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PUC PROJECT NO. 52268

CALENDAR YEAR 2021 – WORKSHOP AGENDA ITEMS WITHOUT AN ASSOCIATED CONTROL NUMBER	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

PUC PROJECT NO. 52373

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

CALPINE CORPORATION'S RESPONSE TO MARKET DESIGN QUESTIONS

Calpine Corporation ("Calpine") appreciates the opportunity to respond to the questions filed by the Commission on August 3, 2021 in PUC Project 52268, *Calendar Year 2021 - Workshop Agenda Items Without an Associated Control Number* and PUC Project 52373, *Review of Wholesale Electric Market Design*.

Since Senate Bill 7 ("SB7") was adopted in 1999 and implemented in 2002, the ERCOT "energy - only" market has continuously evolved as a competitive electricity market including: a transition from a zonal to a nodal market, establishment of Competitive Renewable Energy Zones ("CREZ"), multiple adjustments to the system-wide offer cap, changes to ancillary services, inclusion of the Operating Reserve Demand Curve ("ORDC") in market pricing and adoption of more than 1,000 nodal protocol revisions. The market must now further evolve to support the proper alignment of incentives and participant responses to ensure reliable operation and ultimately the sustainability of the market. A key challenge facing the market arises from increasing energy supply from subsidized intermittent resources that reduce energy market revenue and long-term reliability due to their intermittency. Ensuring revenues exist to support, attract, and retain dispatchable resources is essential to the success of this proceeding. Following Winter Storm Uri, the Commission was directed to focus on reforms that will improve electric reliability in Texas including development of a market to foster adequate and reliable sources of power.[1] To achieve this end,

1 https://gov.texas.gov/news/post/governor-abbott-directs-public-utility-commission-to-take-immediate-action-to-improve-electric-reliability

Calpine understands the Commission will evaluate responses from interested parties through a series of questions and work sessions and will finalize a market design plan to enhance reliability by December 2021.[2]

Calpine supports this focus on reliability and offers suggestions that are intended to provide alignment of incentives and market participant responses consistent with principles that are market based, reduce volatility, provide value for dispatchable resources that bolster reliability, and work within the existing market structure. Calpine believes the Commission has the basic tools within the current market construct to enhance both operational and planning reliability. Along these lines, Calpine respectfully requests the Commission consider the following market design modifications in its market design work sessions:

- Reform the ORDC to ensure it produces revenues sufficient to attract and retain dispatchable generation including possible changes to the Value of Lost Load ("VOLL"), Value of X and the Loss of Load Probability ("LOLP") parameters.
- ERCOT should procure Ancillary Service ("AS") quantities on a daily or longer-term basis as may be necessary to match the desired level of reliability for the ERCOT market, including retention of the changes of this nature made in 2021. Moreover, the cost of additional procurement should be assigned to intermittent resources.
- Review and amend AS market design qualifications that undermine long-term reliability. Specifically, the standard for storage participation in the Responsive Reserve Service ("RRS") market allows batteries with only 1-hour of potential discharge capability to be paid 24 hours/day, which decreases reliability.
- In conjunction with the Weatherization proceeding,[3] develop a premium winter product for resources that meets the Commission's desired weatherization benchmark.
- Support locational and regional needs of the ERCOT system, including development of products to support inertia, voltage and frequency.

Calpine generally agrees that ERCOT operates according to what Chairman Lake has called a "crisis-based model"[4] that only rewards generators with high prices during times of scarcity. In other markets, a minimum level of system reliability is determined up front by policymakers, who then mandate

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[2] See Chairman Lake memo outlining Work Sessions http://interchange.puc.texas.gov/Documents/52373_3_1144899.PDF
[3] Project No. 51840, *Rulemaking To Establish Electric Weatherization Standards.*
[4] See *Chairman Lake testimony during the July 13 Texas Business and Commerce Committee hearing.*

