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

NRG ENERGY INC'S COMMENTS ON MARKET REFORM ASSESSMENT PRODUCED BY ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3)

On November 15, 2022, staff of the Public Utility Commission of Texas ("PUCT" or the "Commission") requested comments on questions concerning a report titled Assessment of Market Reforms Options to Enhance Reliability of the ERCOT System, authored by Energy and Environmental Economics, Inc. ("E3"). NRG Energy Inc. ("NRG") is grateful for the opportunity to participate in this important market design and market structure evaluation process. NRG is pleased to offer these comments and responses to Commission staff questions.

I. INTRODUCTION

NRG appreciates the careful and deliberate review of the Electric Reliability Council of Texas ("ERCOT") market structure by the PUCT over the past year and a half with the focus on system reliability. NRG strongly supports the continuation of the competitive retail and wholesale power market in Texas. The current ERCOT energy-only market has, in most years, produced efficient and low-cost outcomes, but for some customers and market participants these benefits have been completely overwhelmed by occasional high-cost reliability events. As events like Winter Storm Uri demonstrate, the biggest threat to our competitive market is the recurrence of grid reliability events and loss of critical electric service for our customers. Understandably, Texans are intolerant of grid disruptions and the consequences of unreliable service.

Indeed, the Texas Legislature has already spoken on this point by requiring that ERCOT be fundamentally reformed. Senate Bill 3 ("SB3") passed by the 87th Texas Legislature requires the Commission for the first time to establish "requirements to meet the reliability needs of the power region," to establish a competitive mechanism that includes performance requirements and incentives in order to procure services to meet these requirements, and to size these requirements at least annually to "to ensure appropriate reliability during extreme heat and extreme cold weather conditions and during times of low non-dispatchable power production."[1] This statutory mandate contrasts to the *status quo*, where reliability is provided on an as-available basis, with the Commission establishing a value of lost load and an offer price cap for energy, and permitting ERCOT to procure a variety of ancillary services in the day-ahead market only with the short-term operational reliability of the grid in mind. The bottom line is that the *status quo* is a market predicated on hope that the possibility of high energy prices during real-time scarcity conditions will result in long-term reliability, but there is no reliability requirement hardwired into the energy-only market. SB3 requires an important change, where electric market design must proactively define and solve for the reliability requirements under the high-demand and low-renewable-production conditions the law specifies.

II. PROBLEM STATEMENT AND THE NEED FOR A COMPREHENSIVE RELIABILITY SERVICE

The Commission has delineated its work related to ERCOT reform into two phases. Phase I encompassed a variety of standards and targeted approaches intended to remedy defects that became obvious through Winter Storm Uri. The system has been hardened as a result. Phase II was intended to address the challenges of resource adequacy and fulfill the requirements of SB3, Section 18. As such, Phase II called for long-term reform to ensure "the supply of dispatchable generation is sufficient to meet system demand in ERCOT."[2]

Both the law and the Commission's Blueprint specify a service that is intended to assure resource availability during times of system stress. This availability-based reliability service should be interactive with all the energy and ancillary service products that already exist; in essence, the service should act as an option that is bought and sold to ensure the availability of resources to provide the services needed in the day-ahead and real-time markets, which together add up to a reliable outcome. A successful reliability service will ensure a system is "resource adequate" within the standard required by law and adopted by the Commission. Also consistent with the law and the Commission's prior direction, the market design should provide performance

[1] Tex. S.B. 3, 87th Leg., R.S. (2021), Section 18, codified at PURA §39.159(b).

[2] *Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT*, Project No. 52373 (Jan. 13, 2022) p. 4.

incentives for resources to be available to provide operating reserves and real-time system reliability.

As a backdrop to this reliability marketplace, the ERCOT system faces the following challenges that underscore the difficulties and uncertainties of the system's current conditions: robust load growth; increasing quantities of subsidized intermittent renewable resources that can in some hours contribute to reliability but which erode energy prices on which dispatchable generators may depend in an energy-only system; and an aging fleet of thermal generation resources that are being overutilized and require sufficient outage times, and which also face tighter federal environmental regulations.

Only a comprehensive solution that measures resources' availability against a resource adequacy-based reliability standard will focus financial incentives to dispatchable generation and demand response to remedy these challenges. Making changes only within the energy and ancillary service market inevitably will maintain some version of the *status quo*, where resource adequacy is a hoped-for outcome and not a variable to be solved within the market design. Meanwhile, certain market participants have attempted to turn Phase II reforms into a conversation not about resource adequacy, but about adding yet another widget to the day-ahead or real-time operational posture of the grid.

