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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**

COMMENTS OF
PLUS POWER, LLC

Plus Power, LLC (Plus Power) appreciates the opportunity to file these comments on the Energy + Environmental Economics (E3) Report (E3 Report or Report) filed in Project No. 52373, *Review of Wholesale Electric Market Design,* on November 10, 2022. On November 15, 2022, the Public Utility Commission of Texas (Commission) requested comments regarding the Report and responses to questions asked by the Commission be filed by noon on December 15, 2022, in Project No. 54335.[1] Accordingly, these comments are timely filed.

INTRODUCTION

Plus Power is a leader in stand-alone, transmission-connected battery energy storage in Texas, as a developer, owner, and operator with a deep safety ethos and focus on responsible development and deployment. Plus Power, founded in 2018 by storage industry veterans from NextEra and Tesla, develops large scale systems that enable a more efficient and reliable electric grid by performing a range of services, including arbitrage, capacity/load shift, and grid services. Plus Power uses proprietary data-driven development tools to identify project locations that will optimally benefit from energy storage and presently maintains a development pipeline that exceeds 8,000 MW across 25 states. By 2021, Plus Power had developed three 100 MW stand-alone dispatchable battery storage projects in Texas, and now operates the 100 MW / 175 MWh Gambit Energy Storage facility in Angleton, Texas, providing energy and ancillary services in the Electric

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1 47 Tex. Reg. 7991 (Nov. 25, 2022).

Reliability Council of Texas (ERCOT) day-ahead and real-time market. Like many other storage developers, Plus Power has substantial investment in additional projects in Texas that will be online by early 2025. Plus Power is headquartered in The Woodlands, Texas.

Stand-alone battery energy storage systems can be precisely located so they can target certain reliability challenges, such as congestion or price volatility, happening now or expected in the five- to ten-year future. Plus Power's facilities are not co-sited with other generation resources such as wind, solar, or thermal resources, which offers our facilities to be located on a small footprint (often five to 15 acres for a 100-200 MW facility) to enable much greater siting flexibility. The facilities can be sited in and near load pockets to provide reliability services closest to where energy is consumed or near pivotal transmission locations that can benefit from the energy storage and discharge capabilities. Another key differentiator of stand-alone storage is that it can commit to being fully dispatchable, not limited in charging or discharging times by the rules of the federal solar tax credit, and therefore able to provide a fuller range of grid services akin to a conventional power plant (such as RRS, virtual inertia, and even black start) as evidenced by Plus Power's Kapolei Energy Storage facility in Oahu, Hawaii. It is important to recognize that stand-alone storage of any duration brings reliability benefits to the grid.

While large transmission-level stand-alone battery storage is still relatively new to the ERCOT market, ERCOT is already seeing significant benefits from their addition to the market. In comments to the ERCOT Board at the October 18, 2022, meeting, ERCOT Staff noted that the growth of energy storage resources in the ancillary services market is allowing thermal generators to generate energy rather than being held in reserve.[2] More recently, in a presentation to ERCOT's

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[2] *See, e.g.,* Dan Woodfin and Kenan Ogelman, *Item 6: Summer 2022 Operational and Market Review*, Board of Directors Meeting (Oct. 18, 2022) at 10 (available at https://www.ercot.com/files/docs/2022/10/11/6%20Summer%202022%20Operational%20and%20Market%20Review.pdf).

Supply Analysis Working Group on December 13, 2022, ERCOT Staff discussed their estimate that battery energy storage resources that already are deployed in ERCOT provided an average real-time contribution of 947 MW to Physical Responsive Capability (PRC)[3] during the hour of tightest reserves on July 13, 2022.[4] That contribution increased to 1 GW by the end of August 2022.

