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

TEXAS PUBLIC POWER ASSOCIATION'S COMMENTS ON E3 REPORT AND RESPONSE TO STAFF'S QUESTIONS

The Texas Public Power Association (TPPA) appreciates the opportunity to respond to E3's market design report and Commission Staff's questions, as filed in this project. These comments are submitted on behalf of TPPA and do not necessarily reflect the opinions of any individual TPPA member.[1]

Formed in 1978, TPPA is the statewide association for the 72 municipally-owned utilities (MOUs) in Texas. TPPA members serve urban, suburban, and rural Texas and vary in size from large, vertically-integrated utilities to relatively smaller distribution-only systems. We are proud to serve approximately 5.1 million Texans across the state. Sixty-three of our members operate within the Electric Reliability Council of Texas (ERCOT) region[2] and nine are located within either the Southwest Power Pool (SPP) or Midcontinent Independent System Operator (MISO) region. MOUs offer a long track record of stability, and we serve an essential role in providing secure and reliable power to the wholesale electricity markets in these regions, including ERCOT. Many of our member systems have been providing stable and reliable electric power to communities in Texas for over 100 years, and collectively, our members provide more than 13,800 MW of generation and maintain more than 8,500 miles of high-voltage transmission assets.

On November 15, the Commission published its request for comments in the Texas Register, seeking comments by December 15 at noon. Comments are limited to 25 pages, not including an executive summary. These comments are timely filed and within the page limit.

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[1] The Lower Colorado River Authority does not join in these comments.

[2] 70% of Lubbock Power and Light's customers were moved to the ERCOT region on May 29 and 30, 2021. The remainder will be transitioned from SPP in 2023.

I. General Comments

The Commission does not have sufficient information to recommend any major market design change studied by E3 at this time. Significant questions remain as to the feasibility and workability of all the proposals examined in the report, as well as the robustness of the analysis and assumptions made by E3. TPPA will use its limited page count to focus on the specific questions posed by Commission Staff and general feedback on the Performance Credits Mechanism (PCM), given Commission Staff's recommendation that the Commission pursue that option. This focus, however, should not be taken as an endorsement of the PCM or an absence of questions and concerns regarding the other proposals.

TPPA appreciates the Commission's initial technical workshop with E3 to better explain elements of the PCM; however, this was a single workshop, with no recording or transcript available, and questions were pre-screened in advance. TPPA recommends that the Commission continue these workshops to allow stakeholders to ask questions of E3 and/or Commission Staff to better understand the product(s) being developed as they are being developed. This effort should be ongoing, publicly transparent, have a clearly established timeline, and include supplemental forums after major decisions are made, including any decisions based on comments filed today.

Implementing Real-Time Co-optimization (RTC) must remain the Commission's first priority to improve reliability in the ERCOT grid and reduce customer costs. At the December 2, 2022 technical conference with E3, E3 staff noted that the basis for *every* market design proposal under evaluation in the E3 Report was modeled on the Astrapé SERVM model, which assumes full optimization. The Commission must prioritize the implementation of RTC in advance of any market design change to realize the modeled benefits of the E3 Report. RTC is a well-vetted means of enhancing grid reliability with demonstrated experience in many markets across the country. Implementing RTC will also help mitigate some of the customer cost impacts of any market design change, as well as provide immediate grid reliability benefits and improved operational benefits to ERCOT.

To provide regulatory certainty that would help assure investment, the Commission must clarify its intentions for ERCOT's conservative operations posture. If the Commission determines to recommend any market design proposal, it must also simultaneously clarify whether ERCOT's conservative operations posture is expected to continue indefinitely or if it will cease, and the parameters and timeline of that cessation must be clearly stated. TPPA recommends that the Commission consider the effect of ERCOT's conservative operations posture on any market design change, customer costs, and continued grid reliability and health of the generation fleet. TPPA strongly recommends that the Commission make this determination in tandem with any determination it may make on a market design proposal, and, if the Commission determines to cease some portion or all of ERCOT's conservative operations posture, that it provide a public, transparent, detailed, and clear timeline for the phase-out.

II. Response to Staff's Questions for Comment

The Commission must clearly define the problem it is seeking to solve before recommending any market design proposal that is intended to act as a solution. As a threshold issue, TPPA is unsure whether the Commission is seeking to mitigate a resource adequacy issue or an operational issue, or both – and at what cost. The response for each of these is different – a resource adequacy issue would require additional capacity, while an operational issue would require existing capacity to be available in a different timeframe. Further, the right response to one issue could be the wrong approach for the other – incenting existing capacity to remain in the market can depress incentives for new capacity, for instance.

Similarly, it is unclear whether the Commission is seeking to maintain the current generation fleet or incent (or guarantee) new dispatchable generation build. If the latter is the Commission's primary goal, TPPA is unsure whether this effort is technology neutral, including renewables made dispatchable by being co-located with storage or whether it is limited only to ultramodern, quick-start gas generation and small modular reactors. TPPA believes that a technology neutral approach is aligned with the goals of SB 3.

TPPA requests that the Commission explain what issue or issues it is trying to solve with this market design effort and clearly explain how each proposal under consideration would function as meaningful solutions to address that specific issue.

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?*

The PCM is untested, creating additional complexity for implementation and success. TPPA has significant concerns about the novel nature of the PCM. While the ERCOT market has some unique design features compared to other domestic ISOs/RTOs, the Commission should ensure that the market design it chooses is rigorously tested and comes with a substantial probability of success, especially given the cost of implementing any one proposal and the regulatory uncertainty that will further disrupt investment in the ERCOT market. Any of the market design changes under consideration will lead to some regulatory uncertainty and financial and operational risk during the transitional period, but the magnitude and duration of these risks increase as the Commission considers changes that have not been tested and refined in public.

TPPA notes that the Texas economy alone would be considered the ninth-largest in the world – larger than Canada, Russia, and Australia – and the Texas economy is inextricably tied to the ERCOT grid and the prices paid by customers as a result of market changes and regulatory uncertainty. Texans across the state should not be forced to bear the costs and potential instability that comes from iterating an untested and unvetted market mechanism. TPPA notes that several commenters in this project have put forward credible questions about E3's modelling and assumptions, and several members of the legislature have asked probing questions regarding the sufficiency of the report.[3] These are not strong foundations for an ambitious reform of the ERCOT market.

