years) allowed for compliance with cooling towers in EEI (2011). This comparison of various studies highlights the importance of assumptions and the sensitivity of the results to these assumptions but there seems to be a common theme: for the majority of the thermal plants in ERCOT, the regulation that matters the most is the cooling tower requirement.[5]

Table 4: Total New Builds 2015–2024 (MW).

Reference	MRM	Regulations	Renewables	RR
11,370	10,640	16,480	21,200	24,170

B. New builds

Most new capacity is built in the RR case (more than 24 GW), reflecting partially the hardwired renewables capacity and partially the need to replace units retiring due to environmental regulations (Table 4). The least amount of new builds occurs in the MRM case (about 10.6 GW) because there are not many retirements; plants stay online to take advantage of the capacity payments.

In all of the scenarios, a large share of new generation capacity is gas-fired. There is significantly more wind capacity in the renewables case owing to close to 8.7 GW inputted into the model for the period of 2014 through 2017 (Figure 4). The model does not add much more wind through 2024 but adds 12 GW of gas-fired capacity between 2015 and 2024 (Figure 5).

In the Reference case, there is only 200 MW of wind capacity built between 2015 and 2024. In contrast, roughly 11 GW of gas-fired capacity are built, starting in 2017 but increasing in 2020 to more significant levels (Figure 5). More than two-thirds of that capacity is combined-cycle (Figure 4). Retirements in the early years lead to high prices by 2018–19 and low reserve margins (see discussion

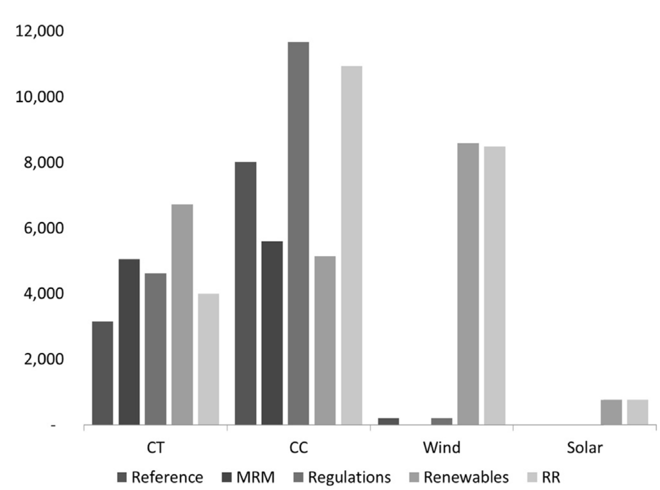

Figure 4: New Generation Capacity by Type 2015–2024 (MW)

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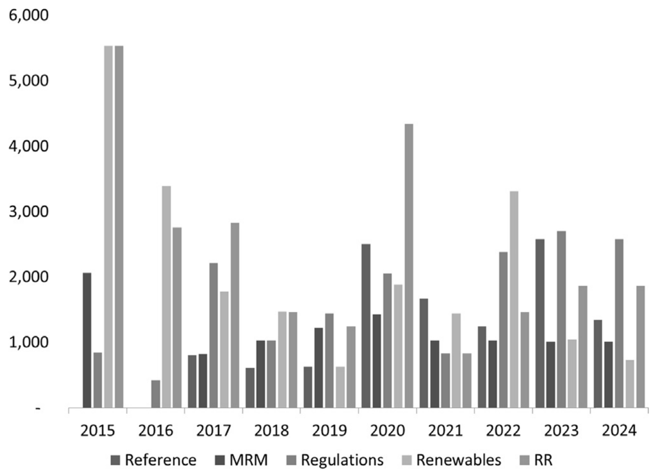

Figure 5: New Generation Capacity by Scenario by Year, 2015–2024 (MW)

later), which seem to encourage combined cycle (CC) plants, most of which are built in the 2020s.

