PROJECT No. 54335

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| **REVIEW OF MARKET reform assessment produced by energy and environmental economics, inc. (E3)** | **§**  **§**  **§**  **§** | PUBLIC UTILITY COMMISSION  OF TEXAS |

TCPA COMMENTS IN RESPONSE TO STAFF’S QUESTIONS

Texas Competitive Power Advocates (“TCPA”) is a trade association representing power generation companies and wholesale power marketers with investments in Texas and the Electric Reliability Council of Texas (“ERCOT”) wholesale electric market. TCPA members[[1]](#footnote-2) and their affiliates provide a wide range of important market functions and services in ERCOT, including development, operation, and management of power generation assets, power scheduling and marketing, energy management services and sales of competitive electric service to consumers. TCPA members provide almost fifty percent (50%) of the total generating capacity and eighty-two percent (82%) of the gas generation capacity in ERCOT. TCPA members have invested billions of dollars in the state and employ thousands of Texans. For the reasons detailed below, TCPA supports the establishment of a mandatory reliability standard and the adoption of a mechanism, like the Performance Credit Mechanism (PCM), to achieve that standard. TCPA members stand ready to bring more than 4,500 MW of additional generation to ERCOT, if a mechanism like the PCM is adopted and implemented consistent with the principles in these comments.

1. **GENERAL COMMENTS**

TCPA appreciates the actions the Commission has taken in Phase I of the market design blueprint, which provided ERCOT with additional tools to manage operational reliability, including during extreme weather. Now that Phase I is being implemented, additional ancillary services or backstop services are not needed. Instead, the task facing the Commission now is to take action, through Phase II of the market design blueprint, to ensure that the state retains existing generation and attracts sufficient new generation to ensure that Texans are not faced with increased reliability risk as identified by E3 in its report (E3 Report),[[2]](#footnote-3) which is the only credible analysis of the Phase 2 market design proposals.[[3]](#footnote-4)

As highlighted by E3, the status quo energy-only market design, even with mechanisms like the Operating Reserve Demand Curve (ORDC), is not sufficient to attract new investment and retain existing generation to deliver a level of reliability acceptable to Texans. Similarly, despite the expected implementation of ERCOT’s new ancillary service, ERCOT Contingency Reserve Service (ECRS), in May 2023, the forward investment signals have not improved. The issue is exacerbated by the conservative operations that ERCOT has been using following Winter Storm Uri to maintain operating reserves without approaching true physical scarcity. While avoiding physical scarcity is a laudable goal, the reality is that those conservative operations do not address ERCOT’s ultimate resource adequacy issue, impede investment signals in the energy-only market, and have resulted in increased reliance by ERCOT on out-of-market actions like Reliability Unit Commitment (RUC), which also increases wear and tear on essential generation resources.

Further, the increasing penetration of renewable resources in ERCOT has and will continue to put downward pressure on energy prices for the foreseeable future, especially in light of the tax incentives that have recently been extended and expanded following the passage of the Inflation Reduction Act of 2022.[[4]](#footnote-5) In addition, coming environmental regulations will increase compliance costs and pose retirement risk for a portion of dispatchable, thermal generation resources in ERCOT.[[5]](#footnote-6)

As required by Senate Bill 3 (SB 3),[[6]](#footnote-7) the Commission must take swift action to adopt and enforce a mandatory reliability standard. As discussed below, the industry standard 1-in-10 Loss of Load Expectation (0.1 LOLE) is a good starting point because it is familiar and thus would be fastest to implement and because it is used in other markets and would at least put the ERCOT market on par with those peers. As the resource mix becomes increasingly intermittent, there is good reason to supplement the 0.1 LOLE standard to set limits on depth or duration of reliability events, but starting with 0.1 LOLE is a no-regrets move for the Commission. Once a reliability standard is set, the E3 Report demonstrates that only three of the studied options will consistently achieve a reliability standard at a comparable cost to consumers and in an efficient manner that is consistent with the competitive market—the PCM, the Forward Reliability Market (FRM), and the Load-Serving Entity (LSE) Reliability Obligation (LSERO).[[7]](#footnote-8)

Of these options, the PCM avoids some of the administrative complexity of the FRM and LSERO (because it would avoid the centralized resource accreditation process), as well as the potential market power concerns voiced by some parties regarding an LSERO. Notably, while the PCM is similar in reliability impact and cost as an FRM, the PCM is not a forward capacity market. It is a retrospective pay-for-performance concept, rather than a forward-looking pay-for-capacity model.