The proposed implementation timelines are not realistic. TPPA also notes that E3's two-to-four-year estimation for full PCM implementation, including market response, is not a realistic projection, especially due to its novelty and high complexity. In its report, E3 suggested that it would take two years to develop the rules and regulations for a Load Serving Entity Reliability Obligation (LSERO), the Forward Reliability Market (FRM), or the PCM, plus an additional one to two years for markets to respond.[4] There is no rationale to assume the same projection for each of these market design systems, with the PCM having no analogue currently in use and versions of the LSERO and FRM currently active and well-tested in CAISO, SPP, ISO-NE, NY-ISO, or PJM electric markets.[5]

This projection is also unrealistic compared to recent major market modifications ordered by the Commission. RTC, a long-standing feature of many markets in this country that the

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[3] *See* Letter from Senator Charles Schwertner, Senator Donna Campbell, Senator Brandon Creighton, Senator Nathan Johnson, Senator Lois Kolkhorst, Senator Jose Menendez, Senator Robert Nichols, Senator Angela Paxton, and Senator John Whitmire to Chairman Peter Lake, Commissioner Lori Cobos, Commissioner Jimmy Glotfelty, Commissioner Kathleen Jackson, and Commissioner Will McAdams (Dec. 1, 2022). https://twitter.com/DrSchwertner/status/1598452253828042755.

[4] Project No. 54335, Assessment of Market Reform Options to Enhance Reliability of the ERCOT System at 81-82 (Nov. 10, 2022) ("E3 Report")

[5] *Id.* at 91.

Commission ordered ERCOT to implement in January 2019[6] (almost three years from the date of these comments), still remains in the planning stages, despite undergoing substantially more design work ahead of a Commission order than the PCM. Commission projects on RTC date back to September 2013, including separate white papers from ERCOT and independent consultants and a simulation conducted by the IMM.[7] The Commission also opened a rulemaking in December 2020, two years from the date of filing these comments, to implement RTC, and no filing has been made in this project to date apart from the project number request.[8]

ERCOT initially suggested that just the ERCOT-side implementation of RTC would take 4-5 years *after* Commission policy decisions have been made and applicable Protocol changes have been approved by the ERCOT Board.[9] While RTC would require changes to ERCOT's SCED system and how it procures ancillary services, these changes are still more targeted than the wide-ranging market redesign that the PCM would require.

Importantly, RTC is not an outlier in this regard. The transition from a zonal to a nodal market was discussed as early as 2003,[10] though full nodal market implementation was not accomplished until December 2010.

Further, TPPA is unsure whether ERCOT would be able to implement the PCM in the near future, given its planned freeze of many system changes to accommodate upgrades to its Energy Management System (EMS), which is currently scheduled to take place mid-2023 through mid-2024. The EMS upgrade has already been substantially delayed, and if it is delayed further, ERCOT may face operational risks going forward by using an outdated and technically

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[6] *Review of Real-Time Co-Optimization in the ERCOT Market*, Project No. 48540, Memo from Chairman DeAnn T. Walker (Jan. 17, 2019) and Letter to Chairman and Commissioners (Jan. 31, 2019).

[7] *See PUCT Review of Real-Time Co-Optimization in the ERCOT Region*, Project No. 41837, ERCOT and IMM Joint Report Regarding Real-Time Co-Optimization of Energy and Ancillary Services in the ERCOT Markets (Dec. 12, 2013), *Commission Proceeding to Ensure Resource Adequacy in Texas*, Project No. 40000, Informational Filing – Report: "Priorities for the Evolution of an Energy-Only Market in ERCOT (May 10, 2017), and *Project to Assess Price Formation Rules in ERCOT's Energy-Only Market*, Project No. 47199, Study of the Operational Improvements and Other Benefits Associated with the Implementation of Real-Time Co-Optimization of Energy and Ancillary Services (June 29, 2018) and Simulation of Real-Time Co-Optimization of Energy Only Market for Operating Year 2017 (June 29, 2018).

[8] Project No. 51588, *Rulemaking to Implement Real-Time Co-optimization in the ERCOT Market*.

[9] *PUCT Review of Real-Time Co-Optimization in the ERCOT Region*, Project No. 41837, Electric Reliability Council of Texas, Inc.'s Progress Report Regarding Real-Time Co-Optimization (July 14, 2017).

[10] *Activities Related to the Implementation of a Nodal Market for the Electric Reliability Council of Texas*, Project No. 28500, Control Number Request From (September 8, 2003)

unsupported EMS system.[11] It is also unclear what system implementation costs ERCOT would face, as the E3 Report focused primarily on a projection of costs to the market.

E3's projection that the Commission and ERCOT would be able to perform the entire suite of regulatory implementation actions and the market would respond in just two to four years is not a realistic timeline given both PCM's novelty and the implementation timeline for recent Commission-ordered major market changes. TPPA is highly skeptical of E3's projections in this arena.

If the Commission determines to move forward with implementing the PCM or any other market design proposal, TPPA recommends that the Commission first have a public, transparent dialogue with ERCOT staff in an open meeting on ERCOT's current project queue to understand market design implementation prioritization given the addition of ERCOT Contingency Reserve Service (ECRS), RTC, and the EMS upgrade. The Commission should request ERCOT staff to give and commit to clear implementation timelines that are reasonable and can be achieved, based on precedent and resources. Additionally, the Commission should direct ERCOT to resume filing quarterly project updates in Project No. 48540, *Review of Real-Time Co-optimization in the ERCOT Market*. TPPA notes that ERCOT has not filed an update in this project in two years.[12] TPPA further notes that it does not appear that the Commission has settled the issue of whether the Day Ahead Market should be enhanced to include a financial-only DAM for ancillary services. This is an additional market feature that may change implementation timelines for RTC but also provide more liquidity in the market if the Commission determines it will improve market outcomes and grid reliability. TPPA provides this additional context to highlight for the Commission the importance of including all of the current project priorities for ERCOT. The attendant unsettled questions and incomplete rulemakings should be incorporated so that a realistic timeframe is used for any market design implementation, especially considering there are significant projects at ERCOT that the Commission has already determined to be beneficial for customers and grid reliability.

