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PROJECT NO. 54335

REVIEW OF MARKET REFORM ASSESSMENT PRODUCED BY ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3)	§ § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

DAVID ENERGY SUPPLY (TEXAS) LLC'S COMMENTS ON E3 REPORT AND RESPONSE TO STAFF'S QUESTIONS

Introduction

David Energy Supply (Texas), LLC (David Energy) appreciates the opportunity to comment on E3's market reform assessment and respond to Commission Staff's questions. David Energy is a digital REP for the modern grid. We provide a vertically integrated platform that allows commercial and residential customers to connect DERs to electricity markets to make smarter energy purchasing decisions resulting in lower energy costs.

All options in the E3 evaluation are evaluated based on fatally flawed, unrealistic, assumptions. These include assuming availability of unlimited gas in all weather conditions, assuming mass amounts of generation retirements without support or precedent, and assuming weather conditions that do not depart from those experienced between 1980 and 2019—specifically excluding the weather conditions in 2021 during Winter Storm Uri that instigated these proceedings, and those experienced since Uri in 2022. All evidence points to more of these conditions, not a return to the weather of 1980-2019.

Implementing a multi-year market redesign is the wrong path for ERCOT. David Energy believes that ERCOT's reliability problem is not an installed capacity problem, but a problem of operational flexibility that is best solved within ERCOT's current market design, by increasing ancillary services, implementing an uncertainty service as proposed by ERCOT's IMM, and thoughtfully adjusting ORDC parameters.

David Energy's Responses to PUCT Staff Questions

1. **The E3's report observes that the PCM has no prior precedent for implementation, does this fact present a significant obstacle to its operation for the ERCOT market?**

Yes, but not solely because of its novelty. Beyond the fatal flaws mentioned above, the proposed PCM design is insufficiently defined and fails to address critical impacts to generators, retailers (REPs) and customers. Specifically:

The proposed design fails to address the impact of the PCM on collateral requirements for ERCOT market participants. In ERCOT, collateral requirements are based on a participant's market activity and are intended to cover the risk of unpaid invoices. Invoices are currently settled daily. In the PCM design, a significant portion of annual energy costs would be invoiced in a single annual look-back settlement. This means that REPs would have to post, not only the collateral for daily invoices, but also increasing amounts of collateral over the course of each year to cover the PCM settlement for the current year, but not invoiced until the following year.

The proposed PCM design also fails to address the impact that customer switching will have on the ability of REPs to recover PCM costs attributable to retail customers who switch to another retailer after creating PCM exposure for that REP, but before the PCM look-back settlement. This would be an entirely new risk that REPs would need to mitigate. Even if REP customer contracts could allow for such invoicing post contract termination, it would surely result in a higher rate of customer nonpayment which would require REPs to price that risk into energy rates. The current PCM proposal does not contemplate the scale of such rate increases, or their impact to consumers. Increasing customer rates to account for this nonpayment risk would not fully mitigate the risk and could, in fact, increase the potential for monthly energy bill nonpayment. Additionally, if the contracts cannot guarantee PCM payment post termination or are otherwise difficult to enforce, customers whose contract termination fees are less than their expected PCM exposure will have the perverse incentive to terminate the contract and switch retailers rather than pay their current REP for last year's PCM charges. With increased customer nonpayment, REPs would risk not being able to pay ERCOT PCM invoices, thereby perpetuating the need for large financial assurance requirements. The impact of such increased financial assurance requirements and the imposition of a brand-new retail switching risk will disproportionally negatively impact small REPs, ultimately resulting in further REP consolidation, likely resulting in ERCOT's current competitive retail market into a gentailer monopsony.

