Filing Receipt

Received - 2022-12-15 11:22:25 AM
Control Number - 54335
ItemNumber - 82

PROJECT NO. 54335

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

TEXAS PUBLIC POLICY FOUNDATION'S COMMENTS ON E3 MARKET REDESIGN STUDY

TO THE HONORABLE PUBLIC UTILITY COMMISSION OF TEXAS:

The Texas Public Policy Foundation (TPPF), through its Life:Powered initiative, respectfully submits the following comments in response to the E3 market redesign study published on November 9 and the PUC staff questions for comment.[1] Our comments begin with some general principles that we will continue to advocate for in the market redesign process, followed by some specific critiques of the E3 report and recommendations for improvement, and ending with answers to the PUC staff questions.

Any market redesign needs to address the *overinvestment* in wind and solar generation in addition to the *underinvestment* in dispatchable generation.

Any program that only addresses the underinvestment problem is simply countering the federal subsidies for wind and solar with state subsidies for dispatchable generation and will lead to skyrocketing costs for ratepayers. Over $80 billion in private capital[2] and $20 billion in federal and state incentives,[3] including the subsidizing of transmission costs, have supported the massive buildout of wind and solar infrastructure in ERCOT. That infrastructure produced only 10% of the state's electricity during Winter Storm Uri, roughly the same amount of electricity as the 5 GW of nuclear generation in ERCOT.[4]

Even directing a quarter of the capital investment in wind and solar toward dispatchable capacity and weather resiliency would easily replace the output of a quarter of the wind and solar fleet during the storm while leaving billions left over to be applied toward weatherization. The ERCOT market does not need more investment. It needs smarter investment targeted toward the needs of everyday Texans and not the whims of federal policymakers who are unaffected by the reliability problems their policies are creating for the ERCOT market.

Although the Performance Credit Mechanism (PCM) and Forward Reliability Market (FRM) represent improvements over the original Phase 2 concepts, TPPF still prefers a targeted firming requirement for wind and solar as the most economically efficient option for addressing *both* the overinvestment and underinvestment problems facing the ERCOT market.

---

[1] Ben Haguewood, "Re: November 10, 2022 Open Meeting, Item No. 5 – Project No. 52373 – Review of Wholesale Market Design," (Memorandum, Public Utility Commission of Texas, November 9, 2022), https://interchange.puc.texas.gov/search/documents/?controlNumber=54335&itemNumber=2.

[2] "Clean Energy in Texas," American Clean Power Association, August 2022, https://cleanpower.org/wp-content/uploads/2022/08/ACP_StateFactSheet_Texas.pdf.

[3] Bill Peacock, *Subsidies to Nowhere: A Year-by-Year Estimate of Renewable Energy Subsidy Costs for Texas and for the U.S.*, June 2021, https://www.theenergyalliance.com/research/subsidies-to-nowhere.

[4] Brent Bennett, Katie Tahuahua, and Mike Nasi, *Pushed to the Brink: The 2021 Electric Grid Crisis and How Texas is Responding*, Life:Powered, August 2022, p. 23 https://lifepowered.org/pushed-to-the-brink-the-2021-electric-grid-crisis-and-how-texas-is-responding/.

As indicated in our previous work outlining our proposal for a firming requirement for wind and solar[5], a firming product that brought the low 5th percentile of aggregate wind and solar output during peak hours up to the average aggregate output would amount to about 12% of current aggregate wind and solar installed capacity. Assuming a lower firming requirement of 8% due to the more optimal 50/50 wind/solar mix in the E3 2026 scenario, compared to the current wind-heavy mix, and applying that number to the 80 GW of wind and solar capacity in the E3 2026 scenario, would result in a firming requirement of 6.4 GW. The cost of new entry for a gas combustion turbine is at least ~$95/KW-year,[6] which would result in an annual cost of the requirement of approximately $600 million. However, that cost could be less if much of the requirement is met by existing dispatchable generation.

It is no surprise that the capacity gap in the energy-only scenario in the E3 report, about 5.6 GW, is similar to the difference in the low 5th percentile output of the wind and solar fleet during peak hours vs. the average output of that fleet. The ERCOT market is optimizing toward the *expected* output of wind and solar during peak hours and not the properly accounting for the increased variability of that output relative to dispatchable thermal generation. This clearly demonstrates that the energy-only market is not functioning properly under the influence of price-distorting federal subsidies and the absence of a reliability requirement for wind and solar generators. Therefore, some capacity mechanism, properly targeted and limited in scope, is needed to counteract the distortions caused by the federal subsidies and ensure a reliable market.

