PROJECT NO. 52373

REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	**§ §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

COMMENTS OF The Regulatory Assistance Project

COMES NOW The Regulatory Assistance Project and files these Comments to the Questions for Comment filed in this proceeding on August 2, 2021.

Introduction

The Regulatory Assistance Project (RAP) is a nonprofit group of energy and air quality experts based in the US, Europe, India and China. We bring a regulator's perspective to our work with regulators and policymakers on matters pertaining to a reliable, affordable transition to a sustainable energy system. We take a comparative approach to our work, drawing on lessons learned across the many jurisdictions in which we have worked over the past 30 years. We offer these comments in the spirit of being of assistance to the Commission in its laudable initiative to identify and remediate the causes of the energy crisis that enveloped Texas in February of this year, in order that such a catastrophe be prevented from ever happening again.

Executive Summary

The Commission has posed six questions to which commenters have been asked to respond. We have appended to our comments an addendum that directly responds to each of those six questions. The body of our comments is an attempt to capture a sufficiently wide view of power grid issues posed by the February crisis, including ERCOT wholesale market issues, focusing on remediating the identifiable root causes while preserving what is best about the Texas electricity market. Our recommendations can be summarized as follows *(with reference to the relevant questions posed by the PUCT)*:

1) *(PUCT Question 1)* We support the PUCT's initiative to examine critically all aspects of the ERCOT market in the wake of February's energy crisis. In doing so, we urge the Commission to base its review on the facts of what did, and as importantly what did not, contribute to the crisis, and to preserve those aspects of the ERCOT market design that remain best practice when compared with other power grids. In particular, calls for adopting the sorts of central capacity planning and procurement mechanisms that have encountered problems in other markets ignore the fact that the amount of investment in capacity, and in particular dispatchable capacity, was not an issue here. The "capacity" issue was the failure of nearly half of that dispatchable capacity to perform as expected.
2) *(Question 3)* Explore ancillary services market mechanisms that better reflect the value to Texas consumers of positioning critical reserve services in advance of high-risk periods. One useful example of such a mechanism is ISO New England's recent Energy Security Improvements proposal, which was designed to address a region-specific fuel supply risk.
3) *(Q 3)* While prioritizing day-ahead and real-time market measures, consider the cost-effectiveness of new regulatory standards for the robustness of dispatchable generators' fuel supply arrangements, without prescribing how generators choose to comply.
4) *(Q 1)* Explore a back-stop mechanism to boost confidence that the market will continue to deliver adequate investment in dispatchable resources going forward as the utilization rate of such resources continues to decline, while avoiding costly over-procurement and misplaced investment. It would be instructive to examine the Retailer Reliability Obligation instrument implemented in Australia's National Electricity Market.
5) *(Qs 1 & 3)* Reform ERCOT's scenario planning process to provide a more comprehensive body of information both on the full range of expected contingency events and their likelihood, and a more robust and comprehensive assessment of the consequences of severe weather across all seasons on system supply and demand conditions. This information should be transparent and available to all wholesale market buyers and sellers.
6) *(Q 1)* Strengthen obligations on the PUCT and ERCOT to assess periodically the ability of power grid resources (and related systems) to perform under extreme but expected conditions. Ensure the PUCT has adequate funding to carry out its obligations.
7) *(Q 4)* Explore cost-effective options to revive and strengthen the now decade-old TDU energy efficiency programs under the PUCT's purview and encourage the SECO to adopt stronger cost-effective efficiency standards for new residential construction, including where appropriate efficient electric heat pumps for heating and air conditioning. Champion cost-effective retrofits for existing residential structures for improved building performance.
8) *(Qs 3, 4 and 6)* Realize greater value from Texas's competitive energy market by taking pro-active measures to mobilize the inherent flexibility and price-responsiveness of many electricity end-uses, including direct support for wider deployment of demand automation technologies and flexible demand management retail service offerings (with appropriate risk mitigation and consumer protection features). Revisit the decision not to require TDUs to make customer usage data available in real time to customers and their service providers.

