PROJECT NO. 52373

REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	§	BEFORE THE
	§	PUBLIC UTILITY COMMISSION
	§	OF TEXAS

COMMENTS OF THE R STREET INSTITUTE TO THE PUBLIC UTILITY COMMISSION OF TEXAS:

The R Street Institute (R Street) is a nonprofit, nonpartisan public policy research organization headquartered in Washington, D.C. with an office in Texas. Our mission is to engage in policy research and outreach to promote free markets and limited, effective government. We believe in the importance of competition within a regulatory framework based on market efficiency. R Street files these comments in response to questions 1 through 5 from the memorandum posing questions for comment filed in these proceedings by the Public Utility Commission of Texas (Commission) on October 26, 2021.

Commission Questions and replies:

1. The ORDC is currently a "blended curve" based on prior Commission action. Should the ORDC be separated into separate seasonal curves again? How would this change affect operational and financial outcomes?

Having ORDC curves that reflect the different characteristics and risks of different seasons would allow the real-time price adder to be most reflective of risks of shortage. Under the current assumptions used for developing the risk curves, it may be that this change, by itself, would reduce the overall contribution of the reserve price adder to real time prices. However, if paired with the ORDC changes proposed by Potomac Economics—raising the value of lost load (VOLL) to $20,000, setting the Minimum Contingency Level (MCL) to 1430 MW and capping the adder at HCAP—would likely increase the overall contribution from the reserve price adder from what it would be under current assumptions.

Before making any changes to the ORDC, the Commission should consider how they interact with other changes, such as a lower HCAP. Changes such as those in the Potomac Economic proposal would be a purer way of increasing the contribution based on market principles, rather than simply increasing the curve by an arbitrary amount. Further, the Commission should be cognizant of how altering the ORDC affects the “missing money” for resource procurement by season and location. This has major implications for non-ORDC design considerations as well.

For example, any efforts to reduce the ORDC will create or exacerbate the "missing money" problem, which could mute dynamic reliability-enhancing price signals and necessitate a firming obligation to maintain an efficient level of reliability.

2. What modifications could be made to existing ancillary services to better reflect seasonal variability?

Modifications to existing ancillary services are not necessary to better reflect seasonal variability. Ancillary service markets already reflect both seasonal and intra-day variability, and the Electric Reliability Council of Texas (ERCOT) has the flexibility and authority to procure quantities of ancillary services necessary to manage risk from variability of generation resources.[1]

3. Should ERCOT develop a discrete fuel-specific reliability product for winter? If so, please describe the attributes of such a product, including procurement and verification processes.

> *a. How long would it take to develop such a product?*
>
> *b. Could a similar fuel-based capability be captured by modifying existing ancillary services in the ERCOT market?*

It is important to distinguish between two types of reliability risks: those caused by the known probability of frequent independent events occurring simultaneously; and those caused by an unknown probability of infrequent dependent events. For the former, strong spot price signals have worked well because market participants anticipate price movements that reflect reliability conditions. This explains why ERCOT generators have outperformed their peers when it comes to "routine" reliability risks like summer peaks.[2] However, researchers have identified that optimally managing the reliability risk of concurrent outages attributable to a single cause—known as common mode failure—may require special sophistication in market design.[3]

Market design should aim to address both types of reliability risk in a resource neutral manner and ensure market participants internalize all reliability risk. Selectively compensating certain resources is economically inefficient, discriminatory and can undermine pre-existing reliability incentives. The Commission should evaluate the extent to which certain infrequent events with large "tail-risk" are or are not internalized by market participants and take corrective action to the

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[1] See, e.g., "2020 State of the Market Report for the ERCOT Electricity Markets," Potomac Economics, May 2021, pp. 41-43, Figures A22 & A23. https://www.potomaceconomics.com/wp-content/uploads/2021/06/2020-ERCOT-State-of-the-Market-Report.pdf.

[2] DeAnn Walker and Bill Magness, "ERCOT Summer 2019 Update," Nov. 5, 2019. http://www.ercot.com/content/wcm/lists/172485/NERC_MRC_11.05.19_ERCOT_PUC.PDF

[3] Karen Palmer et al., "Economic Approaches to Understanding and Addressing Resilience in the Bulk Power System: A Workshop Summary," Resources for the Future, June 2018, p. 2. https://media.rff.org/documents/RFF_workshop_summary_final_0.pdf.

extent that these risks are not currently internalized. Importantly, fuel-specific reliability risks can and should be mitigated via fuel-neutral policies.