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[11] In previous comments, TPPA recommended that the Commission require E3 to analyze whether any of the market design proposals would require ERCOT to reprioritize its project queue, including whether major initiatives already approved and in-flight would need to be delayed. *See Review of Wholesale Electric Market Design*, Project No. 52373, Texas Public Power Association's Comments on Selection of Phase II Market Design Consultant at 3 (May 25, 2022).

[12] *Review of Real-Time Co-optimization in the ERCOT Market*, Project No. 48540, ERCOT Update on the Real-Time Co-Optimization Market (Dec. 10, 2020).

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?*

The Commission should consider actual, historical Operating Reserve Demand Curve (ORDC) outcomes as comparative in its considerations of a modeled PCM. The PCM appears to be an ex-post ORDC, similarly using an administratively-determined demand curve in the residual market to incent generation to come online during periods of high reliability risk, although the PCM is less tied to actual system conditions than the ORDC and settled at regular intervals rather than in the real-time market. Therefore, it may be instructive for the Commission to not only evaluate the ORDC in conjunction with the PCM, as will be discussed below, but also as comparable to the PCM, given that the Commission has many years of real-world experience with the ORDC and actual, as opposed to modeled, results. In 2015, when the ORDC formula was much more harmonized to actual system conditions and loss of load probability on a time block and seasonal basis, as well as risk of actual load shed, the IMM's State of the Market Report found the ORDC adder active, on average, between 50 to 100 hours *per month*, with the ORDC being active for more than 200 hours in the month of March, reflecting the nature of the shoulder seasons on the ERCOT grid.[13] It is unclear to TPPA why the PCM would be limited to so few "hours of highest reliability risk," given the frequent use of the ORDC, considering the similar and overlapping functions of both programs.

This analysis is particularly illustrative given the Commission's use of the ORDC to increase generator revenues. In its original design, the ORDC was intended as an interim substitute for RTC, intended to incent investment in resource adequacy by compensating generators for being available at times of low operating reserves[14] – a concept very similar to the PCM as presented.

In 2019, the Commission determined that it was appropriate to modify the ORDC in its original design to further incent investment in generation for resource adequacy.[15] The Commission also approved a phase-in process to implement a 0.25 standard deviation shift in the Loss of Load Probability (LOLP) in the summer of 2019 and a second 0.25 standard deviation in

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13 2015 State of the Market Report, Potomac Economics, at v. https://www.potomaceconomics.com/wp-content/uploads/2017/01/2015-ERCOT-State-of-the-Market-Report.pdf

14 *PUCT Proceeding to Ensure Resource Adequacy in Texas*, Project No. 40000, ERCOT Presentation Regarding Potential Implementation of Scarcity Pricing Proposal Offered by Professor Hogan at 3 (Jan. 22, 2013).

15 *Review of Summer 2018 ERCOT Market Performance*, Project No. 48551, Memo from Chairman DeAnn T. Walker (Jan 17, 2019).

the spring of 2020.[16] Additionally, the Commission moved to remove the six time blocks and four seasons contained in the ORDC, which better approximated the loss of load risk (a concept very similar to the "highest reliability risk hours" of the PCM), into a single blended curve.

In its 2019 State of the Market Report, the IMM reported that the effects of the first step in the standard deviation increase in the LOLP together with the single blended curve were "significant."[17] The IMM further noted that the changes "led to increased market costs and revenues to generators of roughly $2 billion in 2019."[18] Before the Commission decides to adopt a model much like the ORDC, it should first examine why the ORDC changes, which were adopted on the premise of incenting investment in new generation for resource adequacy, have not been sufficient in increasing investment to the Commission's expectation. A detailed fact-finding investigation on the shortcomings of the ORDC to provide the resource adequacy that the Commission determines necessary will be instructive should the Commission move to the PCM market design and ensure that the Commission is best protecting end-use customers from unnecessary costs that increase revenues to existing generation without incenting the desired levels of new installed capacity.[19]

In 2021, as part of its Phase I market design effort, the Commission further changed the original parameters of the ORDC by shifting the Minimum Contingency Level (MCL) for ORDC deployment from 2,000MW to 3,000MW.[20] ERCOT reports that the effect of this change has been higher price signals during periods of lower reserves and broader, increased revenues to generation.[21] The IMM reports that the total impact of this shift alone, measured from January 1 to July 31, 2022, was approximately $1B, and the total ORDC adder impact on energy costs for

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[16] *Id.*

[17] *Reports of the Independent Market Monitor for the ERCOT Region*, Project No. 34677, 2019 State of the Market Report at ii.

[18] *Id.* at 80.

[19] As a first step, TPPA would recommend that the Commission consider, in lieu of any of the market design proposals considered in the E3 Report, evaluate, in a comprehensive project, increasing the Value of Lost Load (VOLL) in the ORDC to better reflect customer preferences for reliability. Increasing the VOLL will also smooth out the step change at the Minimum Contingency Level and provide generators with more price assurance as reserves approach the Minimum Contingency Level. This action was suggested in the Commission's market design blueprint. *See Review of Wholesale Electric Market Design*, Project No. 52373, Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT at 2 (Jan. 13, 2022) ("PUC Blueprint.")

[20] PUC Blueprint at 2. While the E3 Report does indicate that it factored in these changes (*see* E3 Report at 37), E3 does not appear to have studied the effect of these changes by itself.

[21] *CY 2022 Reports of the Electric Reliability Council of Texas*, Project No. 52933, ERCOT's 2022 Operating Reserve Demand Curve Report – Corrected at 1-2 (Oct. 31, 2022).

this time period was $2B.[22] It is important to note that this shift came on top of the 2019 changes to the ORDC to blend the curve and increase the standard deviations for the LOLP.

While the increases to revenue stemming from the ORDC seem to have created a significant new income stream to generation, it does not appear to have resulted in new dispatchable generation investments from the private sector. Of course, the changes to the ORDC are relatively recent, but it is unclear whether the Commission would be overcorrecting and, in effect, "doubling up" on incentives by maintaining ORDC and implementing a PCM.[23] Regardless, TPPA recommends that the Commission better analyze whether increasing generator revenues through the PCM would be more effective than through the ORDC. TPPA recommends that the Commission further study the interaction between these two market mechanisms before making a decision on whether to move forward with PCM implementation.