To compensate for the larger capacity retired in the Regulations case, significantly more new gas-fired units are expected (Figure 4). A majority of the new builds are combined-cycle facilities: roughly 11.7 GW of CC and 4.6 GW of combustion turbine (CT). Large amounts of new CC capacity start coming online in 2017 and 2018 to compensate for baseload retirements in 2015 through 2017 but most of the CC capacity is built in the 2020s as in the Reference case (Figure 5). The Current Trends scenario analyzed by the Regional Planning Group of ERCOT also predicts more CC than CT but at much lower levels: almost 6 GW of CC, 3.2 GW of CT, and 2.5 GW of solar in addition to projects that meet Section 6.9 of the Planning Guide (e.g. have interconnection agreements and air permits).[6] Our results include 2.1 GW of gas capacity hardwired into the model because they are already under construction or far advanced in development (i.e. compliant with Section 6.9). Still, the model builds significantly more gas-fired capacity than the ERCOT long-term scenario and builds no solar between 2015 and 2024.

Although there are practically no retirements, about 5 GW of CT capacity and 5.6 GW of CC capacity are built in the MRM case (Figure 4). As expected, the capacity mechanism seems to encourage investment in new gas-fired generation facilities in order to achieve and maintain the mandated reserve margin. There is no new wind builds beyond 2015. There is new capacity coming online in every year of the study period, except for 2016, to maintain the reserve margin as demand grows (Figure 5).

There is often a concern that more renewables capacity in a system would discourage new gas generation units. In our analysis, almost 12 GW of gas-fired capacity, slightly more than the Reference case (11 GW), are built in the Renewables case. But, the distribution shifted in favor of CT units: 6.7 GW of CT versus 5.1 GW of CC capacity. The reliance on CT units to provide cycling support for intermittency of wind is consistent with the expectations. Also, energy prices are lower with more renewables in the system (**Figure 7**), which reduces the signal to encourage new CCs; but time periods of high prices still stimulate new CTs.

C. Net capacity additions

The Renewables case leads to largest net capacity additions (11.7 GW) followed by the RR case (11.1 GW), both on the basis of nameplate capacity owing to about 9.8 GW of wind and solar capacity we imposed on the model (**Figure 6**). However, for reserve margin calculations, ERCOT considers only 8.7 percent of installed wind capacity, known as the effective load-carrying capability (ELCC). Once adjusted for ELCC, net additions in the Renewables and RR cases decline to 3.8 and 3.4 GW, respectively, roughly 60 percent lower than the MRM case (10.2 GW) but still noticeably higher than the Reference and Regulations cases (2.1 and 3.2 GW, respectively). Going forward, it is possible that ELCC will be raised to mid-teens for western wind and perhaps as high as 30 percent for coastal wind. Such values will certainly render the Renewables and RR cases more beneficial from the perspective of resource adequacy.

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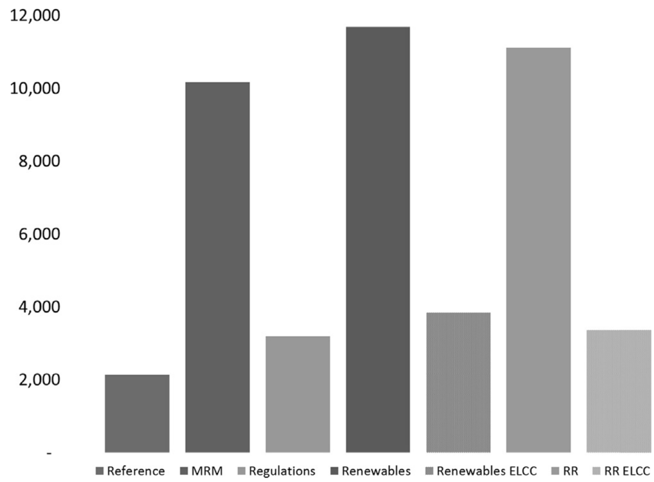

Figure 6: Net Capacity Additions 2015–2024 (MW)

Table 5: Summary Statistics for Wholesale Prices Between 2015 and 2024 ($/MWh).

