MARKET EFFECTS OF WIND PENETRATION IN ERCOT:

HOW WIND WILL CHANGE THE FUTURE OF ENERGY AND ANCILLARY SERVICE PRICES

By LCG Consulting, October 2016

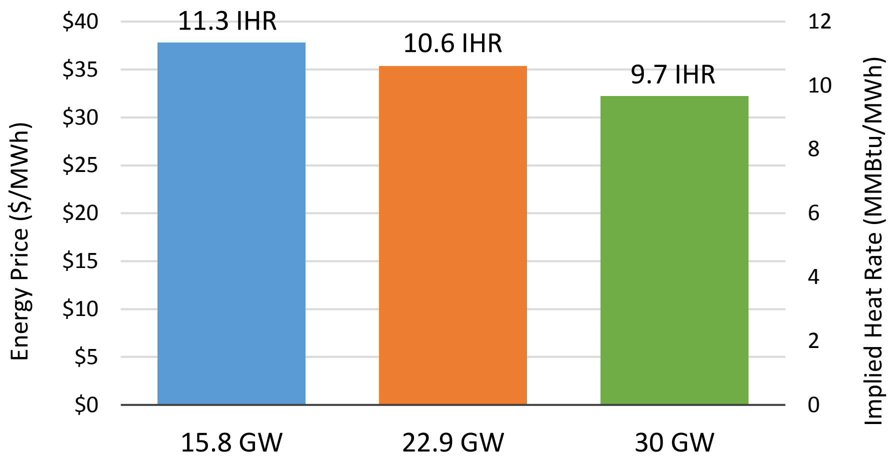
EXECUTIVE SUMMARY

In recent years, the Electricity Reliability Council of Texas (ERCOT) Region has experienced a rapid expansion of wind generation capacity. Nevertheless, wind generation capacity in ERCOT is expected to further increase in the coming years with many new units expected to come online. The aim of this study is to provide insight into the expected impacts of further wind capacity expansion in the ERCOT market through market simulations with the UPLAN Network Power Model. LCG has developed three scenarios for the 2021 calendar year with differing wind capacity assumptions (15.8 GW, 22.9 GW, and 30 GW). With all other factors held constant, the modeling effort is able to isolate the impact that wind generation will have on energy and ancillary service prices in the ERCOT market.

The first scenario includes only 15.8 GW of wind capacity, the amount of wind capacity installed as of the end of 2015. It is intended to serve simply as a point of reference, against which the higher wind scenarios may be compared, since the installed capacity in ERCOT as of the date of this study already exceeds 16.6 GW. The second scenario includes 22.9 GW of installed wind capacity – an addition of 7.1 GW. This scenario is intended to represent a conservative estimate of the likely wind capacity to be operational by 2021. For point of reference, development projects identified in ERCOT's August 2016 Generation Interconnection Status Report (GIS) as having executed an interconnection agreement, posted financial security, and scheduled to be operational by 2019 total 23.1 GW. Comparing this scenario to the 15.8 GW scenario can give us insight into how the market may be affected as we move from current installed capacity to a level more representative of ERCOT's current GIS reports. The third scenario increases installed wind capacity by an additional 7.1 GW to 30 GW, illustrating the impact on the market of further increases in wind capacity, that could be driven by lower costs, wind turbine technology improvements leading to higher capacity factors, federal legislative limitations on greenhouse gas emissions and/or additional or extended tax incentives, transmission upgrades, or other potential driving factors.

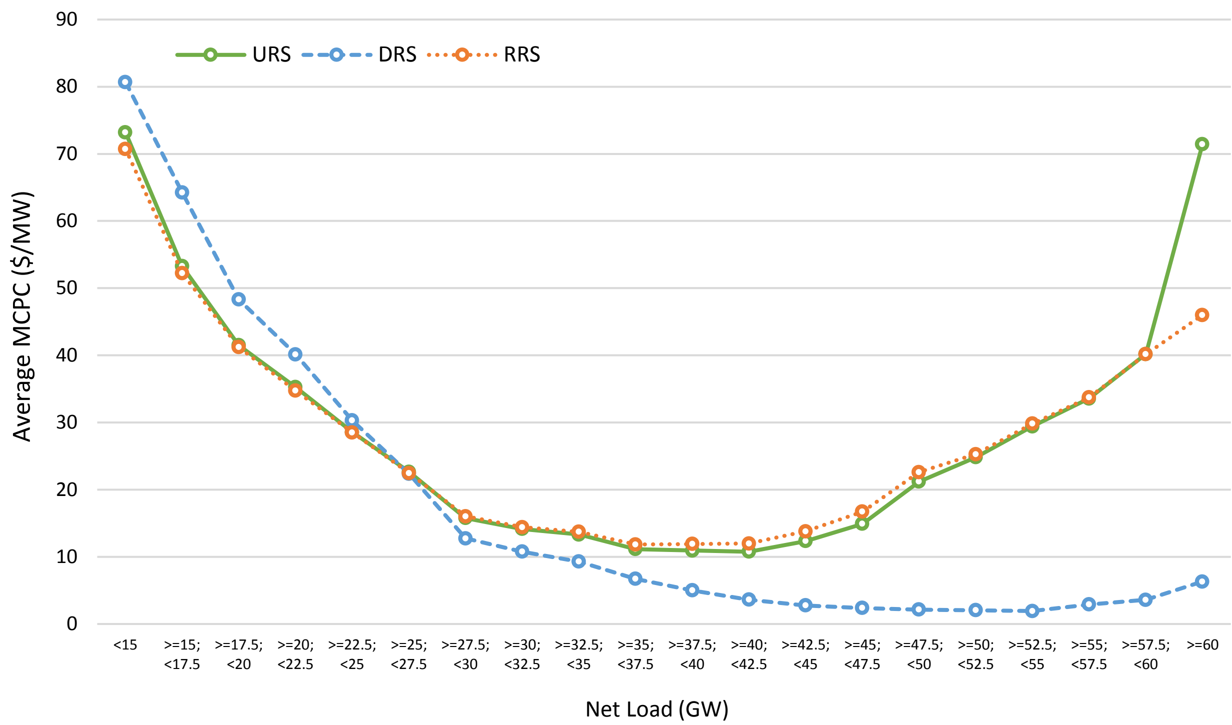
UPLAN simulation results indicate that with higher wind energy deployment, energy prices will be lower and ancillary service prices will be higher. In the 15.8 GW scenario, the annual average load-weighted energy price is $36.30 with a load-weighted implied heat rate (IHR) of 11.3. In the 22.9 GW scenario, load-weighted energy price and IHR fall 6.5% to $33.96 and 10.6, respectively. The 30 GW wind scenario projects a further decrease in the annual load-weighted average energy price to $30.91, with an IHR of 9.7, which represents a 9.0% decrease relative to the 22.9 GW scenario. Figure ES.1 below shows annual average load-weighted system-wide energy price and implied heat rate by scenario.

