ENERGY

The Texas Electricity Two-Step

In reacting to Winter Storm Uri, did the state return to unnecessarily costly supply?

BY ANDREW N. KLEIT

On February 14, 2021, Winter Storm Uri struck Texas, and a deep winter freeze settled over the state. Tens of thousands of megawatts of generation went off-line as producers with various technologies found themselves unable to provide electricity in the cold conditions. The power that was available sold at prices up to 200 times normal levels. For almost four days, the Electricity Reliability Council of Texas (ERCOT), which operates the power grid for most of the state, imposed continuous blackouts on 4–5 million people. The resulting death toll was over 200, and the cost to the Texas economy was estimated at over $100 billion.

The policy consequences of the storm continue to play out. Initially, regulators imposed weatherization standards on power generators and the electricity grid operator took precautions to ensure more capacity was available for the market, at significant cost to consumers. In 2023, the elected politicians took over. Texas lawmakers took two important actions. The first would create a variant of a capacity market to supply dispatchable generators with the "missing money" that arises in electricity markets, as explained below. The second, subject to approval in a referendum this fall, would spend at least $5 billion in taxpayer money to subsidize electricity generation.

FINGER-POINTING AND REGULATORY STEPS

The blame game began soon after Uri. The leadership of ERCOT and the Public Utility Commission of Texas (PUCT) were removed. Texas Gov. Greg Abbott and others accused renewable energy sources of being the primary culprit in the crisis, even though renewable sources performed about as well as anyone would have predicted during the storm. (It was already understood that solar generators would not see much sun and windmills would have a hard time turning during ice storms.) The finger-pointing then shifted to natural gas producers and pipelines. Many producers were shut in, and pipelines were frozen during the storm.

Upon reflection, however, it seems that the primary culprit was natural gas *generators*, which were even more unprepared than producers and pipelines for the storm. The regulatory agencies took the first shot at addressing this problem. The new leadership of the PUCT, an appointive body, passed regulations requiring fossil fuel generators to be able to operate under weather conditions like those that occurred during Uri. Generator company executives must now attest that their generators will be ready for the next deep freeze. Of course, it is hard to know what will actually happen should another major storm hit.

Natural gas producers and pipelines in Texas are regulated by the elected Texas Railroad Commission (RRC). (The modern RRC has nothing to do with railroads.) If one wants to be elected to the RRC, one needs substantial campaign contributions, and a good source of such contributions is the oil and natural gas sector. Unsurprisingly, RRC commissioners are often friendly toward oil and gas companies. Thus, while the RRC passed new regulations imposing winterization conditions on natural gas production and pipelines, it is claimed the measures have substantial loopholes in them. Only when the second version of Uri strikes will we know if these regulations are effective.

BLOWING A HOLE IN THE TEXAS ELECTRICITY CONSTRUCT

ERCOT directs an innovative restructured electricity market created at the turn of the century, with generators subject to market forces and a highly competitive retail market for power. ERCOT is also proudly the home of the only grid operator in the United

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States without a capacity market or similar construct. Capacity markets address a long-standing flaw in electricity markets. Largely for political reasons, electricity markets generally have caps on prices that are well below the value of lost load (VOLL), the amount consumers would pay for uninterrupted service. This difference is "missing money" and indicates insufficient incentive for investing in enough electricity capacity to make the grid reliable.

Capacity markets attempt to address the missing money problem by paying for generators to be available to produce electricity in the event of an outage. Grid operators determine a demand for capacity in a largely arbitrary fashion, and suppliers bid into the market by promising to have capacity available in exchange for a market-determined capacity price. Of course, capacity markets have their own problems, charging rate payers far more for capacity than the underlying economics would imply is appropriate.

Texas did its best to eliminate the need for a capacity market for ERCOT. The PUCT set the price cap for power at $9,000 per megawatt hour (MWh), perhaps the lowest credible value of VOLL that one could draw out of the voluminous economic literature on the topic. Unfortunately, Winter Storm Uri resulted in nearly 72 hours of prices at or near that level and billions of dollars in charges (paid and unpaid) for ratepayers. Soon after Uri, the uproar over prices caused the PUCT to reduce the price cap to $5,000/MWh, though one wonders if even that amount is politically credible.