Plus Power commends the Commission and ERCOT for the swift work in Phase 1, which continues with the implementation of ERCOT Contingency Reserve Service (ECRS). These efforts will go a long way to improve preparation for and management of a winter storm Uri-type event. These comments, as part of Phase 2 and based on the Commission's questions, will focus on the Performance Credit Mechanism (PCM) proposed in the E3 Report. As discussed below, the PCM proposal as E3 has described it would likely fail to improve reliability in the ERCOT region. However, with certain targeted improvements, the Commission could structure a proposal to achieve certain Commission goals, such as targeting additional revenue to existing dispatchable generation resources, which includes all resources that have an "on/off switch" and are able to respond to an ERCOT dispatch instruction, and, potentially, establishing an additional revenue stream that could encourage investment in new dispatchable generation resources. If the Commission's primary goal is to encourage investment in "new steel in the ground," the Commission could explore a Dispatchable Portfolio Standard (DPS) consistent with Commissioner McAdams' original proposal in his November 17, 2021, memorandum filed in

3 "Physical Responsive Capability" is a "representation of the total amount of frequency responsive Resource capability On-Line in Real-Time." ERCOT Protocols Section 2: Definitions and Acronyms (Dec. 9, 2022).

4 Pete Warnken, *November CDR and Winter SARA Review*, Supply Analysis Working Group (Dec. 13, 2022) at 6 (available at https://www.ercot.com/files/docs/2022/12/12/3__SAWG_CDR_and_SARA_Review_12-13-2022_.pptx).

Project No. 52373.[5] While that original proposal was specifically targeted to encourage investment in new fast ramping dispatchable generation resources, the qualifications for the Dispatchable Energy Credits (DECs) could be broadened to encourage all new dispatchable generation resources, regardless of technology. Finally, in the event the Commission determines that a "bridge" is required to improve reliability of the ERCOT grid in the more near term, the Commission could increase ERCOT's procurement of ECRS when ERCOT implements that service in early to mid-2023 above the amounts ERCOT has preliminarily proposed in its proposed 2023 ERCOT Methodologies for Determining Minimum Ancillary Service Requirements[6] as well as increase its procurement of Regulation Service. This action would ensure that ERCOT has adequate fast ramping reserves to address system reliability concerns as well as provide an additional market signal to support investment in fast ramping dispatchable generation resources. This action also would provide a "bridge" as it considers implementing a technology neutral uncertainty product similar to what the Independent Market Monitor (IMM) has recommended.

COMMENTS

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

A lack of precedent for implementation of the PCM need not be a significant obstacle. However, it is imperative that there be robust and transparent analysis of the potential impacts of any proposed PCM to determine whether there may be potential unintended consequences and make appropriate and timely adjustments in advance of implementation. If E3 had applied its PCM

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5 Commissioner McAdams Memorandum filed on Nov. 17, 2021, in Project No. 52373, *Review of Wholesale Electric Market Design,* Item No. 250.

6 *See,* ERCOT Board of Directors' Reliability and Markets Committee Meeting (December 19, 2023), Agenda Item 6, 2023 ERCOT Methodologies for Determining Minimum Ancillary Service Requirements, at 8 (available at https://www.ercot.com/files/docs/2022/12/12/6-Rec-re-2023-ERCOT-Methodologies-for-Determining-Minimum-Ancillary-Service-Requirements.pdf).

to the hours of lowest operating reserves in 2022 thus far, it would have been clear that the PCM as proposed by E3 is flawed. Initial analyses by stakeholders indicate that these hours are almost random and highly correlated to outages of thermal resources rather than the occurrence of high peak net load despite the many statements of E3 to the contrary. The ability of the Commission or ERCOT to forecast which hours of a year will be the key hours for assignment of credits is not practicable. For example, who would have forecast that there would be multiple outages of thermal generation resources on May 13, 2022, that led to that day having several hours of the lowest operating reserves thus far this year? Moreover, forecasting the amount of load that must be served during these hours a year in advance is not reasonable. Both estimates are critical to the implementation of the PCM proposal, and the inability to accurately forecast either variable a year in advance makes it clear that the PCM as proposed by E3 is not workable.