Scenario	Min	Mean	Max	Std. Dev.
Reference	30.6	87.1	161.7	41.3
MRM	29.8	32.0	35.6	2.1
MRM with capacity	41.1	57.6	74.0	11.1
Regulations	30.3	72.8	134.0	36.7
Renewables	30.1	58.8	120.1	28.3
RR	30.1	69.9	118.5	31.8

D. Impact on average prices and reserve margin

The MRM case yields the lowest average price between 2015 and 2024 ($32/MWh) with high stability whereas the Reference case leads to the highest average price ($87.1/MWh) and highest volatility (**Table 5** and **Figure 7**). These prices reflect the wholesale energy-only market; the model simulates a capacity market for the MRM case. We calculate the average simulated ''capacity price'' at about $15.6/MWh, which brings the total cost of electricity in the MRM case to $57.6 (MRM Capacity), still lowest price among all the scenarios. Note, however, that the capacity price is somewhat more volatile as it adjusts over time to induce existing capacity to remain online and/or new capacity to be built in order to maintain the reserve margin level as demand grows (Figure 7). Also note that capacity prices can be higher depending on the specific design of the capacity scheme. We used a generic capacity cost calculation, assuming a fully transparent market, low cost of capital, and no participation from the demand side. Bellman (2015) discusses challenges faced by the capacity market in PJM and recent proposed changes, leading to a much more complex construct than our assumptions would imply.

The Renewables case has the second lowest average price at $58.8 for the 10-year period between 2015 and 2024. Note, however, that the cost of PPAs that often anchor renewables projects and can impact retail prices are not captured in this model, which simply reports the wholesale market price. The introduction of large amounts of

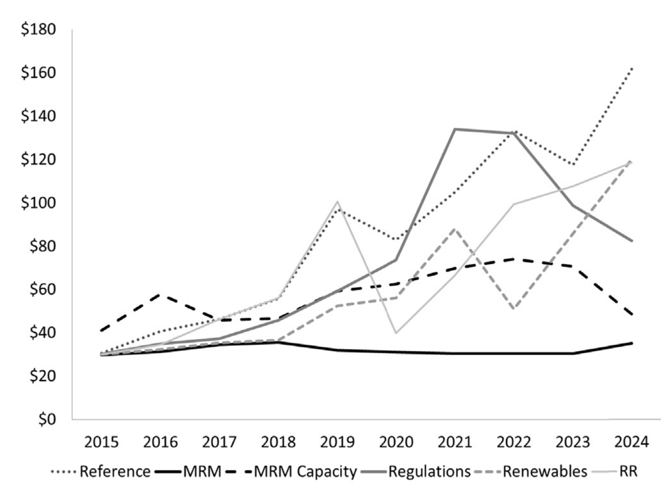

Figure 7: Average Wholesale Electricity Prices ($/MWh)

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Table 6: Summary Statistics for Reserve Margins Adjusted for LRS Between 2015 and 2024 (Percent).

Scenario	Min	Mean	Max	Std. Dev.
Reference	4	7	12	2
MRM	13	14	15	1
Regulations	5	8	14	3
Renewables	6	9	14	2
RR	6	8	14	2

wind capacity between 2014 and 2017 helps resource adequacy in ERCOT but the market shows some volatility and the price increases in later years (Figure 7). These fluctuations result from the variability and non-peak coincident nature of most wind generation (see above the discussion of net capacity additions with ELCC). The RR case leads to a higher price than the Renewables case despite all the wind capacity added into the resource database. We believe that the higher price is a reflection of the additional cost of new baseload plants the model builds to compensate for the retirements.

These price levels are consistent with the 2014–25 average reserve margins in each case (**Table 6**). Note that these reserve margins incorporate 1,918 MW of load responsive services, or LRS, included in ERCOT (2014). The MRM case yields roughly the mandated reserve margin. The Renewables case yields an average reserve margin of 9 percent between 2015 and 2024 as compared to 8 percent in the Regulations and RR cases and 7 percent in the Reference case. Although these averages are below the optimal reserve margin of 10.2 percent as estimated by Newell et al. (2014), they only reflect a 10-year period and fluctuate over time as the market responds to price signals. Annual reserve margins have been higher in the early years for most of the scenarios and can also be higher in the future beyond the 10-year focus of this study (see Figure 7 and sensitivities discussion below).

