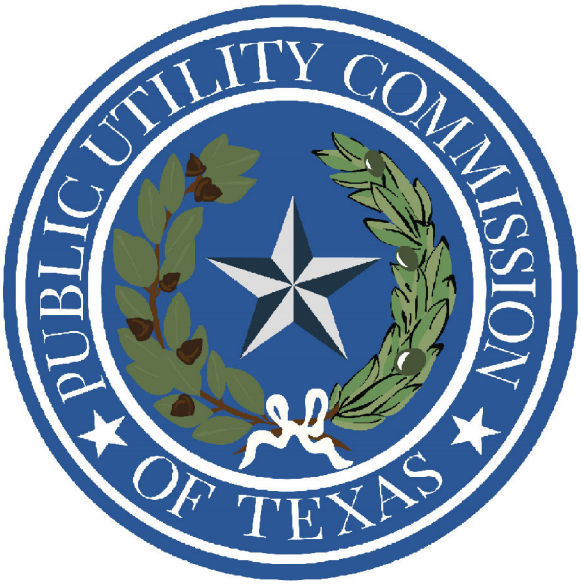

Filing Receipt

Received - 2021-11-01 11:59:56 AM
Control Number - 52373
ItemNumber - 226

PROJECT NO. 52373

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

VISTRA CORP.'S COMMENTS IN RESPONSE TO STAFF'S OCTOBER 25, 2021 REQUEST

TO THE PUBLIC UTILITY COMMISSION OF TEXAS:

Vistra Corp. (Vistra), on behalf of its jurisdictional subsidiaries, files these comments in response to the Public Utility Commission of Texas (Commission) Staff's October 25, 2021 Memorandum in Project No. 52373 seeking comments on 16 questions.[1] These comments are timely filed.[2]

I. COMMENTS

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?

No—the current blended curve should not be separated into seasonal curves. Vistra agrees with Chair Lake's comments at the October 21, 2021 open meeting that the Commission should avoid "over-engineering" the Operating Reserve Demand Curve (ORDC), which is what disaggregating the ORDC into separate seasonal curves would be.[3] The loss of load probability (LOLP) curve is a normal probability distribution calculated based on the mean (or average) and standard deviation of the differences between hour-ahead forecasted reserves versus actual historical reserves during that same operating hour.[4] The result of this calculation today is thus only a proxy for the "actual" LOLP at any given time.

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[1] Memorandum from Ben Haguewood to the Chairman, Commissioners, and Interested Parties (Oct. 25, 2021).

[2] *Id.* (setting deadline for comments on Nov. 1, 2021).

[3] Tr. at 37 (Oct. 21, 2021 open meeting).

[4] ERCOT, *Methodology for Implementing Operating Reserve Demand Curve (ORDC) to Calculate Real-Time Price Adder*, at 1 (version 2.7) (The LOLP is "is the probability, at a given level of reserves, of the occurrence of a loss of reserves greater than the [minimum contingency level (MCL)] reserve level and is therefore determined by calculating the mean and standard deviation of differences between the hour-ahead forecasted reserves and the reserves that were available in Real-Time during the Operating Hour using historical data."), *available at*:

Splitting the curve to represent different LOLPs is false precision, especially given the unpredictability of reserves during shoulder seasons. The reserve level is more predictable during extreme weather situations because historical evidence shows how load responds in those situations, and generators are incentivized to make every megawatt available. In the shoulder seasons (i.e., when planned outages occur), variability in actual reserve levels depends more on wind output, which is inherently unpredictable, and demand tends to fluctuate less predictably.

Additionally, splitting the LOLP into seasonal curves would counterintuitively shift ORDC financial benefits to renewable generation at the expense of dispatchable resources on planned outage (i.e., shoulder months). That is because increased difficulty of predicting reserves in shoulder months increases the forecast reserve error. As a result, the mean and standard deviation of the differences between hour-ahead forecasted and actual historical reserve levels in the shoulder months tend to be higher, resulting in an LOLP distribution that is more likely to yield higher ORDC adders in those months. Thus, splitting the ORDC into seasonal curves could incentivize more intermittent generation at the expense of dispatchable generation, an outcome inconsistent with the policy directives of the state.

