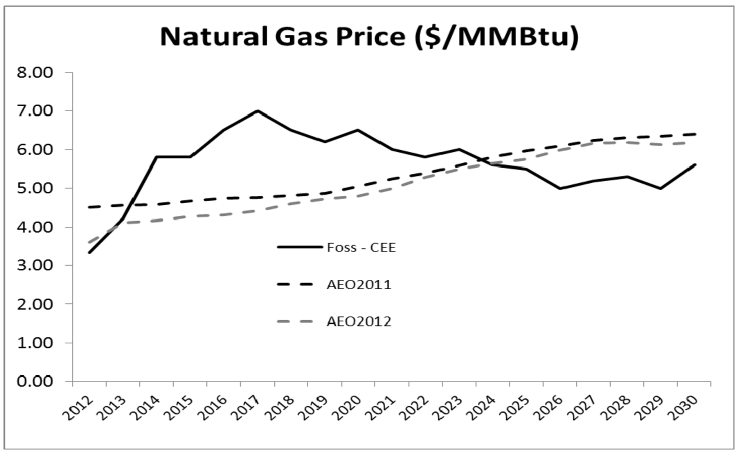
Transmission and Wind Capacity in Texas

By Gürcan Gülen and David Bellman*

Texas has become a leader in installed wind capacity since the early 2000s. As in many other parts of the U.S., the rapid wind expansion was based on the state's mandates but would not have occurred at the rate it did in the absence of federal production tax credits, high quality resources and high natural gas prices.[1] Since most of the wind capacity was built in West Texas, away from major load centers, new transmission lines were needed. The Public Utilities Commission of Texas decided to encourage the construction of the optimal facilities with the competitive renewable energy zones (CREZ) program. The CREZ lines, originally estimated to cost $4.9 billion, but now expected to cost about $7 billion, are now under construction and scheduled to be finished by the end of 2013. One developer did not want to wait for CREZ lines to be completed and built its own transmission connection.[2] The CREZ lines are designed to have a capacity of 18 GW as compared to about nine GW of wind currently built in West Texas. Note, however, that given the competitive market structure in Texas, the grid is open access and any type of facility can be connected to these lines as long as they follow the proper interconnection procedures.

We wanted to test whether the CREZ lines with their 18 GW of capacity will lead to additional wind investment. We used the AURORAxmp software to evaluate their impact but did not want to conduct such an analysis in isolation from several key developments: the impact of Cross-State Air Pollution Rule (CSAPR), and Maximum Achievable Control Technology (MACT) and its implementation standards for power plants, Mercury and Air Toxic Standards (MATS), to control hazardous air pollutants such as mercury on the generation portfolio. Although currently there is no federal law on limiting greenhouse gases, such legislation is possible within the time frame of our study. Already, some states are pursuing their own restrictions. We tried to capture this "threat" of GHG regulation via introduction of a CO_2 price ($14/ton in 2018 to $40/ton in 2030). We also assumed a renewable incentive of $15/MWh; federal production tax credit historically amounted to more than $20/MWh but it has not been available every year. In years after the Congress let PTC expire, renewables expansion fell significantly. It may be allowed to expire again in 2012. Although there are other incentives such as federal investment tax credits or grants, state-level funds and renewable energy certificate markets, these, too, fail to provide consistent, predictable support for all renewables. For example, in Texas, REC prices fell to $1-2/MWh. All of these programs benefited wind projects the most since wind has the lowest cost structure among the renewables.

We used the latest new build cost estimates from the EIA for all types of generators.[3] The model was tested based on the EIA 2010 actuals for calibration purposes; the model slightly underestimated gas demand in 2010, indicating that it is somewhat more conservative than the actual market but otherwise a good fit. For all cases, we assume regional growth rates, primarily based on historical trends and growth projections from RTOs. In fast growth regions such as ERCOT, annual electricity demand growth is estimated at above two percent; in MISO and other growth areas 1.2 to 1.3 percent is common; less than 0.5 percent is used for some regions in the Northeast. Our growth assumption allows for some efficiency improvements but not as aggressive as that of the EIA, the forecast of which is based on an average growth rate of 0.8 percent, which is much lower than the historical annualized growth rate of about 1.5 percent for the U.S (between 1990 and 2010).