In addition, contrary to suggestions that have been made in recent Legislative hearings, paying for the reliability that will result from the PCM will not amount to a wealth transfer from consumers to generators—to the contrary, an effective PCM will result in lower and less volatile energy prices while avoiding the most extreme outcomes that the status quo market design produces (and that generally coincide with grid emergencies). Just like with any service in a competitive marketplace, electricity service has a cost. And, importantly, the projected cost for the PCM to achieve 10 times the reliability compared to the status quo—from more than one load shed event every year under the status quo to one event every ten years under the PCM—is only an incremental increase in total system costs of 2.2 percent. That cost seems well worth the resulting reliability for Texans.

Finally, while there will be design decisions to make during the implementation phase to achieve a reliability mandate, the Commission can and should act sooner rather than later to announce that it will adopt a reliability standard and pursue the PCM, to provide regulatory certainty for existing generators and potential new investors.

1. **RESPONSES TO QUESTIONS**
2. **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 creation of any new product that directs financial incentives to dispatchable resources will become incorporated into the market from an operational and financial perspective and represent a significant improvement compared to the status quo in terms of support for a reliable ERCOT system—according to E3, improving reliability by more than 10X, from 1.25 loss of load events every year to a single loss of load event every ten years.[[8]](#footnote-9)

In addition, while the PCM is a novel concept, its operating components are straightforward and familiar—i.e., a forward-looking voluntary auction and a retrospective settlement based on performance, with obligations and associated costs allocated to LSEs. The retrospective nature of the reliability contribution measurement and settlement process greatly simplifies its implementation. In addition, the PCM lacks one of the most administratively complex and highly contested features of a forward capacity market: the prospective accreditation of resources. To be eligible to be paid for a performance credit (PC), resources must make a forward offer; then, in order to actually create a PC, they must perform through their availability during the relevant hour(s). This design feature removes what is arguably the most administratively complex aspect of alternative comprehensive proposals, including the LSERO and FRM.

The incorporation of a reliability standard and the process to construct a demand curve to price PCs to achieve that reliability standard can leverage lessons from other competitive wholesale markets in the U.S. In addition, as discussed further under Question 3, use of the 0.1 LOLE standard could further simplify implementation of the PCM, as that is the standard that has historically been mandated in other regions (and has previously been an aspirational, though not enforced, standard in ERCOT).[[9]](#footnote-10) Notably, throughout the history of the ERCOT region, there have been much more complex and extensive market changes such as the implementation of the nodal market in December of 2010. Because of its familiar components and the fact that it does not alter the more complex energy market, the implementation of the PCM will be simpler and much less involved than implementing Nodal.

In addition, the PCM concept will spur the development of a robust bilateral market given the size and value of the PC products. The Texas Renewable Energy Credit (REC) market similarly assigns REC purchase requirements to LSEs in a retrospective nature, and there is currently a robust bilateral market available to purchase Texas RECs for the current compliance year through 2030.

1. **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. Section 18 of SB 3 (codified at Public Utility Regulatory Act (PURA)[[10]](#footnote-11) §§ 39.159 and 39.160) in effect contains three directives to the Commission, and the PCM, if it is implemented correctly, will meet them all.