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, it is not likely that the PCM proposal would provide any additional incentive for investment in new generation beyond those signals already in the ERCOT market. According to ERCOT's latest Capacity, Demand and Reserves (CDR) Report, more than 1,500 MW of new gas-fired generation is expected to be online by Summer 2024.[7] Given the long lead time to construct new gas generation, one could (should) expect that the investment decisions for these resources were made based on ERCOT's current market design. Further, the PCM is not likely to improve signals for investment since a financial institution will not be able to anticipate the revenue a new generation resource could expect to earn in future years from the application of the PCM due to

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[7] Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2023-2032, November 29, 2022, Worksheet labeled "Changes" (available at https://www.ercot.com/files/docs/2022/11/29/CapacityDemandandReservesReport_Nov2022.xlsx).

the inability to accurately forecast the hours of low operating reserves. At the same time, E3 estimates that this proposal would remove $5.2 billion from the current energy-only market design by reducing energy and ancillary service costs.[8] The net result is there would be a reduction in the amount of revenue that could be used to support financing new generation resources compared to the current energy-only market design.

Further, while the Commission's question refers to meeting demand during times of peak net load,[9] E3 stated in its Report that the periods of highest reliability risk are "measured as the hours of lowest incremental available operating reserves."[10] Despite E3's statements in its Report to the contrary, though, an analysis of the hours of lowest operating reserves during 2022 shows that these hours are not necessarily coincident with peak net load or extreme power consumption conditions. For example, the hours of low operating reserves on May 13, 2022, were not related to either peak net load or extreme power consumption conditions, but rather to unplanned outages of thermal resources. Moreover, the randomness of the performance credit hours would require generators to always be available to avoid missing an hour during which performance credits could be awarded. Generators must take outages for maintenance to operate reliably, but the randomness of potential hours of low operating reserves would discourage generators from taking outages, especially when other generators are taking outages for maintenance. Discouraging planned outages could lead to more forced outages and detrimental wear and tear on generators that ultimately could lead to an earlier retirement.

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8 E3 Report at 60.

9 Plus Power disagrees with the definition of "peak net load" that E3 uses in its Report, "The maximum total electricity demand in a system during a specified time period (usually a year), net of wind, solar, and storage generation." E3 Report at viii. While there is no formally adopted definition of "peak net load" in Texas statutes, the Commission's Substantive Rules, or ERCOT's Protocols, the definition of this term ERCOT has used for years does not net storage generation against load, but only wind and solar. This is because the issue of "peak net load" is focused on determining how much dispatchable generation is needed to serve load at that time, and energy storage resources are dispatchable.

10 E3 Report at 15.

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)?**

A reliability standard is not required and will not ensure that customers are served at times of lowest incremental available operating reserves or extreme power consumption conditions. For example, prior to winter storm Uri, ERCOT forecasted that it had a reserve margin of 16.2%. Instead, it suffered a reserve margin of -21.1% on February 15, 2021.[11] Clearly, meeting a reserve margin alone is not what ensures grid reliability.

Moreover, to the extent that adoption and enforcement of a reliability standard generally reflects the adoption of a capacity market, E3's own analysis makes clear that ERCOT is not lacking adequate capacity. According to E3, "The results showed that the current system achieves a loss of load expectation (LOLE) of 0.03 days/year, exceeding the common industry benchmark of 0.1 days/year or 'one day in ten years'."[12] E3 also observed that ERCOT's reliability is expected to increase in the coming years, stating, "Without further adjustments to the resource mix beyond CDR additions and retirements, the "per-equilibrium" 2026 portfolio would achieve an LOLE of 0.02 days per year, more reliable than the common benchmark of 0.1 days per year."[13] These statements make clear that ERCOT does not need a capacity market to achieve better reliability than it already has achieved and is achieving with the current market design.

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11 Patrick Milligin, "Winter Storms Wreak Havoc on ERCOT Grid," ICF Insights / Energy, Feb. 23, 2021 (available at https://www.icf.com/insights/energy/winter-storms-ercot-grid).

12 E3 Report at 126.

13 E3 Report at 46.

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?

Both the choice of the number of hours and the period over which those hours are identified appear to be arbitrary. A longer the term over which the hours are identified increases the uncertainty for generators regarding when they must be available to earn a credit. While shorter terms over which hours are identified can be expected to reduce some of the uncertainty of when credits could be allocated, the randomness of those hours will remain, which could eliminate the incremental benefit of the shorter term. For example, allocating 24 credits over a year or allocating two credits per month both face a significant level of uncertainty.