Factors outside of the models in E3's Report must be considered. Moreover, TPPA notes that the investment decisions associated with the new construction or the decision to mothball or retire an existing generation resource are based on a myriad of factors, not just market design. The E3 Report does not provide a substantial amount of modelling regarding how these external factors, including the Inflation Reduction Act and the proposed EPA Ozone Transport FIP rule, would interact with the studied market design changes. As such, it remains difficult, based on the E3 Report alone, to discern whether the PCM will provide the dispatchable generation investment commitments that the Commission would expect. Furthermore, lenders are increasingly basing investment decisions on the assumption that federal policy on greenhouse gas emissions will become more stringent in the future, and thus are reluctant to invest in potentially stranded assets.

It is critical that the Commission evaluate these factors to ensure that investment will follow any market design proposal. The cost estimates in the E3 Report depend on a market response that will help depress the overall cost impact to customers; if the Commission does not consider investment impacts external to the model, it may adopt a market design model that increases cost to consumers without increasing investment or reliability.

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22 *See* Independent Market Monitor (IMM) Report to the ERCOT Board of Directors (August 16, 2022). https://www.ercot.com/files/docs/2022/08/12/7%20Independent%20Market%20Monitor%20(IMM)%20Report.pdf.

23 TPPA notes that E3's report suggests that the incremental cost for PCM would be an estimated $460M per year, and removal of the ORDC mechanism would reduce costs by $417M per year. *See* E3 Report at 5, 71.

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)?*

TPPA believes that, regardless of whether the Commission implements any of the market design proposals in E3's report or suggested by others, the Commission should diligently evaluate what standard or standards it should use for evaluating the overall reliability of the ERCOT grid based on the identified reliability need. Further, the Commission should evaluate whether this standard should operate as a goal or a requirement. The Commission should also consider whether the standard, once met, should act as a signal to ratchet back or eliminate various market incentives or whether these incentives should continue even after the standard is met.

There is Commission precedent for the Commission procuring additional expertise and evaluating the reliability standard in a rigorous manner, as it did when it evaluated the reliability standard in 2014, a process which also included a solicitation of comments on questions about the appropriateness of continuing use of the 1-in-10 LOLE standard.[24]

As Commission Staff explained in the Commission's 2014 reliability project:

> There has been limited academic and industry analysis regarding the use of the 1-event-in-10 years standard (also referred to in this memo as 0.1 LOLE). Consensus in the available literature is that the origins of the "1-in-10" are unclear, that it is unlikely to align with a cost-effective level of reliability, and that it is upheld in certain North American markets (including those that use it as a critical structural input in their capacity market designs) as matter of convention. 0.1 LOLE is not the only standard used in organized electricity markets. Eastern Australia expresses its reliability standard in terms of EUE, or the quantity of annual unmet MWh attributable to inadequate supply. The UK plans its system to meet an Economically-Optimal Reserve Margin (EORM), or the point at which the cost of incremental capacity begins to exceed the full range of reliability-related benefits provided by that capacity."[25]

At its open meeting that followed this memorandum, the Commission expressed broad support for Staff's memo, which informed the Commission's ultimate determination to move away from the 1-in-10 LOLE, which had never been used for capacity planning in the ERCOT market

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[24] Project No. 42302, *Review of the Reliability Standard in the ERCOT Region.*

[25] Memorandum of Commission Staff, Project No. 42302, *Review of the Reliability Standard in the ERCOT Region* (June 11, 2015).

but rather as an evaluation standard, to a portfolio review.[26] The Commission only made this determination after two years of research, comment, workshops, multiple open meeting discussions, and the retention of a consultant to conduct independent research and analysis on behalf of the Commission.

In the E3 Report, E3 states that the 1-in-10 standard was chosen "under the direction of the PUCT" but does not elaborate as to the reasons why the Commission determined this, nor did the Commission openly discuss the merits of changing the reliability standard and moving from its robustly established precedent.

If the Commission wishes to move forward with adopting or recommending a reliability standard, TPPA recommends the Commission open a project, consistent with previous practice, in order to solicit comment on this specific issue. To the extent that the Commission wishes to reverse a decision previously upheld by its predecessors, which was made on the basis of extensive research and information-gathering as discussed above, the Commission should seek a similar level of input before such a reversal. TPPA notes that the 1-in-10 LOLE, as would be noted in a project specific to the reliability standard, does not differentiate between an interruption in power that lasts one hour or 24 hours, even though this is a very meaningful difference to customer experience. EUE, by contrast, provides the magnitude of outages, but does not carry with it a direct sense of duration or frequency.

With an eye toward this future project, TPPA recommends that the Commission consider utilizing a Loss of Load Hours (LOLH) standard, which provides a metric to capture the length of events, thereby balancing the frequency metric provided by LOLE and the magnitude metric provided by EUE. Given that load shed events are almost always resolved in two to three hours, TPPA recommends that the Commission focus on achieving a 0.25 LOLH, which would be roughly equivalent to a load shed event lasting 15 minutes each year, or in the aggregate, a 2.5-hour load shed event once every 10 years. This standard would be more granular than the 1-in-10 LOLE, which should provide the Commission additional visibility into overall system reliability.

Further, should the Commission ultimately decide to pivot from focusing on a 1-in-10 LOLE standard, TPPA recommends that the Commission continue to work with its consultants to provide supplemental reporting on how the various market design proposals E3 studied would fare against each other under the new standard (or standards) applied.

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[26] Open Meeting of June 18, 2015 (Item No. 28).

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?*

A new compensation mechanism based on highest hours of reliability risk is unnecessary, especially given the potentially duplicative nature of this mechanism against the ORDC.

More rigorous analysis as to the selection of the number of hours is needed. If the Commission wishes to study the hours of highest reliability risk for a general understanding of reliability, TPPA notes that the reasoning provided in the E3 Report as to the basis of selecting 30 hours is thin, making it difficult to understand E3's justification in selecting this particular number of hours. E3 comments in the LSERO section that, "~30 hours/year strikes a balance between actual expected loss of load hours (~3hr./year) and including too many hours which are inherently less impactful on system reliability (as would be the case if hundreds of hours were included)."[27] It is not clear if E3 would extend its reasoning here to the basis for selecting 30 hours of "highest reliability risk," but if that is the case, then TPPA believes more rigorous analysis is needed.