resource procurement to attain that pre-specified level of reliability. Depending on the region of the country, the procuring entity is either an Independent System Operator ("ISO") through a centrally procured capacity market, an individual Load Serving Entity ("LSE"), or a utility. Conversely, ERCOT has a structure that relies only on competitive real-time market signals, which are allowed to rise significantly due to the ORDC during tight system conditions, to incentivize investment. Suppliers are paid only when they generate and sell into the real-time ("RT") market, day-ahead market ("DAM"), AS markets or through some other bilateral arrangement (the latter of which often reflects pricing based on price trends in the ERCOT administered markets). Market participant expectations of real-time prices, including both energy and ORDC payments, inform the DAM and AS markets and ultimately drive decisions about long-term resource investment. For this reason, in ERCOT's market, real-time energy and ORDC prices are the linchpin for the entire structure. These prices are relied upon to provide the operational signals to both load and suppliers that allow ERCOT to operate reliably during tight system conditions. Critically, market participant and investor expectations about the future levels of these prices signal new investment in generation, or conversely, they largely determine the need for retirements. Thus, long-term reliability is not a front-end mandate, but is instead the back-end result of the competitive market structure.[5]

In fact, the Commission has long sought to estimate the impacts of the shape of the ORDC, along with expected market conditions, on long-term investment and resulting reserve margins by estimating the Market Equilibrium Reserve Margin ("MERM") and Economically Optimal Reserve Margin ("EORM").[6] Since 2018, ERCOT has funded an independent biannual study[7] to evaluate the MERM and EORM. These studies are predictors of reliability conditions in ERCOT resulting from market signals and are intended to provide a view of expected reserves, loss of load probabilities, and amount of unserved energy associated with a given level of reserves. The Commission should revisit these studies as part of a market design

[5] In 2012, ERCOT commissioned The Brattle Group to address exactly the impacts of different markets structures on investment incentives as well as the impacts of different market structures on resource adequacy.
http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/Brattle_ERCOT_Resource_Adequacy_Review_2012-06-01.pdf
6 The estimated MERM represents the long-run level of investment anticipated given the cost of new entry and expected energy margins.
[7] In 2016, the PUC directed ERCOT to conduct an assessment of the Economically Optimal Reserve Margin (EORM) and the Market Equilibrium Reserve Margin (MERM) for the ERCOT region on a biannual basis. https://interchange.puc.texas.gov/Documents/42302_43_915925.PDF

workshop. The studies may provide insight to the Commission as it considers market design reforms since the reserve margin "is ultimately determined by suppliers' costs and willingness to invest based on market prices, where prices are determined by market fundamentals and by the administratively-determined Operating Reserve Demand Curve (ORDC) during tight market conditions." [8]

Finally, it is critical that the Commission recognize that the changes contemplated in this proceeding will have potentially significant consequences, both intended as well as unintended, on operational reliability as well as on long-term investments, retirements, and ultimately the reserve margin. It is also critical for the Commission to note that it already has an important tool to move away from a "crisis-based" model by shifting the ORDC so that is starts producing higher prices, and thus a larger real-time response from both generation and load resources well before the system is nearing a crisis; at the same time, this incentivizes new investment in dispatchable generation. By shifting the ORDC, the Commission can incentivize new investment and increase reliability at a nominal cost. This was pointed out by the Commission's consultant as part of Project 48551 in 2018 to shift the ORDC.[9] As a result of the project, the PUCT decided to shift the ORDC in 2018 to incentivize new investment and a better operational response, and successfully so, but the shift was not big enough.

Response to Questions

1. ***What specific changes, if any, should be made to the Operating Reserve Demand Curve (ORDC) to drive investment in existing and new dispatchable generation? Please consider ORDC applying only to generators who commit in the day-ahead market (DAM). Should that amount of ORDC-based dispatchability be adjusted to specific seasonal reliability needs?***

No single feature of the market structure should be considered in isolation, as changes in one component of the ORDC will impact others. These comments are provided for the Commission's consideration as it evaluates the market structure holistically. As just one example, Calpine believes that within the current market structure, SWOC set at a VOLL of $9k provides important operational incentives

[8] 2024 Analysis can be found at http://www.ercot.com/content/wcm/lists/219844/2020_ERCOT_Reserve_Margin_Study_Report_FINAL_1-15-2021.pdf