Comments

The energy crisis in February of this year inflicted incalculable harm, and it is incumbent upon the responsible authorities to seek to ensure it never happens again. It is right to examine critically every aspect of the energy system, including the ERCOT market design. With that said, the Texas power market has shown how a competitive "energy-only" market can deliver the investment in dispatchable generating capacity needed to comply with established resource adequacy standards while efficiently integrating what is among the world's highest penetration of variable wind generation. At the same time, Texas's power market has over the past two decades delivered significant savings to Texas consumers. Care should be taken not to throw the baby out with the bath water. The PUCT should focus on what actually precipitated this crisis, and in so doing should not make the mistake of importing centralized resource procurement policies from other markets that have proven inferior to the Texas market approach.

The current ERCOT market design delivered investment in a quantity of dispatchable capacity that should have been sufficient for ERCOT to manage what was a 25- to 30-year winter event with load curtailment that falls within prudent planning parameters. Nearly half of that dispatchable capacity failed. Market changes that would have driven investment in more capacity designed and built to prevailing standards, under prevailing planning assumptions and reliant on prevailing fuel supply infrastructure, would have been of little value. Central long-term procurement to meet a higher reserve margin is an answer to the wrong question.

In addressing the calls to introduce market design changes, the right questions arising from the February crisis regarding resource adequacy are:

1) Against what range of planning scenarios should we expect market participants to be investing and risk-managing to deliver value for money to Texas consumers?

2) How do we increase confidence that generating plants and demand-side resources actually respond at the level anticipated when they are most needed?

3) How do we increase confidence that market participants will continue to invest in enough of the mix of resources ERCOT needs to deliver a prudent standard of reliable service across the range of planning scenarios, especially as the utilization rate of the dispatchable generation needed to meet that standard continues to decline?

4) How do we increase confidence that fuel-based resources have access to adequate supplies of fuel when they are most needed?

Questions 3 and 4 tackle the issues most relevant to market design. Question 4 is perhaps the most pressing one, given the central role gas supply issues played in the crisis. It is worth exploring the recent Energy Security Improvements proposal from ISO New England to see if and how it could be applied in the ERCOT context. It creates day-ahead auctions for call options for a new set of ancillary services, with clearing prices that reflect what it will cost generators to arrange guaranteed fuel supply whether they clear in the day-ahead energy market or not. This can lead to additional arrangements with producers and pipeline companies, or to the stockpiling of oil inventories at dual-fuel plants, or both. For plants reliant on just-in-time natural gas supplies, stronger incentives for anticipatory measures may have addressed some of the issues that arose in February. But in the end, there is only so much one can do when, for instance, throughput at Permian Basin gas processing plants is down 43% before any load shedding occurs and declines further by 85% week-on-week, as was the case in February. Absent concerted efforts by gas industry regulators to address that vulnerability, the only alternative is incremental investment in on-site fuel systems, which in the case of gas plants means oil backup. Gas-fired generators may well undertake dual-fuel retrofits on their own in the wake of the February event and given existing market incentives, but more direct regulatory action may also be warranted.

Question 3, regarding the confidence that the market will continue to attract investment in an adequate quantity and mix of resources, is at least in part a market design question. Lack of dispatchable capacity was not a root cause of the February crisis, but concerns have been raised that as the utilization rate of dispatchable (thermal) resources continues to decline in coming years, it may become a problem. Multi-year forward capacity markets, such as those in PJM and ISO New England, have been problematic for a number of reasons and go well beyond what is needed. Market participants have provided the business case needed to drive adequate capacity investment to date, including dispatchable capacity, and confidence is sought that they will continue to do so.

