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

OFFICE OF PUBLIC UTILITY COUNSEL'S INITIAL COMMENTS TO COMMISSION STAFF'S REQUEST FOR COMMENTS

The Office of Public Utility Counsel ("OPUC") respectfully submits these initial comments to the Staff of the Public Utility Commission's ("Staff") request for comments on the Energy and Environmental Economics, Inc.'s ("E3") *Assessment of Market Reform Option to Enhance Reliability of the ERCOT System* ("E3 Report") and consideration of the Performance Credit Mechanism ("PCM") market design.

RESPONSE TO REQUEST FOR COMMENT

A. INTRODUCTION

On May 10, 2022, the Commission contracted E3 for consulting services related to analysis, development, and implementation of market design and market structure changes in the Electric Reliability Council of Texas ("ERCOT") wholesale market.[1] E3 developed and analyzed six specific market design options and compared the impacts of each against a status quo "energy-only" market design.[2] Those six market design options are:

- Load Serving Entity Reliability Obligation ("LSERO");
- Forward Reliability Market ("FRM");
- Performance Credit Mechanism ("PCM");

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[1] Review of Market Reform Assessment Produced by Energy and Environmental Economics, Inc. (E3), *Memorandum Re: November 10, 2022 Open Meeting, Item No. 5-Project No. 52373-Review of Wholesale Market Design* at 1 (Nov. 10, 2022). ("Memo")

[2] Memo at Attachment B, E3's *Assessment of Market Reform Options to Enhance Reliability of the ERCOT System* at 1 (Nov. 10, 2022). ("E3 Report")

- Backstop Reliability Service ("BRS");
- Dispatchable Energy Credits ("DEC"); and
- DEC/BRS Hybrid.[3]

Based on its analysis and its broad experience in market design, E3 recommends that ERCOT implement a Forward Reliability Market design.[4] E3 believes that the creation of a forward reliability product offers a more suitable fit for the market based on the following criteria:

a. out-of-market reliability solutions, such as the BRS, should be temporary;
b. implementation of the PCM entails significant risk because of its novelty; and
c. procurement of a forward reliability product provides a more natural year-to-year stability in market outcomes.[5]

The LSERO and FRM market reforms both create a forward reliability product, but the LSERO requires individual load serving entities ("LSEs) to procure their share of total reliability credits through bilateral contracting, whereas the FRM relies upon a centrally cleared auction to procure the requisite quantity of reliability credits.[6] Between these two structures, E3 finds the centrally cleared market to be a better fit for Texas' competitive market landscape for several reasons, including:

a. a centrally cleared market unlocks powerful tools for market power mitigation, and
b. a centrally cleared market can be more easily integrated into Texas' dynamic retail market.[7]

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[3] *Ibid.*

[4] *Id.* at 9.

[5] *Ibid.*

[6] *Ibid.*

[7] *Ibid.*

The Commission has signaled that its principal interest at this time is in the PCM, with the Commission's questions in this project centered on this mechanism.[8] The PCM, seemingly modeled to have outcomes similar to that of a capacity market, establishes a requirement for LSEs to purchase performance credits ("PCs"), earned by generators based on their availability to the system during the hours of highest risk, at a centrally determined clearing price.[9] The PC requirement is a fixed quantity that is determined in advance of the compliance period, while the settlement process occurs retroactively based on the quantity of PCs that were actually produced.[10] PCs are awarded to generators after the close of the compliance period based on a look-back of their availability across a predetermined number of hours of highest reliability risk (e.g., top 30 hours) measured as the hours of lowest incremental available operating reserves.[11] Of note, the E3 Report shows solar will earn about 2% of capacity as PCs, with wind at about 14%, effectively shifting revenue from renewable energies to other types of capacity.[12]

Each LSE's obligation to purchase PCs is based on its pro-rata share of system load during those same hours, and the clearing price of PCs is determined based on an administratively determined demand curve designed to achieve a target reliability standard (a Loss of Load Expectation ("LOLE") standard of 0.1 days per year is assumed).[13] In addition to this retroactive settlement process, ERCOT would also administer a centrally cleared voluntary forward market for LSEs and generators to exchange PCs to hedge against potential adverse outcomes in the retroactive settlement process; while this forward market is voluntary, generators must participate in the forward market in order to qualify to participate in the retroactive PC settlement process.[14]

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[8] Memo at Attachment A, Draft Notice of Request for Public Comments (Nov. 10, 2022).

[9] E3 Report at 21.

[10] *Id.* at 21 – 22.

[11] *Id.* at 22.

[12] *Id.* at 60.