The stated purpose of Phase II—sufficient resources to meet system demand—is *not* the same as having sufficient operating reserves, though the former will lead to the latter. Instead, the comprehensive market design that emerges from this phase of ERCOT reform should target the problem directly: ensuring enough resources exist on the system that are in a position to be available (including for operating reserves) during the most challenging grid conditions. Already, through the procurement of ancillary services such as Non-Spinning Reserve Service ("NSRS") and ERCOT Contingency Reserve Service ("ECRS"), ERCOT secures both online and quick-start resources to provide ample operating reserves to manage real-time fluctuations in electric demand and renewable output. In fact, the procurement methodology to determine the quantities for both NSRS and ECRS include net load forecast error to address real-time system uncertainty. The sufficiency of ERCOT's existing tools to manage uncertainty was recently highlighted on November 26, 2022, when actual ERCOT system net load was 3,400MW higher than forecasted for the 5pm to 6pm hour due to solar and wind output decreases in combination with the evening load ramp.[3] ERCOT deployed NSRS to manage this operational uncertainty and noted that "the use of Non-Spin worked as designed to cover forecast errors and net load ramps."[4]

Notably, in times of grid stress after Winter Storm Uri, nearly all generation resources were already online and operating. A new "uncertainty" product in such conditions would have nothing to procure, and it is fanciful to believe such a service would meaningfully promote new investments. Ancillary services do not get new generation built. ECRS was approved as a new ancillary service in 2019[5] and there was little to no response by the investment community in anticipation of this new product. The same goes for California, which implemented an "uncertainty" product in 2016 (but only after spending *five years* developing it).[6] Proponents of a product with a limited quantity and a narrowly specified range of operational characteristics have it backwards: Creating an ancillary service for "uncertainty" does not speak to the problem of resource adequacy, though resource adequacy solutions will furnish additional resources to be available to supply ancillary services.

NRG understands the temptation to believe that a narrowly targeted fix may allow the Commission to act surgically and then conclude its work. But that is a false hope. In addition to an "uncertainty" product, alternative designs the Commission has considered, including the Backstop Reliability Service ("BRS") and a Dispatchable Energy Credit program ("DEC"), have fatal flaws because they are not comprehensive. Subsidies targeting one set of reliability technologies will ultimately decrease energy-market revenues the unsubsidized resources rely upon to continue operations, unless some element of the market design prevents this outcome from occurring. Within the DEC market, energy prices would be suppressed in favor of side payments

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[3] Presentation of Dan Woodfin, Vice President, System Operations to ERCOT Reliability and Markets Committee Meeting, Item 7.2, Slide 8, (Dec. 19, 2022) *available at:* https://www.ercot.com/files/docs/2022/12/12/7-2-System-Operations-Update.pdf.

[4] Presentation of Dan Woodfin, Vice President, System Operations to ERCOT Reliability and Markets Committee Meeting, Item 7.2, Slide 8, (Dec. 19, 2022) *available at:* https://www.ercot.com/files/docs/2022/12/12/7-2-System-Operations-Update.pdf.

[5] ERCOT Nodal Protocol Revision Request 863, Board Report (Feb. 12, 2019) *available at:* https://www.ercot.com/files/docs/2019/02/13/863NPRR-29_Board_Report_021219.doc.

[6] *See* California Independent System Operator, "Flexible Ramping Product" *available at:* https://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedClosedStakeholderInitiatives/FlexibleRampingProduct.aspx

to only some sources of reliability, leading to a "bump out" effect that would exacerbate the resource-adequacy problems in ERCOT. Meanwhile, BRS neutralizes this effect, but only by doing something just as harmful: intentionally withholding capacity from participating in the energy market and not co-optimizing the economically efficient production of energy from resources receiving BRS side payments. In most markets, market participants withholding energy offers artificially to cause scarcity pricing would be frowned upon or unlawful; but BRS would codify energy withholding as a mandated program. The proposal contravenes the basic logic that should apply to market design, which is to encourage payments for availability to all resources capable of making such a commitment to interact in an efficient way with the production of energy. Both BRS and DEC make clear how narrowly targeted approaches are illusory in the resource adequacy conversation. A market design for resource adequacy must be comprehensive or it will be counterproductive.