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

The ERCOT ancillary services (AS) plan already factors in seasonal variation and provides ERCOT with flexibility to make changes to AS quantities throughout the year. Thus, Vistra does not believe changes are needed to better reflect seasonal variability. While Vistra generally prefers for AS procurements to remain in line with the approved AS plan, ERCOT has the ability to modify AS amounts as needed throughout the year.[5] In this way, ERCOT already has tools to modify existing AS procurements to reflect seasonal variability.

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http://www.ercot.com/content/wcm/key_documents_lists/89286/Methodology_for_Implementing_ORDC_to_Calculate_Real-Time_Reserve_Price_Adder.zip.

[5] ERCOT, *Methodologies for Determining Minimum Ancillary Service Requirements* (effective Jan. 1, 2021), at 2 ("If necessary, any additional incremental adjustment to the posted Ancillary Service requirements for a particular month will be made using this procedure and will be posted to the MIS prior to the 20th of each month for the upcoming month. If the AS requirements identified through this process for a particular operating day are found to be insufficient based on the expected operating conditions for that day, ERCOT may make an updated AS requirements posting for that day if the need for incremental adjustments is identified day-ahead and may use the Supplemental Ancillary Service Market (SASM) process for similar adjustments made closer to real-time."), *available at*: http://www.ercot.com/content/wcm/key_documents_lists/89135/Zip_to_be_posted.zip.

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.

Yes, ERCOT should develop a fuel-specific winter reliability product, with these features:

- Procurement Process – Black Start Service could serve as a process template. The timeline for submitting bids could be similar (e.g., by a set date several months in advance of the contract term), and ERCOT could execute a multi-year contract for the service, with a gap between its selection of the resource and the onset of contract responsibility, to allow time for any needed testing and preparation.[6] The product should be open to new and existing qualified resources.

- Procurement Sizing – Procured fuel-secure MW should be targeted based on the expected extreme tail risk of fuel insufficiency. For example, ERCOT could start, as a baseline assumption, with the fuel insufficiency observed during Uri[7] and expand that to reflect the likelihood that fuel insufficiency issues would have been more impactful with fewer generation outages. Better weatherized plants will lead to increased demand for fuel, both from the power plants and from the incremental gas customer demand for heating. It is unclear whether issues experienced in the natural gas industry (e.g., force majeures, gas freeze offs) have been fixed. Thus, the grid may see higher demand for fuel, without an increase in supply. In addition, load growth means that increases in demand at homes and businesses will contribute to fuel insecurity in any future Uri-like event.

- Qualified Resources – Technology Neutral - The service should be technology neutral, meaning it should be available not only for gas plants with on-site or nearby fuel storage, dual fuel capabilities, or even reliably firm fuel/transportation contracts, but also for nuclear, coal, hydro, and other resources that can demonstrate fuel security. Energy storage facilities also could have limited eligibility based on their ability and scope to charge/discharge before a potential reliability event.

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[6] *See* ERCOT Protocols § 3.14.2 (bids for Black Start Service are due on or before February 15th of each two-year period, and contracts must be entered by December 31 for the following two-year period).

[7] For example, see *Update to April 6, 2021 Preliminary Report on Causes of Generator Outages and Derates During the February 2021 Extreme Cold Weather Event* (April 27, 2021) at 25, showing fuel limitation-driven outages or derates driving as much as ~9 GW of outages or derates during Winter Storm Uri, *available at:* http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf.

- Pricing – ERCOT should use a single clearing price to the extent fuel-reliable megawatts are comparable. For example, with natural gas, in determining which resources to include in a given clearing price, ERCOT may need to score the relative reliability value of onsite storage or dual fuel versus offsite storage plus firm transport versus firm gas plus firm transport.

- Enforcement/Performance: Performance standards should be established, and ERCOT could report non-compliance to the Commission, which could enforce under 16 Tex. Admin. Code (TAC) § 25.503(f)(2) and (g)(3).

a. How long would it take to develop such a product?

With enough guidance and direction from the Commission, Vistra believes ERCOT and stakeholders should be able to develop requirements within six months, but generally defers to ERCOT on this question.[8] As described above, Vistra does not believe implementation would be impacted by ERCOT's pending Energy Management System (EMS) upgrade.

b. Could a similar fuel-based capability be captured by modifying existing ancillary services in the ERCOT market?