[13] *Id. at 22.*

[14] *Ibid.*

B. OPUC'S GENERAL COMMENTS

THE OPTIONS PRESENTED IN THE E3 REPORT FOCUS MORE ON NEW REQUIREMENTS ON LSES WITH PENALTIES FOR NON-PERFORMANCE, AND IT IS NOT CLEAR HOW LSE OBLIGATIONS WILL FORCE GENERATION COMPANIES TO BUILD NEW GENERATION ASSETS

While the E3 Report presents options to try and improve reliability and resiliency of the ERCOT grid by enhanced development of generation, especially dispatchable generation sources,[15] the vast majority of the options presented focus on enacting new requirements on LSEs, often with penalties for non-compliance.[16] How LSEs are supposed to force generation companies to build additional assets, especially those assets that meet specific characteristics needed by ERCOT, is not clear. In fact, the E3 Report seems to have a fairly aggressive amount of equilibrium adjustments (i.e., reductions in capacity from the market, or retirements) from now until 2026 in the base energy-only case (6,172 MW coal-fired, 5,087 MW natural gas-fired),[17] which seems counter to the idea that more generation is needed.

IT APPEARS ALL PRICE RISKS ARE BOURNE BY THE END-USERS UNDER THE PCM MECHANISM

Regarding the PCM, it appears that all price risk is borne solely by the end-user, who is assigned their share of costs based on their contribution to demand during periods of low operating reserves.[18] The centrally cleared forward market allows LSEs to procure credits in advance, but since it is a voluntary market there is no guarantee that sufficient credits will be available so the balance of credits will still be assigned based on the actual cost of contribution during low reserve conditions. This may not be an effective hedge (i.e., a dirty or imperfect hedge). It is also not clear if there will be penalties for generators who sell into the forward market but fail to perform.

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[15] *Id.* at 1.

[16] *Id.* at 12.

[17] *Id.* at 46.

[18] *Id.* at 24.

Additionally, there is a significant credit risk to LSEs. ERCOT conservatively requires market participants to post credit such as cash or letters of credit based on future exposure, typically for just a few weeks in advance of the present day.[19] However, if 25% of the total value of the market is settled annually in the capacity market and is charged on a "look back basis" from the prior year, then there will be substantial, annual credit requirements that could impact customers. Any decision on PCM should take into consideration the credit implications that will result.

PAYING GENERATORS FOR PCs MAY NOT RESULT IN BUILDING NEW GENERATION ASSESSTS

Finally, and most importantly to improve system reliability, there are no assurances that paying generators for PCs will result in the building of any new generation assets that may reduce overall energy prices and result in fewer scarcity pricing events currently enjoyed by generators in the current market. There is the potential for generators to simply sell PCs from existing assets forward in the voluntary market. A limited supply will make the value of each PC higher without the risk of investment in new assets.

C. OPUC'S RESPONSE TO PROPOUNDED 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?

Response: The lack of precedent would be a significant obstacle to implementation of a PCM within the ERCOT market to the extent that all of the parameters of a PCM must be developed from scratch, including: (a) determining the reliability standard, (b) determining the shape of the sloped demand curve, (c) determining the number of hours on which to award

[19] *See* ERCOT Nodal Protocols, Section 16, Registration and Qualification of Market Participants. (Dec. 1, 2022).

performance credits, and (d) developing the forward PC market. This will lead to significant market uncertainty as the PCM is implemented and adjusted over time based on its performance.

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?

Response: Texas has implemented a number of market programs designed to provide incentives to encourage the addition of dispatchable generation capacity (i.e. Nodal, ORDC, and its subsequent modifications). Unfortunately, none has worked in a significant way. The PCM is yet another mechanism that is intended to provide incentives to build generation. While the PCM may incentivize performance of existing generation during periods of lowest operating reserves, there is no evidence that this latest mechanism will result in the addition of dispatchable generation.

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)?

Response: OPUC does not recommend a specific reliability standard at this time. However, the cost to consumers to meet any reliability standard must be met with an obligation by developers to build dispatchable generation.

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?

Response: OPUC does not recommend a specific number of hours but points out that, because generators have an incentive to be online and loads have an incentive to be offline, the hours that will have the lowest reserves may be hard to predict. Generators can turn on and loads can turn off merely to try to target these 30 hours, and not because of an actual reliability need. For example, if an hour would have been the 29th worst hour, but extra generation turns on and some loads turn off, the hour might shift to be the 35th worst hour. This is inefficient and will increase the overall societal costs of the market design. E3 concluded that a reasonable range within which to define the highest reliability risk is 30 hours to 100 hours. OPUC suggests that if a higher number of hours results in lower average costs to consumers or a more stable availability of PCs, than it can support a higher number of hours to determine reliability risk.

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?

Response: OPUC does not recommend a specific time period but suggests that regardless of the time period, the gaming issue described in response to Question 4 can still occur.