Finally, the Commission should avoid any market design path that relies on the Reliability Must Run ("RMR") mechanism. RMR is a cost-of-service-based mechanism that represents a partial reregulation of the competitive wholesale market. It is one of the most inefficient mechanisms from a cost perspective, that sinks new consumer dollars into the oldest and most inefficient generation resources in the market. The presence of RMR contracts is indicative of a market failure and the opposite of what a competitive market seeks to provide: smooth entry and exit of dispatchable capacity based on private investment, not captive ratepayers.

III. IMPORTANT PRINCIPLES FOR A PERFORMANCE CREDIT MECHANISM

NRG supports a policy direction that addresses reliability comprehensively in accordance with the principles that are codified in SB3, and which are elaborated upon in the Commission's Blueprint.[7] At the November 10th Open Meeting, the majority of Commissioners expressed support for the Performance Credit Mechanism ("PCM") market design. While NRG is still evaluating the specific details of the PCM proposal, the concept meets statutory requirements and the Commission's principles, and provides a significant improvement in the necessary incentives for reliability. NRG recommends the PUCT set a policy direction to implement PCM by June 1, 2025, focusing stakeholders on reviewing and working through the design details. Other proposals

[7] These are restated in part in the Memorandum for the Nov. 10, 2022 Open Meeting.

are distractions that do not directly address the problem statement based in law, resource adequacy. At best, they attempt to attract more installed capacity through indirect and inefficient means (*i.e.*, artificially inflate energy prices by withholding capacity). A more direct approach to address reliability like the PCM will be more efficient and cost-effective. NRG recommends the Commission set the policy path for PCM by doing the following:

1. Establish a reliability standard based on maintaining 0.1 loss of load expectation in both winter and summer, further subject to the conditions specifically identified in Section 18 of SB3.[8]
2. Set a summer 2025 deadline for the first season of a PCM, with the intention to promote a financially non-binding trial run of the market in the 2024 seasons.[9]
3. Ensure that an eventual PCM design will include strong performance requirements by clarifying that a must-offer obligation in both the forward trade of performance credits and in the day-ahead energy and ancillary services markets is a necessary precondition of being paid through PCM.[10]

IV. RESPONSES TO COMMISSION QUESTIONS

1. The E3 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?

No. The core components of the PCM are familiar from other markets and the novel aspects of the PCM only represent improvements compared to similar concepts. The PCM relies heavily on the bilateral market which is robust after 20 years of history in ERCOT. Construction of a demand curve occurs in nearly every other market. The implementation of a voluntary forward auction resembles the current Congestion Revenue Rights market but in much simpler form. Retrospective settlement of PCs is similar to how Texas Renewable Energy Credits are retired and managed. The novel aspect of the PCM is the performance-based accounting of reliability contribution compared to forward accreditation. This design feature significantly simplifies the administrative process to implement and maintain the PCM. NRG believes that it is reasonable to have the PCM running as a financially binding market in 2025. It is important that the Commission

[8] Further explained in response to Questions 3, 4 and 5.

[9] Further explained in response to Question 1.

[10] Further explained in response to Question 6.

set some clear expectation of a deadline so that investors and developers with new generation projects in the interconnection queue can understand the policy backdrop against which they are committing substantial capital and other resources.

Other than a clear deadline of 2025, the Commission should also consider a trial run of the PCM in 2024. Uniquely, some of the PCM's results can be observed even without being financially binding. Specifically, the market's demand is based on a known number of hours, with bids based on a demand curve anchored by net cost-of-new-entry with known price inputs. The market's ultimate demand clears based on the observable, actual performance of resources. The market's costs are allocated to load-serving entities based on actual load ratio share. These three features allow ERCOT to perform a financially non-binding trial run to promote stakeholder awareness of the mechanism's functioning. These results would omit two important considerations that NRG would expect to feature prominently in the "tradeable" market: forward hedging to lock in costs on both the supply and demand side, as well as a highly active demand-response sector as load serving entities seek to avoid performance credit costs. However, a trial run may promote confidence in the PCM ahead of its first financially binding season.

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?