No. The existing AS products each address specific system reliability needs that are operational and generally unrelated to fuel security. Rather than attempt to shoehorn a fuel security need into an existing AS, Vistra recommends either incorporating these desired features into a new AS product (such as the Dispatchable Standby Reserve (DSR) concept or creating a new focused stand-alone service in the nature of Black Start). This would also be necessary if the Commission wants to avoid the delays ERCOT has warned may be associated with the EMS upgrade.

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?

As an initial matter, the definition of "firming requirement" must be clarified. The real-time market provides one form of firming today as a balancing market. If by "firming requirement," the Commission means that all generation capacity is expected to provide some projected percentage of its nameplate capacity at all times, then that is a fundamentally different

[8] For comparison, when the Commission directed ERCOT to implement Real-Time Co-optimization (RTC), the stakeholder process to develop key principles took 12 months and the process for developing Protocol language to implement those key principles took another 12 months. However, RTC touched nearly every aspect of ERCOT's Protocols; implementation of a targeted, limited fuel security product that does not impact ERCOT's market or energy management operations should take significantly less time.

market structure than the current energy-only market. Such a firming requirement that presumably obligates generation resources to offer capacity into the market would typically require a contract with those resources (paying them to be available). This type of construct can be met by an LSE obligation (LSEO) or, alternatively, through a capacity market.

Other proposals, including Vistra's DSR proposal (addressed in September 30th comments in this Project), would provide a framework to incentivize generators to be available and online when needed—or for ERCOT to commit the needed resources via the DSR product. The DSR product would have a similar practical firming effect as a capacity market, but would concentrate the firming capabilities in specific reserve capacity, which, as discussed below, is significantly different than a capacity market structure.

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

Yes, such alternatives include a centralized forward capacity market with a sloped demand curve or a product like DSR. While Commissioners appear to have declined to take up the DSR concept at this time, Vistra would like to address observed or inferred concerns that appeared to be aimed at DSR, so that the Commission might view DSR objectively with the benefit of that feedback.

- Concern: "Capacity market disguised as a new ancillary service"[9] – the major difference between DSR and a capacity market is that DSR would be a targeted procurement of dispatchable reserves held for tight operational contingencies such as extremely low wind output combined with above-normal thermal outages, whereas a capacity market is a fleet-wide requirement based on satisfying a specified reliability standard. DSR is far more analogous to existing AS products—a targeted procurement of specific characteristics required to meet an anticipated operational need through ERCOT commitment.

- Concern: DSR "would sit on the sideline"[10] – Just like any other AS, DSR would be reserved for ERCOT to commit. And, of course, unless the DSR is reserved, then no reliability insurance has been obtained. Over time, as the energy market incentivizes more dispatchable resources,

[9] Tr. at 9 (Oct. 21, 2021 open meeting).

[10] Tr. at 11 (Oct. 21, 2021 open meeting).

DSR procurements could decline (either in absolute terms or as a percentage of load) thereby lowering its cost.

- Concern: DSR cannot be hedged – part of the reason that Vistra would propose to explicitly remove DSR capacity from the ORDC calculations, but also allow DSR capacity to receive ORDC payments when committed by ERCOT is so that a DSR resource can reasonably expect scarcity revenues if/when activated by ERCOT. Thus, a DSR resource should be incentivized to offer into the DSR auction with a lower availability price point (meaning that a large amount, if not most, of the cost impact of DSR should flow to LSEs through real-time prices, which are hedgeable). In many respects DSR may be easier to hedge than most AS products since qualified loads could provide DSR or manage exposure by curtailing.

Load Serving Entity (LSE) Obligation

6. How can an LSE Obligation be designed to protect against the abuse of market power in the wholesale and retail markets?

The LSEO idea is still lacking detail, but a properly constructed LSEO could provide resources the opportunity to recoup the "missing money" they cannot reliably obtain through the current energy and AS markets. In addition, an LSEO construct would give the Commission and ERCOT new tools to have load firm up its obligations, impose participation requirements on generators, and facilitate a market-based forward liquidity mechanism to support various reliability initiatives such as new build and winterization.

Regarding the expression of "market power" concerns, it is unclear how a bilateral open forward market that requires LSEs to procure reserves would be uncompetitive or raise unique or insurmountable market power concerns. As a forward product, it would be more like non-power commodities (e.g., oil, agricultural output, metals, etc.) than power; these commodities all trade economically in bilateral markets without concerns about market power abuse. Today, LSEs participate broadly in the competitive wholesale markets for energy and AS, both through Commission regulated markets like the ERCOT day ahead and real time markets, as well as financially via bilateral transactions or on exchanges like the Intercontinental Exchange (ICE). In fact, ERCOT market participants regularly use a broad range of bilateral products without market power concerns arising. Over time, the market for the LSEO products should develop broadly, including participation in the broker markets and on exchanges. Each of these steps would further

reduce any potential for market power abuse and could be accelerated through policy choices by the Commission.