An individual day's greatest risk of reliability is over one or two hours, so this metric would hone in on the 15-30 riskiest days, which tend to cluster, rather than being spread out evenly over a year. In this circumstance, a single multi-day forced outage could dramatically shift which entities the PCM considers "reliable," and if ERCOT undergoes a Reliability Unit Commitment (RUC), its decision of whom to RUC could swing these results further. This would, of course, be exacerbated if the PCM was implemented, where these issues would be directly coupled with compensation mechanisms. Under this scenario, ERCOT's RUC decisions could easily result in litigation at extensive cost to the organization, which would ultimately be recouped, at least in part, through ERCOT's system administration fee.

TPPA does not believe an analysis of four hours per month (or 48 hours yearly) would meaningfully change this issue. In fact, an even split of analysis between the most secure shoulder month and the riskiest summer month may downplay certain seasonal risks, while exacerbating the problems that come from a limited dataset. For instance, ERCOT set six peak demand records in July 2022, and on five of these days, ERCOT deployed offline non-spin after physical

[27] E3 Report at 96, Table 48.

responsive capacity appeared to drop below the deployment trigger.[28] If only four hours a month were studied, only a subset of these days would be studied under this approach. Similarly, this levelized approach would likely require ERCOT to study intervals where the reserve levels were far away from any meaningful operational 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?*

To the extent that the Commission wishes to further study these hours, TPPA recommends a seasonal evaluation or even a monthly one, similar to ERCOT's existing and near-future reporting for the Seasonal Assessment of Resource Adequacy, which ERCOT recently announced would move from a seasonal report to a monthly one.[29] Reliability risk is often difficult to fully discern a year out, as maintenance scheduling can still be in flux[30] and anticipated future weather patterns still too unclear to develop a firm prediction.

However, as noted above, TPPA does not believe that the Commission should artificially limit its analysis to a handful of hours each month.

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?*

A mandatory forward market would be needed, as recommended by E3. TPPA notes that the E3 Report, insofar as the PCM is concerned, appears to recommend a *mandatory* forward market for generation offers and the voluntary aspect of the market would be for LSE purchases.[31] To the extent that the Commission intends to modify the version of the PCM that E3 studied to one where generation would be allowed to withhold from the forward market, TPPA would be firmly opposed, as this would create a clear incentive for market power abuse.

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28 With the implementation of Nodal Protocol Revision Request 987, PRC during nearly all of these intervals would have remained above the non-spin deployment trigger. *See* System Operations Update to the Reliability and Markets Committee (October 17, 2022). https://www.ercot.com/files/docs/2022/10/10/9.2%20System%20Operations%20Update.pdf

29 *See* System Planning and Weatherization Update to the Reliability and Markets Committee (October 17, 2022). https://www.ercot.com/files/docs/2022/10/10/9.1%20System%20Planning%20and%20Weatherization%20Update.pdf

30 This flux may be greater in the near term as ERCOT implements its new process for approving maintenance outages under Nodal Protocol Revision Request 1108, *ERCOT Shall Approve or Deny All Resource Planned Outage Requests*.

31 E3 Report at 22.

However, the report does not provide sufficient data regarding the criteria for the mandatory offers by generators. TPPA is unclear as to whether there would be maximum offer prices for generators based upon the demand curve that will be used in the residual market or if no such limits on offer prices will be in place. TPPA is concerned that the structure and specifics of this proposed mandatory offer market for generators could pose significant market power risk given the concentration of dispatchable resources on the hands of so few entities. In the early years of such a program, to the extent that there is a tight supply, Performance Credit (PC) sellers will likely offer at or close to the cap since this is a new source of additional revenues and failure to offer would result in no revenues in the residual market. Consequently, there is little incentive to offer prices below the cap. If the PCM does not adequately incent more dispatchable generation investment and other sources of PCs, the same dynamic is likely to occur in subsequent years.

Even the forward price discovery envisioned by E3 is uncertain as no details are provided as to what constitutes participation in the voluntary centrally-cleared forward PC market. In theory, participation by a generator could simply be offering in PCs at exorbitant prices knowing that these offers will not be lifted by LSEs. Taken to its fullest extent, such bid/offer behavior could result in no forward market prices with all PCs clearing in the residual market, further delaying the price signals needed to incentivize new dispatchable generation.

The retroactive settlement in the PCM must be further studied. TPPA also recommends that the Commission further study the effects of the retroactive settlement process for LSEs. E3 suggested a once-yearly settlement process, with each LSE being required to show or purchase sufficient PCs to meet their pro-rata share of system demand during the hours of highest risk. E3 did not analyze how this would apply if a market participant exited the market during the year, nor did E3 analyze how this settlement process would function if an insufficient number of PCs were created to meet the total system demand.

Further, if an LSE was required to pay for an entire year's worth of PCs at the same time through a once-yearly settlement process, this could present financial difficulty, particularly for smaller LSEs, as well as significant new credit and collateral obligations. These obligations could also present a substantial barrier to entry for new market participants.

A monthly settlement process, coupled with a focus on a set number of projected risk hours in that month (as discussed above in response to Question 4) would resolve some of these issues, but it would also introduce new ones. In addition to the concerns mentioned above regarding levelizing risk allocation, a monthly settlement process would create inconsistent costs to LSEs, with large spikes during summer and winter months, while also limiting an LSE's ability to hedge against those costs, due to the limited duration of the forward market.

Regardless, more clarity is needed around the mechanics of the voluntary forward market. As noted below, TPPA strongly recommends that the Commission engage an expert to produce detailed backcasts for multiple versions of a PCM implementation to better understand these issues.

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

TPPA does not believe that a centrally-cleared market through ERCOT, by itself, mitigates the risk of market power abuse, whether it be part of the FRM or PCM. Among other protections, the Commission needs to maintain a strong and objective IMM that is protected from interference, regardless of the final market design. The Commission should also ensure transparency whenever possible, while still allowing for protection for competitively-sensitive information.