[9] See "Sensitivity of the Market Equilibrium Reserve Margin To Potential Changes in the ORDC." Brattle/Astrape (Dec. 3, 2018) http://interchange.puc.texas.gov/Documents/48551_34_996109.PDF

for both generation and load in emergency situations. Any change to the System Wide Offer Cap ("SWOC") or VOLL, and the timing of any such change, should take into consideration the current generation resources available to the market, anticipated additional generation over time, and the interdependence between the ERCOT market and the market for natural gas, including potential spikes in the price of natural gas. Calpine supports reforming the ORDC to ensure it produces revenues sufficient to attract and retain dispatchable generation. A key problem with the current ORDC construct is that it only allows generation suppliers to recover their investment when the system is very tight and at or near emergency conditions. Furthermore, the slope of the ORDC is extremely steep, so prices rise significantly over a very narrow range of reserves. There are three fundamental inputs to the shape of the ORDC:

1) The Value of Lost Load ("VOLL"), currently set at $9,000/MWH and which generally represents consumer's willingness to pay for electricity service, or to avoid load curtailments. VOLL is also known as the high System Wide Offer Cap ("SWOC");
2) "X," is the minimum "contingency" level of reserves at which point the ORDC will be at the VOLL;
3) The estimated Loss of Load Probability ("LOLP") at each level of reserves.

Each of these inputs can be modified to change the shape of the curve in a way that allows suppliers to start recovering some of their investment prior to the system hitting crisis mode, and slopes more gradually as the system tightens. Specifically, Calpine supports the Commission making the following changes:

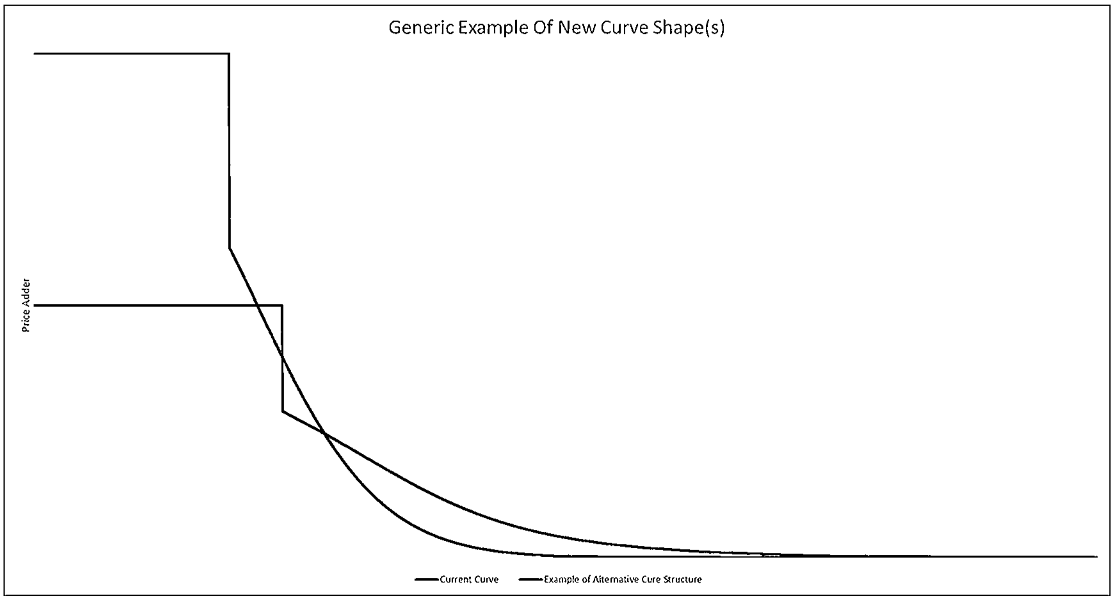
1) Reducing the SWOC to a lower level, but still high enough to incentivize significant demand response and, consistent with SB3, moving to a lower SWOC after the higher SWOC has been in effect for more than 12 hours in a 24-hour period.
2) Increasing the value of "X" from 2,000 to 2,800 MW by January 1, 2022 to align with the current responsive reserve procurement levels. Calpine believes there has been strong argument for making this change for many years, and has argued as such in filings before this Commission.[10]

[10] *See Calpine's comments on the "Review of Summer 2018 ERCOT market performance" Project No. 48551, and "Review of the Parameters of the Operating Reserve Demand* Curve," Project No. 45572.

3) Increasing the LOLP which has the effect of flattening and elongating the curve.

4) In addition, the Commission may also wish to review payment of the ORDC to select resource types that meet a dispatchability and duration criteria determined by the Commission.

