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

SOUTH TEXAS ELECTRIC COOPERATIVE, INC.'S COMMENTS ON MARKET REFORM ASSESSMENT

TO THE HONORABLE PUBLIC UTILITY COMMISSION OF TEXAS:

COMES NOW, South Texas Electric Cooperative, Inc. ("STEC") and submits its Comments to the Public Utility Commission of Texas ("PUCT" or "Commission) on the Review of Market Reform Assessment Produced by Energy and Environmental Economics, Inc. ("E3"). STEC supports the comments filed by the Texas Electric Cooperatives ("TEC") and files these comments both in support of, and with respect to, additional items not raised in the TEC comments. The deadline for filing Comments is Noon on December 15, 2022; as a result, these comments are timely filed. An executive summary is attached hereto as Attachment A.

INTRODUCTION

It is important that the Phase II implement market-based products consistent with SB 3 that are targeted to dispatchable generation, include performance-based incentives, and include non-discriminatory cost-allocation based on cost-causation principles. Consistent with the requirements of SB 3 and with the current market design and in recognition that the new critical care requirements will mean that more dispatchable generation will be needed to keep the system reliable during peak net load events which include extreme weather events, STEC provides the following comments.

I. RESPONSES

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

The need for reliable, dispatchable generation that can be brought on-line was evident in Winter Storm Uri. In order for the investment to flow into the ERCOT market needed to support new dispatchable generation and preserve existing dispatchable generation, certainty in the market structure and framework, and attendant revenue streams for that generation is key. A new, untested model is unlikely to provide the confidence for investors to support new investment. It is significant that PCM, and for that matter LSERO and FRM, use the 30 hours of tightest operating reserves and not net peak load. Net peak load is a tested reference point that demonstrates which generators are capable of running on an as-needed, dispatchable basis.

The 30 tightest operating reserve hours do not reflect the true scarcity of dispatchable capacity. In fact, operating hours can be tight merely because ERCOT missed the load forecast and as a result, less generation is on-line because ERCOT has forecast lower operating needs than actually occur. The Commission is keenly aware that forecasts are unreliable and ERCOT uses multiple forecasts and picks the forecast to use on a particular day. If the ERCOT load forecast predicts lighter load conditions, less generation will be on-line and operating reserves will be tight. In that case, any generator that is capable of running, and was offered into the market at some level of megawatts, will get PCM credits. That includes non-dispatchable capacity and may specifically exclude dispatchable generation that would have stayed on-line had ERCOT's load forecast been accurate. Inaccurate load forecasts are not something to criticize because all forecasts are inaccurate. However, the PCM makes operating reserves that could result from under-forecasted load conditions the basis for generators to earn credits. That is not something that will generate investment. In fact **no other market** uses the tightest operating reserve hours as a trigger for any purpose. PCM, however, uses the tightest operating reserve hours as a trigger not only for the creation of capacity credits, but also for the allocation of costs to be borne by loads as an outcome of this capacity market.

Tight operating reserve hours can also be gamed by large loads that can either participate, or not, in the Day-Ahead Market ("DAM") leading to lower generation commitment than is likely to be needed. This behavior would particularly benefit large load-serving entities with affiliated generation fleets. The resulting tight operating reserves that would ultimately lead to Performance Credit creation and PCM cost allocation would not be due to weather, or to net peak load, but instead due to market participant participation in the DAM.

Making payments to generators in reliance on ERCOT's forecast or swings made in the markets by larger loads (and notably there is no market power cap on load serving entities as there is on installed generation capacity) can help to ensure that an entity with large load and with generation can better predict tight operating reserves than other market participants.

Similarly, because the PCM model lacks an accreditation mechanism to ensure support for particular types of needed resources, specifically dispatchable generation, some entities may be compensated simply for being on-line after they have bid in 1 MW or more of capacity in the voluntary market. This type of system will not drive investment in dispatchable generation and has the same level of uncertainty with respect to payments as the energy-only market.

Additionally, during the shoulder months, when operating reserves are lower due to the limited time periods within which dispatchable generation must go down for maintenance, the PCM appears to be designed to penalize generation that takes the necessary maintenance. If generators forego maintenance, the risk of forced outages will increase exponentially, making the dispatchable capacity less reliable than without PCM.

