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

JOINT COMMENTS OF

EAST TEXAS ELECTRIC COOPERATIVE, INC.

AND

GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.

December 15, 2022

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Table of Contents

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JOINT COMMENTS OF
EAST TEXAS ELECTRIC COOPERATIVE, INC. AND
GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.

East Texas Electric Cooperative, Inc. ("ETEC") and Golden Spread Electric Cooperative, Inc. ("GSEC") (collectively, the "Joint Commenters") respectfully submit these joint comments in response to the Public Utility Commission of Texas ("Commission") Staff's ("Staff") questions regarding Energy and Environmental Economics, Inc.'s ("E3") *Assessment of Market Reform Options to Enhance Reliability of the ERCOT System* report ("E3 Report").[1] The request for comments directs responses to be filed by noon on December 15, 2022. These comments are timely filed.

I. DESCRIPTION OF COMMENTERS

A. East Texas Electric Cooperative, Inc.

ETEC is a non-profit electric generation and transmission ("G&T") cooperative headquartered in Nacogdoches, Texas. ETEC generates and purchases wholesale electric power from various sources. ETEC then resells that power to its member cooperatives, including a G&T cooperative, Northeast Texas Electric Cooperative, Inc. ("NTEC"), and ultimately ten (10) member distribution cooperatives,[2] which provide retail electric service to approximately 340,000

[1] E3 Report, Staff Memo and Updated Questions, Attachment B (Energy and Environmental Economics, Inc.'s ("E3") *Assessment of Market Reform Options to Enhance Reliability of the ERCOT System*) (Nov. 10, 2022) ("E3 Report").

[2] Bowie-Cass Electric Cooperative, Inc. (Douglassville, Texas); Cherokee County Electric Cooperative Association (Rusk, Texas); Deep East Texas Electric Cooperative, Inc. (San Augustine, Texas); Houston County Electric Cooperative, Inc. (Crockett, Texas); Jasper-Newton Electric Cooperative, Inc. (Jasper, Texas);Panola Harrison Electric Cooperative, Inc. (Marshall, Texas); Rusk County Electric Cooperative, Inc. (Henderson, Texas) Sam Houston Electric Cooperative, Inc. (Livingston, Texas;) Upshur Rural Electric Cooperative Corporation (Gilmer, Texas), Wood County Electric Cooperative, Inc. (Quitman, Texas).

member consumers in portions of over forty (40) east Texas counties. ETEC owns or manages generation and provides wholesale power to member distribution cooperatives serving member consumers located in the geographic areas managed by the Electric Reliability Council of Texas ("ERCOT"), the Southwest Power Pool ("SPP"), and the Midcontinent Independent System Operator ("MISO").

B. Golden Spread Electric Cooperative, Inc.

GSEC is a non-profit electric G&T cooperative organized under Texas law with its principal place of business in Amarillo, Texas. Its main corporate purpose is to supply cost effective and reliable wholesale electric power to its sixteen (16) member distribution cooperatives.[3] GSEC's member distribution cooperatives serve about 310,000 retail electric meters serving their member-consumers located over an expansive area, including the Panhandle, South Plains and Edwards Plateau regions of Texas (covering twenty-four percent (24%) of the state), the Panhandle of Oklahoma, and small portions of Southwestern Kansas and Southeastern Colorado. GSEC owns or manages generation and provides wholesale power to member distribution cooperatives serving member consumers located in the geographic areas managed by ERCOT and SPP.

C. Relationship to Texas Electric Cooperatives

Both ETEC and GSEC (as well as their collective twenty-seven (27) member cooperatives) are members of Texas Electric Cooperatives ("TEC"), the state-wide association of electric cooperatives operating in Texas, representing its members except as their interests may be separately represented. With respect to the E3 Report, ETEC and GSEC join the comments filed by TEC and also believe it is beneficial to the Commission to provide stand-alone comments and responses to the Commission Staff's questions.

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[3] Bailey County Electric Cooperative Association (Muleshoe, Texas); Big Country Electric Cooperative, Inc. (Roby, Texas); Coleman County Electric Cooperative, Inc. (Coleman, Texas); Concho Valley Electric Cooperative, Inc (San Angelo, Texas); Deaf Smith Electric Cooperative, Inc. (Hereford, Texas); Greenbelt Electric Cooperative, Inc. (Wellington, Texas); Lamb County Electric Cooperative, Inc. (Littlefield, Texas); Lighthouse Electric Cooperative, Inc. (Floydada, Texas); Lyntegar Electric Cooperative, Inc. (Tahoka, Texas); North Plains Electric Cooperative, Inc. (Perryton, Texas); Rita Blanca Electric Cooperative, Inc. (Dalhart, Texas); South Plains Electric Cooperative, Inc. (Lubbock, Texas); Southwest Texas Electric Cooperative, Inc. (Eldorado, Texas); Swisher Electric Cooperative, Inc. (Tulia, Texas); Taylor Electric Cooperative, Inc. (Merkel, Texas); and Tri-County Electric Cooperative, Inc. (Hooker, Oklahoma).

II. GENERAL COMMENTS

A. Introduction

The challenge facing the Commission and ERCOT is not unique. Nearly every energy marketplace is facing resource and energy adequacy issues, whether in the United States or abroad. Identifying the types and amounts of generation and generation attributes that are needed to sustain reliability is complex because the goal is a moving target as both elements on the electrical system continuously vary. The type of resource attributes and the total amount of generation needed are dependent on the rest of the resource mix at any given time, which changes based on the productivity of intermittent resources, the availability of limited duration resources (e.g., energy storage and demand response), and unplanned outages of all types of resources.