Finally, we used a price trajectory developed from other CEE work.[4] The current price of less than $3/MMBtu is too low for many producers to generate acceptable revenues and continue investing in new gas development. Oil field service costs remain strong, pushed by persistent high oil prices and other factors such as technical challenges, work force shortages and so on. In the low natural gas price environment that is expected to prevail through 2013, producer margins will be heavily pressured. The industry is in the process of adjusting; consolidation, write downs, and other actions will eventually restore balance, as will stronger gas consumption in response to the lower price signal. The historical pattern of price cycles is expected to return with an initial increase from the current levels to about $7/MMBtu, adjusted for inflation, by the middle of this decade.

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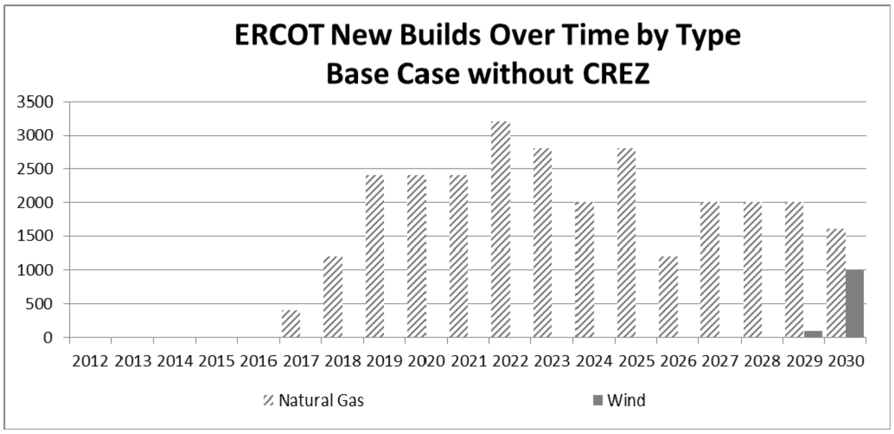
See footnotes at end of text.

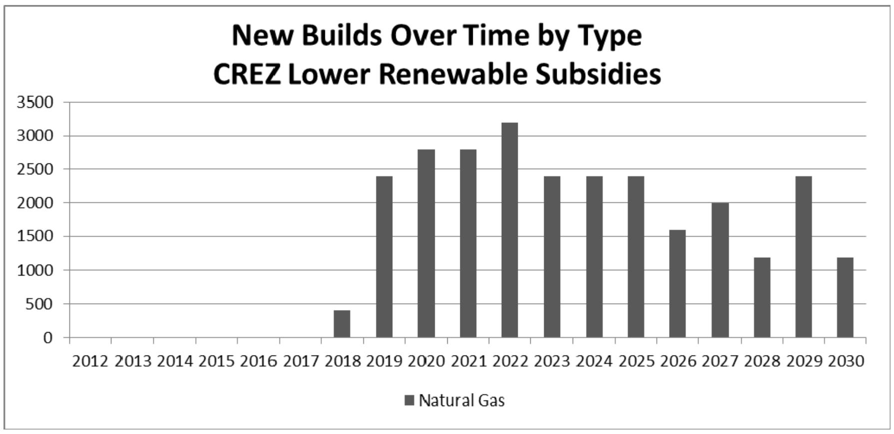
The Base Case

We simulated Eastern Interconnect and ERCOT regions since the 27 states covered by CSAPR are located in these regions. We accounted for trading of emissions allowances across states for the first two years as allowed in the program.[5] Although much retirement of coal capacity is predicted, for the most part, gas-fired capacity (more than 28 GW) will replace them and meet growing electricity demand, with additional wind (1.1 GW) becoming a factor later in our time frame. It is likely that the prospects of wind are hurt with the low price of natural gas in later years of our cyclical forecast.



The ERCOT system came close to wide-ranging outages in the summer of 2011; and there are concerns about shortages in peak summer days going forward. Despite these concerns, no new capacity is expected to be built until 2017. ERCOT does not have a capacity market and energy prices are capped at $3,000/MWh. The price signals are not strong enough for new builds although the model implies demand side curtailment (i.e., shortages) picking up over these initial years.[6]