The PCM mechanism will not provide certainty to investors or a revenue stream to support either existing or new investment in generating capacity in the ERCOT market. These are some of the issues STEC has identified with PCM in the short time given to review the new proposal. PCM will not provide investor certainty that dispatchable generation will be supported. As the Commission's consultant pointed out, PCM will have unintended consequences, take longer to implement as new product, and will likely make investors weary of investing in the ERCOT market. Similarly, the incentives created by penalizing dispatchable generation for not offering into the market during low operating reserve periods that are likely to occur during maintenance periods, is counterproductive to keeping this much-needed generation in the market. If the ultimate Phase II product does not target net peak load, rather than tight operating reserves, it will likely further drive dispatchable generation from the market. In addition, having a product that has never been tried or successful in any other market at this critical juncture creates additional uncertainty and will likely substantially delay implementation (much like the nodal market cost $650 Million and was delayed for several years when it could have been purchased from the PJM market and implemented for $150,000 and PJM ultimately offered it to ERCOT at no charge to have comity between the markets). The fallacy behind the 30-hour operating hours is that tight operating reserves equate to net peak load. The reality is that net peak load at times drives tight operating reserves, though tight operating reserves can be caused by many other issues not related to dispatchable generation. Even so, dispatchable generation will still be penalized for not meeting these periods, while dispatchable generation may not benefit from the credits themselves.

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?**

As set forth above, the PCM design is not tied to net peak load or extreme power consumption conditions. Using tight operating reserves as the trigger for Performance Credits does not result in supporting dispatchable capacity, and may further penalize dispatchable capacity due to the risk created by the must-offer requirement in the forward market for generators to be eligible for Performance Credits. Contrary to the Senate Bill 3 requirements, PCM is not designed to incentivize performance, retention or market entry with respect to net peak load. As described above, PCM relies on lower operating reserves that may not be attributable to the dispatchability of the system, are reflective of other external influences, and can be gamed.

The PCM model captured in the E3 Report appears to be changing even from what is set forth in the E3 Report. It is clear following comments made in both the Texas Senate Business and Commerce Committee hearing and at the House State Affairs Committee hearing, that the tightest operating hours for the PCM model are very much in flux. Discussion that the tightest operating hours would change to 4 hours per month, or possibly a seasonal construct, rather than the 30 hours per year that the E3 Report assumed in reaching its conclusions. Furthermore, the E3 Report assumes that ***all*** generators available during tight operating hours are eligible for PCs, not just dispatchable generators. This design provides inappropriate Performance Credits for reliability to non-dispatchable generation despite its inability to contribute to reliability when needed. PCM rewards the very non-dispatchable generation that dispatchable generation is needed to support, and further undermines the intent to provide incentives to retain or incent new dispatchable generation. The E3 Report did not find that the PCM model was designed to manage a Uri-level or extreme weather event; other models were better suited to manage tail-end events, including the Forward Reliability Model that was recommended by E3. Lastly, the PCM model creates yet another crisis-based model that is intended to clear credits in some years at $0 and some at the administratively set offer cap. Such a binary outcome has proven to be ineffective in the current energy-only construct. ERCOT is destined to repeat the crisis-based management of the grid under the PCM construct when new generation cannot site and existing generation cannot be maintained on the system based on the volatility associated with PCM price signals.

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)?**

All of the longer-term models require that a reliability standard be set so that a reserve margin is defined. The defined reserve margin both establishes the minimum threshold to be met to prevent prolonged rotating outages in the ERCOT region and provides a benchmarking tool to determine if the reliability objectives are being met. STEC believes that the traditional 1-in-10 Loss of Load Expectation is the correct standard and is the standard used by most regional transmission organizations and independent system operators. STEC does not believe that ERCOT-grid should have a less stringent reliability standard than other markets and the 1-in-10 Loss of Load Expectation has proved to be an effective planning tool for ERCOT. The standard is identifiable, predictable, readily available and easily understood. A standard that both predicts and allows certain levels of Expected Unserved Energy, and necessarily presupposes load shed and outages to customers, is not acceptable. Standards other than the 1-in-10 Loss of Load Expectation are metrics find differing levels of load shed acceptable and plan for reliability to meet the accepted level of load shed. The public and the Legislature have demanded higher reliability in the wake of Winter Storm Uri, which is inconsistent with a reliability standard that both accepts and expects some arbitrary level of load shed.

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 reliability risk identified in SB 3 was the lack of dispatchable generation. A reserve margin must be calculated to be able to dispatch to the reserve level. The operating reserve measurement under PCM does not do that and does not accredit contribution to reserves based on dispatchability. Net peak load should be the measure that is used in ERCOT, consistent with the requirements of SB 3. During Winter Storm Uri, dispatchable generation was expected to backstop all renewable generation and had all of the dispatchable generation performed flawlessly, there would not have been enough of it to avoid substantial periods of load shed on the ERCOT system. That entire period was a net peak load period. The days over the summer where ERCOT needed conservation were net peak load days. Since SB 3 is abundantly clear that dispatchable generation is to be supported especially because other generation is not available at all times, the actual problem to be addressed should be the trigger—net peak load—for incentivizing performance by dispatchable generation and non-dispatchable generation that can pair with additional back-up or other dispatchable generation. Similarly, an accreditation mechanism can be used that reflects the Effective Load Carrying Capability of a unit to contribute to reserves during net peak load periods.