Because no market design in any market has found a solution that fully addresses the challenges that have been identified, there is no roadmap for ERCOT to follow. To assist in meeting this challenge, the Joint Commenters recommend design solutions with a forward looking and repeatable process to achieve reliability while balancing efficient economic outcomes and ultimately helping ensure reliable and affordable power for the citizens of Texas in ERCOT.

The Joint Commenters' analysis and recommendations are guided by the objectives of Senate Bill 3 from the 87th Texas Legislative Session ("SB 3")[4] and the principles established for Phase II of the Market Design Blueprint ("Blueprint") described by the Commission earlier this year. Four primary objectives of SB3 are:[5]

> **Objective 1**: Determine the <u>quantity</u> and <u>characteristics</u> of <u>ancillary or reliability services</u> necessary to ensure appropriate reliability during extreme weather conditions and during times of low non-dispatchable production.
>
> **Objective 2:** Procure <u>ancillary or reliability services</u> on a competitive basis to ensure appropriate reliability during extreme weather conditions and during times of low non-dispatchable power production.
>
> **Objective 3:** Develop appropriate qualification and performance requirements for providing <u>ancillary or reliability services</u>.

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[4] Senate Bill 3, Sec. 18, codified as Public Utility Regulatory Act (PURA), Tex. Util. Code § 39.159(b).

[5] These objectives are from PURA § 39.159(b)(2)-(5) (emphasis added). They are logically consistent with Chairman Lake's statement at the recent Sunset Commission hearing that the goal with the market design is to find a way to deliver the cheapest most efficient power in sufficient quantities to meet growth in Texas. *See* Sunset Hearing at 1:34 (Dec. 7, 2022).

Objective 4: Size ancillary or reliability services to prevent prolonged, rotating outages due to net load variability in high demand and low supply scenarios.

In addition to these four objectives, SB 3 also requires the following:

- Resources that provide [the ancillary and reliability services] must be dispatchable and able to meet continuous operating requirements for the seasons in which the service is procured.
- Winter resource capability qualifications for [the ancillary and reliability services] include on-site fuel storage, dual fuel capability, or fuel supply arrangements to ensure winter performance for several days.
- Summer resource capability qualification for [the ancillary and reliability services] include facilities or procedures to ensure operation under drought conditions.[6]

Specifically, consistent with SB 3, the Joint Commenters recommend both ancillary service market reforms and an evaluation by ERCOT of the need for additional centrally procured reliability services that financially target multiple reliability metrics based on needed reliability attributes.

To develop the details of these comments, the Joint Commenters began with the following premises:

- First, the Legislature, in SB 3, requires the Commission to implement a plan that ensures dispatchable resources are used to meet the reliability needs of ERCOT, and not, in contrast, a more complex solution that involves accreditation and use of non-dispatchable resources.[7]
- Second, the method of incentivizing the needed amounts of dispatchable generation should be contained within the existing market design and should be sustainable going forward, as opposed to a temporary band-aid. This premise means that generators can be incentivized through energy prices, ancillary services, and forward-looking reliability service products. Reliability service products are not specifically defined in SB 3 or by ERCOT, but for purposes of these comments the Joint Commenters assume they include the established Emergency Response Service ("ERS"), Firm Fuel Supply Service ("FFSS"), and new products designed in accordance with SB 3.[8]

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[6] PURA § 39.159(c).

[7] *See* PURA § 39.159(c)(1) (requiring the Commission to ensure resources that provide ancillary and reliability mandated by subsection (b) "are dispatchable and able to meet continuous operating requirements for the season in which the service is procured").

[8] *See* PURA § 39.159(b).

- Third, to achieve the amounts of dispatchable generation with the appropriate attributes needed for the reliability and resiliency of the ERCOT grid and to ultimately incentivize the construction of new dispatchable generation, the expected generator compensation for providing ancillary or reliability services (along with energy-related revenue) must be equal to or exceed the expected cost of constructing new generation. The E3 Report quantifies this dollar amount as the Cost of New Entry of a combustion turbine at $93.5/kW-yr ("CONE").[9] While the Joint Commenters do not take a position on the accuracy of this cost, a value of some manner must be established to properly design the services and incentives that will achieve the objectives of SB 3 and result in the development of new generation.

With these premises in mind, the Joint Commenters suggest the following modifications to the ERCOT Market Design.

B. The Commission Should Direct ERCOT to Modify or Develop New Ancillary Services and Utilize More Than One Reliability Metric to Determine Need.

1. <u>New Ancillary Services Should Be Targeted to Meet Resource Attributes Associated with Dispatchable Generation.</u>

Existing dispatchable generation must be appropriately compensated to be available when needed, and new dispatchable generation must be incentivized to be developed. The term "dispatchable" has been used to represent a combination of resource attributes, including but not necessarily limited to long duration, ramp, and flexibility of start and stop.[10] One way to improve the compensation model for dispatchable generation is through the modification or development of ancillary services.

The Joint Commenters understand that the Coalition for Dispatchable Reliability Reserve Service ("DRRS Coalition") filed comments in support of an uncertainty type product, and the Joint Commenters are generally supportive.[11] Under the DRRS proposal, a four-hour service, which is available two hours after deployment, could create new incentives to spur continued investment in resources with the operational characteristics that meets evolving grid conditions and implement a robust, competitive market that appropriately values the reliability benefit provided by flexible dispatchable resources. Specifically, this service would ensure additional

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[9] E3 Report at 7.

