Texas Power Crisis Suits Bring Market Price Questions

By **Todd Aagaard and Andrew Kleit** (July 28, 2021)

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The Texas power crisis of February 2021 has spawned numerous lawsuits.

Of particular relevance to many of these lawsuits are the electricity prices charged during the last stages of the crisis.

For the last several years the Texas Public Utility Commission, or TPUC, has set a wholesale market maximum price of $9,000 per megawatt-hour, or MWh. This price cap,[1] which is higher than in most other U.S. jurisdictions, reflects Texas's competitive market philosophy, which relies on prices — and the revenue they create for generators — to incentivize investments in generation.

During the crisis, the price of electricity in Texas rose to the maximum level and stayed there for three days on Feb. 14-16 while the demand for power exceeded the available supply. On Feb. 17 and 18, however, after the shortages had ended, the TPUC kept prices at the maximum level of $9,000/MWh for an additional 32 hours.[2]

Had the market been allowed to set prices, the market equilibrium price during this additional period would have been lower than $9,000/MWh.

Keeping the wholesale electricity price at the maximum level even after outages ended has become an important issue in litigation filed in the aftermath of the crisis.[3] Numerous electricity suppliers had contracts to buy wholesale power from Texas generators that during the crisis were unable to provide the promised levels of power.

This raises the question of how much the generators now owe the suppliers for the shortfall. For example, many solar generators in Texas sold their power forward to counterparties but then, during the crisis, failed to deliver the promised power to the Electric Reliability Council of Texas, or ERCOT, system.

To illustrate, assume a solar generator with a 50 MW capacity and a 20% average capacity factor which means that the generator on average can supply 10 MWh per hour. Assume that the generator enters into a forward contract to sell this 10 MWh per hour to an electricity retailer. By the terms of the contract, if the generator does not supply the entire 10 MWh per hour of power, it must purchase the remainder at real-time power prices.

Assume now that, during the February crisis, the solar generator was only able to deliver 5 MWh per hour for the 32-hour period when prices were artificially high. Essentially, the solar generator needs to pay for the 32 * (10-5) = 160 MWh that it is short.

At a typical ERCOT price of $25/MWh, the solar generator would have to pay $4,000. But at the TPUC-mandated price of $9,000/MWh, the solar generator would owe $1.44 million!

Numerous solar and wind generators that were short on their contracted deliveries have refused to pay the $9,000/MWh market price set by the TPUC and have been sued by their counterparties. A crucial question in these cases may be what the market price would have been if prices were set competitively rather than by TPUC order.

Conceptually, the market price for power can be calculated by examining the relevant supply and demand curves. Yet, that is not all that is relevant to pricing in the Texas ERCOT market. ERCOT also imposes an adder on the price of electricity, known as the operating reserve demand curve, or ORDC.

When supply is scarce, as it was during the February crisis, ORDC values can constitute an important component of the price of electricity. Thus, calculating hypothetical ORDC values may be significant to litigation around the 2021 blackout.

As is well known, ERCOT does not operate a capacity market to ensure generator resource supply adequacy. Instead, it does two things.

First, it allows a higher maximum price in the market than other regional transmission organizations, or RTOs. Since 2015, the ERCOT maximum price has been $9,000/MWh, as compared to $1,000 in other RTOs. ERCOT interprets its maximum price as equal to the value of lost load, a measurement of what the highest-demanding consumers would be willing to pay for at least some electricity during a blackout.

In addition to using higher offer caps in its energy market, since 2013 ERCOT also addresses resource adequacy through the ORDC.[4] The ORDC augments energy and ancillary services prices to represent the marginal value of resources to the customers in the grid.[5]

Essentially, the ORDC is based on the idea that resources contributing power to the system should also receive compensation for their potential value to consumers in the event of a supply shortage. The marginal value of energy to the system for potential shortages is equal to the net value of avoiding a system shortfall times the probability of such a shortfall. Once this value is calculated, it is added to the price paid for both reserve services and energy.

The net value term of the ORDC adder is conceptually fairly straightforward. It is equal to the marginal value of energy during a shortage, or the value of lost load, minus what consumers are paying for energy in real time, the clearing price in the energy market.