In addition, should the Commission move forward with a major market redesign, TPPA recommends that the Commission instruct the Executive Director to terminate all existing Voluntary Mitigation Plans (VMPs) that the Commission has negotiated with generation entities,[32] as these VMPs were not negotiated with these new market design elements in mind and would be inappropriate to carry into the new market. Moreover, should the new market design implement a credit system, the Commission should ensure that its rules on market power abuse reflect the potential for withholding and self-dealing of these credits as well as energy. The rules should also specifically prohibit the potential for collusion/joint offering between all potential PC providers.

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[32] *See Petition of Calpine Corporation for Approval of Voluntary Mitigation Plan*, Docket No. 40545, Order (Mar. 28, 2013); *Request for Approval of an Amended Voluntary Mitigation Plan for NRG Companies*, Docket No. 42611, Order (July 11, 2014); and *Request for Approval of a Voluntary Mitigation Plan for Luminant Energy Company LLC, pursuant to PURA § 15.023(f) and 16 TAC § 25.504(e)*, Docket No. 49858, Order (Dec. 13, 2019).

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?*

TPPA first notes that the Commission instructed E3 to "[d]esign a turnkey Load-Side Reliability Mechanism . . . that can be fully operational and functioning in the ERCOT power region *within one year* of Commission adoption" (emphasis added).[33] None of the market design mechanisms analyzed by E3 have a one-year implementation timeframe – the LSERO, FRM, PCM, and Dispatchable Energy Credits (DEC) programs would each require up to four years to fully implement.[34]

Unfortunately, the version of BRS analyzed by E3 is also reported to require up to three years to fully implement, limiting its effectiveness as a bridge solution. TPPA is also skeptical that these timelines are realistic and that ERCOT has the operational bandwidth to implement a major or a bridge market design project with the pending EMS upgrade, as discussed in greater detail above. TPPA also notes that there are significant problems in creating BRS as a bridge without supporting pillars such as RTC implementation.

That said, with the understanding that any major market redesign could not be implemented until 2025 at the earliest and, more realistically, 2030 or later (with the majority of new investments to follow full implementation), TPPA believes that the Commission should engage in a deeper study of the effects of its Phase I market design efforts as well as ERCOT's conservative operations posture to see how these changes affected market outcomes. This would also allow ERCOT to make greater progress on its project queue, including the EMS upgrade, ECRS implementation, the proposed single model for distributed energy storage resources, and RTC. These projects may be able to serve as the bridge solution that the Commission is seeking.

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33 *RFP for Consulting Services Relating to the Electric Market Design Blueprint*, Project No. 53237, Electric Market Design Blueprint Executed Contract at 24 (May 10, 2022). For the Backstop Reserve Service, E3 was tasked with developing a product that can be fully operational and functioning by Summer 2023. *Id.* at 25. TPPA is also doubtful as to whether the PCM mechanism, as discussed in the report, should be considered a "turnkey" design, given the number of questions it leaves unaddressed.

34 E3 Report at 81-82.

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?

As noted above, TPPA believes that the Commission should consider many of the Phase I and other in-flight ERCOT projects as a potential bridge solution. TPPA is concerned about the effects of out-of-market actions, such as an additional procurement of 5,630MW of existing ancillary services as a way of incenting investment in dispatchable generation.

Investment in dispatchable generation requires regulatory certainty, and a bridge solution where ERCOT expands its current conservative operating posture would not provide that certainty. Moreover, many generation entities have noted that ERCOT's aggressive procurement of ancillary services has suppressed scarcity pricing, further reducing investment incentives. An expansion of these practices may be counterproductive to the Commission's end goals.

9. *What is the impact of the PCM on consumer costs?*

It is critical that the Commission understand that the customer costs as modeled in the E3 Report *assume a market response.* That is, if the PCM does *not* result in new generation investment, then the actual costs may be significantly higher for no increase in reliability. TPPA understands that the Commission's current statutory authority only allows it to incent investment in the competitive wholesale market, not guarantee it, but it must keep this delicate balance of customer costs in mind. Simply put, the only thing *guaranteed* by implementing the mechanism is new customer costs. If the PCM (or whatever market design proposal the Commission decides to implement) is successful, the benchmark for that success will be whether those costs incented sufficient construction of new generation and retention of existing generation to meet the reliability needs of the grid. The PCM will fail if it increases customer costs without leading to new generation sufficient to justify those costs. As noted below, several implementation questions would need to be addressed before it could be understood whether a PCM will incent any new generation, much less the amount of generation projected in the E3 Report. Given that it is untested and unvetted, and could increase costs without increasing reliability, the Commission may wish to consider meaningful benchmark metrics and associated costs for unwinding the PCM if it does not increase investment in the market and guarantee reliability.

It is difficult to discern the impact of the PCM on consumer costs, given the lack of detail provided by E3, what appear to be significant flaws in the analysis, and the length of the provided comment period. Moreover, several other commenters in this project have put forward credible questions regarding E3's methodology and assumptions, particularly the projected 11GW of retirements by 2026 based on the assumption that all projects in the ERCOT May 2022 CDR will be built regardless of market forces,[35] and the lack of modelling on how increased renewable generation will affect ORDC revenues. TPPA recommends that the Commission study these issues in greater detail.

TPPA does note, however, that E3's projected costs for the LSERO, DEC, and BRS programs differ widely from the recent report by the Consumer Fund of Texas and ICF Resources, LLC,[36] which puts E3's estimations into question. TPPA hopes that others will be allowed to submit more detailed cost analyses and the Commission will review those analyses in detail, even if they are submitted after the December 15 deadline for these comments.

In addition, it appears that E3 limited its analysis of interactions with other market elements to the ORDC, without providing analysis on whether, for instance, a PCM market would allow ERCOT to end conservative operations as discussed earlier in these comments or to modify the Reliability Deployment Price Adders (RDPA) program. Adjustments to other existing market elements could provide substantial reductions to customer costs.