Examples of less invasive mechanisms exist in markets elsewhere. In July 2019 the National Electricity Market in Australia adopted a Retailer Reliability Obligation (RRO), under which the system operator annually assesses adequacy for the coming five years. If a shortage of contract cover is identified three years and three months out, the regulator can trigger the RRO, at which point “liable entities” are formally notified of an obligation to acquire adequate contract cover. If a shortage persists one year out, the system operator is empowered to enter into contracts directly and recover the related costs from the offending retailers. The RRO is therefore truly a backstop mechanism to boost confidence that market participants are supporting needed investment. (The obligations must be for financial contracts, not physical, especially where retailers must manage changing customer bases, so that they retain the ability to hedge, and to adjust their hedging positions, in a liquid traded market.) The RRO has the benefit of locating principal control over ensuring an adequate supply of capacity *and* capabilities with those parties closest to the customer and with the greatest incentive and ability to optimize the mix of supply-side and demand-side solutions. The CAISO Resource Adequacy Requirement mechanism is a similar example in structure, but it exists in a regulatory context in which it has no practical effect. The NYISO Installed Capacity mechanism shares features with other forward capacity mechanisms that can distort market incentives, including a centrally administered and enforced "demand curve" and no explicit differentiation of capacity value based on resource capabilities. But it is a case study in the efficacy of limiting capacity-based intervention in the market to biannual auctions that lock in commitments only for the upcoming six-month "capability period."

The answer to Question 1, regarding contingency planning procedures, is not a market design issue *per se* but is instead a challenge to system operators and regulators to establish the conditions necessary for *any* market design to function, including systemic risk assessments that only they can provide. If market participants don't have access to a shared body of information about expected demand and supply conditions under a sufficiently wide enough range of credible circumstances — updated to reflect the best science on the impact of climate change — redesigning the market would be an exercise in futility.

As to Question 2, regarding resource responsiveness, this should not have been a problem given the strong (some might say extreme) incentives in the current market design to respond under system stress conditions. It obviously was a problem. As with Question 1, the issue isn't market design *per se* but rather a planning and regulatory failure. ERCOT's contingency planning failed to reflect the full range of statistically credible scenarios, and the PUCT failed to exercise the authority they were granted post-2011 to set and police standards for winterization. Capacity owners had neither the systemic risk overview needed to properly evaluate investments in the capability to perform under such conditions, nor any obligation to make such investments. Based on data in the recent UT Austin report,[1] to the limited extent winterization was claimed to have been undertaken, in most reported cases it appears to have been ineffective. Again, unless these flaws in planning and regulation are addressed, there is little point in redesigning a market that already offers extremely strong incentives to perform when most needed.

Looking beyond the important but narrow issue of how the market delivers needed investment in generation resources, other market matters raised by the February crisis can be usefully pursued. The PUCT took important steps in June to reform the way administrative scarcity pricing would operate under any future load-shedding events. But there is enormous untapped opportunity to empower Texas consumers to help ensure future reliability at the lowest reasonable cost. This is the "low-hanging fruit" of energy efficiency and flexible demand.

The stellar performance of the Texas economy in recent decades has led to a sustained boom in residential construction. Unfortunately, most residential structures in Texas are relatively energy-

[1] *The Timeline and Events of the February 2021 Texas Electric Grid Blackouts* (UT Austin Energy Institute, July 2021, pp 34-36).

inefficient, needlessly increasing energy demand for heating and air conditioning. The resulting impact on the power grid was compounded under severe winter conditions by the fact that over the past 20 years, most residential structures were built with highly inefficient resistance electric heating systems. Many retrofit options for residential structures can reduce the demand for electricity that must be met in summer and winter at a far lower cost than building new generating capacity, including where appropriate replacing resistance heating with efficient electric heat pumps. The lowest-hanging fruit of all is improving the efficiency of new buildings.

Another largely untapped opportunity is to enable inherently flexible demand to be more directly responsive to the dynamics of Texas's competitive energy market, by making the technology and services to do so more widely available. Some of the improvements to smart meter technology in recent years can be beneficial in facilitating demand flexibility and are worth considering for cost-effectiveness. However, the "smartness" of the meter, over and above what has been deployed in Texas so far, is not the most important factor in tapping into latent demand flexibility. The ease, convenience and cost-effectiveness of building energy services management has been radically transformed over that period but is still not widely deployed. There is still only limited availability of flexible demand management service offerings in the competitive retail market. Each of these represents an area where the PUCT could take a more proactive role, as a complement to any market design changes that may be warranted. In particular, the PUCT should revisit the decision not to require TDUs to make customer usage data available in real time to customers and their energy management service providers. When considering changes at both the wholesale market level and in the competitive retail markets, it will be important to ensure that the market design values and fairly compensates consumers and their energy service providers for investments in innovative demand-side technologies and services.