Note that the reserve margins for the Reference and Regulations cases are consistent with the expected reserve margins from ERCOT (2013), which average 8 percent between 2015 and 2023, throughout that period (**Figure 8**). The RR case reserve margin also follows a similar path but only through 2019, after which the new builds contribute to a higher reserve margin. In contrast, the reserve margins from ERCOT (2014), which average 9 percent between 2015 and 2024, are significantly higher than those in any of our scenarios (with the exception of the MRM case) until 2020, after which they overlap with the Renewables and RR cases through 2022 before collapsing below 4 percent. The Renewables case, with the additional wind and solar capacity inputted, yields the reserve margins closest to those from ERCOT (2014) in the early years.

Given that ERCOT reports can only incorporate resources that have interconnection agreements and air permits, projections beyond 2017 should be treated with caution. Still, we observe that our model runs and

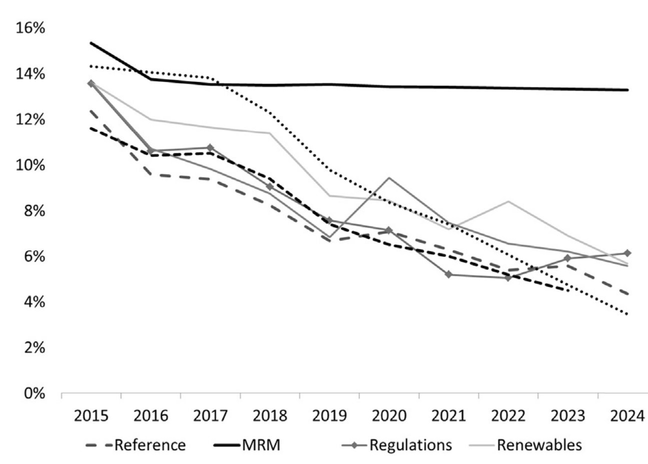

Figure 8: Reserve Margins Adjusted for LRS

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ERCOT projections converge around 6 percent in the early 2020s.

E. Sensitivities

We report a couple of sensitivities for the Reference case only; other scenarios react in the same direction. First, we raise the price forecast for natural gas by a dollar for every year in the study period. The electricity prices in ERCOT are sensitive to the natural gas price; higher gas prices lead to higher energy prices and often higher margins for generators, hence enhancing the price signal for either building new capacity or maintaining existing capacity. These expectations are supported by the model: the $1 increase in natural gas price leads to reduced retirements and increased new builds, including 2.8 GW of wind. Net builds increase to almost 7 GW, partially due to fewer retirements but mostly owing to more new builds, versus 2 GW in the Reference case. The reserve margin averages 9 percent versus 7 percent whereas the wholesale price averages $75 versus $87 in the Reference case.

In contrast, raising the price cap to $20,000/MWh from $9,000/MWh prevents 1.2 GW of retirements but leads to 500 MW less in new builds. Overall, net builds are slightly higher than those in the Reference case. Still, this increase in net builds lead to an average reserve margin of 8 percent versus 7 percent and an average wholesale price of $82 versus $87 in the Reference case.

Table 7: New Capacity in ERCOT (SNL/ERCOT) in Comparison to Reference and Renewables Cases.

	Under Construction (2015–2016)	Advanced Development (2015–2018)	Early Development (2015–2018)[b]	Reference/ Renewables (2014–2018)
Gas	900/1,500	5,800/240	17,000	3,510/3,130
Wind	3,600/7,500[a]	400/5,300	8,900	300/9,040
Total	4,600/9,000	7,100/5,540	29,500	3,810/12,170

Source: SNL, ERCOT (2014).
[a] 1,100/3,300 MW in 2014.
[b] SNL data.