The concepts contemplated in the E3 report could all be improved significantly by limiting eligibility to long-duration dispatchable resources, targeting the services to performance during the times of highest net load, reducing the need for poorly targeted scarcity pricing, and allocating costs in a holistic manner among intermittent generators, non-performing dispatchable generators, and loads, in proportion to their contribution to system variability during times of highest net load.

Our comments on the market redesign proposal from the South Texas Electric Cooperative in March 2022[7] provide greater detail on our opinions as to how to design these types of capacity mechanisms. In short, while we have concerns about properly sizing such a service and ensuring the continued vitality of the energy-only market in an environment with a strong capacity mechanism, we cannot ignore the fact that the price distortions and volatility caused by the federal incentives for wind and solar and the overbuilding those resources have created a reliability deficit in the ERCOT market.

These incentives will continue affecting the market for at least another couple of decades, which necessitates a counterbalancing capacity mechanism to reduce volatility and investment risk and ultimately ensure that ERCOT has enough dispatchable capacity to prevent significant loss of load events. Given this ongoing need and absent a targeted reliability requirement for wind and solar that

---

[5] Brent Bennett, *Improving the ERCOT grid through a reliability requirement for variable generation*. Life:Powered, October 2021, https://lifepowered.org/improving-the-ercot-grid-through-a-reliability-requirement-for-variable-generation/.

[6] Potomac Economics, *2020 state of the market report for the ERCOT electricity markets*, June 2021, p. 72-73, https://www.potomaceconomics.com/wp-content/uploads/2021/06/2020-ERCOT-State-of-the-Market-Report.pdf.

[7] Jason Isaac and Brent Bennett, "Public comment on PUC project no. 52373," Life:Powered, March 2022, https://interchange.puc.texas.gov/Documents/52373_354_1195083.PDF.

preserves more of the energy-only market, a broader capacity mechanism like the PCM can address this problem if it contains four main characteristics. First, it must be targeted toward reducing volatility during times of highest net load, Second, it should reward only long-duration dispatchable resources (generation or load) that reduce the risk of long-duration loss of load events. Third, it should reduce the need for the Operating Reserve Demand Curve (ORDC), which rewards generators that show up during scarcity periods regardless of whether they are committing to run during those periods ahead of time or showing up by chance. Paying for performance is important but ensuring long-term resource adequacy and reducing market volatility is also important. Finally, the cost should be allocated among intermittent generators, non-performing dispatchable generators, and loads that are driving the need for the service.

Suggestions for Improvement to the PCM

Given the commission Chairman's stated preference for the PCM concept, we offer a few suggestions for improving that concept as outlined in the E3 report. We also believe these changes would improve the FRM as well and urge the commission to study more closely whether the FRM with these changes might be better suited than the PCM to achieving the goals of this market redesign process. Incorporating the first three suggestions noted above into either service will help ensure that the service is properly targeted toward rewarding dispatchable generation that can commit to being online during times of scarcity, as required by SB 3. A service that lacks these elements will likely not be sized properly or will improperly reward generators who happen to be online during a scarcity event but cannot guarantee their availability under all conditions.

The final element of cost allocation is the key element that would bring the PCM closer in line to the firming requirement that we have long advocated for. It is still our opinion that the Commission has the authority to enact a holistic cost allocation mechanism for this service under Senate Bill 3, and Governor Abbott's July 2021 letter[8] indicated a clear support for allocating at least some of the cost for reliability services to intermittent generators. However, in view of not defeating the good in search of the perfect and stunting all progress, we would still support the commission moving forward with implementing the PCM if it included the first three elements below, with the hope that the legislature will provide more clear direction to the commission on cost allocation as soon as possible.

1. **Size the service to reduce net peak load variability.** Size is critical as a mechanism that is too large or too lucrative will threaten the vitality of the energy-only market and impose greater costs on ratepayers than what is necessary to meet the targeted reliability standard. Following this principle, we believe the PCM should be sized according to the goal of reducing peak net load variability sufficiently to meet the targeted reliability standard, as required by SB 3. Sizing the standard according to the times of lowest operating reserves as the E3 report contemplates, is not appropriate for a mechanism that is trying to ensure adequate dispatchable capacity. There are numerous reasons operating reserves can be low, including under forecasting load conditions, whereas times of highest net load actually represent the highest demand on dispatchable capacity. Therefore, any capacity mechanism should be centered on ensuring resource adequacy during times of peak net load.
2. **Do not allow non-firmed wind and solar generators to be eligible for the service.** A technology-agnostic approach may still direct a lot of payments to wind and solar that by chance produce