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 greatest risks to the system are during net peak load and are seasonal—summer and winter—with the highest risk now appearing in the winter. Given the declining dispatchable capacity in ERCOT as a result of the energy-only market, STEC believes that net peak load presents the greatest risk to the system. Net peak load is a risk in both summer and winter, as well as during extreme weather events. Dispatchable credit procurement should be structured in the same manner as the FRM, though based on net peak load hours, on a seasonal basis, and for a period of time that is no less than one year into the future.

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?**

STEC does not believe that a market that has a one-sided forward participation requirement only for generation and not for load is effective. The market, if implemented, should be wholly voluntary as is seen in the Day Ahead Market which has proven to be a very robust and efficient market. There is absolutely no reason to make the forward market mandatory for only one set of participants if the intent of the market is to provide a hedging tool. Furthermore, secondary bilateral markets will develop providing additional hedging opportunities, further negating the need for a must-offer requirement for one class of market participants in an ERCOT-administered PCM forward capacity market.

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

Yes, a centrally cleared forward market would mitigate market power abuse coupled with market monitoring by the Independent Market Monitor. Such a centrally-cleared market should be binding on all participants in order to effectively manage market power. It is the binding nature of the market that makes the market competitive. If it is not mandatory for load, it should not be mandatory for generation. Only a truly competitive market will address market power. It is important for load-serving entities that have obligations to require capacity under any construct to have a competitive market with a liquid, transparent process for obtaining market-based pricing from generation owners that also compete in the competitive markets through retail electric providers. The liquidity that a centrally-cleared, forward capacity market provides is beneficial to all market participants and serves to reduce the ability for either loads or generators to exercise market power.

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?**

If the implementation can truly be 2-4 years, such as for the FRM model that includes either accreditations for generators at their Effective Load Carrying Capability, or that is procured for the net peak load periods to meet the reserve requirements, as is in effect in other markets with a proven track record, a "bridge" product should not be utilized. STEC has concerns that the PCM model will be much delayed, in excess of the 2-4 year estimate, due to the novelty of the approach and may not result in needed investment in expansion of existing dispatchable capacity or in new dispatchable capacity being added to the system. Other backstop mechanisms already exist to bridge the gap, including Reliability Must Run ("RMR"). Instead of devoting time and resources to implement an interim product, STEC recommends that RMR, which was designed as a backstop for the market, be utilized for this purpose. STEC does not believe that RMR is a permanent solution. However, until such time as a long-term solution can be implemented, that supports existing and new dispatchable generation, and that uses a forward, transparent market tied to net peak load, the period of greatest risk to the market, RMR is a ready-made stop-gap mechanism that has been tested in the market over many years.

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. STEC does not believe a "bridge" mechanism should be considered because it will delay implementation. STEC supports the 1-in-10 LOLE reliability standard, however, STEC is concerned that if an interim measure such as the long-term commitment for ancillary services is used, it will only come from existing resources and may inhibit some dispatchable generation from being able to take outages, which are already limited to a small window of time. Implementing an increase in ancillary services will not incent investment and depending on when the ancillary services are procured, could further strain the existing fleet of dispatchable generation. Buying additional Ancillary Services is not a panacea that can replace well-designed and implemented market design.

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

PCM will increase consumer costs over the FRM, and substantially over the STEC Reliability Service models, both in terms of design and implementation for an entirely new construct and may also continue to put consumers at risk for costs during weather events because it does not effectively incent dispatchable generation. Because the PCM rewards generation for being on-line and offered into the market during low operating reserve hours, but does not specifically incentivize dispatchable generation to develop, it is unclear that it will create the financial signals necessary for investment in new generation. The impact on consumer costs would then be that additional PCM charges must be paid, but similar to the energy-only market, price volatility in other hours will need to signal investment in new generation. Unlike the FRM or the Reliability Service models, there is no forward look, and no accreditation for participation. Further, because the 30-hour period is not designed to incent dispatchable generation, and particularly if the 30-hour annual period is shifted to a 4-hour per month period, if the operating reserves are low due to a weather event similar to Winter Storm Uri, the generation that will be paid in that year will be generation that can run for 4 or 30 hours, but not for the bulk event—leaving customers exposed for the balance of the remaining days with human costs in addition to property and other economic costs. All of the E3 models using the tightest operating reserve hours (PCM, LSERO and FRM) do not target the dispatchable generation SB 3 contemplated. If these models keyed off of net peak load, they would be closer to targeting the SB 3 requirements and would lower consumer costs by creating incentives for dispatchable generation investment while mitigating the volatility that exists as a result of renewable variability.