[10] Senate Bill 3 from the 87th Texas Legislative Session (SB 3) describes a generation facility as "non-dispatchable if the facility's output is controlled primarily by forces outside of human control."

[11] *See Review of Wholesale Electric Market Design*, Project No. 52373, The Coalition for Dispatchable Reliability Reserve Service's Comments (Dec. 14, 2022).

dispatchable generation availability in real-time to cover for the uncertainty around variable generation, load variability, and thermal generation forced outages.

The Joint Commenters support this uncertainty type product, as well as ramping, and potentially other ancillary service products targeted at the identified reliability attributes as ERCOT determines is needed. The Joint Commenters believe this proposal is consistent with the direction in SB 3.[12]

However, by themselves, these types of ancillary service products in other markets, including those where the Joint Commenters participate, have not been fully successful to incentivize the construction of new dispatchable generation, nor have they prevented the retirement of dispatchable generation. These results may be partly because these products are tied to energy prices, which will on average continue to be lower, and frequently are negative for many hours. The irony is that as the need for these products grows, the energy prices are likely declining, deflating the incentives for which these ancillary service products are typically designed.

2. <u>ERCOT Needs to Address the Diminishing Returns Associated with Limited Duration Resources and Tie Ancillary Services Pricing to a Cost Metric.</u>

ERCOT is expected to see an increasing amount of limited duration resources on the system, primarily in the form of energy storage and large flexible loads. While these resources add value and can and should provide ancillary services, the ancillary service products themselves are not currently able to address the reliability risks associated with limited duration resources when the duration of the system need exceeds the operational duration of the resources. The solution proposed by DRRS Coalition also will not address the need for longer duration resources. While a four-hour duration product may be adequate today, there are diminishing returns to limited duration resources.

While the E3 Report does not include an in-depth discussion on the issue, it is likely that the Loss of Load Expectation ("LOLE") can be at least partially attributed to the depletion of limited duration resources. Specifically, the extremely low accreditation of solar in the Report

[12] *See* PURA § 39.159(b)(2)-(5); *see also* Dec. 1, 2022, Letter from Senators Schwertner, Campbell, Creighton, Johnson, Kolkhurst, Menendez, Nichols, Paxton, and Whitmire to Chairman Lake and Commissioners Cobos, Glotfelty, Jackson, and McAdams at 1 (encouraging the Commission to "evaluate the impact of creating a new market-based ancillary or reliability service to meet" a Commission-required reliability standard).

indicates that the loss of load hours likely occurred when there was no irradiance and after storage and/or other limited duration resources had been deployed. This result is consistent with observations of other Independent System Operators ("ISO"). California ISO, for example, is experiencing issues with limited duration resources and indicated it will need at least eight-hour storage to maintain reliability. At some point, eight-hour duration resources will not be sufficient. Long duration resources, including those that can sustain through weeklong or even season long periods of low interment generation output, are needed.

Additionally, Joint Commenters suggest development of an ancillary or reliability service that is priced separate and distinct from the real-time energy price. This proposal is not intended to be inconsistent with co-optimization of energy and ancillary services, rather the price associated with ancillary service need not be directly correlated to energy pricing. For example, an uncertainty product for generation ready-to-dispatch may be needed in circumstances when prices are negative, and a large amount of wind might drop off suddenly. The Joint Commenters are supportive of initially developing ancillary services tied to energy prices in the short term, with the caution that this alone is unlikely to incentivize dispatchable generation to be built, or even to remain online. If traditionally priced ancillary services are developed, however, then forward-looking reliability services for needed attributes must be procured to provide for the revenue gap between ancillary services and the costs incurred by the resources with those attributes. For example, if the CONE is determined to be the correct metric, and energy and ancillary services are not sufficient to incentivize new entry, then the reliability service should be designed to compensate that difference.

3. The Commission Should Direct ERCOT to Consider Several Reliability Metrics.

While E3 proposed multiple solutions to meet a LOLE standard of 1 day in 10 years, E3 did not evaluate adjustments to and effectiveness of existing ancillary services, nor did E3 focus on the need for attributes associated with dispatchable generation that are needed to maintain reliability in a real-time operations environment. The focus on a single static number that results from thousands of different model runs, as is performed when using LOLE, does not sufficiently analyze the adequacy of ramp, duration, and flexibility that will be needed as the energy mix continues to transition. In the context of resource accreditation and winter weather, E3 alluded to the challenge of addressing the infrequency of more extreme events,[13] but merely stated these challenges are all actively being studied across the country, and other markets have not indicated that they pose intractable challenges to incorporating these factors. Notably, E3 did not propose a solution, nor did E3 consider other possible infrequent events, such as long periods of low wind and/or irradiance, issues other markets have begun to face. Dispatchable generation has the needed ramp, duration, and flexibility attributes.

The Joint Commenters suggest the establishment of multiple reliability metrics to incentivize generation resources with the most desired attributes and to ensure appropriate reliability. The priority of establishing a reliability standard is consistent with SB 3.[14] The first set of metrics could be based upon the traditional LOLE and contemplated Economic Unserved Energy ("EUE"); however, meeting these targets should not solely be about adding capacity. As a simple example, if LOLE events were projected in nighttime hours, adding more solar would not improve reliability. Similarly, if the system is saturated with four-hour duration resources, adding additional four-hour duration resources will provide little value. Further, the addition of certain types of resources, especially combined with the retirements of others, can exacerbate shortages of ramp or inertia, particularly during planned outage seasons such as fall and spring. For these reasons, more targeted reliability metrics associated with ramp, inertia, and uncertainty are necessary. The megawatt-hour ("MWh") amount of particular products will vary depending on the resource mix, which makes the calculation challenging; however, it is nonetheless critical to maintain reliability. An EUE standard and evaluation of the distribution of EUE may indicate energy uncertainty but it is not clear if it would provide any indication of the sufficiency of ramp or inertia. Again, the Joint Commenters reiterate that it is not adequate to look at a single EUE number from a study and assume that any type of capacity addition will maintain reliability.