Through this combination of ORDC changes, Calpine is suggesting changes to the ORDC that would change the shape of the curve as shown below.



These parameter changes can be made very quickly, with low implementation effort, to enhance the price signals in the market without a fundamental overhaul of the structure, or the creation of any unintended consequences. Finally, as has been done before, Calpine encourages the Commission to engage an independent economic consultant to determine the impact of these changes on future investment, and thus future reserve margins.

Calpine has considered whether the ORDC should apply only to generators that commit in the DAM and does not believe this proposal is workable without significant changes to the overall structure of the market. As the structure currently exists, even if the rules were changed only to pay generators ORDC that have committed in the DAM, that generator could easily skirt the rule by engaging in financial or physical arbitrage between the DAM and RT market. A simple example will hopefully illustrate this point. Assume a 100 MW generator does the following:

1) Simultaneously, the generation owner submits an offer to sell 100 MW into the DAM and bids to buy 100 MW at a nearby hub.
2) The DAM clears at $50, the owner has now sold its 100 MW generation and bought 100 MW of supply at a nearby hub.
3) In real-time, the generation owner makes good on its 100 MW, but then "sells back to the market" the 100 MW of supply it bought in the DAM. If conditions are tight in real-time and ORDC makes prices high, the generation owner is selling back the energy it bought the day before into the market and receiving revenues that now include the ORDC.
4) The net result is no additional day-ahead certainty for ERCOT because the generation owner sold and bought back the same amount in the DAM, and the resource gets paid the ORDC.

A possible mechanism to fix these concerns is to fundamentally change the current structure from a real-time market to a mandatory day-ahead market for all resources and load, with a smaller residual real-time market. This structure exists in other competitive electricity markets across the country (PJM, ISO-NE, CAISO), but those markets compensate generators for the mandatory day-ahead obligation to bid with a capacity payment, which is inconsistent with ERCOT's current "energy-only" structure.

Regarding seasonal reliability needs, the Commission may wish to review an additional seasonal shift during shoulder months to incentivize generators to pay additional labor cost to shorten essential maintenance outages.

2. ***Should ERCOT require all generation resources to offer a minimum commitment in the day-ahead market as a precondition for participating in the energy market?***
    a. ***If so, how should that minimum commitment be determined?***
    b. ***How should that commitment be enforced?***

Calpine does not support a "minimum commitment" or "must offer" requirement in the DAM. From its outset, the ERCOT energy-only market has always been a voluntary day-ahead market.[11] As noted above, other competitive markets that include mandatory day-ahead market offer requirements compensate generators for the mandatory obligation to bid capacity with consideration, typically in the form of a capacity payment. Requiring an offer without compensation for the risk associated with a must offer requirement transforms the nature of the energy-only market to a capacity market in which the capacity value is administratively set at zero. Offers may not be cleared in the DAM, and so restricting participation in the RT market to committed offers could reduce reliability by restricting participation from capacity that is otherwise able to perform and serve load.

However, if the Commission determines there is a need for additional capacity, it can increase the quantity of AS capacity, including capacity procured through longer-term markets including development of new ancillary services for summer, winter and intermittent firming.

3. ***What new ancillary service products or reliability services or changes to existing ancillary service products or reliability services should be developed or made to ensure reliability under a variety of extreme conditions? Please articulate specific standards of reliability along with any suggested AS products. How should the costs of these new ancillary services be allocated?***

Calpine supports ERCOT's procurement of additional reserves that total 6,500 MW, which have already been implemented by ERCOT. These reserves are procured through a market mechanism and so no change is needed. This procurement level should be made permanent. Additionally, consistent with the increased Non-Spin Reserve Service ("NSRS") procurement by ERCOT, Calpine recommends adding a requirement for offline NSRS to also include the same offer floor as on-line NSRS. This price floor will help ensure the impact of additional reserves on RT prices are mitigated.