IV. Outlook for ERCOT

Modeling is useful, especially for complex systems like electricity markets. However, the industry and market conditions are quite dynamic and it is impossible to know the actions and strategies of individual players in the future, especially in response to certain policy changes. Hence, it is informative to review recent and expected developments in the ERCOT market and contrast them to our model results. In **Table 7**, we summarize the generation projects in various stages of development as reported by SNL and ERCOT (2014).

Projects under construction, mostly wind, account for 4,600 MW according to SNL, which is smaller than our estimates for the period of 2014 through 2016, including the inputted gas and wind units (the Renewables case). Once the projects in advanced development (7,100 MW) included, the total of 11,700 MW through 2018 is higher than the MRM case new builds of 10,100 MW between 2014 and 2018 but slightly lower than 12,170 MW in the Renewables case. The Reference case seems too pessimistic when compared to projects classified in SNL database as under construction and in advanced development, especially for gas units. When compared to ERCOT (2014) data, the Reference case is still pessimistic but this time with respect to wind capacity. Overall, our new build results are certainly within the range of known projects either under construction or advanced development; but the model does not seem to support building a great majority of early development projects by 2018, or even 2024.

According to ERCOT (2014), there are three coal units that can potentially retire and are currently mothballed and considered unavailable to ERCOT. Their capacities add up to about 1.9 GW; two of these units are retired in the Regulations case.

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V. Discussion and Conclusions

There are several key factors, each with considerable uncertainty, which could impact the resource adequacy in the ERCOT market. In this article, we focus on the impact of several new EPA regulations and expansion of wind and solar capacity. The results from these two scenarios are compared to those from a reference case and a mandated reserve margin (MRM) case, which simulates a capacity market. The focus should be on directional differences of retirements, builds, net builds, and resulting reserve margin relative to these two scenarios; absolute values are likely to be different at least in their timing. Overall, the scenarios analyzed yield results mostly consistent with general expectations and known projects in the near future.

The MRM scenario leads to a stable reserve margin through the years by providing additional revenues to generators (capacity payments) that either delay retirement or encourage building new capacity. Even with the estimated cost of capacity payments added, this scenario yields the lowest average wholesale price of electricity, although it must be noted that design specifics of the capacity scheme might lead to much higher prices and/or inadequate capacity at times. The Reference case leads to lowest average reserve margin and highest average wholesale price between 2015 and 2024.

The second-highest average reserve margin and second-lowest average wholesale price (which does not necessarily relate to the retail price owing to PPAs) are realized in the Renewables case. Despite concerns of incorporating large amounts of intermittent wind capacity that does not follow the load curve, especially in summer afternoons when system peak is observed, the sheer size of the wind resources under development seem to help the ERCOT system within the timeframe of this study. The modeling software uses wind shape curves developed by the National Renewable Energy Laboratory that might be more generous to wind generators than the ELCC of 8.7 percent, which can be increased by ERCOT in coming years, especially for coastal wind. With new transmission lines to the West and increasing share of coastal wind, the contribution of wind to resource adequacy can be more positive in the future.

The results from our modeling of environmental regulations are within the range of outcomes reported in studies by ERCOT and others, especially in terms of retirements but the assumptions regarding demand growth, price of natural gas, investment decision criteria, and implementation details of regulations seem to matter, especially for new builds. But, overall, the baseload generation will transition from coal-sourced generators to gas-sourced generators. Although not the focus of this article, this transition should reduce carbon emissions in ERCOT without the implementation of a specific carbon policy. Large capacity additions from wind and solar will reduce the carbon intensity of the generation further. The emission benefits of the RR case are counterbalanced by low average reserve margin and high average wholesale price of electricity in our study period.■

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Endnotes:

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

2. For example, see http://www.energychoicematters.com/stories/20140123a.html

3. Model description can be found at www.epis.com

4. According to data from the presentation made at the Aug. 19, 2014, meeting of the RPG: http://www.ercot.com/content/meetings/rpg/keydocs/2014/0819/LTSA_8-19-2014_Scenario_Results_-_updates.ppt (last accessed Oct. 13, 2014).

5. The comparisons do not include an evaluation of possible regulation on CO_2 emissions.

6. See reference in endnote 4.

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