Fuel-specific reliability risks are not unique to Texas, nor is the contemplation of a fuel-specific winter reliability product. A growing body of research (described below) and real-world applications are emerging and Texas should examine the successes and failures of other regions coordinating the natural gas and electricity industries. For example, the Independent System Operator of New England has employed out-of-market winter reliability programs for years to mitigate natural gas fuel supply risk, such as on-site oil backup. This may have provided short-term assurance for some forms of fuel firming, but it has suppressed market price signals and undermined the incentive for generators to invest in a variety of fuel firming activities, including firm pipeline delivery and liquified natural gas contracts. As discriminatory concerns and unintended consequences emerged, subsequent changes to the program expanded resource eligibility – highlighted by the theme of "energy security" in lieu of "fuel security" – and improved processes for verification of energy secure resources, ISO forecasting and market processes like inclusion of opportunity costs for use-limited resources, especially oil and dual-fuel resources that are key physical hedges against disruptions in natural gas delivery.

The Commission should examine the emerging body of industry research on developing metrics and methodologies for common mode risk and pursue market design changes consistent with economic principles. For example, an Electric Power Research Institute study released earlier this year found that extreme weather events and natural gas unavailability are occurring more frequently and that weather shifts are causing changes in the correlated output of variable resources.[4] Pursuing economic assessments of incentive alignment of the current market design would be prudent and help identify what instruments are appropriate, rather than rushing to create an ad hoc product that may not be compatible with the base market design.

For example, scenario assessments using a VOLL estimate for long duration events—which are often multiples higher than short duration events and better represents the unique risk profile of common mode fuel risk—would inform the degree to which current market design achieves incentive compatibility.[5] Such work could estimate probability distributions of interrelated systems—especially the electricity and natural gas interface—and provide probability distributions of the benefits and costs of different resource compositions and market design. This

[4] "Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy," Electric Power Research Institute, Jan. 28, 2021, p. vii. https://www.epri.com/research/products/000000003002019300.
[5] Devin Hartman, "Differentiated Reliability," Future Power Markets Forum, July 22, 2021, pp. 5-6. https://www.rstreet.org/wp-content/uploads/2021/07/Hartman-FPMF-Differentiated-Reliability.pdf.

would help identify whether a new product is warranted or if modifications to existing mechanisms would suffice.

If the Commission elects to pursue a new reliability product, the procurement type and target should have non-discriminatory resource eligibility and be tailored to remedy a specific reliability risk profile. The procurement amount needs to reflect the event the reliability risk is protecting against, and the Commission should be cognizant to avoid concentrating resource procurement in ways that retain or exacerbate vulnerabilities to correlated outages. Paying for a 'token' amount of narrowly-eligible capacity to be "fuel-secure" would not provide sufficient aggregate resources to hedge against profound correlated outages and would carry adverse economic and reliability side effects. A few gigawatts (GW) of "firm-fuel" capacity is not going to be helpful when 60-70 GW of capacity will be needed to serve load. Such an approach would not have prevented the February 2021 event.

An accurate verification process would use an independent assessment of expected performance under anticipated future conditions. Continued reliance on historical data, which is not reflective of future conditions, will produce false negatives in reliability assessments. Better data on specific outage causes and improved modeling of the electric-natural gas industry co-dependencies in Texas will be vital to this effort. For example, 31 percent of power plant outages in the February 2021 event were attributed to fuel supply issues—almost all of which came from gas-fired units—but this problem may be understated because some plants that reported outages due to equipment failure would not have been able to get fuel even with fully operating machinery.[6]

Industry practices are rapidly evolving in this manner, including efforts by the Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC). FERC and NERC have an ongoing investigation into the February 2021 winter event and a separate proceeding on reliability and extreme weather.[7] The resulting changes to reliability standards would be applicable to ERCOT generators and thus may influence the incentives of Texas generators to firm fuel supplies, which in turn would affect the efficacy and efficiency of the Commission's policy reforms.

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[6] Josiah Neeley, "Texas grid reforms must not overlook natural gas supply," R Street Institute, Oct. 15, 2021. https://www.rstreet.org/2021/10/15/texas-grid-reforms-must-not-overlook-natural-gas-supply.