As a potential alternative, the Commission could consider allocating credits daily based on a particular hour of concern, such as the hour of lowest operating reserve or the hour of highest peak net margin. While there would be some degree of randomness still impacting uncertainty of when credits would be issued, the shorter timeframe would provide greater opportunity for generation to target their hour of availability and for load to target when demand response could be most beneficial. In addition, this broader allocation of credits also could avoid the "feast or famine" nature of the PCM as proposed in the E3 Report. Whereas missing one of 30 hours could have major adverse financial impacts under the proposed methodology, each hour under a daily methodology would be worth significantly less, meaning that missing a single hour would not have the same dramatic adverse impact on a generator's financial performance that year.

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

Please see response to Question 4.

6. Would a voluntary forward market for generation offers and a mandatory residual settlement process for Load Serving Entity procurement provide additional

generation revenue sufficient to incentivize resource availability in a way that improves reliability?

No. If the voluntary forward market depends on bids for specific hours from individual generators in order for that generator to be eligible to earn performance credits later in the year (or shorter term) during the hours offered in the forward market, the risk of missing any particular hour during which performance credits may be earned may be so great as to discourage participation in the forward market above any minimal requirement since the potential for missing any particular hour for which forward offers have been submitted would be unpredictable and the potential liability could be significant. The residual settlement process does not address this uncertainty, but instead shifts the financial risks to load serving entities that must address, on a retrospective basis, how to identify and bill a customer for costs the customer caused in the past and collect the amounts billed, which may be significantly more difficult if the customer switched to an alternate load serving entity during the interim period.

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

No comment.

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?

It is not clear that there is a need for the Commission to adopt a "bridge" product or service to maintain system reliability. In its Report, E3 recognizes that ERCOT currently has sufficient reserves to meet a reliability standard of 0.03 LOLE, or a reliability standard more than three times better than the standard E3 proposes ERCOT achieve through any of the proposed market design reforms.[14] Moreover, ERCOT already is on a path to greater reliability over the next few years. E3 also observed, "Without further adjustments to the resource mix beyond CDR additions and retirements, the "per-equilibrium" 2026 portfolio would achieve an LOLE of 0.02 days per year, more reliable than the common benchmark of 0.1 days per year."[15] This improvement is not surprising since ERCOT's latest CDR Report indicates that more than 1,500 MW of new gas-fired generation is expected to be online by Summer 2024, in addition to 806 MW of wind generation, 5,340 MW of solar generation, and 3,056 MW of energy storage resources.[16]

If the Commission determines that a "bridge" is required despite ERCOT's improving reliability under the status quo, such as to eliminate the ongoing reliability unit commitments ERCOT procures, Plus Power recommends that the Commission and ERCOT take advantage of the work already done to implement ECRS in 2023 and expand the procurement of fast-ramping resources to be available to ERCOT to address sudden changes in generator outages, demand on the grid, and wind and solar production. ERCOT already has expanded its procurement of Non-Spin Reserve Service as part of its "conservative" operations, and, since NERC requirements restrict the deployment of Responsive Reserve Service, ECRS is the next best alternative to provide greater reserves to ERCOT. ERCOT also could consider expanding its procurement of Regulation Service to provide even more fast-ramping resources to address frequency fluctuations as well as consider implementing a technology neutral uncertainty product similar to the Independent Market Monitor's (IMM) Recommendation 2101-2 in its 2021 State of the Market

14 In its Report, E3 states, "The results showed that the current system achieves a loss of load expectation (LOLE) of 0.03 days/year, exceeding the common industry benchmark of 0.1 days/year or 'one day in ten years'." E3 Report at 126.

15 E3 Report at 46.

16 Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2023-2032, November 29, 2022, Worksheet labeled "Changes" (available at https://www.ercot.com/files/docs/2022/11/29/CapacityDemandandReservesReport_Nov2022.xlsx).

Report for ERCOT.[17] Expanding the procurement of ECRS and Regulation will not delay any other market changes.

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?

See response to Question 8 above.