2. **Would the PCM design incentivize generation performance, retention, and market entry consistent with the Legislature's and the commission's goal to meet demand during times of net peak load and extreme power consumption conditions? Why or why not?**

Probably not. In the PCM model, generators are not required to sell PC and responsible generators and their lenders will not assume unrealistic market, weather, and retirement conditions. Specifically, in extreme weather events, gas may be unavailable leading to generator inability to perform. Much like 4CP, load shifting to avoid PCM hours would shift which hours end up being PCM hours, and generators will have to weigh the risk of non-performance for reasons outside their control against any potential benefit from PCM revenues. Given the uncertainty of PCM revenues in any given year, let alone year-over-year, coupled with non-performance risk, lenders will heavily discount or entirely ignore the potential for PCM revenues in financing decisions. Generators who do sell PC may have to run at prices below their O&M costs to avoid PCM penalties, which is detrimental not only to those generators, but also to generators and demand resources that would otherwise have cleared economically above their O&M (or opportunity) costs. This outcome would be both perverse and likely.

Additionally, since there is no obligation for generators to sell PC but load is exposed to the PCM, existing generator owners have a financial incentive to optimize PC scarcity to ensure maximal value to their entire fleets. This incentive directly competes with the incentive to build new generation based on the risk-adjusted benefit specific to the PCM.

3. What is the appropriate reliability standard to achieve the goals stated in Question 2? Is 1-in- 10 loss of load expectation (LOLE) a reasonable standard to set, or should another standard be used, such as expected unserved energy (EUE). If recommending a different standard, at what level should the standard be set (e.g., how many MWh of EUE per year)?

This question cannot be answered without first clearly defining the reliability risks facing the ERCOT electrical island. The E3 report assumes away the realities of ERCOT's market and creates unrealistic assumptions about retirements, which has the effect of making ERCOT's reliability problem look like an installed capacity problem that can be solved by managing to a reliability standard like LOLE. However, ERCOT's problem is not an installed capacity problem, as acknowledged by E3's estimate of ERCOT's current LOLE at 0.03. Given the widespread power outages in February of 2021 and the extremely tight operating conditions in the spring of 2022, it is clear that ERCOT's problem is one of operational flexibility, not installed capacity, and that the risks facing the ERCOT market cannot be solved by adopting reliability standards developed for interconnected capacity markets.

There should be a more robust analysis of ERCOT's highest risk hours that includes years 2021 and 2022, in order to test E3's assumption that these hours are mostly concurrent to net peak load hours. Only once this is completed, will it be possible to understand which, if any, existing reliability standards are appropriate for ERCOT.

4. **The E3 report examines 30 hours of highest reliability risk over a year. Is 30 the appropriate number of hours for this purpose? Should the reliability risk focus on a different measure?**

No. The 30 hours are used as a proxy and will not necessarily reflect actual scarcity conditions. Generators and load will chase the 30 hours, inherently changing which hours end up as PCM hours. This will result in uneconomic generator operation and load customer fatigue. In both cases, chasing 30 hours that may not represent scarcity conditions could result in some resources not responding during actual scarcity conditions. Customers exposed to 4CP charges often must curtail for more than 15 hours in order to hit the four 15-minute 4CP intervals. While the same ratio may or may not apply to customers trying to curtail for 30 PCM hours, it is certainly the case that they will have to curtail for several multiples of 30 hours in order to ensure that they hit PCM hours. This is disruptive to Texas businesses and will result in reduced economic activity, and ratepayer dissatisfaction.

5. **Over what period should the hours of highest reliability risk be determined? A year, a season, a month, or some other interval? At what point in time should that determination be made?**

Please see answers from Questions 3 and 4 above. There should be a thorough study of actual scarcity conditions including years 2021 and 2022. The period should reflect the outcome of that study and the impact of the period duration on such factors as collateral requirements and retail switching risk.

6. **Would a voluntary forward market for generation offers and a mandatory residual settlement process for Load Serving Entity procurement provide additional generation revenue sufficient to incentivize resource availability in a way that improves reliability?**

   David Energy does not take a position on this question

7. **Does a centrally cleared market through ERCOT sufficiently mitigate the risk of market power abuse? Should additional tools be considered?**

No. Central clearing does not mitigate the market power of large existing generation fleets. They would still have the option to offer PC in a market where load exposure is not optional, and incentivized to optimize the value to their exiting fleets vs. building new generation. Additionally, the PCM limits the credits available to specific types of generation, concentrating the market power of thermal generation fleets.