TPPA is also unsure of how compliance will be measured on the LSE side. For instance, the number of peak demand records seen in ERCOT during the summer of 2022 would have most likely put LSEs in a position with insufficient PCs to hedge against the associated temporal period demand. This would force the LSEs to the residual market for the shortfall. It is unclear whether REPs that offer fixed-price contracts would be able to collect these costs from their customers, which may ultimately pressure smaller REPs toward default, lessening retail competition and increasing potential uplift cost to all retail customers in ERCOT, including those served by MOUs.

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[35] E3 Report at 46.

[36] *Review of Wholesale Electric Market Design*, Project No. 52373, ICF Report, "Assessment of ERCOT Market Structural Changes," (October 26, 2022). While the DEC design differs substantially between the two reports, the versions of LSERO and BRS appear to be similarly structured.

10. 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.

As indicated above, E3 estimates that even the BRS would require a multi-year market design process. To the extent that the Commission is seeking a product with a high potential for near-term implementation, TPPA believes that, in addition to more analysis on the effectiveness of the Phase I market design changes, the Commission should study an Uncertainty Product ancillary service, either as proposed in the IMM's 2021 State of the Market Report[37] or by the Coalition for Dispatchable Reliability Reserve Service in its recent filing in this project.[38] The product may provide a targeted incentive for dispatchable generation that would shore up system needs while minimizing costs to end-use customers.

However, the introduction of another ancillary service designed to incentivize new dispatchable generation should be considered another layer of cost that will ultimately be paid by Texas electric consumers. If an Uncertainty Product ancillary service was instituted, its intended and projected impact on dispatchable generation additions will have a domino effect on each of the market design options evaluated in the E3 Report, necessitating additional study.

11. 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?

E3 put forward an extraordinary amount of detail regarding the eligibility requirements for the version of the DEC program that it analyzed, including specific heat rate, duration, and ramp rate requirements. TPPA believes the other proposals analyzed merit the same level of granularity and specificity as E3 provided for the DEC. Nonetheless, TPPA recommends that the Commission engage in an analysis of the DEC using a broader eligibility pool, allowing existing generation units (including batteries co-located with renewable generation) to maintain eligibility. TPPA believes that a broader analysis of year-round generation of credits may provide some clarity on the workability of the PCM proposal, even if neither the PCM nor the DEC is ultimately adopted.

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37 *Reports of the Independent Market Monitor for the ERCOT Region*, Project No. 34677, 2021 State of the Market Report at xviii (May 27, 2022).

38 *See* Project No. 52373, The Coalition for Dispatchable Reliability Reserve Service's Comments in Support of Dispatchable Reliability Reserve Service Market Design Alternative (Dec. 14, 2022).

III. Further Public and Stakeholder Engagement

A backcast analysis of the PCM is needed. TPPA agrees with the testimony provided by Texas Electric Cooperatives that the Commission should perform a backcast analysis utilizing several variations of the PCM to determine its effect on the market.[39] In addition, TPPA supports additional Commission-facilitated technical workshops to allow stakeholders to ask questions of E3 and/or Commission Staff to better understand the product being developed as it is being developed. TPPA also recommends that the Commission directly consider large flexible loads, such as cryptocurrency miners, in its analysis to ensure that these loads can operate within the market design without an unfair advantage. Given E3's assumption of market response in one-to-two years, this sort of pre-planning, expectation-setting, and issue-spotting will be critical.

Engage the public and market participants. Should the Commission implement a major market design change, the best chance of success comes with harmonious support from the public and the stakeholders charged with operating under the new regime. The Commission should utilize its new Office of Public Engagement to host town halls (whether virtual or in-person) to provide customer education efforts to ensure that the public at large understands the anticipated reliability benefits and the costs associated with market design changes. This effort will assist in mitigating complaints received about increased bills and/or new pass-through charges. Some MOUs may need to undergo rate cases to offset these new costs, and this sort of customer education could assist in boosting understanding of why these rate increases are necessary.

IV. Fundamental Unanswered Questions Remain

TPPA believes that the E3 Report does not provide sufficient information about the contours of a PCM market, and the uncertain nature of how this product would be implemented limits the ability of all stakeholders and the public to truly voice opinions on whether the product would deliver the results the Commission expects. Below is a non-exhaustive list of outstanding questions that the E3 Report does not address.[40] While the Commission may be able to defer seeking firm answers to some of these questions as it works through a development process, others

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[39] *See* Testimony of Julia Harvey on behalf of Texas Electric Cooperatives, before the Texas Senate Business and Commerce Committee, Nov. 17, 2022 at 3:02:10-3:02:25. https://tlcsenate.granicus.com/MediaPlayer.php?view_id=52&clip_id=17072

[40] TPPA also recommends that the Commission provide formal responses to the questions posed by OPUC prior to the Commission's technical conference. *See* Project No. 54335, Office of Public Utility Counsel's Questions to Staff of the Public Utility Commission (Commission Staff) on its Technical Presentation and Q&A (Dec. 1, 2022).

require answers that are fundamental to how the PCM would be implemented and operate. The Commission should have clear answers to these questions before it moves forward with broad-scale development. TPPA recommends that the Commission or its consultant provide answers to as many of the below questions as possible before the Commission moves forward with a vote to proceed with developing a PCM.

Implementation

- What ERCOT products (such as ECRS, the EMS upgrade, or RTC) should be prioritized ahead of PCM implementation?
- What costs would ERCOT face in implementing a PCM?
- What statutory changes would be needed to implement a PCM?
- What Commission rules would need to be amended to implement a PCM? Do 16 TAC §§ 25.503 and 25.504 need significant changes?
- What ERCOT Protocols, Operating Guide, Retail Market Guide, or Other Binding Documents requirements would need to be changed to implement a PCM?
- Should the Commission require regular reporting from ERCOT on the health of the PCM and market outcomes?
- Are there any current market constructs that would become duplicative of PCM or conflict with it?
- What, if any, Phase I reliability measures will no longer be necessary and what savings could be achieved should the Commission implement a PCM while also eliminating these reforms?
- In reviewing transmission projects, should the Commission factor any effects the project would have on the PC market?
- Should LSEs be required to show 100% of the required PCs during the first run of the retroactive settlement, or should there be a phase-in to test operability?

ERCOT Forward-Looking Assessment

- Should ERCOT's forward-looking assessment set a ceiling for the number of PCs that can be offered in the forward market?
- Should there be circumstances under which ERCOT should be required to re-run its assessment between cycles, such as a major generation retirement?