Yes. By establishing a reliability standard and a market mechanism to achieve it, the PCM hardwires into the market a revenue stream for protection against reliability risks in the form of performance incentives for resource availability. By contrast, the current market structure relies on scarcity events actually occurring to produce financial incentives. Resource developers and investors may or may not believe that scarcity events will regularly come to pass in the course of their investment determinations, but under PCM they would better understand the stream of payments for the availability of their resources—even if, as the Commission has proposed, the mechanism is self-correcting and ultimately results in a zero price when the market is oversupplied. As described in the introduction, the PCM meets the requirements of SB3 by providing a market construct to ensure sufficient dispatchable generation to meet a reliability standard.

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 1-in-10 loss of load expectation ("LOLE") is the industry standard for electric reliability and has the benefit of substantial history. While many other reliability standards can be considered, the important step is to establish one. A significant amount of time could be spent on analyzing various standards and NRG recommends the PUCT review prior work on reliability standards in PUCT Project 42302 if there is interest in considering other standards. To the extent that LOLE may not capture the duration or severity of an event, NRG believes that the approach we recommend in the responses to Questions 4 and 5 addresses this issue as it relates to winter, by separately defining winter as a season that PCM must solve for (so that PCM hours are not exclusively concentrated in the summer) and by having PCM's hours replicate the continuousness of a winter storm's risk to reliability (as versus the summer's more staccato pattern of reliability risks during only certain hours across possibly many hot days).

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?*

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?*

Questions 4 and 5 are answered together. NRG supports a methodology to measure reliability contributions during times of peak net load and low reserves. However, NRG recommends a modification to the PCM that would more closely adhere to the statutory language enacted by Section 18 of SB3. There should be distinct summer and winter seasons for PCM, as indicated by the statutory language, which expressly refers to the "season in which the service is procured."[11] The risk of severe reliability events typically occurs during the winter or summer seasons. In addition, ERCOT already has sufficient tools to manage tight conditions during the spring and fall such as Reliability Unit Commitment, NSRS and ECRS procurement, and the ability to deny or recall planned outages by generation resources.

[11] PURA §39.159(c)(1).

In addition, SB3 recognizes that the winter and summer seasons are different. Winter is a time when extreme cold fronts and fuel security concerns may transpire to cause long outages. Summer tends to unfold in periods where demand is very high, resources are attuned to performance at those hours of stress, and outages, were they to occur, would unfold over a shorter period of time.

Consequently, we recommend that the PCM be designed such that half of revenue from performance credits go to each season. Furthermore, the winter season's PCM hours could be measured over a sequence of multiple hours to impose a duration requirement, either anchored around the hour with the lowest number of operating reserves or the lowest average reserves during the multi-hour period. This would better align with the conditions that were witnessed during Winter Storm Uri and it speaks directly to the statutory language concerning long outages in the winter season. It would address the criticism the Commission has seen since this docket commenced about the market design not addressing Winter Storm Uri-like conditions. Meanwhile, for summer, the proposal as described—spread out over 30 hours, or half of that reflecting the seasonal bifurcation—is appropriate. The summer reliability events that do exist tend to unfold in a greater range of days, but over a more limited set of hours, concentrated in the hour of peak net load.

A seasonal construct also would prevent the exhaustion of the 30 hours during a prolonged winter event and reduce the incentive to be available during the summer, or *vice versa*.

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?

The forward market proposed by E3 as part of the PCM proposal creates an opportunity for generation resources to lock in revenue streams and mitigate uncertainty. It also functions to let buyers and other market participants, ERCOT, the Commission, and policymakers know what quantity resources have offered to be available at some price. A more stable revenue stream for reliability services will help support investments in new dispatchable resources and demand response technology which will improve reliability.

The Commission also should clarify that while not all performance credits need to be sold forward, the quantity offered by a resource or portfolio of resources functions as a ceiling for the ultimate quantity for which that owner may be paid. This will ensure liquidity and transparency in the forward market.

Finally, consistent with E3's commentary in the technical session, the Commission should ensure that "availability" is not contrived but is measured by a resource having made an energy or ancillary-services offer in the day-ahead markets in order to be paid a performance credit in an hour that falls within the credit measurement period. A day-ahead offer requirement creates a built-in penalty for non-performance, because a resource not only would forego performance credit revenue, but also would have to buy out the energy position of an offer that clears the day-ahead energy market.

These two clarifications would ensure the full range of resource availability is transparent in any forward market, and that all dispatchability through the PCM is made available to ERCOT, allowing ERCOT to select the unit to commit, or not, in the day-ahead markets. The PCM's compensation mechanism should ensure that a *bona fide* ability to produce energy and ancillary services—dispatchability—is the basis to compensate availability, tying the PCM closely together with SB3's statutory language.