8. **If the commission adopts a market design with a multi-year implementation timeline, is there a need for a short-term "bridge" product or service, like the Backstop Reliability Service (BRS), to maintain system reliability equivalent to a 1-in-10 LOLE or another reliability standard? If so, what product or service should be considered?**

The most pressing need is for a quickly implementable solution, but not just as a bridge. A solution like the uncertainty product proposed by ERCOT's IMM, is worthy of robust exploration. In addition to such reliability services, rather than seeking to fundamentally change

ERCOT's energy-only construct, once a proper reliability standard is developed, capacity and/or operational flexibility can be directly incentivized through adjustments to ORDC. This would provide the same type of incentive that the E3 report contemplates, in addition to incentivizing operational flexibility, without first having to pay economic rent on all of ERCOT's existing generation.

9. **If implementing a short-term design as a "bridge" delays the ultimate solution, should it be considered? Is there an alternative to a bridge solution that could be implemented immediately, using existing products, such as a long-term commitment to buy the additional 5,630 MW of Ancillary services necessary to achieve the 1-in-10 LOLE reliability standard?**

The proposals in the E3 report are built upon fatally flawed assumptions, lack sufficient definition, and a dearth of research regarding their effectiveness and market impacts to retailers and customers. Additionally, the LOLE is an inappropriate reliability standard for ERCOT's reliability needs. ERCOT's reliability problem can be addressed with increased ancillary services procurement and thoughtful adjustment to the current market structure, most likely via ORDC, in addition to implementation of new reliability services like the IMM's uncertainty product that can utilize the capabilities of generators, demand response and distributed energy resources.

10. **What is the impact of the PCM ton consumer costs?**

Please see response to Question 1.

11. **What is the fastest and most efficient manner to build a "bridge" product or service, such as the BRS, in order to start sending market signals for investment in new and**

dispatchable generation, while a multi-year market design is implemented by ERCOT? Please provide specific steps

David Energy takes the position that a multi-year market redesign is the wrong path for ERCOT. As stated above, we believe that increasing ancillary services, implementing an uncertainty service, and thoughtfully adjusting ORDC parameters is the appropriate solution for ERCOT.

12. In what ways could the Dispatchable Energy Credit (DEC) design be modified through quantity and resource eligibility requirements, e.g. new technology such as small modular nuclear reactors, in such a way that it incentivizes new and dispatchable generation?

David Energy does not take a position on this question.

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DAVID ENERGY SUPPLY (TEXAS) LLC'S EXECUTIVE SUMMARY OF COMMENTS ON E3 REPORT AND RESPONSE TO STAFF'S QUESTIONS

All options in the E3 evaluation are evaluated based fatally flawed, unrealistic, assumptions. Implementing a multi-year market redesign is the wrong path for ERCOT. David Energy believes that ERCOT's reliability problem is not an installed capacity problem, but a problem of operational flexibility that is best solved within ERCOT's current market design, by increasing ancillary services, implementing an uncertainty service as proposed by ERCOT's IMM, and thoughtfully adjusting ORDC parameters.

Regarding the Proposed PCM:

- It would significantly increase capital requirements for retailers by increasing ERCOT collateral requirements to cover PCM exposure.
- It would create a new retail-switching risk that would require REPs to increase rates, and simultaneously increase the risk that REPs are unable to pay ERCOT invoices due to customer nonpayment of bills.
- Retail customers would have to curtail potentially hundreds of hours in order to hit 30 PCM hours, because these hours aren't known until after the fact, and the very act of market participants chasing those hours will change the hours that end up as PCM hours
- As a result of the above points, cost to customers will increase and customer satisfaction will decrease.
- It does not guarantee new capacity, or additional flexibility, and it may reduce reliability.

Respectfully,

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