[8] Greg Abbott, "Letter to the Commissioners of the Public Utility Commission of Texas," Office of the Governor of Texas, July 2021, https://gov.texas.gov/uploads/files/press/SCAN_20210706130409.pdf.

during the assessed hours and will not impose proper market discipline or any incentive for intermittent generation to provide firm power. Requiring resources to bid ahead may achieve a similar result as a dispatchable-only requirement, but in either case, it is essential that the service direct revenue to the types of long-duration dispatchable resources that can reduce the probability of long-duration loss of load events during extreme weather. Experience with the ORDC has shown that a non-targeted approach will tend to incent more of what is already being built in the market, which is non-firmed wind and solar.

3. **Ensure that the service minimizes or eliminates the need for the ORDC and frequent use of reliability unit commitments.** Especially in the absence of cost allocation for backup power to wind and solar generators, the new service must reduce or eliminate the need for ORDC payments that go to wind and solar generators who happen to show up during one scarcity event but cannot guarantee in advance that they will be available during the next scarcity event. Any mechanism to ensure resource adequacy must properly value dispatchable generators that can ramp up to meet demand under all conditions. The mechanism should also reduce the frequency of scarcity events and largely eliminate the need for reliability unit commitments, which should only be used very sparingly in a properly functioning market.
4. **Create a mechanism to allocate the cost of the service back to the entities that most contribute to the strain on the system during net peak load hours.** The cost of the service should be allocated holistically to a combination of non-performing thermal generation, non-firmed renewables, and load, which will encourage demand response and/or conservation. Please see our comments on the South Texas Electric Cooperative proposal[9] for more details on how we believe cost allocation should be applied in the context of a market-wide capacity mechanism like the PCM.

Critiques of the E3 Report

Before we offer criticisms of the report, we want to highlight the value of these types of resource adequacy studies as a means of informing the policymaking process. In an environment where many observers, including federal regulators,[10] are saying that there is not a shortage of dispatchable capacity in ERCOT or that the operational and Phase 1 reforms are sufficient, this type of study, while flawed and incomplete in certain ways, shows that there is a looming shortage of dispatchable capacity in ERCOT and that market reform is needed in order to achieve the levels of reliability that Texans expect. Below are the primary critiques we have of the report.

1. **As the PUC further develops its policy direction, the timeline of study needs to be extended beyond 2026 to appropriately model the cost and impacts of the new programs and the likely resource mix when the programs go into effect.** We understand that longer-term forecasting in a market where the resource mix is changing so rapidly is difficult and there are modeling and resource limitations as to how many years can be modeled. However, 2026 is not enough time to capture the long-term cost of the programs, particularly the PCM. Our opinion is that the cost of the PCM, as currently proposed without cost allocation, will have to rise steeply to keep up with the growth of wind and solar and pay generators to stay online for fewer and fewer hours.

---

[9] Isaac and Bennett, "Public comment on PUC project no. 52373."

[10] Federal Energy Regulatory Commission, *The February 2021 cold weather outages in Texas and the south central United States*, November 2021, https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

Ultimately, without cost allocation, we believe the market will bifurcate into an energy market dominated by wind and solar and a capacity market for dispatchable generation, which would be more expensive than an energy-only market where resources are used at much higher annual capacity factors.

2. **Modeling based on a 1-in-10 reliability standard fails to appropriately capture the probability of long duration loss of load events in grids with high wind and solar penetration.** Low wind output tends to correlate with high demand as high pressure systems bring extremely hot or extremely cold weather throughout the state. Winter Storm Uri was an extreme example of this very common phenomenon. Wind and solar droughts, that is, several days of low wind or solar output in a row, are also common in summer and winter, and such scenarios would put a strain on energy storage and dispatchable generation. It is difficult to capture the true probability of these types of correlated events in the type of Monte Carlo simulation that we are assuming this study employs. As a result, we suspect the study underestimates the probability of long duration loss of load events in a grid with such high levels of wind and solar penetration.
3. **The cost of the high-renewable scenario is substantially lower than in the reference scenario, whereas numerous other models show costs increasing substantially above 50% wind and solar penetration.** Without having visibility into some of the intricacies of the model, it is hard to discern how the model produces $4 billion lower weighted average costs for a system with 40 GW more wind and solar and 10 GW more storage than the reference system. Our modeling indicates costs rise substantially above 50% wind and solar penetration due to increased curtailments of wind and solar, increased storage costs, and the inefficiency of paying dispatchable generators to operate for fewer hours.[11] The fact that the reliability and performance credits in Table 29 are almost the same as they are in Table 22 is puzzling, given that dispatchable resources would likely have to draw a large majority of their income from the program at that point. Furthermore, E3's non-technology neutral option for the PCM shows lower costs to ratepayers in the short-term but not in the long-term. E3 should provide more explanation of how they arrived at these results, and how they accounted for the impact of federal subsidies in their modeling.