First, the establishment of a reliability standard (i.e., in the words of SB 3, “establish[] requirements to meet the reliability needs of the power region”[[11]](#footnote-12)) is paramount to the success of any mechanism. According to the E3 Report, the PCM, LSERO, and FRM all do that in a roughly identical manner and at a comparable cost,[[12]](#footnote-13) because they all are comprehensive approaches that ensure an adequate number of resources capable of meeting all uninterruptible ERCOT demand during peak net load hours, within the conventional 0.1 LOLE standard. By contrast, other evaluated proposals set aside or target a lower quantity of resources and hope that by reserving them from the market (Backstop Reliability Service, or BRS) or subsidizing them (Dispatchable Energy Credits, or DEC), reliability will result. Similarly, other proposals not evaluated by E3 (such as buying more or different ancillary services) also fail at this requirement for reasons discussed more fully below.

Second, Section 18 provides that the Commission must, consistent with the standard adopted in the first part, right-size and procure on a competitive basis a quantity of resources sufficient to ensure reliability in view of two interrelated factors: extreme weather (both winter and summer) and low non-dispatchable resource production.[[13]](#footnote-14) Again, PCM, LSERO, and FRM all do this. But PCM may here pose an advantage because it is expressly tied to the actual performance of resources in a defined set of hours that are defined in terms of the highest reliability risk, which are the conditions that will prevail when the conditions described in the statutory text—i.e., extreme heat, extreme cold, and low non-dispatchable production—exist.[[14]](#footnote-15) Further, even though the PCM is currently proposed as an annual assessment of critical hours, rather than an assessment of critical hours in extreme heat and extreme cold, those critical hours presumably would coincide with extreme temperatures (cold or hot) and low non-dispatchable power (whether that condition occurs during extreme temperatures or on a “blue sky” day). Thus, the objectives of the statute are met through the PCM design, in its current proposed configuration as an annual assessment. In addition, SB 3 (in PURA § 39.159(b)(2)) expressly recognizes that ERCOT’s determination of the quantity and characteristics of the reliability service required by the statute can be made on an “annual” basis, thus indicating that an annual determination of critical hours is consistent with the statute, so long as those hours generally align with the objectives of addressing extreme heat, extreme cold, and low non-dispatchable power. Further, as needed during the PCM implementation process, the exact mechanics of determining the critical hours (and whether to assess those hours by season in order to best align with the statutory objectives) can be further refined.

Third, the Commission must “ensure that resources…are dispatchable and able to meet continuous operating requirements for the season in which the service is procured,” and the statute specifically mentions resources with “on-site fuel storage, dual fuel capability, or fuel supply arrangements to ensure winter performance for several days” and (for summer) “facilities or procedures to ensure operation under drought conditions.”[[15]](#footnote-16) While the PUCT has also already taken steps to address this SB 3 requirement through its introduction of Firm Fuel Supply Service, PCM also indirectly addresses this in part, with its innate results-oriented design that focuses on incentivizing and rewarding performance during the highest risk operating hours of the year. Again, if during the implementation process, the need for further refinement to the timing and number of hours (and whether to include a seasonal component) becomes apparent, then that can be addressed at that time. Even as currently framed, TCPA agrees with the E3 Report that the PCM satisfies the referenced statutory objectives based on its focus on performance during high-risk hours.[[16]](#footnote-17)

Finally, the PCM allocates the costs of the PCs to LSEs based on each LSE’s share of system load during those same hours. In doing so, the PCM establishes the financial incentives to drive customer behavior, retailer offerings, and business practices to conserve electricity demand in order to minimize costs. LSEs would have strong financial incentives to help their customers reduce their share of system load during the times of tight grid conditions.

As an additional reference, TCPA has created a table (below) comparing the PCM’s consistency with the statutory objectives in Section 18 of SB 3 with those of an additional ancillary services product (i.e., an “uncertainty” product as has been proposed by the Independent Market Monitor (IMM) and suggested by others as being an alternative to Phase 2 market design):