Thus, if the value of lost load is $9,000/MWh and the market-clearing price of electricity in the energy market is $2,500/MWh, then the net value of alleviating a shortage is $9,000 – $2,500 = $7,500/MWh. In the context of the administratively determined pricing during the end of the blackout, this definition implies that the value of the ORDC would have been zero, as the transaction price was set by the TPUC equal to the value of lost load.

Had the market determined electricity pricing, however, prices would have been significantly lower, resulting in a substantial difference between the value of lost load and the market price.

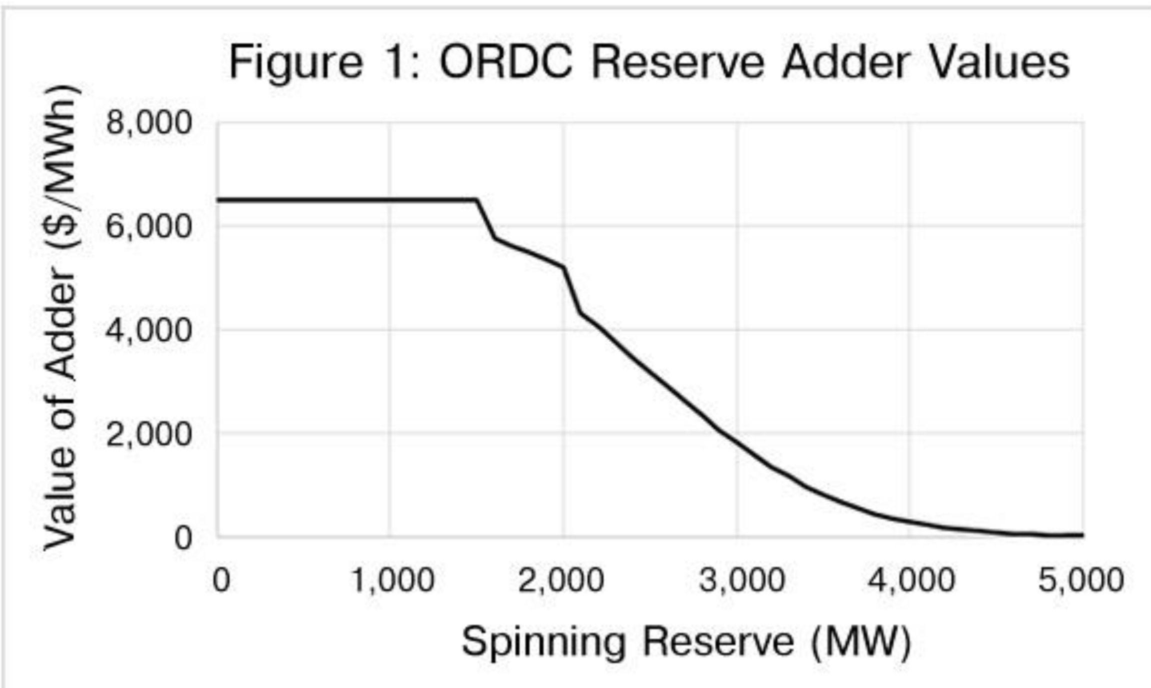
The derivation of the probability of a shortage is more complicated.[6]

For a given hour, ERCOT determines the probability of a shortage during that hour based on several factors: (1) the mean observed difference in previous periods between the reserves available an hour in advance of the relevant time and the reserves actually available at that time; (2) the variability of available reserves, as measured by the standard deviation of the mean difference; (3) the lowest level of reserves ERCOT holds before it begins to shed load; and (4) the actual amount of reserves available at the relevant time, with the more reserves available, the lower the probability of an outage.

The ORDC also accounts for the additional value of spinning reserves — that is, reserves that are ready to contribute power at very short notice — as compared with nonspinning reserves, which are slower to respond.[7] Because nonspinning reserves take more time to contribute power, they are less valuable.

One additional feature is needed to understand the ORDC. The ERCOT system requires 2,000 MW of total spinning plus nonspinning reserve capacity to operate safely, before it must start shedding load. Therefore, the probability of a shortage is set equal to 100% if the level of reserves falls below 2,000 MW.

Figure 1 presents estimations of the values of the ORDC across a range of spinning reserves values, under the assumption that the level of nonspinning reserves is 500 MW, together with the other parameter values used by ERCOT. The ORDC is flat across low quantities, representing an effective price cap, then slopes sharply downward and then is flat at essentially zero price for high quantities.