Additionally, the Commission should evaluate the standards of participation in RRS regarding energy storage. Currently the standard for storage participation is based on a 1-hour qualification, which has permitted short duration 1-hour batteries to be paid around the clock for RRS even though their actual

[11] See 25.501(c), "ERCOT shall operate a voluntary day-ahead energy market, either directly or through contract."

physical capability is only 1 hour, not 24 hours. During Winter Storm Uri, energy from RRS was deployed multiple times for durations longer than 1 hour. Allowing short duration 1-hour batteries to participate in RRS decreases reliability because the service is being provided by short duration resources rather than resources that have the duration to continuously supply RRS. During Winter Storm Uri, RRS was deployed for energy at durations lasting longer than one hour at least four times.[12] In such circumstances, 1-hour battery resources that are awarded may not be able to physically deploy for the duration of the time the resource is released to SCED. Calpine recommends either reforming the RRS product to separate the frequency and energy component of the service or to increase the duration requirement to provide the service.

Calpine supports development of a winter product consistent with the requirements in SB3 for dispatchable generation that is competitively procured that can continuously operate for several days and have firm fuel supply including from firm natural gas transportation and storage.

4. ***Is available residential demand response adequately captured by existing retail electric provider (REP) programs? Do opportunities exist for enhanced residential load response?***

One of the most robust and dynamic features of the competitive ERCOT market is its ability to allow competitive retailers to respond to market conditions. REPs through their relationships with customers have the ability to provide incentives for demand response. REP design and investment in demand response programs are economic choices that are a function of long-term expectations of costs. No special Commission program is needed for REPs to design demand response, rather it is an investment choice for each REP to consider as a means to manage customer supply costs, and ultimately as a means to differentiate themselves across the competitive landscape.

5. ***How can ERCOT's emergency response service program be modified to provide additional reliability benefits? What changes would need to be made to Commission rules and ERCOT market rules and systems to implement these program changes?***

[12] http://www.ercot.com/content/wcm/key_documents_lists/214010/February_2021_ERCOT_Operations_Report_Public.docx

Calpine suggests limiting participation in the emergency response service program ("ERS") to only load. All generation should positively contribute to price formation and participate in SCED. Generation that is financed using an ERS capacity payment is on an uneven playing field and takes revenue from the market that is needed to support system reliability. Moreover, from a reliability and economic efficiency perspective, pre-deployment of awarded ERS capacity should not be permitted. ERCOT does not know how much ERS capacity pre-deploys because it is not telemetered and so expectations regarding actual ERS deployment are uncertain because of pre-deployment. Additionally, ERS that pre-deploys is doing so in response to real time prices, and so the market is paying resources for a service that they would provide for free. Calpine also supports the thorough review of resources providing ERS to ensure that critical loads are not participating in this service.

6. ***How can the current market design be altered (e.g., by implementing new products) to provide tools to improve the ability to manage inertia, voltage support, or frequency?***

A local ORDC pricing mechanism would improve the relationship between the local electricity prices and the cost of reliable supply within localized areas, thus providing an incentive to locate new resources in higher priced, constrained areas of the system. Many Commenters agreed that if there is a current or future concern regarding locational issues, then a local ORDC should be explored. As an alternative to a locational ORDC, the Commission could consider a shadow price mechanism as a way for prices to reflect locational scarcity. This would be simple to implement as ERCOT already has a value for local constraints – the shadow prices. Under the current market design, the shadow prices are used to mitigate prices in constrained areas to the value of the constraint and prevent prices from going all the way to the $9,000 cap when a local constraint binds. A local ORDC pricing mechanism would improve the relationship between the local electricity prices and the cost of reliable supply within localized areas. Many Commenters agreed that if there is a current or future concern regarding locational issues, then a local ORDC should be explored.

The adoption of marginal losses, consistent with other ISO market designs, is necessary for the development of efficient region-wide prices in ERCOT — the market is currently distorted by its omission.

Because line losses impact the value of energy at a particular location, they are implicitly not transmission services, therefore, the idea that marginal losses are a transmission service should be rejected. Pricing differences in costs based on location is a crucial design element of ERCOT's nodal-based energy-only market and drives economic efficiency. The proliferation of remote generation has changed the dispatch pattern in ERCOT and exposed the inefficiency of socializing transmission losses. Accurately expressing these costs in pricing will drive more efficient dispatch and investment siting decisions for consumers. The Commission could consider implementing a marginal loss methodology in a way that minimizes impacts to end-use customers as well as existing dispatchable generation.

Conclusion

Calpine appreciates the opportunity to present these views on this very important matter and will remain engaged as this Project develops. We will make available representatives to discuss these positions if helpful to the Commission.

Respectfully submitted,

By: */s/ Diana Woodman Hammett*__________________

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