It is possible that concerns raised about market power abuse actually reflect opposition to paying the costs required for reliability. Securing sufficient reserves to operate the grid reliably and resiliently will have costs, and regardless of the path forward, a competitive market will provide price discipline (as the Chair has noted, "the cure for high prices is high prices"[11]), and Commission Staff and the Independent Market Monitor (IMM) are empowered to identify potential market power abuses if market forces are not working. Moreover, affiliated generation and retail operations are not inherently sources of market power abuse. While there are transactional cost advantages to such arrangements (e.g., credit efficiencies, avoiding the loss of bid-ask spread to a third-party exchange), competitive markets should encourage economic efficiency, including in business forms. Additionally, each of the affiliated generation and retail entities are not monoliths—they are distinct competitive market players that can and often do buy and sell to and from unaffiliated third parties when it is in their economic interest to do so. That's only logical—for example, in a market structure that creates a value for energy or for capacity, or both, marginal pricing principles still apply, so if a generator can sell to a third party for more than its retail affiliate is willing to pay for it, then it should (and will) do so.

a. Will an LSE Obligation negatively impact customer choice for consumers in the competitive retail electric market in ERCOT? Can protective measures be put in place to avoid a negative impact on customer choice? If so, please specify what measures.

Much of the criticism of the LSEO addressed hypothetical threats to the competitiveness of this market, and presumed, without foundation, that affiliated generation and retail businesses are able to and will exercise market power, to the disadvantage of smaller retail electric providers (REPs). That presumption is incorrect. Market power abuse is expressly prohibited by 16 TAC § 25.503, and the penalties for engaging in such abuse are high:[12]

[11] *E.g.*, Tr. at 40 (Oct. 21, 2021 open meeting) (paraphrased above).

[12] Not only are violators subject to penalties of up to $25,000 per violation per day, but the Commission can order disgorgement of revenues in certain instances. 16 Tex. Admin. Code (TAC) §§ 22.246, 25.503(o).

> "a market participant must not engage in market power abuse. Withholding of production, whether economic withholding or physical withholding, by a market participant who has market power, constitutes an abuse of market power."[13]

Creating a new product, be it DSR, LSEO, or any other new AS product should not incrementally increase the risk of market power abuse. The Commission manages this risk in current energy and AS markets. Procuring resources sufficient to manage the grid's expected obligations is a reliability initiative that does not raise incremental market power concerns. The Commission can continue to apply its robust oversight, effective mitigation, and serious enforcement penalties to new products.

Moreover, the Commission can design processes to avoid a negative impact on customer choice, including:

- Full visibility to ERCOT, the IMM, and the Commission into the bilateral market;
- Transparent price reporting to allow the market to mark the price and foster a robust traded market; and
- Use of existing market power mitigation measures, such as update and approval of publicly available Voluntary Mitigation Plans.[14]

Bilateral markets are extremely common across markets and commodities and are regularly used by LSEs to hedge energy and AS costs today. However, if the Commission wants an LSEO structure and believes that market participants cannot fairly negotiate and contract with each other bilaterally, then this product could be procured through a centralized market at a common price. While it is unclear how an LSEO proposal is inherently uncompetitive or more prone than any other market (such as the existing ERCOT markets) to market power abuse, to the extent that a valid concern exists, then the centralizing of the market should solve that concern.

Further, counter to the concerns expressed, this type of proposal would likely reduce the risk of market power abuse rather than increase it. Participation in a new product enables the Commission to condition the obligation with a number of different requirements. For example, this could include a must-offer requirement in the day ahead or real time markets, weatherization

[13] 16 TAC § 25.503(g)(7).

[14] See 16 TAC § 25.504(e)

requirements, etc. To the extent a concern is based on an entity having "too much" generation capacity, PURA already sets a 20 percent market share cap.[15] And any concerns about affiliated generation and LSEs hypothetically dominating the market by acting as monoliths are unfounded, as discussed in the introductory response to Question 6.

b. How can market power be effectively monitored in a market where owners of power generation also own REPs that serve a large portion of ERCOT's retail customers?