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[13] E3 Report at 8.

[14] *See* PURA § 39.159(b)(1). *See also* Dec. 1, 2022, Letter from Senators Schwertner, Campbell, Creighton, Johnson, Kolkhurst, Menendez, Nichols, Paxton, and Whitmire to Chairman Lake and Commissioners Cobos, Glotfelty, Jackson, and McAdams at 1 (encouraging the Commission to "first take action to define the reliability goals for the ERCOT region prior to moving forward with any significant market redesign.").

4. <u>Resource Parity Should be Considered when Designing New Ancillary Services.</u>

The E3 Report fails to address ways to mitigate net load uncertainty, risk, and cost driven by the expected growth of intermittent renewable resource capacity in ERCOT. In developing the new ERCOT Market Design, the Commission and ERCOT should consider operational solutions mitigating net load uncertainty resulting in the exponentially growing need for online, fast-ramping, dispatchable resources to accommodate the evening solar ramp down. Much of the associated net load uncertainty can be mitigated by treating intermittent renewable resources in parity with all other market resources. The proposed uncertainty ancillary service products discussed above should be married with ERCOT's ability to dispatch intermittent renewable resources. ERCOT can then reduce net load uncertainty, risk, and market cost by optimizing the cost between (a) intermittent renewables continuing to generate including the necessary ancillary service cost of on-line, fast ramping resources and (b) dispatching renewable resources down replaced with two-hour ramping, off-line dispatchable resources. The continued growth of renewable resources in ERCOT will not be deterred and a broader array of cost-effective dispatchable resources will be financially induced both to remain as well as to develop new investment helping to ensure reliability and resilience of the ERCOT grid. If ERCOT does nothing to mitigate the growing net load uncertainty, all the potential solutions evaluated by E3 will be but expanding bandages on a growing wound to the ERCOT Market.

C. Wholesale Market Redesign Should be a Deliberate and Mindful Process Considering the Evolving Nature of the Grid.

The appropriate quantity of needed generation cannot be determined (i.e., a traditional capacity reserve margin) without also considering the attributes of the resources available on the system. Therefore, the Joint Commenters propose that ERCOT run analyses, and then ERCOT and the Commission develop metrics, for specific resource attributes such as inertia, ramp, fast-start, and long duration, to ensure the appropriate reliability standards are achieved. These established metrics should then be utilized in combination with CONE as targets in designing incentives. The analysis should not only consider the expected outcome but also some sensitivities that identify a range of likely outcomes to be faced in the real-time operations. The combination of all margins, including those associated with new ancillary services, must be expected to be greater than the cost metric for dispatchable capacity to achieve the objective of SB 3.

D. Considering the Concepts That the Joint Commenters Describe in These Comments, Most of the Market Design Proposals Described in the E3 Report Present Unnecessary Challenges or Undue Risks.

As stated in the introduction, the Joint Commenters are Texas not-for-profit electric cooperatives; in other words, our stockholders and ratepayers are one in the same. Both ETEC and GSEC were developed to provide low-cost, reliable power for their respective members. The not-for-profit status of the Joint Commenters means that the ultimate costs of any market design changes are passed directly through to their members. The Joint Commenters support an overall market design that meets the goals of low-cost, reliable power and do not support market design changes that impose undue costs on their members that exceed the expected benefits—any market design revision must be cost-effective, achieve grid reliability, and be in the public interest.

Keeping these mission statements in mind, the Joint Commenters are concerned that many of the proposed market redesign alternatives considered by E3 would be the most significant alteration to the ERCOT market since Senate Bill 7 ("SB 7") passed in 1999. The processes that led to SB 7's enactment offer at least two vital lessons as the Commission, the Legislature, and stakeholders look to update the ERCOT market for the next generation. First, SB 7 was developed through the close coordination of the Commission, the Governor's Office, and the Legislature. Second, SB 7 was not rushed. Retail deregulation was proposed in the 1997 Legislative Session, was examined in the interim, and then passed in the 1999 Session. While the current plan may not require multiple years like SB 7, a thoughtful and strategically targeted design is more likely to yield a desired outcome than a hurried one. It is also more likely to moderate regulatory risk for investors as they consider financing power plants in Texas.

Prior to the filing of SB 7, officials (including the bill sponsors, Commissioners, and the Office of Public Utility Council ("OPUC")), industry stakeholders, and others, researched various power markets including CAISO, PJM, and the United Kingdom and met with numerous experts. Following this research and the passage of SB 7, it was reported that "Texas appears to have learned from problems in California and other states. . .. Moreover, state regulators, an interim legislative committee, consumer groups and electric utilities, are closely watching the California situation for signs of problems that can be corrected before electricity deregulation arrives in Texas."[15]

[15] "*Texas Should Monitor California Problems Closely*," DALLAS MORNING NEWS, Aug. 20, 2000.