Answers to PUC Staff Questions

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

   Given that no existing market design is properly dealing with the disruptive nature of massive federal subsidies for wind and solar generation, we think a new approach is not only warranted, but necessary. Novelty alone should not be an obstacle for Texas. However, implementation time is critical given the potential of new federal rules that could quickly shutter more than half the existing coal generation and several GW of gas generation in the ERCOT market. Also, regulatory certainty is important for driving investment. Therefore, time is of the essence in implementing any changes, including the PCM. At the same time, such changes should be designed for the long-term and help ensure market stability.

---

[11] Brent Bennett, *Green New Deal Will Put Texas in the Red: Effects on Texas Electricity Costs and Energy Production up to 2030*, Life:Powered, October 2019, https://lifepowered.org/wp-content/uploads/2019/10/2019-08-PP-LP-Bennett-Green-New-Deal.pdf.

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?*

   Referencing our comments above, we think that the PCM design could meet these goals with proper eligibility requirements focused on meeting demand during times of net peak load. However, absent proper cost allocation to generators, the PCM will likely fail to impose discipline on wind and solar generation in ERCOT, which means that dispatchable generators will increasingly rely on the PCM for revenue. In this case, the market will be in a constant state of "chasing its tail" as it works to maintain enough dispatchable generation, operating for fewer hours at higher cost every year, to back up wind and solar generators, causing overall system costs to rise considerably.

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)?*

   The challenge with a 1-in-10 standard is that it doesn't properly capture the duration and depth of a loss of load event. A loss of load event every year will do little harm if it lasts for only a couple hours and involves only a few GW. Ratepayers are accustomed to brief outages from equipment failures, tree branches, etc. But a 20 GW loss of load event, as occurred during Winter Storm Uri, over a full day or consecutive days, is unacceptable, even if it only occurs once every 10 years.

   For example, the E3 report notes a 13% probability of 10 or more hours of lost load under the existing energy-only market. If those hours occurred nonconsecutively, that situation might be tolerable, but if they occurred consecutively, it would be a disaster. Even if there were no weather-related failures during Winter Storm Uri, loss of load would have occurred for nearly 24 hours and peaked at almost 10 GW.[12] Every thermal generator in ERCOT would have had to operate to near perfection to avoid a loss of load, with no planned or forced outages, and such perfection cannot be expected. It would be prohibitively expensive to ensure no loss of load during a storm like Winter Storm Uri, but the current situation is not acceptable.

   Even after the reforms that have been enacted following Winter Storm Uri, a similar weather event would still bring an unacceptable amount of lost load. And as the proportion of dispatchable capacity declines on the system, less extreme weather will result in similar outcomes. Therefore, any reliability standard that is adopted should address the depth and duration of a load event in addition to the frequency and be targeted toward reducing the probability of a large loss of load event over multiple consecutive hours.

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?*

[12] Bennett et al., *Pushed to the Brink*, p. 22.

Given the high variability of a market with large amounts of wind and solar generation, we think 30 hours per year is probably not enough, even if properly targeted toward the highest net peak load hours. Capturing an appropriate share of the potential risk scenarios would probably require factoring in at least 100 hours each 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?*

   Looking at the 100 hours of highest net peak load over an annual period appears to be a good start—based on resource adequacy modeling we've done for ERCOT, SPP, and MISO—but some sensitivity analysis must be done in order to determine the best period. We also have some concern that a backward-looking assessment may fail to capture the fact that, as the ERCOT market transitions to much higher solar penetration, as contemplated in the E3 report, the periods of highest net peak load are likely to shift from the summer to the winter over the next several years.

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?*

   No comment.

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, to maintain system reliability equivalent to a 1-in-10 LOLE or another reliability standard? If so, what product or service should be considered?*

   We do believe the reliability risk in the near term justifies the cost of a bridge product like the BRS. The greater risk lies in the 2027 to 2030 timeframe, especially if federal regulations currently being proposed are implemented. Therefore, we feel there is still time, although not much time, to develop a comprehensive reliability solution without a bridge product.