Concerns about transparency in an LSEO market could be managed simply by requiring transaction reporting. Market participants regularly report trades in other contexts, for example, Commodity Futures Trading Commission (CFTC) regulations require reporting of relevant swap transactions.[16] This approach, implemented pursuant to the Dodd-Frank Act, facilitates compliance monitoring by the CFTC and its various exchanges (e.g., ICE, CME, Nodal, etc.) and enables trading in a multitude of products and markets, including power, across jurisdictions and with varying degrees of liquidity. While the required level and detail of reporting used by the CFTC might not be necessary, it shows that concerns about transparency can be cured through a reporting requirement.

c. What is the impact on self-supplying large industrial consumers who will have to comply with the LSE Obligation and will it impact their decision to site in Texas?

There should be no specific impact on self-supplying large industrial customers that is different from the obligation they already face for energy and AS products. Today, these customers may choose to participate in the bilateral hedging of existing products, and an LSEO would simply add another product. Enhanced confidence in the reliability of the Texas grid should motivate additional customers to relocate to Texas from other regions.

d. What is the impact of an LSE Obligation on load-serving entities that do not offer retail choice, such as municipally owned utilities or electric cooperatives?

The impact of an LSEO on municipally owned utilities or electric cooperatives should be analogous to the impact on competitive REPs. These entities would participate in the wholesale market securing obligations, as they do today in hedging their energy and AS exposures or

[15] Public Utility Regulatory Act (PURA), Tex. Util. Code § 39.154.

[16] See CFTC Regulation(s), 17 Code of Fed. Regs. (CFR) §§ 45.1, 45.3 and 45.4.

participating in reliability products such as Black Start contracts. These entities would not be disadvantaged in any respect as compared with other competitive market participants.

e. Can market power be monitored in the bilateral market if an LSE Obligation is implemented in ERCOT? Can protective measures be put in place to ensure that market power is effectively monitored in ERCOT with an LSE Obligation? If so, please specify what measures.

Please see Vistra's preceding answers under this Question 6.

f. Should the LSE Obligation include a "must offer" provision? If so, how should it be structured?

A reasonable condition to participation in an LSEO market could be a must-offer requirement. This approach is used in other markets and helps provide those Independent System Operators (ISOs) with additional certainty about availability in day ahead and real time markets. With that said, we believe that a must-offer requirement without compensation, i.e., without an LSEO or similar product, would be unlawful and subject to challenge. In the context of an LSEO, a must offer requirement, alone, should alleviate concerns about market power abuse. Must offer requirements reduce the potential for market power abuse and provide more command and control to the ISO.

7. How should an LSE Obligation be accurately and fairly determined for each LSE? What is the appropriate segment of time for each obligation? (Months? Weeks? 24 hour operating day? 12 hour segments? Hourly?)

While the LSEO concept is new and this novel question was not contemplated in the original E3 proposal, on first thought the simplest of these models would appear to be a periodic product procured ahead of time (e.g., annually) with opportunities closer to delivery to update positions and make incremental purchases. Incremental procurement opportunities will also provide new REPs with opportunity periods to secure obligations. An alternative would be a mix of products that reflect the traded products for ERCOT (e.g., 5x16, 2x16, 7x8). However, such an alternative would introduce a level of complexity that is likely not necessary. Regardless of design, an effective LSEO will require loads to procure sufficient generation to cover unexpected load swing.

8. Can the reliability needs of the system be effectively determined with an LSE Obligation? How should objective standards around the value of the reliability-providing assets be set on an on-going basis?

    a. Are there methods of accreditation that can be implemented [with] less administrative burden or need for oversight, while still allowing for all resources to be properly accredited?

There are two primary ways to manage accreditation. First, and Vistra's recommendation, is to assign an accreditation value based on the technology type and fuel supply. For example, plants with onsite fuel (e.g., diesel, uranium, etc.) would receive a higher accreditation than those without, and technologies with intermittency would, in turn, receive a lower accreditation (but the level could be increased to reflect enhancements like co-location of a storage device). In the alternative, a methodology could use a combination of historical availability, testing, and other unit-specific facts—including fuel sources—to produce a unit-specific accreditation; however, developing and implementing a system with that level of complexity seems unnecessary and burdensome, without a commensurate benefit to reliability or the market.

    b. How can winter weather standards be integrated into the accreditation system?