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

Yes. The inclusion of a centrally cleared forward auction in the PCM proposal will greatly improve price transparency and improve the ability of the ERCOT Independent Market Monitor to monitor the behavior of market participants buying and selling the product. The details of market monitoring for such a concept are important, well established in other markets, and solvable.

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. NRG recommends the Commission, ERCOT, and market participants focus on the implementation of the PCM as the ultimate solution for long-term reliability in ERCOT. The purpose of BRS is already met through ERCOT's procurement of ECRS and additional NSRS. These services provide excess operating reserves when deployed by ERCOT prior to grid emergencies. BRS accomplishes the same thing. In order to meet a reliability standard, the BRS supplier has to inefficiently withhold existing capacity from the ERCOT market, artificially inflating energy prices. This is an indirect, convoluted, and inefficient way to try to induce new investment. Since energy prices are subject to price suppression from renewable subsidies, the amount of withholding of capacity would need to overshoot, making this technique costly compared to a direct incentive like the PCM.

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?

NRG does not recommend a short-term or bridge solution. ERCOT should use the existing tools it already has including NSRS and ECRS which accomplish similar objectives as it focuses on implementing the PCM as the long-term solution.

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

The E3 report shows that system costs increase by approximately 2.2% with the PCM proposal and yield a tenfold increase in average system reliability. The results of E3's cost analysis are verified by a similar analysis conducted by the Brattle Group last year.[12] Brattle's cost analysis reached nearly the same conclusion as E3's analysis.

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.

NRG does not recommend the implementation of a bridge solution. ERCOT should leverage its existing tools and allow the Commission, ERCOT, and market participants to focus on implementing a long-term solution for reliability.

[12] Review of Wholesale Electric Market Design, Project No. 52373, Brattle Group Market Design Options for Managing Reliability in ERCOT, Slide 7, (Nov. 19, 2021) *available at:* https://interchange.puc.texas.gov/Documents/52373_255_1168764.PDF.

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?

As filed, the DEC concept acts as a subsidy for a very narrow subset of dispatchable capacity needed for reliability in ERCOT. As explained by both E3 and Brattle, a mechanism such as DEC will accelerate the retirement of existing resources needed for reliability. Therefore, the DEC proposal should be eliminated from consideration given its discriminatory nature and negative impact on reliability.

V. CONCLUSION

NRG appreciates the opportunity to comment on this crucial reform effort. The Commission should set a clear policy path for long-term reliability as it implements a market design targeting resource adequacy to satisfy the requirements of SB3. NRG will continue to engage in this effort and looks forward to further discussions with the Commission and all stakeholders.

Respectfully,

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

<u>EXECUTIVE SUMMARY OF</u>
<u>NRG ENERGY INC'S COMMENTS ON MARKET REFORM ASSESSMENT</u>
<u>PRODUCED BY ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3)</u>

NRG Energy, Inc. ("NRG") appreciates the opportunity to provide comments on the market reform assessment produced by Energy and Environmental Economics, Inc. (E3), and offers the following executive summary of its comments:

- NRG recommends the Commission, ERCOT, and market participants focus on the implementation of the PCM as the ultimate solution for long-term reliability in ERCOT. The PCM meets the requirements of SB3 by providing a market construct to ensure sufficient dispatchable generation and demand response to meet a reliability standard.

- NRG recommends the Commission set the policy path for PCM by doing the following:

    - Establish a reliability standard based on maintaining 0.1 loss of load expectation in both winter and summer, further subject to the conditions specifically identified in Section 18 of SB3.
    - Set a summer 2025 deadline for the first season of a PCM, with the intention to promote a financially non-binding trial run of the market in the 2024 seasons.
    - Ensure that an eventual PCM design will include strong performance requirements by clarifying that a must-offer obligation in both the forward trade of performance credits and in the day-ahead energy and ancillary services markets is a necessary precondition of being paid through PCM.

- NRG recommends a modification to the PCM that would more closely adhere to the statutory language enacted by Section 18 of SB3. There should be distinct summer and winter seasons for PCM, as indicated by the statutory language, which expressly refers to the "season in which the service is procured."

- Ancillary services do not get new generation built. Creating yet another ancillary service for "uncertainty" does not speak to the problem of resource adequacy, though resource adequacy solutions will furnish additional resources to be available to supply ancillary services.