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| **Consistency with Statutory Objectives in Section 18 of SB3** | | | |
| **PURA Subsection** | **Specific PURA Requirement** | **PCM** | **Uncertainty Ancillary Service** |
| PURA 39.159(b) requires the PUCT to ensure that ERCOT: | “(1) establishes requirements to meet the reliability needs of the power region;” | Yes: establishes a reliability standard for ERCOT region. | No: duplicates existing operating reserve functions, ignores resource adequacy considerations, and sets no reliability standard. |
| “(2) periodically, but at least annually determines the quantity and characteristics of ancillary or reliability services necessary to ensure appropriate reliability during extreme heat and extreme cold weather conditions and during times of low non-dispatchable power production in the power region;” | Yes: PC demand curve maps reliability standard (“appropriate reliability”) to annual (or possibly seasonal) determination of generation needed to meet “highest risk” hours (aligns with extreme weather and/or low intermittent output). | No: does not address ability of ERCOT fleet to ensure appropriate reliability during specified criteria or extreme weather conditions; only focuses on “uncertain” times with a single ancillary service that largely duplicates others. |
| “(3)  procures ancillary or reliability services on a competitive basis to ensure appropriate reliability during extreme heat and extreme cold weather conditions and during times of low non-dispatchable power production in the power region;” | Yes: PCs are a “reliability service” (or an ancillary service) procured on demand curve that maps reliability standard (“appropriate reliability”) to the determined amount of generation needed to meet “highest risk” hours (aligns with extreme weather and/or low intermittent output). | No: does not address ability of ERCOT fleet to ensure appropriate reliability during specified criteria or extreme weather conditions; only focuses on “uncertain” times with a single ancillary service that largely duplicates others. |
| “(4)  develops appropriate qualification and performance requirements for providing services under Subdivision (3), including appropriate penalties for failure to provide the services; and” | Yes (with potential refinements)  Yes: generators must participate in forward market and be available during “highest risk” hours to qualify for PC reliability service. This penalty structure is similar to the current energy market where failure to perform results in lost revenue.  Potential refinement: while E3 report does not specify penalties for failure to perform (aside from clawback), PUCT could consider penalties of 1.X times PC value to comply. | No: Failure to provide ancillary services results only in claw-backs and replacement cost assignment; penalties would have to be administrative, based on PUCT enforcement action, and not a design feature. |
| “(5)  sizes the services procured under Subdivision (3) to prevent prolonged rotating outages due to net load variability in high demand and low supply scenarios.” | Yes (with potential refinements)  Yes: PCs are a “reliability service” (or an ancillary service) procured on demand curve that maps reliability standard (“appropriate reliability”) to the determined generation needed to meet “highest risk” hours (aligns with extreme weather and/or low intermittent output).  Potential refinement: while proposed 0.1 LOLE does not address “prolonged” nature of rotating outages, PUCT should consider (in the future) further refining the 0.1 LOLE standard to limit that one event every 10 years to no more than X hours on probability-weighted basis. | No: may incentivize some additional reserve on-call capacity in real-time operations, but does not address ability of ERCOT fleet to ensure appropriate reliability during specified criteria. |
| PURA 39.159(c) further directs the PUCT to ensure that: | “(1)  resources that provide services under Subsection (b) are dispatchable and able to meet continuous operating requirements for the season in which the service is procured;” | Yes (with potential refinements)  Yes: while PCs as proposed are technology neutral and do not expressly contain continuous operating requirements, the incentive structures should encourage intermittent renewable resources to avoid PCM.  Potential refinement: implementation could be done on a non-tech neutral basis and more definitively meet this criterion, as SB 3 focuses on dispatchable resources. | Yes: only dispatchable resources would qualify for uncertainty ancillary service product, and ERCOT could define seasonal duration requirements. |
| “(2)  winter resource capability qualifications for a service described by Subsection (b) include on-site fuel storage, dual fuel capability, or fuel supply arrangements to ensure winter performance for several days; and” | Yes (indirectly): Addressed separately via the Firm Fuel Supply Service ancillary service. PCM also provides strong incentive to resources to only bid in to forward PCM what they can reasonably expect to deliver, which should take into account fuel risks. | No: uncertainty ancillary service product is not proposed with this characteristic and would not incentivize it. |
| “(3)  summer resource capability qualifications for a service described by Subsection (b) include facilities or procedures to ensure operation under drought conditions.” | Yes (indirectly): PCM does provide strong incentive to resources to only bid in to forward PCM what they can reasonably expect to deliver, which should take into account drought risks. | No: uncertainty ancillary service product is not proposed with this characteristic and would not incentivize it. |