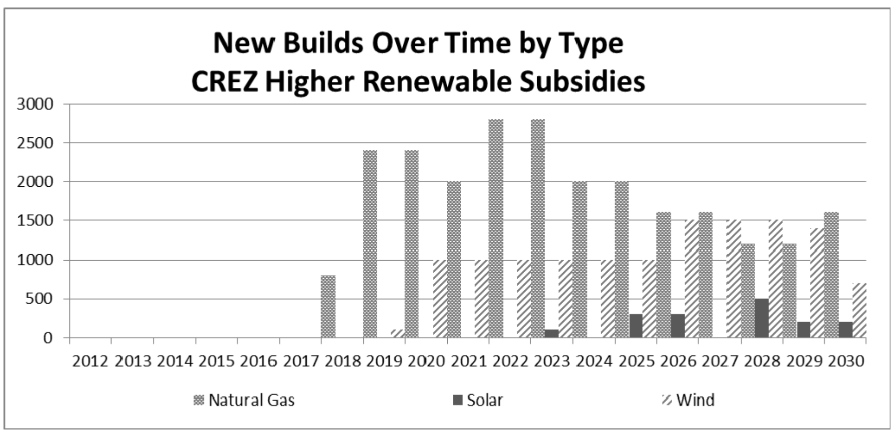
The ERCOT CREZ Case



In order to evaluate the impact of additional CREZ lines, we increased the capacity of lines to the planned 18 GW limit in the Western part of the ERCOT grid. The additional transmission capacity in West Texas with some of the best wind resources did not lead to any new wind (or any other renewable capacity) in ERCOT. A little over 27 GW of gas-fired capacity will be needed to compensate for lost coal capacity and to meet demand growth. The $15/MWh renewable subsidy is not sufficient for dispatch economics to favor wind over gas-fired generation given our gas price forecast.

However, CREZ yielded benefits in the form of reduced congestion, which allowed more wind generation from the West to get dispatched in the ERCOT market. In the base case without CREZ, we observe wind builds in 2029 and 2030 but these occur in Houston and North zones. With CREZ lines, these units are no longer necessary.

Next, we increased the incentives to $25/MWh for wind, which is more consistent with support provided by federal production tax credits and renewable energy certificates in the past, and to $35/MWh for solar, which remains more costly and requires additional support. These additional subsidies, with an estimated cost of $9 billion from 2019-2030, encourage 12.7 GW of wind and 1.6 GW of solar thermal capacity. Less, but still significant, gas-fired capacity (24 GW) will still be needed.



It is also worth noting that expansion of renewable capacity (as well as gas capacity) speeds up after 2018, the year we introduce a cost on carbon emissions and when MATS is expected to become fully implemented.

Conclusion

With this exercise, we have seen that it is important to capture dynamic interactions among energy and environmental policies as well as industry developments. Analyses that focus on a single factor will likely miss important forces and counterforces. Although CREZ lines may not directly lead to new builds of renewables, they seem to provide additional benefits to the grid by lowering the cost of congestion and allowing the dispatch of more wind power from the West. However, the impact of CREZ lines is dwarfed by the importance of renewables subsidies, the impact of EPA regulations, and potential penalties on carbon emissions. In future work, we plan to introduce technology improvement for renewables that would enhance capacity factors and reduce their costs going forward. Related to ERCOT, we will investigate price signals and demand side curtailment further.

Footnotes

[1] See *Lessons Learned from Renewable Energy Credit (REC) Trading in Texas* (2009), CEE project report to State Energy Conservation Office. (http://www.beg.utexas.edu/energyecon/transmission_forum/tf.php).

[2] For example, see http://www.reuters.com/article/2009/10/26/utilities-wind-texas-idUSN2620354820091026 (last accessed on March 12, 2012).

[3] *Updated Capital Cost Estimates for Electricity Generation Plants*, November 2010. http://www.eia.gov/oiaf/beck_plantcosts/index.html

[4] See Foss, *The Outlook for U.S. Gas Prices to 2020: Henry Hub at $3 or $10?*, Oxford Institute for Energy Studies, December 2011, http://www.oxfordenergy.org/2011/12/the-outlook-for-u-s-gas-prices-in-2020-henry-hub-at-3-or-10/ for a comprehensive review of U.S. natural gas market conditions and prospects.

[5] See *U.S. Gas-Power Linkages: Building Future Views* for a detailed discussion of these factors and their impact on the electricity generation portfolio and gas demand. (http://www.beg.utexas.edu/energyecon/thinkcorner/Think%20Corner%20Gas-Power%20Linkages.pdf).

[6] We will investigate these conditions further in a separate article.