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.**

STEC believes that devoting resources to a "bridge" product or service will further delay implementation of the final product. The FRM could be implemented in 2-4 years, while one of the interim products such as BRS could also take 2 years to implement and DECs may take up to 4 years to implement. Although the PCM is stated to take 2-4 years, because this is a novel product, it is likely to take much longer to implement. For example, when ERCOT was offered the nodal systems from the PJM market originally to be sold and later being offered without charge for purposes of comity between the markets, the decision was to design an ERCOT-specific nodal market. That decision cost $650 Million and saw several years of delay. During that time, because all of the ERCOT resources were devoted to the nodal market, any other, interim product would have further delayed nodal implementation. Whatever decision the Commission makes should be able to be implemented within the 2-4 year period, without requiring a bridge mechanism. Dispatchable capacity would take 2-4 years to come on-line once the signal is sent that the Commission is creating regulatory certainty by incentivizing that generation for reliability. The signal that will be sent, when the Commission puts in place the plans for a reliability model that credits dispatchable capacity, will be more important than a bridge mechanism during any interim period.

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?**

STEC does not believe that the DEC mechanism should be used as a bridge mechanism.

II. CONCLUSION

STEC appreciates the opportunity to provide comments to the Commission on these important issues and the need for a reliability mechanism that will incentivize the retention of dispatchable generation and encourage new dispatchable generation to locate in the ERCOT market.

Respectfully submitted,

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ATTORNEYS FOR SOUTH TEXAS ELECTRIC COOPERATIVE, INC.

Attachment A

Executive Summary of South Texas Electric Cooperative, Inc. Market Reform Assessment Comments

1. PCM is unlikely to provide support for dispatchable generation using the tightest operating reserve hours as a trigger for Performance Credits instead of net peak load.

2. Tight operating reserve hours can be caused by ERCOT missing the load forecast or by load-serving entities scheduling conduct in the DAM such that they are not related to dispatchability of the system and can be gamed by entities with both large load and generation portfolios.

3. PCM will reward non-dispatchable generation that happens to be on-line when ERCOT misses the load forecast, dispatchable generation is down for maintenance or when large loads reduce schedules in the DAM which causes tight operating reserves and benefits what become predictable tight operating reserve hours for the load's affiliated generation fleet (gaming).

4. No other market uses tight operating reserves as a trigger; it is not appropriate for ERCOT since dispatchable capacity must backstop renewables.

5. Performance Credits based on tight operating reserves are a crisis-based approach to capacity given that the revenues may be $0 or may be at the administratively set offer cap, but will not provide the certainty and predictability needed for the retention of existing dispatchable capacity or new installed capacity.

6. Dispatchable capacity will be penalized for taking maintenance during the limited times permitted under the PUCT's schedule limitations simply due taking maintenance. If generation does not take maintenance to try to earn Performance Credits, forced outage rates will be higher and the system will be less reliable.

7. The PCM model's tightest operating reserve hours are in flux, and if changed from 30 hours annually to 4 hours a month, will not reflect the assumptions made in the E3 Report.

8. The FRM model was the E3-recommended model, preferred over PCM because it could better address weather disruptions on the grid and provide more certainty, though FRM would need to be used with net peak load to improve the FRM model.

9. The 1-in-10 Loss of Load Event standard is the best reliability standard for ERCOT; it has only been a "target" in ERCOT which has had no reliability standard. ERCOT's reliability standard should not be a lower standard than other markets, which use the 1-in-10 standard. Standards that accept or expect "unserved energy" (a euphemism for load shed) are not appropriate for ERCOT.

10. Net peak load should be the trigger for any reliability model construct since the tightest operating reserves do not address the need for dispatchable generation to backstop intermittent generation.

11. A voluntary market that is only binding on one set of market participants is not a true market and the DAM is a better forward market with the attendant bilateral hedging that occurs simultaneously. A partially non-binding market does not mitigate market power.

12. No new bridge mechanism should be used due to the delayed timing and the resource drain that would interfere with a permanent solution, however, RMR was designed and has been tested in ERCOT for this purpose.

13. PCM will be more expensive to consumers than FRM and will lead to crisis-based capacity constructs.