1. **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 0.1 LOLE reliability standard is the widely used industry standard,[[17]](#footnote-18) and it is thus well understood and familiar to policymakers and industry, making it reasonable to apply in ERCOT. With that said, there may be value in considering refinements to incorporate depth and duration of those events at some point in the future, given that ERCOT has experienced 4 loss of load events, including 3 extreme cold-weather-related outages, in the past 33 years,[[18]](#footnote-19) and each time those events have coincided with extreme weather they have been deemed unacceptable by policymakers and the public. The E3 report contains important heuristics regarding expected unserved energy (EUE) and Loss of Load Hours (LOLH) expectations that provide a general framework for how one or both of those measures could add benefits to a LOLE standard.[[19]](#footnote-20) However, adopting a new measurement for the reliability standard at this time may unnecessarily delay the implementation of Phase II. Thus, unless the Commission finds overwhelming evidence for taking up an alternative at this point, TCPA recommends that the Commission adopt a 0.1 LOLE standard for the initial PCM implementation. Depth and/or duration could be layered onto that standard in the future after the PCM is well established, without requiring significant re-working of the PCM structure.

1. **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?**
2. **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?**

TCPA answers Questions 4 and 5 together. As described in response to Question 2, TCPA believes that the PCM, as currently proposed by the E3 Report as an annual measure of high-risk operating hours, would adhere to the statutory language enacted by Section 18 of SB 3. With that said, as part of the initial implementation (or potentially in subsequent years, as the market gains more experience with the structure), the PCM could be refined to more specifically target reliability hours to specific timeframes or seasons. Different considerations can come into play during different seasons (and for different types of resources), which may weigh in favor of such refinements.

For example, in spring and fall, extreme weather events resulting in loss of load are generally less likely. In the winter, extreme and long-lasting cold fronts, poor coincidence of peak demand and solar output, and fuel security concerns may transpire to cause higher risk periods. [[20]](#footnote-21) Summer tends to unfold in periods where demand is very high, and while resources are attuned to performance at those hours of stress, the ERCOT grid currently gambles on intermittent renewable generation to meet those highest loads. In the spring and fall, higher levels of planned generation outages can potentially result in tight conditions that may require ERCOT to use existing tools to manage the risk.[[21]](#footnote-22) These differences in risk throughout the year may counsel refinement of the determination of highest risk operating hours, to take into account seasonal or other temporal components.

The Commission should also further evaluate alignment of the PC qualification rules’ incentives with the qualification periods and number of hours. The policy cuts that the Commission makes regarding the performance criteria for earning PCs could warrant further refinement of the methodology for determining critical hours.

In short, the specific mechanics of determining the critical hours is something that can be refined during the implementation process, as more policy cuts are made on other gating items. What is more critical at this time is that the Commission provide the market with a signal that it is going to adopt a mandatory reliability standard and a mechanism, like the PCM, that can meet that standard in an effective manner and at a reasonable cost consistent with SB 3.

1. **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 auction administered by ERCOT as described by E3 would provide additional liquidity and hedging opportunities for LSEs and generation resources, which, in turn, would create additional forward revenue streams and stability. TCPA expects the adoption of the PCM to spur the creation of a robust bilateral market composed of financial intermediaries and brokers, similar to how Texas RECs and the energy-only market did for their corresponding products. Increased certainty of revenues enables the gears of the financial markets to begin turning and support the development of new resources. During the implementation process, it is important that the forward market be designed to allow for sufficient flexibility in generator offers, e.g., to reflect how generators’ physical limits change with ambient temperatures, and to take into account a generators’ judgment about opportunity costs and performance risk.