As Figure 1 indicates, the value of the ORDC can be quite substantial.

For example, if the market price of power is $2,500/MWh and there are 2,000 MW of spinning reserves available, then the value of the ORDC adder will be $5,217/MWh. The value of the ORDC falls off rapidly, however, as the amount of spinning reserves increases. At 3,000 MW of spinning reserves, for example, the value of the ORDC is $699/MWh. At 5,000 MW of spinning reserves, the value of the ORDC is essentially zero.

Prior to the February storm, the ORDC had made a real, albeit limited, impact on electricity prices. Averaged over the year, the ORDC added $1.41/MWh, about 5% of total costs, to wholesale energy prices in 2015, $0.13/MWh in 2016, $0.24/MWh (less than 1%) in 2017, $1.97/MWh in 2018, and $9.75/MWh, about 21%, in 2019.[8]

A review of the ORDC data available from ERCOT reveals the pattern of ORDC adders during a year.

Not surprisingly, the impacts are heavily concentrated during times in which demand is high and reserves are scarce, which in Texas usually occurs during the summer months.

For example, in 2019, the ORDC adder equaled $0/MWh over 78% of the time and was over $1/MWh only 5.2% of the time.[9] Monthly average ORDC adder prices varied widely. The average ORDC value in January and December 2019 was $0.0036/MWh and $0.0045/MWh respectively. On the other hand, the average ORDC value for August 2019 was $48.35/MWh, with a maximum value of $4,850/MWh on Aug. 13 at 3:30 PM.

While the ERCOT system was not short of capacity on Feb. 17 and 18, its available reserves were no doubt limited. In this circumstance, it is likely that a substantial ORDC adder would have been placed on electricity prices.

Thus, even if the TPUC set the price of electricity artificially high, which inflated the amount of money that generators owed their counterparties under the terms of their forward power contracts, market prices including the ORDC also would likely have been high.

Thus, looking only at what the market price would have been without factoring in the ORDC may seriously underestimate what the price of power would have been.

Therefore, any estimate of how much the TPUC's pricing orders affected generators' liability under their contracts is likely to be significantly reduced by consideration of the ORDC.

ERCOT has implemented the ORDC as a method of reimbursing generators for the value of deployed resources in scarcity situations. While the actual mathematical calculations may be somewhat challenging, its pricing mechanism comes straight out of simple economic theory.

In any analysis of what prices would have been at the end of the February crisis absent TPUC's override, calculation of the levels of the ORDC will be critical.

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[1] Technically ERCOT has an offer cap which limits bids by generators to no more than $9,000/MWh. This effectively caps the price very close to the $9000 limit.

[2] See Letter from Carrie Bievans, ERCOT Independent Market Monitor Director, to Public Utility Commission of Texas, re PUC Project No. 51812, Issues Related to the State of Disaster for the February 2021 Winter Weather Event (Mar. 4, 2021).

[3] See, e.g., Christiaan Hetzner, European Renewables Giant Sues Texas for the Massive Loss It Ran Up During February Ice Storms, Yahoo! Finance (May 17, 2021).

[4] Potomac Economics, 2015 State of the Market Report for the ERCOT Wholesale Electricity Markets 99 (June 2016).

[5] William W. Hogan, Electricity Scarcity Pricing Through Operating Reserves. 2 Econ. Energy & Envtl. Pol'y 65 (2013).

[6] ERCOT, Methodology for Implementing Operating Reserve Demand Curve (ORDC) to Calculate Real-Time Reserve Price Adder, Version 2.7 (Apr. 21, 2021), http://www.ercot.com/mktinfo/rtm.

[7] The spinning reserve market and non-spinning reserve market are types of ancillary services (reserve) markets. The spinning reserve market ensures that the system operator has access to quick-response resources that can quickly provide power when needed. In ERCOT, a spinning reserve resource must be available to the system within five minutes of receiving notice. The non-spinning reserve market is open to slower-ramping resources. In ERCOT, a non-spinning reserve resource must be available to the system within 30 minutes.

[8] Potomac Economics, Ltd., State of the Market Report for the ERCOT Wholesale Electricity Markets (various years, June 2016 through 2020).

[9] ERCOT, Historical Real-Time ORDC and Reliability Deployment Price Adders and Reserves (2019), http://www.ercot.com/mktinfo/rtm.