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

Response: As OPUC explained in response to Question 2, Texas has implemented a number of market programs designed to provide incentives to encourage the addition of dispatchable generation capacity and none have worked in a significant way. There is no evidence that sending additional market signals will incent building dispatchable generation, thus no improvement in reliability.

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

Response: OPUC believes that the market must be effectively monitored to mitigate market power abuse so that the cost to consumers is not adversely affected. A centrally cleared market would help provide this mitigation, but ERCOT should use any and all tools available to it to ensure the market operates in a fair and competitive manner.

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 ReliabilityService (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?

Response: OPUC believes that if a new market design mechanism will require a multi-year implementation timeline, then a "bridge" product would be necessary to address short term reliability issues. OPUC does not propose a specific product or service but suggests the product or service should be already established and can be readily implemented.

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?

Response: OPUC believes that a short-term design "bridge" that delays the ultimate solution should not be considered. As explained in response to Question 8, OPUC does not propose a specific product or service but suggests the product or service should be pre-established and readily implementable.

10. What is the impact of the PCM on consumer costs?

Response: The actual cost to consumers is unknown because the PCM has not yet been developed. However, as previously described, loads must purchase PCs under the PCM. The cost of PCs will necessarily be passed on to consumers, thereby increasing costs to consumers. Notably, the price of PCs will be based on an administratively determined demand curve, so it will not be set by the market. This may work counter to the competitive nature of the current energy market construct.

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.

Response: OPUC does not propose a specific process but notes the current market structure has been sending signals for investment in new and dispatchable generation for some time, with limited success. There is little reason to believe the latest market redesign will be more effective in doing so.

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?

Response: OPUC does not propose any specific modifications to the DEC but supports the idea that any new market mechanism should encourage construction of new and dispatchable generation. However, the current market structure has been providing incentives for investment in new and dispatchable generation for some time, with limited success. It appears a requirement to build generation, rather than simply an incentive to build generation, would be more effective.

CONCLUSION

OPUC appreciates the opportunity to provide these initial comments and looks forward to working with Commission Staff and other stakeholders on this project.

Date: December 15, 2022

Respectfully submitted,

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OFFICE OF PUBLIC UTILITY COUNSEL'S INITIAL COMMENTS TO COMMISSION STAFF'S REQUEST FOR COMMENTS

EXECUTIVE SUMMARY

1. The Energy and Environment Economics, Inc.'s ("E3") *Assessment of Market Reform Option to Enhance Reliability of the ERCOT System* ("E3 Report") presents options to try and improve reliability and resilience of the ERCOT grid by enhanced development of generation, especially dispatchable generation sources. However, the vast majority of the options presented focus on enacting new requirements on Load Serving Entities ("LSEs"), often with penalties for non-compliance.

    a. How LSEs are supposed to force generation companies to build additional assets, especially those assets that meet specific characteristics needed by ERCOT, is not clear.

2. Regarding the Performance Credits Mechanism ("PCM"), it appears that all price risk is borne solely by the end-user. The centrally cleared forward market allows LSEs to procure credits in advance, but there is no guarantee that sufficient credits will be available so the balance of credits will still be assigned based on the actual cost of contribution during low reserve conditions.

    a. There is a significant credit risk to LSEs. While ERCOT conservatively requires market participants to post credit such as cash or letters of credit based on future exposure, if 25% of the total value of the market is settled annually in the capacity market and is charged on a "look back basis" from the prior year, then there will be substantial, annual credit requirements that could impact customers.

    b. There are no assurances that paying generators for PCs will result in the building of any new generation assets that may reduce overall energy prices and result in fewer scarcity pricing events lucrative to generators in the market.

3. While the E3 Report examines different approaches to create financial incentives for generation companies to develop new dispatchable resources in ERCOT, the report seems to ignore that there are also incentives for incumbent generation companies not to build new generation.

4. All of the options reviewed in the E3 Report impose an obligation for loads to pay more. But none of these proposed options provide an obligation to build more.

    a. While ERCOT has spent the last decade creating incentives to promote the building of additional generation resources (preferably dispatchable) to little avail, the Federal Government has been extremely successful in seeing new renewable generation resources (mainly wind and solar) built by utilizing a more direct subsidization approach via Investment Tax Credits and Production Tax Credits. These credits, combined with ERCOT socializing grid interconnection costs, has resulted in probably one of the most successful buildouts of renewable energy in the United States, if not the world.

    b. It may be time for Texas to consider following the successful lead of the Federal Government and enact some form of direct subsidization of future dispatchable generation resources.

5. ERCOT could perform some planning functions to determine the most feasible and desirable spots for future generation siting as well as what type of generation would work best and at what size. This can provide the assurance that new generation development occurs when and where it is needed.