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

No comment.

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.

As noted above, increased procurement of ECRS and Regulation would be the fastest and most efficient "bridge."

12. In what ways could the Dispatchable Energy Credit 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 concept Commissioner McAdams originally proposed to create a Dispatchable Portfolio Standard (DPS) and use Dispatchable Energy Credits (DECs) to encourage investment in new efficient fast ramping dispatchable generation resources could easily be modified to be technology-agnostic and to encourage the development of all forms of new dispatchable generation. Rather than limiting the eligibility for DECs to the original performance criteria, eligibility should be expanded to include all new dispatchable generation resources and allow the

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[17] Potomac Economics, 2021 State of the Market Report for the ERCOT Electricity Markets, May 2022 (available at https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-the-Market-Report.pdf).

competitive market to determine which are the best resources to bring to the ERCOT market. Rather than basing the procurement goals of the DPS on load growth, the proposal could be modified to establish a specified amount of capacity of new generation resources to be encouraged, like the goals set in Utilities Code §39.904(a). In addition, the proposal could allow the creation of DECs through performance in the energy and ancillary service markets at all times rather than the original proposal of creating DECs through performance between the hours of 6:00-20:00. The minimum duration requirement of 48 hours that E3 proposed should not be adopted since that requirement is not fact based and would eliminate eligibility for technology such as energy storage resources that are proven to help ERCOT meet its reliability needs. When ERCOT analyzed the potential duration needs for resources providing ECRS, ERCOT determined that 99% or more of the events for which it would deploy ECRS have a duration of less than two hours.[18] Based on this analysis, ERCOT determined that a 2-hour duration requirement was appropriate for ECRS. Imposing a 48-hour duration requirement on these resources is not supported by any factual basis. Finally, setting an Alternative Compliance Payment (ACP) and applying funds paid as ACPs to the cost of ancillary service procurement are key to capping the cost of the DPS. All these changes would expand the ability of the DPS proposal to incentivize new and dispatchable generation and do so more directly than any other proposal that E3 studied in its Report.

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[18] ERCOT Staff, *NPRR 1096 Sustained Duration for ECRS and Non-Spin Ancillary Services*, Performance, Disturbance, Compliance Working Group (Nov. 12, 2021) at 6 (available at https://www.ercot.com/files/docs/2021/11/11/NPRR_1096_Update_11042021_v9.pptx).

CONCLUSION

Plus Power appreciates the opportunity to provide these Comments and looks forward to working with the Commission and other interested parties on these issues.

Respectfully submitted,

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EXECUTIVE SUMMARY OF
COMMENTS OF PLUS POWER, LLC

- The PCM proposal as E3 has described it would likely fail to improve reliability in the ERCOT region. However, with certain targeted improvements, the Commission could structure a proposal that could achieve certain Commission goals, such as targeting additional revenue to existing dispatchable generation resources. Those improvements include allocating credits on a shorter term, such as daily, and based on a particular hour of concern, such as the hour of lowest operating reserve or the hour of highest peak net margin.

- If the Commission's primary goal is to encourage investment in "new steel in the ground," the Commission could adopt the Dispatchable Portfolio Standard (DPS) consistent with Commissioner McAdams' original proposal in his November 17, 2021, memorandum filed in Project No. 52373. The qualifications for the Dispatchable Energy Credits (DECs) could be broadened to be technology-agnostic to encourage innovative and new dispatchable generation resources, including small modular nuclear reactors. E3's proposal to impose a 48-hour duration requirement should be rejected.

- In the event the Commission determines that a "bridge" is required to improve reliability of the ERCOT grid in the more near term, the Commission could increase ERCOT's procurement of ERCOT Contingency Reserve Service (ECRS) when ERCOT implements that service in early to mid-2023 above the amounts ERCOT has preliminarily proposed in its proposed 2023 ERCOT Methodologies for Determining Minimum Ancillary Service Requirements as well as increase its procurement of Regulation Service. This action would ensure that ERCOT has adequate fast ramping reserves to address system reliability concerns as well as provide an additional market signal to support investment in fast ramping dispatchable generation resources.