Figure ES.1 – 2021 Annual Average Load-Weighted System-Wide Energy Price and Implied Heat Rate by Scenario



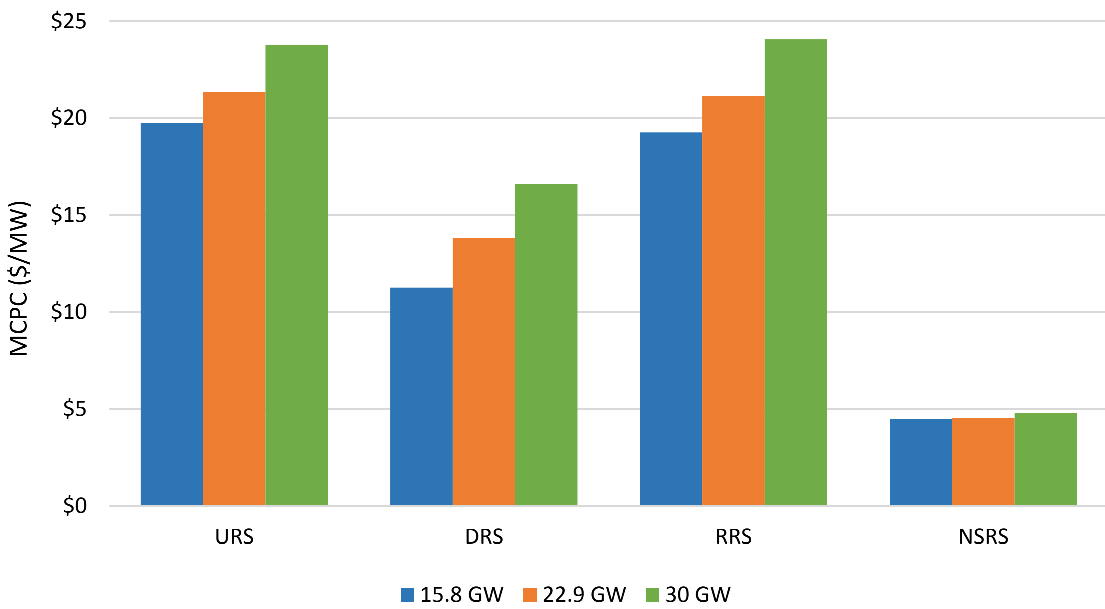
A relationship can be observed between levels of system-wide net load (defined as total customer demand less the energy provided by wind generation) and prices of ancillary service products, in particular, Regulation Up Service (URS), Regulation Down Service (DRS), and Responsive Reserve (RRS). Pictured below in Figure ES.2 are simulation results from the 22.9 GW wind scenario illustrating this relationship. As shown below, higher levels of net load have higher average prices of URS and RRS. In addition, at very low levels of system-wide net load, prices of URS and RRS are higher on average, as is the average price of DRS. In contrast, energy prices have a positive relationship with net load for all levels (higher when net load is higher and lower at low net load levels).

Figure ES.2 – 2021 Average Ancillary Service Prices by Net Load (22.9 GW Wind)



With higher levels of wind deployment, there is a greater occurrence of low net load hours. In UPLAN simulations this leads to increases in annual average ancillary service prices. Figure ES.3 below shows simulation results for average ancillary service prices for the three scenarios.

Figure ES.3 – 2021 Annual Average Ancillary Service Prices by Product



In the 2021 UPLAN simulations, the annual average Operating Reserve Demand Curve (ORDC) price adder is significantly higher than in the 2015 ERCOT market due to the expected increase in load with little thermal generation expansion. However, the ORDC price adder declines as wind generation increases across the modeled 2021 scenarios, as net load is reduced with greater wind generation.

It should be noted that this study assumes only capacity additions and retirements that are currently announced by the ERCOT ISO – with the exception of the variation in wind additions reflected by each scenario. Non-wind capacity expansion for purposes of this study includes those units that have a signed interconnection agreement and have posted financial security according to ERCOT's August 2016 Generator Interconnection Status Report. Retirements are based on scheduled retirements announced by the ISO. Further retirements would impact the energy and ancillary service markets and we leave the analysis of these impacts to future studies.

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