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

Central clearing of the PCMs through a forward auction will provide price discovery for LSEs and allow the IMM to surveil transaction prices for potential market power abuse. TCPA agrees with the E3 Report’s assessment of market power risk of the PCM as “low.”[[22]](#footnote-23)

1. **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?**

The Commission should consider a “bridge” product only if it could be guaranteed that the “bridge” product or service would not delay the implementation of Phase II and, with respect to the BRS or another ancillary service, only if it were implemented as a viable alternative (rather than an addition) to the current conservative operations by ERCOT (including increased procurement of ancillary services) that have resulted in excessive out-of-market actions like RUC.

It is always more efficient to directly procure the service or reliability attribute that is needed for the grid. The PCM directly procures the reliability service by setting a reliability standard and paying generators for the performance credits needed to meet that standard. It is also important to note that purchasing BRS, additional ancillary services (AS), or another “uncertainty” product as proposed by the IMM and others would not address the root cause of ERCOT’s reliability issues—i.e., resource adequacy. These products provide operating reserves and not new or additional dispatchable capacity, which is the deficiency in ERCOT. Operating reserves are capacity that can respond to help manage fluctuations in load or renewable output. Requiring more operating reserves only forces more generation online when it is not needed and may undermine the work the Commission has already done in Phase I of its market design blueprint, by artificially suppressing prices. The ERCOT market needs new capacity to meet even the existing operating reserve requirements; thus, adding more operating reserve requirements—without creating a resource adequacy mechanism to ensure that the resources needed to provide the required operating reserves even exist—will only exacerbate the reliability issue facing ERCOT. The PCM, LSERO, or FRM are the only market design concepts that directly target that need.

In separately-filed comments, a TCPA member, TexGen, proposed a phased-in PCM interim proposal that merits consideration by the Commission.[[23]](#footnote-24) As explained in TexGen’s comments, implementing a look-back mechanism that reveals the tightest hours and the generation that was online/available during those hours, and then assigning a fixed compensation for PCs during those hours (i) would begin to provide the market with signals regarding when to self-commit, (ii) would thus reduce the need for RUCs, and (iii) would provide economic incentives for existing dispatchable resources to remain in service. This interim mechanism could be done in a straightforward manner that could enable it to be put in place even more quickly than the other proposed “bridge” mechanisms like BRS or a new ancillary service.[[24]](#footnote-25)

In addition, and in any event, a no-regrets move that the Commission should take regardless of its interim decisions is to continue to close the gaps in RUC compensation to ensure conservative operations do not drive out existing generation:

* Nodal Protocol Revision Requests (NPRRs) 1124 and 1140 were a good way to quickly provide a backstop for RUC’d resources to recover previously unrecoverable fuel costs, but the RUC make-whole process is slow and resource-intensive (for example, RUC make-whole payments continue to require an after-the-fact dispute process that takes several months to complete).
* It would be more efficient to reflect fuel costs of RUC’d resources in market prices and allow those costs to be recovered through normal settlement processes. In addition:
  + Existing offer caps in the Day-Ahead Market (DAM), which limit offers to 200 percent of the fuel index price,[[25]](#footnote-26) should be removed to give the market a chance to commit high gas cost units in the first place.
  + The use of Exceptional Fuel Costs should be expanded to ensure payment of actual costs at initial settlement, allow for recovery of emissions costs, and ensure that costs associated with securing firm gas, such as demand charges, are also recovered.[[26]](#footnote-27)
  + For units that run mostly under RUC instructions, the Protocols should allow for recovery of fixed costs such as labor, fixed operating and maintenance (O&M) costs, and property taxes. Otherwise, such units will still face economic pressures.

1. **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?**

As noted above, the Commission should not pursue a short-term solution like BRS if it delays the implementation of PCM, and even then, should only do so if it will supplant the existing conservative operations that are resulting in excessive out-of-market actions by ERCOT. ERCOT has tools now that it uses to manage operational risks (e.g., RUC, ECRS, and Non-Spinning Reserve Service (NSRS)), and those tools are sufficient for that purpose. Further, as detailed above, neither BRS, nor any other ancillary service or “uncertainty” product, will do anything other than what the existing operational tools do, because they will not attract new and existing dispatchable generation capacity. Rather, they draw from the pool of resources that already exist (but should not be presumed to exist indefinitely absent more meaningful changes, such as implementation of a workable PCM framework).