Many of the proposals contained in the E3 Report have not been subject to comparable review. Based on the information known today, proposals such as the Forward Capacity Market ("FCM") and Load Serving Entity Obligation ("LSEO") that require complicated resource accreditation processes should not be pursued as they take too much time and money to implement and do not efficiently target the resource attributes needed for resource adequacy and reliability. With respect to the Performance Credit Mechanism ("PCM"),[16] the Joint Commenters believe it would be premature to implement without additional opportunity for comment and evaluation. There are various issues and details (as described in these Comments) that need deeper analysis before any market design is ready for approval and implementation.

III. RESPONSES TO STAFF QUESTIONS

A. Question 1: The E3 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. The lack of precedent imposes challenges for implementation, most likely leading to delays and unintended consequences caused in part by a steeper learning curve for market participants. Solutions that more closely resemble the existing ERCOT market construct or

[16] While Commission Staff has held one technical conference concerning the E3 Report, several questions continue to be unanswered including many of those submitted by the Joint Commenters on December 1, 2022, consistent with Commission Staff's request. For example, these include:

1) What specific criteria will be used to identify the 30 hours that will be used in the PCM? Does E3 recommend adopting a process for market participants to participate in developing those criteria or commenting on the PUCT or ERCOT's selection of the 30 hours? Should the criteria include consideration for energy limited resources, such as storage or permit limited resources, that are cleared and/or deployed just prior to the occurrence of tight supply hour? Will it matter if those resources are deployed as part of the typical clearing process or at the direction of ERCOT to address grid conditions? Should offline resources with long start-up time that are nonetheless available and bid into day ahead be credited?
2) How will the unpredictability of whether an hour is one of the 30 (until end of the year) affect opportunity costs? Did E3 consider these costs and what assumptions or conclusions were made? If opportunity costs were not considered, should they be?
3) What is the purpose of the proposed must-offer requirement in the forward market (in order to qualify to sell PCs ex-post)? Would you foresee any limits on the quantity that must be offered by each resource, and the offer price?
4) Please provide the MWH distribution of EUE annually. For example, 5th, 50th, and 90th percentile.
5) Please provide an annual distribution of which hours in the year EUE occurs. For example, 5th, 50th, and 90th percentile.
6) Did E3 conduct an analysis of what impact the PCM would have had based on actual conditions over some historic period? Did that analysis suggest seasonal variations as to when the 30 hours are likely to be?

another ISO or Regional Transmission Organization ("RTO") are more likely to be quickly understood and to be implemented by the market. However, any option, or combination of options will inevitably require time to adapt to the ERCOT market and will require modifications as conditions change. Concerns specific to the PCM proposal as well as suggestions to partially mitigate these concerns are detailed below.

The lack of precedent also means there is no real-life data to validate that the PCM would succeed in providing reliability services, incentivizing new dispatchable generation, or extending the life of existing dispatchable generation to ensure appropriate reliability. As the E3 Report acknowledges, it is a conceptual model. If adopted, ERCOT would become the first implementation case study for the rest of the United States. Being a laboratory for other markets is not itself problematic, but there is a risk that after years of expense and implementation, the first PCM in the United States (i.e., ERCOT's) would not solve the need for reliability services at certain times or more dispatchable generation. ERCOT's current situation may not be conducive to such a high risk-high reward plan as both the Legislature and the Commission have identified an immediate desire for investment in dispatchable resources.

The transition to the nodal market offers the only example where a change as fundamental as the proposed PCM has occurred in ERCOT since the initial implementation of SB 7. The nodal market transition had precedent in other US markets, unlike the PCM, and still took years longer than planned and cost hundreds of millions more than expected. At the December 5 House State Affairs hearing, Chairman Lake estimated than PCM implementation would take five years or more. This expectation may be optimistic if the implementation timeline for the ERCOT nodal market is an indicative measure. To compare against the nodal market transition, ERCOT was able to adapt existing systems in other markets as it changed the market design. Given that there is no precedent, system designers would have to begin with a clean slate for the PCM.

ERCOT implemented the nodal market in December 2010 after a process that took more than seven years, beginning with the Commission adoption of a rule in August 2003 directing ERCOT to implement a nodal market design, with ERCOT approval of the Protocols for operation of the nodal market in April 2006.[17] The estimated budget for completing the nodal market design

[17] 2011 Report on the Scope of Competition in Electricity Markets at 24.

was $319.5 million in February 2008. By the end of November 2010, ERCOT had spent $523.4 million.[18] This process relied on similar market designs already in operation in other markets. In 2003, when the Commission ordered adoption of the nodal market, three other RTOs already had operating nodal markets—PJM, NYISO, and ISO-NE.[19]

B. Question 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?

No. While the PCM does provide an incentive for generation performance, the effectiveness of the PCM would be highly dependent on the details of the design, including, but not limited to, the development of an accurate demand curve, the clearing mechanism, and the method of selecting tight supply hours (including both identifying the optimal number of hours to include and determining when those hours are likely to occur). If the PCM chooses the tight supply hours from a single year, a single year may or may not include an extreme weather event. For this reason, while the PCM likely would incentivize performance, it is not likely to address extreme winter events that are very infrequent and are not guaranteed to occur, but for which SB 3 requires the Commission to consider when designing and adopting new ancillary or reliability services to ensure appropriate reliability. Other already-adopted Commission-led solutions—such as a firm fuel products and weatherization requirements—are steps in the right direction, but it is not yet clear whether these regulatory revisions by themselves fully address the types of seasonal and extreme weather challenges the industry saw during Winter Storm Uri when, for example, natural gas never reached some dispatchable resources

Even if a PCM design is pursued, the Joint Commenters still support the addition of additional ancillary services, as discussed above, to better target the specific resource attributes needed in the market. If implemented together, ancillary service products tied to a CONE metric would decrease the cost and risk associated with the PCM. The details underlying any market solution set are vital to its success or failure and underscores the need for a deliberate process and consideration before any particular design is adopted.