This created (or enlarged) the missing money in the ERCOT system. Perhaps more importantly, however, Winter Storm Uri destroyed the political consensus on the way the ERCOT market is to operate. Politicians now desired an electricity market with a higher level of reliability than what the existing market forces could supply. No one wants to be responsible for the next massive electricity blackout. In effect, the political imperative increased the effective amount of missing money.

In response, ERCOT greatly expanded its use of what it refers to as Reliability Unit Commitment (RUC). Versions of RUC exist in most or all restructured electricity markets. RUC is generally intended to address the problem that, because of transmission constraints, there are "load pockets," places on the grid where market prices are not sufficient to ensure system reliability. In those circumstances, the grid operator pays generators their costs to operate, even if such costs are above the market-clearing price.

In 2020, all ERCOT's use of RUC was to address variants of the load pocket problem. After Uri, however, ERCOT dramatically expanded its use of RUC to address circumstances where it perceived the market might face reliability challenges. This was despite the fact that ERCOT already had a set of ancillary (backup) markets designed to address precisely this problem.

By 2022, RUC commitments for perceived systemwide problems were almost seven times the commitments for local load pockets. RUC commitments are costly, not only because of the direct payment to affected units, but also because RUC commitments preclude the affected units from offering into energy and ancillary markets, driving up those prices. The ERCOT Independent Market Monitor reports that use of the RUC mechanism to address perceived reliability issues cost ratepayers almost $1 billion in 2022.

NOT QUITE A CAPACITY MARKET

RUC was a stopgap measure, and its expense created criticisms. Given the problems with RUC, the PUCT looked for a more systematic solution to the missing money problem. But, for historical reasons, it seems that one cannot have a capacity market in ERCOT, or at least something called a "capacity market." Instead, the PUCT sought other capacity alternatives to address the missing money problem. What they came up with was a new idea referred to as a Performance Credit Market (PCM).

A PCM would work like this: The PUCT would administratively create a demand curve where "quantity" refers to the total quantity of electricity produced in the highest (perhaps 60 highest) demand hours of the year. ERCOT would determine how much electricity was produced during those hours, that quantity would be mapped onto the PCM demand curve, and a PCM price would be calculated. Generators would then be paid an amount equal to their PCM contribution multiplied by the market clearing PCM price.

The PCM has some important advantages over traditional capacity markets. Traditional capacity markets have a difficult time enforcing commitments. Capacity commitments are generally made three years in advance, and historically there have been only limited penalties, if any, for failing to provide power in critical situations. Creating effective penalties has proved challenging.

For example, the PJM grid operator, which covers a portion of the Mid-Atlantic and Midwest, several years ago implemented a set of stringent performance requirements for generators that sold capacity into the capacity market and then were unable to meet their commitments during a grid emergency. In late December 2022, Winter Storm Elliot hit PJM, causing critical problems for the grid and limited blackouts. The PJM penalty formula called for generators that did not meet their capacity obligations to pay nearly $1.8 billion to generators that exceeded their performance obligations during the storm. Naturally, producers did not take this level of penalties lying down, resulting in a Federal Energy Regulatory Commission proceeding to determine exactly who should pay what. It is unclear what FERC will decide or when it will release its decision.

The PCM gets rid of this enforceability problem. There are no commitments, so there is no need to determine what commitments generators are allowed to make. Determining allowable commitments is a challenging problem in a world with non-dispatchable generation because the grid operator is forced to create complex models to determine the effects of wind and solar generators on system reliability.

The PCM also potentially addresses another capacity market problem. In PJM and in the grid operator ISO–New England, capacity market demand curves are determined by forecasts made years in advance because the capacity auctions take place three years before the capacity delivery period. This has systematically resulted in over-estimation of demand because system operators have a natural desire to act conservatively for future events. With a PCM there is no need to estimate demand so far in the future.

A PCM would not be without flaws. Prices would depend on how the projected demand curve is determined, a question that no other grid operator has been able to address in a systematic fashion. In particular, the PCM demand curve would depend largely on measurements of something called the Net Cost of New Entry (Net CONE), which was, at least originally, intended to be a measure of the missing money. Unfortunately, grid operators have systematically overestimated Net CONE.

Renewable generators will not be eligible for PCM funding. There is no obvious rationale for this. Renewable generators do supply power during electricity crises. For example, in June 2023 there was a period of high temperatures and stress on the ERCOT system. Solar generators supplied substantial power during the period. Not paying renewable operators for their contributions to the grid when it is stressed will likely result in too much capacity in the ERCOT system and higher bills for ratepayers.