In addition, procuring an additional 5,630 MW of ancillary services (AS) (e.g., under the BRS or an “uncertainty” product, whether as a short-term bridge or long-term design change) would be inefficient because it would result in additional unnecessary resource commitments to address a possible but not imminent reliability risk. ERCOT has a well-developed suite of AS products already to address operational reserve needs. AS is not designed, however, to achieve broader resource adequacy goals such as the 0.1 LOLE reliability standard – that is the purview of resource adequacy.

In an analogous context, the North American Electric Reliability Corporation (NERC) defines reliability in a two-pronged approach, requiring both adequate operating reliability and resource adequacy.[[27]](#footnote-28) Operating reliability is defined as “the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components.” Resource adequacy is “the ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.”[[28]](#footnote-29) While market revenues from the energy and ancillary service markets have important impacts on resource adequacy, they effectively treat resource adequacy as a side effect rather than an explicit goal that must be solved for. And it must be noted that increased AS reserves have the effect of depressing ORDC inputs—in other words, they trade off energy market revenues for AS capacity revenues and can actually be a net negative market signal for investment. Therefore, augmenting the amount of AS procured is an imprecise, indirect, and internally-conflicted means of addressing resource adequacy objectives.

Instead, the Commission should consider the TexGen interim proposal (if it can be done in a manner that does not delay full implementation of the PCM) and should pursue the other “no regrets” improvements to the RUC compensation process detailed above under Question 8.

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

The modeling approach used by E3 leverages a robust and sophisticated model of the ERCOT market developed and refined by Astrape for almost ten years.[[29]](#footnote-30) ERCOT uses the same modeling system for their biennial market equilibrium reserve margin and economically optimal reserve margin studies that no stakeholder has raised concerns with.[[30]](#footnote-31) The outcome of E3’s cost analysis is also similar with the results produced by Brattle in 2012[[31]](#footnote-32) and 2021.[[32]](#footnote-33) This consistency helps establish credibility of the results and integrity of the cost analysis. The E3 study finds that consumers will see a 10X improvement in average system reliability for an incremental cost increase of 2.2%.

As important as the total system cost, it is equally important to note the variability of total system costs in any given year. In the PCM, LSERO, or FRM, extreme volatility of system costs is limited. More stable market outcomes improve the ability of both retail electric providers (REPs) and generators to meet credit requirements, financing, and business operations. In the status quo or BRS, the price excursions are the point. In DEC, it is a “hope-and-pray” scenario that subsidized resources do not drive out existing resources that are needed for reliability—an outcome that economists and market experts have repeatedly and credibly warned against. TCPA believes that a *risk-adjusted* comparison of costs would yield a system cost that was lower, in equilibrium and over time, for PCM. Phase II of the Commission’s blueprint concerns long-term resource adequacy for the long-term health of Texas’ economy, and TCPA believes that is the correct paradigm through which to measure costs and resulting benefits.

1. **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.**

If operational concerns remain, then given the similarities to the current procurement of NSRS to BRS, the fastest and most cost-efficient manner to develop a bridge service would be to utilize the existing tools to manage operational reliability in the interim. This could potentially include expanding the eligibility of NSRS to longer lead time generation resources for additional procurement amounts. Regardless of whether operational concerns remain, the Commission should take the “no regrets” actions outlined above related to RUC compensation, to ensure that when resources are RUC’d to support ERCOT’s continued conservative operations (in advance of the implementation of Phase II, which should reduce the need to rely on RUC), those resources are actually compensated for the costs incurred. Further, as noted above, the Commission should consider TexGen’s proposed interim PCM mechanism as a “bridge” option to begin providing economic incentives and investment signals to new and existing resources sooner.

1. **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 DEC concept as proposed and described in the E3 report—and regardless of whether new technology such as small modular nuclear reactors was added to the concept—would be detrimental to system reliability and cost given its discriminatory nature. Providing subsidies to only a subset of resources that the system needs for reliability will only accelerate the exit of other, equally-needed resources. E3 and Brattle both explained the flaws with the DEC proposal in great detail, and the results of the E3 Report highlight its deficiencies. It should be discarded in its current form from further consideration.