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[18] *Id.*

[19] *Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas, Order*, Project No. 26376 (Sept. 23, 2003) at 124-25.

C. Question 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)?

Multiple reliability standards should be considered and implemented for ERCOT. Capacity adequacy, or having enough capacity, is not the same as energy adequacy, which is having enough energy in every given hour. As the resource mix changes from more traditional resources that have long-sustained output to those that are more intermittent and dependent on the weather, energy adequacy concerns increase. The 1-in-10 LOLE standard measures the number of loss of load events, whereas the EUE measures the number of MWhs associated with the loss of load. The 1-in-10 LOLE standard has been used to estimate an amount of capacity adequacy, and more recently EUE is being considered as a metric for energy adequacy. Both numbers used to represent 1-in-10 LOLE and EUE are the average of thousands of model iterations and, therefore should be understood as indication of risk but not necessarily an expectation of a specific outcome. For example, some iterations may have more or fewer loss of load events and will vary in terms of magnitude. The Joint Commenters submitted a question for the E3 technical conference asking E3 to provide the distribution of EUE, such as at the 5th and 90th percentile levels but did not receive a response to this question.[20] Understanding this distribution will be critical to understanding what an EUE reliability metric does or does not achieve.

While EUE and 1-in-10 LOLE are positively correlated, the combination of load and resources mix could result in EUE increasing at a faster rate than 1-in-10 LOLE. For this reason, some measurement and standard for energy adequacy is needed; and, at this time, EUE is one consideration. Australia for example has implemented a .002%, or 20 PPM standard (Unserved energy in the NEM | AEMC) as calculated by the number hours of EUE divided by the number of load hours in the study. The Astrapé analysis (described in the E3 Report) indicated an approximately 0.0004%, or 4 PPM EUE at a 0.1 LOLE (1 in 10 LOLE) for PCM, FCM, and LSO (1.6 GWh/400 TWh), but the E3 Report did not recommend an EUE standard. While the Joint Commenters are also not specifying what an EUE standard should be, energy adequacy needs to be monitored on a forward-looking basis in a way that allows ERCOT to address any emerging

[20] *See supra* note 16.

concerns. Furthermore, establishing a reliability metric does not provide a map for efficiently achieving the metric. As outlined in comments above, Joint Commenters suggest targeted metrics for duration, inertia, ramp, and/or uncertainty that can be used in conjunction with one another to meet broader EUE metrics, additional reliability metrics, as well as cost targets, such as the CONE.

D. Question 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?

The Joint Commenters do not necessarily support using the 30-hour standard discussed in the E3 Report. Using thirty hours after the fact places a tremendous amount of risk on both generators and load. Predicting which hours will get the approximate but uncertain $3,000/MWh adder would be challenging and would frustrate limited duration resource dispatch, such as storage and demand response, as well as utility maintenance decisions. The Joint Commenters submitted a question for the E3 technical conference asking E3 to explain how Performance Credits ("PCs") would be allocated if the hours occurred just after a limited duration resource was fully exhausted but did not receive a response.[21]

While the purpose of the PCM is to incentivize generation availability in these 30 hours, there should be options to both hedge positions and also to right-size positions to load and expected generation availability. A generator must be able to take maintenance outages, Load Serving Entity ("LSE") load may vary greatly across the seasons, and Retail Electric Provider ("REP") customers may shift from month to month. For these reasons the Joint Commenters believe that it is imperative to allow bilateral trading on a sub-annual basis, similar to how energy can be traded. Also, for this reason, the forward market should be split into seasons and consideration may need to be given to allow prudent planned resource outages. While this change would require allocating the "demand" curve among seasons and/or different times of the year, it would also improve predictability of tight supply hours. Given the analysis in the E3 Report predicting a capacity value of near zero for solar, the tight supply hour may shift to nighttime hours or hours with low solar output in the future.

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[21] *See supra* note 16.

E. Question 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?

The hours of highest reliability risk should be allocated at least seasonally (potentially monthly), and bilateral trading should be facilitated to right size load and generation. ERCOT will also need to consider how the trends in additional interconnection of intermittent and limited duration resources affect when the critical hours are likely to be experienced. A simple back cast of the top thirty highest reliability risk hours indicates that most hours have been during summer afternoons; however, there are a few in the winter and shoulder months. The more recent years have increased hours in the shoulder months likely due to the due to the shift in the resource mix. The allocation of the critical hours in the future would need to change as additional intermittent and limited duration resources continue to be added to the grid. A distribution of the thirty hours across a season would send a better signal for load and generation to be hedged and available in all hours of the year, as opposed to counting on previous years and choosing not to hedge in months where expectations of low amount of high reliability risk hours are expected to occur. Of course, this is a balance with purely incentivizing the hours of highest risk, but it is assumed that one objective of the PCM is to provide more year-over-year price certainty for incentivizing the building of dispatchable capacity, otherwise changes to the Operational Reserve Demand Curve ("ORDC") would more purely accomplish the goal of the highest prices in the highest reliability hours.

