Bajo-Buenestado, R., 2021. Operating reserve demand curve, scarcity pricing and intermittent generation: Lessons from the Texas ERCOT experience. Energy Policy 149, 112057. https://doi.org/10.1016/j.enpol.2020.112057

In this paper, Bajo-Buenestado uses hourly data to show a significant negative association between increased wind generation and ORDC pricing in ERCOT between January 2015 and February 2019. “This paper’s main contribution is to empirically estimate and quantify how (intermittent) wind generation affects the ORDC price adder.” This empirical analysis is performed with regression. The author finds a link between increased wind generation and reduced ORDC prices, to the point where when wind reaches 9000 MW, the price is zero.

For their analysis, they take into account seasonal and time varying factors that could affect generators such as peak loads at certain times of day or year by using “time-of-day dummies, day-of-week dummies, day-of-month dummies, year dummies, month dummies, and month-year dummies.” This accounts for the fact that some technologies will produce energy on specific hours and days of the week.

Their model for all this is as follows: log(RTORPA)t = α0 + α1 log(Wind)t + α2 log(Wind) 2 t + α3 log(Load)t + α4Θt + εt,

Or, log(Real time price adder $/MWh) = log(total wind in an hour (MW)) + log(total wind in an hour)­2 + log(Ercot load for that time period) + time dummies + error, with the alpha’s as constants.

The deal with logging the RTROPA (which is often 0) by adding 1 to it before processing.

They capture dynamic components by adding a lagged version of the dependant and explanatory variables with an autoregressive distributed-lag (ARDL) model.

Important note: “Before March 2019, in order to capture historical differences at different times and seasons, ERCOT also valued reserves differently according to the time of the day and season of the year. In particular, operating hours were divided into four seasonal and six daily bins –ERCOT (2013) and Levin and Botterud (2015). However, on March 1, 2019, the ORDC was changed to replace the seasonal and time-of-day bins by a blended curve –Potomac Economics (2020).”

Basically, they did [ $$$ ~ Wind + Wind2 + Load ], with some dummy variables and lagging. That’s pretty solid. Biggest R2 with the most dummies, best p values with 5 of 6 dummies.

In their appendix, they looked at adding weather data (Wunderground daily means for cities in TX) to their model. Temp had a correlation with load, and wind generation still had the same association with price.

They also repeated the model with a squared load ([ $$$ ~ Wind + Wind2 + Load +Load2]). “ we find evidence of a **non-linear effect of load on ORDC prices** if **load is relatively low**. This is consistent with the fact that, if load is low and the ORDC price is zero, a further decrease in load does not impact upon the ORDC price, since it cannot be negative. However, **this non-linear effect occurs within a very small range** of the **load parameters**.”

They also dropped hours where the system lambda (The cost of providing one MWh of energy at the reference Electrical Bus) is negative and found the same results again. Sweet.

Shan, R., Abdulla, A., Li, M., 2021. Deleterious effects of strategic, profit-seeking energy storage operation on electric power system costs. Applied Energy 292, 116833. <https://doi.org/10.1016/j.apenergy.2021.116833>

This is another paper focused on the ORDC. They demonstrate that with the new ORDC schema,

Model in 15 minute intervals: (🥧 profits from new generation unit $/MWY) = ((market price of electricicty $/MWh) – (Variable costs $/MWh)) \* (unit online [binary])

Where variable costs for a 15 minute interval are VC = (Heat rate MMBtu/MWh) \* (Gas price on a given day $/MMBtu) + (Per MW variable O&M costs $/MWh)

With all that, they find the cost of a new plant: K. When (🥧 – K) < 0, new plants aren’t profitable.

As the ORDC is shifting “right” and the price is increasing for increased available loads, the paper finds that new plants will be more incentivized. They show that if the price has shifted earlier, the plant operators would have made more money. They believe this shift will stave off some retirements in the near future, but the overall growth of renewables means that prices will keep falling, while at the same time, reserve margins will keep shrinking as low prices disincentivize new plants. They believe that this shift to the ORDC will be insufficient to solve the “missing money” problem that is pushing plants to retire as investment returns dwindle. Suggestions for what actually to do are “beyond this paper’s scope, lmao)

Mills, A., Wiser, R., Millstein, D., Carvallo, J.P., Gorman, W., Seel, J., Jeong, S., 2021. The impact of wind, solar, and other factors on the decline in wholesale power prices in the United States. Applied Energy 283, 116266. <https://doi.org/10.1016/j.apenergy.2020.116266>

This paper looks at the whole of the US, to investigate the trend of power prices declining and power plants retiring. “Wholesale prices at major trading hubs declined by $19–64/MWh between 2008 and 2017,” and they think it may be due to more than cheap natural gas. The “‘merit order’ effect—namely, that the addition of VRE with low marginal costs leads to lower market-clearing prices” is called up here, and they are trying to hammer out just how much VRE’s contribute nationwide, alongside a wide array of other price drivers.

They start by reviewing 16 papers that correlate VRE penetration % with decrease in wholesale power price in different markets. These are set up to get a feeling for the average effects of this stuff.

For their model, they construct a “fundamental supply curve model”. They compare modeled annual average prices while changing one variable at a time to the 2008 level. Their model is supposedly simple, but to implement it, they used a boat load of data: “wind and solar deployment, changes in natural gas prices, thermal plant retirements and additions, changes in electricity load, permit prices for pollution emissions, and hydropower water levels.” Hella data.

They validate this model by comparing the output of the model (wholesale prices) with historical pricing, using historical figures for input variables. The model was accurate within 13% for most years tested this way. Their model fails to capture hourly volatility, however, so they say you should only use this model to look at drivers of annual wholesale prices market-wide, and not to look at geographic or temporal variability in the prices.

The ultimate results of this model show natural gas prices as the main driver in falling wholesale prices, but wind and solar are the 2nd place, though at a significantly lower magnitude. “Across all markets, each incremental percentage-point increase in wind or solar penetration since 2008 reduces average wholesale prices in 2017 by approximately $0.14/MWh. In most markets, the total impact on average prices in 2017 is below $1.3/MWh.”

Given increasing projections of VRE growth in the coming years, the authors expect the downward pressure from VREs to increase. That said, they’re still going to be on a different scale form the effect of nat gas prices.

Factors were also found to interact, with individual factors understating the magnitude of wholesale price decrease compared to everything all together.

“The finding that the reduction in natural gas prices was the primary contributor to the fall in wholesale electricity prices since 2008 is consistent with an emerging literature” – nice to see this in print again, haha. They also state that “non-linear interactions between factors place a limit on isolating the effect of changes in individual factors.” Temporal and geographic factors may be more heavily affected by wind and solar, and since those were not accounted for by this model, they may have a more significant affect than these authors determined.

Woo, C.K., Zarnikau, J., Tsai, C.H., Zhu, S., 2020. Cost-effectiveness of a modest expansion of renewable generation capacity in Texas. The Electricity Journal 33, 106696. <https://doi.org/10.1016/j.tej.2019.106696>