While estimates vary, it appears that a PCM would generate around $3 billion annually in revenues. This would not be a net cost for ratepayers, however, because a PCM would draw in new capacity, thereby lowering energy prices. When the biannual Texas Legislature reconvened in 2023, the projected price tag for the PCM created some controversy. In response, the legislature restricted the "net" cost of the PCM to $1 billion, where "net" apparently means the direct cost of the PCM minus the savings to ratepayers from lower energy prices. Unfortunately, the latter value is extremely difficult to calculate. The legislature also took the positive step of directing ERCOT to reduce its usage of RUC.

The legislature authorized, but did not require, the PUCT to set up a PCM. Creating the PCM would be a challenging task. As of this writing, the path the PUCT will take is unclear.

SUBSIDIZING NEW GENERATION

The PCM, however, was not enough for the 2023 Texas Legislature. There still was unrequited demand for action from industrial consumers that did not want to pay the costs of the PCM, politicians worried about blackouts in the relatively near future and developers eager to get their hands on state money. This was combined with a record state budget causing state money to be left lying around with no apparent purpose, and the political heft of a lieutenant governor, Dan Patrick, who under the odd vagaries of the Texas Constitution effectively runs the Texas Senate. The result is a program for massive state subsidies for the Texas generation sector.

Under the plan, subject to approval in a state referendum, at least $5 billion will be allocated for low-cost loans and direct grants. New generators will be eligible for 20-year loans at a 3 percent interest rate, payable starting three years after a generator starts operation. Generators must have an installed capacity of at least 100 MWs, and loans can account for no more than 60 percent of a generator's capital costs. Assuming a 6 percent market rate of interest, this would amount to a subsidy of about 35 percent per dollar of loan. In addition, generators that come online by June 1, 2026, are eligible for bonus payments with net present values of about 7 percent of the cost of the generators. Of course, renewable generators and storage facilities need not apply for such subsidies.

The program calls for building up to 10,000 MWs of power in a system with a peak load of perhaps 80,000 MWhs. It is a retreat from the commitment to electricity markets that Texas made two decades ago.

This year's bill does have a limited time horizon for generators wanting to take advantage of the subsidies. But once electricity generators get on the government payroll, it will be difficult to get them off. This year's multi-billion-dollar subsidy plan seems likely to result in overcapacity in the Texas electricity grid and further subsidies to bail out the existing generators that will be harmed by the resulting new entry.

CONCLUSION

In many ways, the ERCOT market has been a regulatory economist's dream. But Winter Storm Uri ended that dream, making electricity reliability an explicit political issue.

In 2023, Texas legislators took two steps toward shoring up their electricity grid. The PCM would address the missing money problem and potentially eliminate many, though not all, of the problems associated with capacity markets. If the political realities require that there is missing money, a PCM may be a viable approach.

The direct subsidies to generators are more troubling. Electricity restructuring happened in large part because generator operators previously did not worry about where their profits were coming from because they knew public utility commissions would approve rates that ensured their profitability. As a result, generators often utilized inefficient forms of production and ratepayers shouldered the expense. The Texas Legislature may have now returned to something akin to that arrangement, making the public, rather than operators, responsible for expensive generation.

Unfortunately, there was little discussion in Texas about other approaches to improving grid reliability. Reliability problems largely occur because most consumers do not have "demand response"—access to real-time prices—and therefore do not have incentives to reduce their consumption during a grid emergency. While there is some demand response in ERCOT, there is little appetite for expanding such programs.

The ERCOT grid also has limited transmission links with the rest of the United States. More links could help during a grid emergency. They would also help Texas producers export relatively low-cost power outside ERCOT. But it seems that Texas would like to address this problem, as much as possible, on its own.

In political terms, the response of the Texas Legislature to Winter Storm Uri is fully understandable. No one wants the blame for a massive electricity blackout. As a result, ERCOT may no longer be the freest electricity market in the United States, and taxpayers and Texas ratepayers can expect to end up paying the cost. But the fallout from Uri also serves as a cautionary tale for those who wish for electricity grids to be more dependent on non-dispatchable renewable energy. If something goes wrong, there will be a price to pay. *R*

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