Two additional changes or clarifications should also be considered when identifying the thirty critical hours upon which to base the PCM. First, during actual load curtailment hours when reserves are maintained, or in hours where generation is committed for reliability—and not economic—reasons, the PCM calculation may need to be adjusted to align with the truly high-risk hours. Second, the Commission would need to clarify how certain types of demand response resources would be seen on the resource side of the equation so that they would be eligible for PCs for availability even if they are not deployed.

F. Question 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?

It is uncertain whether a voluntary forward market for generation offers and a mandatory residual settlement process for LSE procurement would provide additional generation revenue sufficient to incentivize resource availability in a way that improves reliability, as there are too many details yet to be worked out. Moreover, these designs are not necessary and not as effective or efficient as using additional real-time ancillary and reliability services. The Joint Commenters prefer these real-time tools and support a voluntary forward market construct with the ability to bilaterally trade to more efficiently match load and generation, similar to that which exists today through the use of bilateral agreements and other forward transactions. In the event the Commission directs ERCOT to institute a voluntary forward market as discussed in the E3 Report, then ERCOT should ensure that market participant credit is proactively addressed for loads that may be unhedged and subject to the PCM assessment costs.

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

No. PURA prohibits withholding of generation assets to manipulate ERCOT markets, and the PCM creates a new risk in this regard. The trigger to qualify as one of the thirty paid hours in the PCM is relative scarcity of generation to load. Consequently, two drivers impact when these hours occur: (1) increases in load and (2) decreases in systemwide generation. A party with control over a significant amount of generation can withhold its resources and trigger a PCM hour. This unintended incentive could result in a situation similar to the RUC problem that the IMM identified in the 2021 State of the Market Report where generators would identify as "on" for ERCOT but would not bid their marginal costs into the market. These actions caused them to be RUC'ed and to receive considerably higher revenues. The PCM risks the same problem as the E3 Report currently estimates the PCM charge would be about $3,000 MWh. If the Commission elects to implement the PCM, the IMM would need to monitor market participant behavior, likely to a much a greater extent than today, to ensure that LSEs, like the Joint Commenters' members are not saddled with unnecessarily high costs and that the PCM revenues are not concentrated in a small handful of beneficiaries.

H. Question 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?

No. The Joint Commenters do not currently see a compelling need for a "bridge" product or service, especially given the time and cost associated with developing such a product. If implementation of a bridge is preferred by the Commission as a tool to maintain system reliability, then the Joint Commenters do not oppose the Backstop Reliability Service ("BRS") as a short-term bridge.[22] Of all the designs the E3 Report analyzed, the BRS is the only one that both targets dispatchable resource attributes and is shown to be cost effective in meeting the reliability standard of 1 day in 10-year LOLE. The BRS, as studied, was designed to have greater than eight hours of duration for three days. The effectiveness of the BRS to meet the reliability standard is likely tied to the resource attributes. The Joint Commenters do not specifically support the BRS product, rather that it is evidence of the contribution of reliability attributes needed to enhance reliability. If a BRS were implemented, it should be used only until other market designs fully addressing the concerns discussed by the Joint Commenters are resolved and should not be a permeant solution. Further, if needed in the interim to forestall imminent dispatchable generation retirements (until BRS is implemented), ERCOT could develop a temporary product similar to the existing Reliability Must Run ("RMR") mechanism, focusing on capacity adequacy instead of transmission congestion as is the intent and design of RMR.

I. Question 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?

No. The DRRS Coalition uncertainty type product, and other ancillary service products described by the Joint Commenters, can have relatively short implementation timelines and a bridge product likely is not needed. If a compelling need is identified, then either BRS or a temporary, modified RMR-like product could be implemented more immediately to deter retirements in the interim. It is doubtful that any of these would delay the ultimate solution (if one

[22] E3 Report at 25-27.

were even needed) given that they build on existing market frameworks. Importantly, however, the market design as a whole, including any energy, ancillary service, reliability service, or PCM, should have both reliability and cost metrics. Implementing a bridge solution may therefore affect how other pieces of the market design should be calibrated. If BRS, RMR-like service, or any other bridge mechanisms were pursued, then the purpose of the bridge should be clearly defined to avoid any unnecessary recalibrations of the other market design components.

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

The cost of the PCM will vary based on both the load and generation conditions of each year as well as the level of detail and guidance provided by the Commission and ERCOT to allow market participants to predict when the thirty critical hours are likely to occur. In years in which the margins are low, the net CONE will be higher, and hence the net cost of the PCM will be higher. The E3 Report estimates this cost to be $460 million annually, or 2% higher than the cost of an Energy Only Market,[23] which on average might equate to about $3,000/MWh for the PCM. The Joint Commenters believe this cost estimate greatly understates the ultimate cost to consumers. This estimate, for example, does not account for the cost of hedging either through financial hedging, offsetting load with demand side resources, or from the cost of hedging with generation. Due to the uncertainty of identifying the potentially relevant thirty hours, hedging would be more costly based on the level of risk perceived by the entity acquiring and or selling the hedge. This additional cost and risk highlights the critical need to allow bilaterally hedges to better match load up with generation. Simply put, the more transparent the calculation of hours combined with ability to hedge would mitigate some of the increased costs that the PCM would impose on the end use consumer.

The challenges in hedging the PCM also may increase fluctuations in the rates assessed retail consumers. While cooperatives, including the Joint Commenters' members, try to minimize the pass-through of fluctuations in costs in their retail tariffs, there is a limit to how much volatility in ERCOT charges can be absorbed without passing that volatility through in rates.