Similar to the must-offer requirement, participation by generation resources in an LSEO could require compliance with developed winterization standards (in addition to the standards that will apply to all resources under the Commission's new weatherization rule). Failure to comply with those requirements, which are already being audited by ERCOT, would remove the accreditation, putting an additional significant penalty on generators that do not properly winterize.

9. How can the LSE Obligation be designed to ensure demand response resources can participate fully and at all points in time?

Demand response will be able to participate fully in the LSEO market, including by contracting to meet LSEs' needs, so long as they can provide a sufficiently reliable curtailment. Such a program is likely to significantly increase participation by load in these markets, as it provides important price signals and revenue certainty to loads that are prepared to curtail. Similar to generation, participation by demand response would require accreditation standards and penalties for non-compliance. However, these reasonable and equitable requirements should not prejudice demand response participation.

10. How will an LSE Obligation incent investment in existing and new dispatchable generation?

Today, ERCOT relies on an energy market that assumes that the receipt of marginal clearing prices for electric energy (plus volatile adders) from a resource is sufficient for resource owners to make rational long-term investment decisions about whether to build or retire resources. However, in recent years, this pricing model has failed to send sufficiently accurate long-term price signals for dispatchable new build. Real costs, such as the cost to procure firm gas transportation and storage, are not recoverable on the margin, which further undercuts reliability. The ERCOT market model's reliance on extreme volatility, ESG (environmental, social, and governance) limitations on financing, and difficulties in securing reliable and predictable fuel at reasonable costs all discourage thermal dispatchable investment (there is new growth in battery investment, which is dispatchable but is of limited duration and therefore of limited reliability value for long-duration events such as Uri). What the existing system lacks is an incentive for loads to hedge forward over a long-time horizon or a mechanism to lock in longer-term revenues and mitigate volatility. Any product that provides that certainty is likely to make marginal units less likely to retire, incentivize investment in existing units to improve performance and reliability, and lastly, if prices justify it, provide a proper basis for new build. In particular, a well-designed LSEO, coupled with needed improvements to the ORDC, should provide an environment attractive to capital investment.

11. How will an LSE Obligation help ERCOT ensure operational reliability in the real-time market (e.g., during cold weather events or periods of time with higher than expected electricity demand and/or lower than expected generation output of all types)?

The LSEO puts the onus on load to secure needed resources ahead of day-ahead or real time markets. The onus is also on generators to be prepared and ready to operate, so they avoid non-performance penalties. This alignment of incentives should support ERCOT's need for operational reliability. If tied to a mandatory reliability standard (or standards), then the LSEO construct should, over time, draw enough capital into the market such that there is sufficient capacity to meet operational extremes on a risk-adjusted basis.

12. What mechanism will ensure those receiving revenue streams for the reliability services perform adequately?

Non-performance by generation should include some form of penalty or claw back. This approach would provide proper incentives for generation to be available outside of times of

planned or maintenance outages. While generators are already incentivized to perform in order to capture energy revenues, this penalty construct would provide an additional deterrent against non-performance.

13. What is the estimated market and consumer cost impact if an LSE obligation is implemented in ERCOT? Describe the methodology used to reach the dollar amount.

Vistra did not develop the LSEO construct and thus does not have a specific estimated market or cost impact for the LSEO proposal, but believes that securing improved reliability in ERCOT (no matter what mechanism is used or how those costs are assigned) will entail additional cost for consumers. However, any cost will be accompanied by significant economic and societal benefits from a more reliable electrical grid, along with a reduced threat of forced load shed and the accompanying substantial economic and human costs.

14. How long will the LSE Obligation plan take to implement?

While Vistra did not develop the LSEO proposal, Vistra could envision a product like the LSEO being developed and implemented within 2 to 3 years. It is a longer-term solution, requiring significant effort to develop the reliability standard(s), LSEO specifications, resource accreditations, etc., and thus highlights the need to implement immediate solutions like Vistra's recommended improvements to the ORDC and DSR product.[17] The ORDC changes are necessary to mitigate the proposed reduction in the high-system wide offer cap (HCAP), which, standing alone, is bearish to energy prices, as evidenced by a decline in the forwards, and would likely push units out rather than draw development in.

15. If the Commission adopts an LSE Obligation, what assurances are necessary to ensure transparency and promote stability within retail and wholesale electric markets?