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?*

   We generally do not support a bridge product, at least in a form similar to the Backstop Reliability Service. Such a program would fail to impose discipline on the wind and solar growth that is driving the need for it, making it an expensive and temporary band-aid at best. Also, such a "temporary" program would inevitably tend to become permanent as generators become reliant on it for revenue and future regulators see a continued need for supporting dispatchable generation as wind and solar generation grows unimpeded.

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

    This is our greatest concern with the PCM over the long term if the program does not include cost allocation to generators. While the cost of the PCM will naturally tend toward zero if the wholesale energy market is sufficiently compensating generators, from what we can tell in the current outline of the program, there is not a corresponding check on the size of the program as wind and solar generators capture a larger share of the revenue in the wholesale energy market, forcing more and more dispatchable generators to rely on the PCM to remain solvent. This would lead to exactly the kind of inefficient dual market—energy market for wind and solar plus capacity market for dispatchable generators—that we have been concerned about from day one of this market redesign process.

    In contrast, a firming requirement for wind and solar will automatically impose the needed market discipline. As wind and solar generators are added to the grid, the firming requirement for those generators will grow correspondingly, ensuring that they only enter the market to the extent that they can meet the reliability standard. Depending on the cost of wind and solar, its value in the market, and the cost of backup power, the requirement will naturally land on the economically optimum balance of wind and solar to dispatchable power and preserve more of the energy market by requiring wind and solar to bid at higher prices to cover their cost of backup power.

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.*

    No comment.

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?*

    We do not think a DEC program focused solely on new dispatchable generation will benefit the ERCOT market. Any program to promote dispatchable capacity should be open to all dispatchable generators that can commit in advance with long duration, and the costs should be allocated not only to load but also to non-performing generators, particularly wind and solar.

...

Sincerely,

<u>*/s/ Jason Isaac*</u>
Hon. Jason Isaac
Director, Life:Powered
Texas Public Policy Foundation

<u>*/s/ Brent Bennett*</u>
Dr. Brent Bennett

Policy Director, Life:Powered
Texas Public Policy Foundation

PROJECT NO. 54335

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

COMMENTS OF THE TEXAS PUBLIC POLICY FOUNDATION: EXECUTIVE SUMMARY

General Comments

- Any market redesign needs to address the overinvestment in wind and solar generation in addition to the underinvestment in dispatchable generation.
- Although the PCM and FRM represent improvements over the original Phase 2 concepts, TPPF still prefers a targeted firming requirement for wind and solar as the most economically efficient option for addressing both the overinvestment and underinvestment problems facing the ERCOT market.
- The concepts contemplated in the E3 report could all be improved significantly by limiting eligibility to long-duration dispatchable resources, targeting the services to performance during periods of highest net load, and allocating costs in a holistic manner among intermittent generators, non-performing dispatchable generators, and loads, in proportion to their contribution to system variability during times of highest net load.
- Any reliability standard that is adopted should address the depth and duration of a load event in addition to the frequency and be targeted toward reducing the probability of a large loss of load event over multiple consecutive hours.

Critiques of the E3 Report

- In an environment where many observers are saying that there is not a shortage of dispatchable capacity in ERCOT or that the operational and Phase 1 reforms are sufficient, this study accurately shows that there is a looming shortage of dispatchable capacity in ERCOT and that market reform is needed in order to achieve the levels of reliability that Texans expect.
- As the PUC further develops its policy direction, the timeline of study needs to be extended beyond 2026 to appropriately model the cost and impacts of the new programs and the likely resource mix when the programs go into effect.
- Modeling based on a 1-in-10 reliability standard fails to appropriately capture the probability of long duration loss of load events in grids with high wind and solar penetration.
- The cost of the high-renewable scenario is substantially lower than in the reference scenario, whereas numerous other models show costs increasing substantially above 50% wind and solar penetration. This is a cause for concern with the design of the model.

Suggestions for Improvements to the PCM Concept

- Size the service to reduce net peak load variability.
- Ensure that non-firmed wind and solar generators are not eligible for the service.
- Ensure that the service minimizes or eliminates the need for the ORDC and frequent use of reliability unit commitments.
- Create a mechanism to allocate the cost of the service back to the entities that most contribute to the strain on the system during net peak load hours. Under this holistic approach, the cost allocation will be applied to a combination of non-performing thermal generation, non-firmed renewables, and load, which will encourage demand response and/or conservation.