The hindsight-driven model of the PCM also could create an inter-generational fairness problem for retail consumers. For example, applying the annual design contemplated in the E3 Report, it would be possible for a consumer to take service in January of year 1 when a 30-hour

[23] E3 Report at 60.

event occurs, ERCOT to charge the LSE after year 1 and for the charges to be assessed the LSE in year 2. This process could take 12-15 months from operational day to billing. In that time, the consumer may have left, and new customers who did not have service in year 1 might be added. The PCM costs still must be recovered, leaving the next generation of customers to bear that cost. Historically, the Commission and regulators generally have shied from designs with intergenerational issues.[24] To avoid this issue, bilateral trading, and hedging, as suggested above must be enabled. For retail customers a requirement to hedge forward or an increase of credit requirements may be warranted.

K. Question 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.

The fastest and most efficient manner to build a "bridge" product or service would be to provide regulatory certainty. Certainty's significance as a signal for new investment cannot be overstated. It is difficult for market participants, including the Joint Commenters, to develop capital investment plans when the future design of the ERCOT wholesale market is so uncertain. Similarly, regulatory uncertainty can affect the availability and cost of financing for projects because the uncertainty adds risk for financiers. ERCOT has added more new generation in the past decade than many other markets in the United States. The stability of the pre-Winter Storm Uri ERCOT wholesale market design has contributed to the successful addition of resources as load growth continues in our state. History, both successes and failures, can be a powerful guide to how best to proceed. For example, CAISO arguably has the most constantly changing market design in the country, and, not coincidentally, enjoys very little investment. As this market design process continues to evolve, the Commission should be mindful of regulatory certainty and its ability to incent long-term investments.

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[24] *See, e.g.*, *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Order on Hearing at 9-10.

L. Question 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?

The DEC incentivizes dispatchability in resources that bid into energy and ancillary services markets and are dispatched, without regard to scarcity and without limitation on certain hours. The expected result of this DEC design is to reward regularly generating dispatchable plants (i.e., combined cycles) most. There are several modifications that would be necessary for the DEC to be on a more even playing field with some of the other proposed market design options. They are:

1) Both new and existing generation must qualify; otherwise, the design risks incentivizing the development of new generation to simply displace existing generation. There likely would be no net gain in dispatchable generation.

2) A metric for how much dispatchable generation is needed, along with the specific attributes needed must be established.

3) The qualification for dispatchable generation should be broadened to include resource availability and consideration of specific attributes. These criteria could include generation capable of starting within a certain time frame (e.g., ten minutes) and/or resources that available for at least a certain time period (e.g., 72 hours).

Ultimately, the DECs may offer new money for eligible resources like Renewable Energy Credits ("RECs") do. But they do not address usefulness in tight hours or when demand is high. Also, much like RECs, DEC production can be limited by factors outside of the generator's hands. Using the REC example for analogy, generation can be ordered down to account for congestion, transmission stability, etc. DECs can have these problems but also their production is a function of where the generator falls on the bid stack. For example, an efficient combined cycle power plant that is already in the money bidding energy and existing ancillary services would receive more DECs than a peaking facility with a lower capacity factor. If the goal is to add more combustion turbines to cover short periods, like the duck curve, then the DEC would not achieve that goal. The proposal would appear to award the needed peaker resources fewer DECs than a combined cycle would receive. Moreover, it is unlikely this type of program would be able to sunset without additional incentives for the type of resource attributes. For these reasons, while the DEC proposal does incentivize dispatchable resources, its existing design parameters do not make it an optimal solution for the ERCOT market redesign.

IV. CONCLUSION

For the reasons stated above, the Joint Commenters respectfully request that the Commission consider these comments as it moves forward.

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Respectfully submitted,

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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**

JOINT EXECUTIVE SUMMARY OF
EAST TEXAS ELECTRIC COOPERATIVE, INC. AND
GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.

- Consistent with SB 3, the Joint Commenters recommend both ancillary service market reforms and an evaluation by ERCOT of the need for additional centrally procured reliability services that financially target multiple reliability metrics based on needed reliability attributes.
- Any market reform should comport with the following:
  1. The plan should ensure that dispatchable resources are used to meet reliability needs as opposed to a more complex solution that involves accreditation and use of non-dispatchable resources.
  2. The incentives for dispatchable generation should be contained within the existing market design and should be sustainable going forward. These incentives should include compensation for energy prices, ancillary services, and forward-looking reliability service products. These products should be targeted to meet resource attributes associated with dispatchable generation, or the cost of new entry ("CONE") of the preferred type of resource.
  3. To achieve the correct amount and types of dispatchable generation for the reliability and resiliency and to incentivize the construction of new dispatchable generation, the expected compensation for providing ancillary, reliability, and energy service must exceed the expected cost of constructing new generation.
- The fastest and most efficient manner to promote investment in needed resources is improved regulatory certainty.
- Most of the proposals in the E3 Report present unnecessary challenges or undue risks. The proposals in the E3 Report have not been subject to the level of scrutiny and review previously applied by the Commission and the Legislature when major changes to the ERCOT market have been adopted.
- If the PCM is adopted, hours should be allocated at least seasonally (and potentially monthly) and bilateral trading should be facilitated. While most critical hours historically would have been in summer afternoons, additional intermittent resources likely will change when those hours will occur in the future. A distribution across the seasons would also send a better signal to be hedged and to be available in all hours of the year.
- The Commission should direct ERCOT to consider several reliability metrics, not just LOLE or EUE in isolation from other metrics.