Adoption of an LSEO, or a similar product, requires little to no more assurances than are used today in the energy or AS markets. As discussed above, the Commission has ample tools to monitor and assess the market, to ensure competitive outcomes and a reliable grid. If anything, providing a forum for public disclosure of prices and volumes would provide needed price

[17] See Vistra's comments in this project filed on September 30, 2021, as well as in Project No. 52631 on September 30 and October 28, 2021.

transparency without divulging competitively sensitive LSE- or resource-specific information, and ought to be sufficient.

16. Are there relevant "lessons learned" from the implementation of an LSE Obligation in the SPP, CAL-ISO, MISO, and Australian markets that could be applied in ERCOT?

One exceedingly important feature, as identified in MISO, is the shape of the demand curve. Use of a vertical demand curve is the most significant design flaw identified by the MISO IMM, Potomac Economics, in the MISO State of the Market Report.[18] A vertical demand curve values at zero dollars all incremental generation above the minimum requirement. That is inconsistent with the true reliability value of that generation. Use of a sloped demand curve would properly reflect the reliability value of the surplus resources in excess of the minimum clearing requirement. Vistra recommends that if an LSEO is implemented, then it should include a sloped demand curve, which would improve price signals, encourage efficient market entry and exit, increase market stability, increase consumer and investor confidence in the market, and more accurately value generation.

II. CONCLUSION

Vistra appreciates the opportunity to provide these comments for the Commission's consideration as it works to improve the ERCOT market design. Vistra looks forward to continued participation in this effort.

Dated November 1, 2021

Respectfully submitted,

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[18] Potomac Economics, *2020 State of the Market Report for the MISO Electricity Markets* at viii-ix, 83-86 (May 7, 2021), *available at*: https://cdn.misoenergy.org/2020%20State%20of%20the%20Market%20Report364567.pdf

PROJECT NO. 52373

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

STAND-ALONE EXECUTIVE SUMMARY OF VISTRA CORP.'S COMMENTS IN RESPONSE TO STAFF'S OCTOBER 25, 2021 REQUEST

- Improvements to the Operating Reserve Demand Curve (ORDC), such as those recommended in Vistra's September 30, 2021 comments, should be made as an immediate term improvement to the market and should be implemented simultaneously with any reduction to the high-system wide offer cap.
- The Commission should not disaggregate the loss of load probability (LOLP) curves for the ORDC into seasonal curves—that is "over-engineering," creating false precision.
- ERCOT's current process for setting AS quantities already accounts for seasonality, so there is no need to modify AS products to take into account seasonal variations.
- The Commission should establish a winter fuel security product. It could be procured and compensated in a similar manner as Black Start Service (and thus would not depend on the Energy Management System (EMS) upgrade). Participation should be open to any existing or new resource that can provide fuel security—e.g., in addition to natural gas-fired units, it should be open to coal, nuclear, hydro, and (with a discount to capacity value to account for limitations in duration) storage resources.
- A product like Vistra's proposed Dispatchable Standby Reserve (DSR) product would provide additional insurance to the Commission against insufficient capacity during extreme weather events and is similar in nature to existing ancillary services (rather than a capacity market in disguise).
- Should the Commission desire instead to impose some sort of fleet-wide firming requirement, then the only viable alternative to the load-serving entity (LSE) obligation would be a forward centralized capacity market.
- While some have raised hypothetical "market power" concerns for an LSE obligation construct, such a construct does not raise significant or unique market power abuse concerns or provide unfair advantage to LSEs with competitive generation affiliates. As the Commission has noted, the market functions quite competitively today, and an LSE

obligation construct would simply add a product, without raising new fundamental structural changes that would change the competitive dynamic. Moreover, the Commission has ample tools to monitor and address potential market power abuses and could adopt a number of features with an LSE obligation to enhance its competitiveness and transparency, such as a must offer requirement (in the day-ahead and/or real-time markets) and transaction reporting.

- Accreditation for an LSE obligation should be based on the reliability attributes of different resource types and technologies (rather than done on a resource-specific basis, which would be unduly complex).
- An LSE obligation will entail some cost to consumers, but should also provide significant benefits in the form of enhanced reliability.
- An LSE obligation could potentially be implemented within 2 to 3 years.
- A sloped (rather than vertical) demand curve should be used for valuing LSE obligations, as a lesson learned from the MISO market.