[7] See, e.g., Federal Energy Regulatory Commission, "FERC, NERC Staff Review 2021 Winter Freeze, Recommend Standards Improvements," Department of Energy, Sep. 23, 2021. https://www.ferc.gov/news-events/news/ferc-nerc-staff-review-2021-winter-freeze-recommend-standards-improvements; See, e.g., Federal Energy Regulatory Commission "Technical Conference to Discuss Climate Change, Extreme Weather, & Electric System Reliability," Department of Energy, June 2021. https://www.ferc.gov/news-events/events/technical-conference-discuss-climate-change-extreme-weather-electric-system.

If the Commission goes forward with a fuel-specific winter reliability product alone, it must do so with the understanding that lots of capacity will need to be procured to meaningfully address winter risks. If the Commission uses this option as a stop gap while implementing a more comprehensive solution, then clear limits on duration should be established at the outset.

4. Are there alternatives to a load serving entity (LSE) Obligation that could be used to impose a firming requirement on all generation resources in ERCOT?

It is critical to note that the imperative is overall system dependability, not uniform dependability for all individual generators. Expecting every individual generator to be 100 percent dependable is not only economically inefficient—it is impossible. All types of generation are subject to the potential for unexpected unavailability. Thermal generators (coal, natural gas and nuclear) are all subject to unexpected equipment failures. Coal and natural gas units are also subject to fuel delivery interruptions, such as flooding that stalls coal train deliveries and freezing weather that interferes with natural gas deliveries. Although these units may be thought of as “firm,” in reality the industry has been dealing with their specific unavailability risks for decades and has become accustomed to those risks, developing various backstops to protect against potential unavailability. The outage risks of thermal units are usually independent, and are generally handled as random, uncorrelated risks. Correlated thermal outages are becoming more common, however, and often result from shifting weather patterns such as region-wide freeze limiting gas deliveries or region-wide drought limiting cooling water effectiveness.

Variable energy generators (wind and solar) have different risks of unavailability than those of thermal units. Their risks of unavailability are generally the result of the inability to accurately forecast very specific weather conditions, such as wind speeds and cloud cover. These generator performance risks are generally more correlated than for thermal outages. Historically, the risks of a sudden drop off from these sources has been smaller than the risk of the sudden loss of a thermal unit. However, as the composition of ERCOT’s generation fleet has changed, with wind and solar capacity comprising a larger share of the total, the magnitude and frequency of these somewhat correlated outage risks has increased—at times to be larger than the presumed random outage of a single large thermal unit.

All of this is to note that “firmness” is on a spectrum within and across resource types and the value of a resource’s availability depends on dynamic system conditions. This is why price signals that reflect system conditions convey critical information on resource value in a manner that an administrative requirement cannot. They drive voluntary actions by resource developers and owners to build, exit and configure resources in a manner that firms the aggregate system such that benefits exceed costs. Top-down firming obligations on generators often induce uniform responses across a resource fleet with some resource decisions having lower net benefits than what a decentralized resource decision model would produce. Some firm generator requirements also depart from any ability to achieve the economically efficient level of reliability in the aggregate.

If the Commission decides to make market design changes that impose a minimum level of resource adequacy, the first step will be to articulate the required reliability standard. Any changes made without a stated objective are just 'turning the dial' in hopes of an acceptable outcome. A clear objective—such as an economically efficient resource margin—is needed. This could be evaluated by how close the system comes to maximizing net benefits.

A variety of generator firming requirement options exist, such as a centralized capacity market, targeted capacity payments and strategic reserves. However, they are all likely to involve more administrative errors and inefficiencies when compared to a firming obligation on load serving entities (LSEs).

5. Are there alternatives to an LSE Obligation that could address the concerns raised about the stakeholder proposals submitted to the Commission?

The Commission expressed two concerns clearly during their October 21 workshop: avoiding harm to independent retail energy providers (REPs); and preventing market power abuses. These two concerns are related.

The concerns of independent REPs having to arrange for a new requirement will be whether there are options and alternative methods that meet their obligation without being subject to a small number of suppliers abusing market power to increase prices above what a competitive, liquid market would provide.