- What process should ERCOT follow in developing the forward-looking assessment?

Forward PC Market

- Should a generation resource be required to make available all its expected PCs for the forward market, or should it be able to meet its obligation by offering a single PC for purchase? Who should make the determination as to whether a generation resource sufficiently participated in the forward market?
- How far into the future should a generation resource be able to offer PCs?
- Should LSEs be able to procure fractional credits, or should the LSE obligation be rounded off?
- Should LSEs be able to procure substantially more PCs in the forward market than their expected individual requirement?
- Should there be transparency requirements for PC transactions? How will ERCOT publish the results of the forward market?
- Should there be rules regarding PC transactions between affiliates? How will the market ensure that affiliate transactions are done at market?
- Should there be a cost ceiling and/or floor set on PC transactions in the forward market?
- If a generation resource exits the market, what should happen to any PCs sold in the forward market? Should the generation resource be required to buy back any PCs sold?
- If an LSE exits the market between settlements, what should happen to any PCs previously acquired in the forward market?

PC Creation

- What resources should be eligible to produce PCs?
- Should a generation resource be able to produce fractional credits, or should credits be rounded off?
- Is there a minimum percentage of the High Sustained Limit (HSL) that must be offered to enable the entire resource to participate in the Residual Market?

PC Settlement

- What process should ERCOT follow in setting the sloped demand curve for settlements?
- Are there circumstances under which ERCOT should be required to set a new demand curve, including calculation or data input errors?

- Should settlement occur yearly, or would a more frequent settlement be preferred?
- What should happen if an insufficient number of credits are produced to meet aggregate LSE requirements?
- Should PCs have an automatic expiration date to prevent excessive purchasing and hoarding of PCs in the forward market? Will compliance for the LSE require the same year vintage PCs as when the load was served or will surplus PCs from prior years be eligible for meeting the LSE's obligations in subsequent years?
- If an LSE exits the market between settlements, who should be responsible for procuring that LSE's pro rata share of PCs? Does the Commission have the authority to draw on a letter of credit or guarantor agreement to purchase PCs?
- If an LSE under-procures PCs for load that has migrated at the time of the residual market clearing, how will the LSE collect from the migrated load customer and what penalties will be assessed to the LSE if they do not fully cover?
- If a generation resource experiences an outage beyond its control (such as a force majeure fuel outage), should the generation resource be given an exemption against its obligation to procure any PCs it sold in the forward market but did not produce?
- If a generation resource is curtailed by ERCOT due to congestion, should the generation resource be given an exemption against its obligation to procure any PCs it sold in the forward market but did not produce?
- How will batteries, large flexible loads, energy efficiency, and demand response affect a LSE's obligation? Assuming demand resources are eligible to offer PCs into the voluntary forward market and residual market, what curtailment parameters must the demand resource meet?
- Will resource capacity that has been committed to ERS be eligible to participate in the PCM or will ERS and other reliability ancillary services be eliminated under the PCM design?

<u>Compliance</u>

- If an LSE does not procure sufficient credits, what penalty would be imposed? What should be the size of that penalty? Does this require changes to PURA § 15.023 and/or 16 TAC §§ 22.246 or 25.8?

- Should penalties go towards the purchase of PCs or to the general revenue fund? Does this require changes to PURA § 15.027?
- How will defaults be addressed if an LSE or generation entity cannot meet its obligation?

External Factors

- How does the Inflation Reduction Act affect PCM implementation and costs?
- How does the EPA's proposed Ozone Transport FIP rule affect PCM implementation and costs?
- What price signals would a PCM send to innovative technologies, such as batteries and demand response?

V. Conclusion

TPPA appreciates the opportunity to submit these comments. As always, TPPA looks forward to working with the Commission, its staff, and the stakeholders on these important questions and this broader discussion in the coming months.

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Respectfully,

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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**

EXECUTIVE SUMMARY OF TPPA'S COMMENTS ON E3 REPORT AND RESPONSE TO STAFF'S QUESTIONS

- The Commission does not have sufficient information to recommend any major market design change studied by E3 at this time.
- Implementing Real-Time Co-optimization (RTC) must remain the Commission's first priority to improve reliability in the ERCOT grid and reduce customer costs.
- To provide regulatory certainty that would help assure investment, the Commission must clarify its intentions for ERCOT's conservative operations posture.
- The Commission must clearly define the problem it is seeking to solve before recommending any market design proposal that is intended to act as a solution.
- The PCM is untested, creating additional complexity for implementation and success.
- The proposed implementation timelines are not realistic.
- The Commission should consider actual, historical Operating Reserve Demand Curve (ORDC) outcomes as comparative in its considerations of a modeled PCM.
- Factors outside of the models in E3's Report must be considered.
- A new compensation mechanism based on highest hours of reliability risk is unnecessary, especially given the potentially duplicative nature of this mechanism against the ORDC. More rigorous analysis as to the selection of the number of hours is needed.
- A mandatory forward market would be needed for a PCM, as recommended by E3, and the retroactive settlement in the PCM must be further studied.
- TPPA does not believe that a centrally-cleared market through ERCOT, by itself, mitigates the risk of market power abuse. Should the Commission move forward with a major market redesign, TPPA recommends that the Commission instruct the Executive Director to terminate all existing Voluntary Mitigation Plans that the Commission has negotiated with generation entities.
- TPPA believes that the Commission should consider many of the Phase I and other in-flight ERCOT projects as a potential bridge solution.
- It is critical that the Commission understand that the customer costs as modeled in the E3 Report assume a market response. The Commission may wish to consider meaningful benchmark metrics and associated costs for unwinding the PCM if it does not increase investment in the market and guarantee reliability.
- To the extent that the Commission is seeking a product with a high potential for near-term implementation, TPPA believes that, in addition to more analysis on the effectiveness of the Phase I market design changes, the Commission should study an Uncertainty Product ancillary service, either as proposed in the IMM's 2021 State of the Market Report or by the Coalition for Dispatchable Reliability Reserve Service in its recent filing in this project.
- A backcast analysis of the PCM is needed.
- The Commission should better engage the public and market participants.