Addendum: Responses to the six questions posed by the PUCT:

1) *The quantity of dispatchable capacity was not a contributing factor to the February energy crisis. The current ORDC arrangements, including recent changes that strengthened investment signals, were successful in delivering a capacity reserve margin (15.3% for 2021 vs reference margin of 13.75%) that exceeded what both ERCOT and the North American Electricity Reliability Corporation projected to be required to comply with long-standing and very conservative resource adequacy standards. Seasonally adjusting dispatchable capacity investment needs would also have been of little benefit — even under the historically rare winter conditions that prevailed during that week, peak demand was slightly below the extreme summer peak contingency scenario for 2021, and investment in dispatchable capacity was sufficient to manage through an historic winter event with a modicum of disruption, had dispatchable capacity performed as expected. The fault in adequacy lies not in the design of the ORDC, which performed as intended given the planning parameters upon which it was implemented, but in the failure by electricity and gas market authorities to stimulate investments in winterizing available capacity and supporting infrastructure by adequately accounting for and broadly communicating the possibility of such a winter event and its likely consequences for supply and demand.*

2) *This would compromise the effectiveness of the two-settlement system with no conceivable benefit to Texas consumers. There is no evidence that failure to offer into the DAM was a contributing factor in the crisis. Indeed, based on DAM pricing for February 15, it is likely most of the capacity that went offline in the early hours of that morning had been offered into the DAM, and while committed reserves were expected to be tight, available generation was*

expected to be adequate even after accounting for expected low wind output. Annual state-of-the-market reports by the Independent Market Monitor have consistently found strong price convergence between the day-ahead and real-time markets, indicative of proper interaction between these two settlement periods.

3) *As noted in the recommendations, it is worth exploring day-ahead procurement of call options, especially in high-risk periods, designed to compensate resources competitively for the costs of extraordinary day-ahead measures necessary to secure the availability of needed reserves, whether they clear in the DAM or not. While existing market arrangements should accomplish this, it is possible that under high-stress conditions in either the electricity or the gas markets, the risk of being unable to recover the cost of advance measures may be greater than the value of such arrangements to Texas consumers. The costs of such new mechanisms should be transparent and recovered through their effect on DAM clearing prices.*

4) *Answered in our recommendations (including energy efficiency as demand response).*

5) Participation in and payment for ERS should be restricted for customers with facilities needed to optimize system reliability under conditions in which ERS may be activated. While ERCOT clearly has a role to play in identifying the affected facilities, the principal responsibility for implementation will be at the PUCT, the TRRC and the TDUs. (Improved sectionalization of distribution feeders is needed generally and should be employed to ensure that protecting critical infrastructure does not preclude participation by other connected loads in rolling curtailments.) The PUCT should also revisit the bases for current constraints on procurement of ERS.

6) *This topic is rich with opportunity. It is worth recalling that ERCOT in 2016 brought its forward-looking FAST proposal (NPRR667) for an expanded suite of ancillary services precisely*

to deal with these challenges, for implementation as early as 2019. That proposal was rejected by ERCOT stakeholders, in retrospect a tragically short-sighted action. The PUCT is right to revisit this topic and would be well advised to use NPRR667 as a starting point.

Conclusion

The February energy crisis brought misery to Texas citizens that they should never again have to experience. The Commission's initiative is a laudable effort to identify and implement changes with the goal of ensuring they never will. While the ERCOT market design offers clear opportunities for improvement, it has performed well on many dimensions, including its incentives for investment in a sufficiently diverse portfolio of generating capacity at a reasonable cost to Texas consumers, and care should be taken to protect what is best about the Texas market model. These comments have attempted to focus on what actually precipitated the February crisis. They are not meant to be comprehensive, but rather to highlight topics that offer especially strong potential for redressing what went wrong during Winter Storm Uri.

The Regulatory Assistance Project appreciates the opportunity to provide these Comments and looks forward to working with the Commission and other interested parties on these issues.

Respectfully submitted,

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