Market power abuse is a concern in a market as concentrated as ERCOT. Other concentrated markets successfully deter market power abuse by using a combination of methods, including must-offer requirements, offer caps, market transparency and by having rules that clearly prohibit market power abuse coupled with effective enforcement procedures. Market power abuse is a valid concern, but it can be addressed. The fear of a party exercising their market power to the point of abuse should not be an excuse for avoiding a market design that is preferable to alternatives that would improve confidence in ERCOT's reliability performance.

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Respectfully submitted,

/s_____________________

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EXECUTIVE SUMMARY FOR COMMENTS OF THE R STREET INSTITUTE TO THE PUBLIC UTILITY COMMISSION OF TEXAS:

The Commission was correct to act quickly to prevent repeat conditions from the February 2021 event. Outages during February were primarily the result of poor resource performance, with the most generator outages resulting from inadequate weatherization and natural gas fuel supply limitations.[8] It was also exacerbated by an underdeveloped demand side of the marketplace and policies that poorly allocate scarce resources when all firm load cannot be satisfied.[9] The Commission's swift action on weatherization has been a critical improvement to grid reliability, though ensuring firm fuel supplies during extreme cold weather remains a key outstanding reliability concern heading into this winter.

In addition to and separate from this, the Commission is considering market design changes to deal with longer term issues with regard to reliability and changes in the generation mix. While important, these issues do not face the same urgency as weatherization, and they will need to be implemented over the course of multiple years. Given this, it is important that the Commission not rush this rulemaking but act in a deliberate manner that allows for full stakeholder engagement. The Commission should not sacrifice quality for expediency. Instituting major changes to the Texas electricity market design without a full opportunity for vetting and discussion of the proposals poses a significant reliability risk to the system. Reliability risks experienced in February can be mitigated this winter without a market design overhaul, whereas rushed reforms may leave lasting unintended consequences with minimal or no reliability benefit.

Permanent market design decisions should be guided by economic principles that maximize system net benefits, including reliability. These include assigning costs on a causation basis and ensuring incentive compatibility of market participants, such as aligning market participants' net

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[8] Testimony of Beth Garza, House Committee on Science, Space, and Technology, "Lessons learned from the Texas blackouts: Research needs for a secure and resilient grid," March 18, 2021. https://science.house.gov/imo/media/doc/Ms.%20Garza%20Testimony.pdf.

[9] Ibid.

revenues with efficient and reliable system investment and operations. Applying these concepts helps prioritize reforms and eliminate problematic proposals from consideration.
Concepts consistent with economic principles include strengthening black-start procurement; modifying the ORDC to reflect proposed lower offer caps; and reducing barriers to self-supply and distributed and demand side resource participation. This can be paired with complementary reforms like modifying distribution circuits for granular outage management, improving ERCOT forecasting and scenario analysis, and ensuring identification and resilience measures like back-up power are in place for critical infrastructure facilities. Other items, such as cost-effective weatherization of natural gas production and pipelines would also be net beneficial, but fall outside the jurisdiction of the Commission.[10]

Some concepts should be dismissed as they are inconsistent with economic principles. These include out-of-market support for new power plants or charging the costs of a new ramping service entirely to renewable generators rather than proportionate to all causers of ramp requirements. By contrast, including the concept of marginal losses is growing in importance in wholesale market design given greater reliance on generators further away from load. It is a staple of locational marginal pricing in theory and already employed by other independent system operators.

Economic principles should guide decision-making under different sets of policy assumptions. For example, market design can be modified in the absence of a firming requirement to ensure incentive compatibility for reliability risks like correlated generator outages. If a firming requirement is a foregone conclusion, some options are more economically efficient than others. In particular, an LSE Obligation would outperform both a more rigid, centralized capacity market and a partial capacity market, where only some of the resources needed to reliably meet customer requirements are directly compensated. Important considerations for an LSE Obligation include what reliability standard is directed and how resources (both supply and demand) will be accredited to meet that standard. The performance of this construct will be sensitive to the quality of its implementation, especially for elements like accreditation, which underscores the imperative of getting the right policy in place, not merely the most expeditious.

[10] Pat Wood III, et al., "Never Again: How to prevent another major Texas electricity failure," PUC of Texas Commissioners Report, June 3, 2021. https://cgmf.org/blog-entry/435/REPORT-%7C-Never-Again-How-to-prevent-another-major-Texas-electricity-failure.html.