1. **CONCLUSION**

TCPA appreciates the opportunity to submit comments on the E3 Report and the Commission’s continued consideration of Phase II market design implementation. TCPA urges the Commission to act swiftly to set and mandate a reliability standard and to direct implementation of a market design to achieve that reliability standard. TCPA supports the PCM as a mechanism that can accomplish those objectives and satisfy the statutory mandates of SB 3.

Dated: December 15, 2022

Respectfully submitted,

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Michele Richmond

Executive Director

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PROJECT No. 54335

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| **REVIEW OF MARKET reform assessment produced by energy and environmental economics, inc. (E3)** | **§**  **§**  **§**  **§** | PUBLIC UTILITY COMMISSION  OF TEXAS |

TCPA COMMENTS IN RESPONSE TO STAFF’S QUESTIONS

Executive Summary

* The E3 Report demonstrates that the status quo energy-only market will not incentivize sufficient new generation or retain sufficient existing generation to ensure resource adequacy and reliability outcomes acceptable to Texans.
* Senate Bill 3 from the 87th Texas Legislature requires the Commission to adopt a reliability standard for the grid and a mechanism to achieve that mandate, in order to ensure reliability during extreme weather (heat and cold) and periods of low non-dispatchable power. The Performance Credit Mechanism (PCM) can achieve this; alternative and unstudied half-measures cannot. Nor can state-subsidized generation or loan programs, which may marginally reduce the cost of new generation, but would also accelerate the retirement of the gas generation that kept the power on this summer.
* The Commission should act swiftly to adopt such a reliability mandate—beginning with the 1-in-10 Loss of Load Event (0.1 LOLE) standard as a familiar and reasonable starting point and potentially refining later to include depth and/or duration of events.
* The Commission should endorse a market design mechanism to achieve that reliability mandate at a reasonable cost to consumers, such as the PCM—which, according to the E3 Report, will improve resource adequacy by 10X (from a loss of load event every single year beginning in 2026 to a loss of load event every 10 years), while increasing system costs by only 2.2 percent.
* TCPA members stand ready to bring more than 4,500 MW of additional generation to ERCOT, if a mechanism like the PCM is adopted and implemented consistent with the principles in these comments.
* The Commission should not pursue, as either an interim measure or a long-term measure, procurement of additional “backstop” services, ancillary services, or an “uncertainty” product. Adding more operating reserve requirements—without creating a resource adequacy mechanism that can ensure that the resources needed to provide the required operating reserves even exist—will only exacerbate the reliability issues facing ERCOT and will not address resource adequacy.
* The Commission should consider, as an interim measure while working on the PCM, implementing a look-back mechanism and straightforward compensation for the PCM, as proposed by TexGen in separate comments.
* Regardless of the design mechanism pursued, as a “no regrets” measure, the Commission should make changes to Reliability Unit Commitment (RUC) to ensure that, when that tool is used (which will be less often if a mechanism such as the PCM is implemented), resources are appropriately compensated for their service.
* The Commission should eliminate the Dispatchable Energy Credits (DEC) mechanism from further consideration, for the reasons detailed by the E3 Report.

1. TCPA member companies participating in these comments include: Calpine, Cogentrix, Constellation (formerly Exelon), EDF Trading North America, Luminant, NRG, Rockland Capital, Talen Energy, Tenaska, TexGen Power, and WattBridge. [↑](#footnote-ref-2)
2. Project No. 54335, Energy+Environmental Economics (E3), *Assessment of Market Reform Options to Enhance Reliability of the ERCOT System* (Nov. 2022) (hereafter, E3 Report). E3’s analysis shows the ERCOT system experiencing at least one loss of load event every single year under the status quo. E3 Report at 7. [↑](#footnote-ref-3)
3. While another analysis by ICF, commissioned by Texas Consumer Association, was filed in Project No. 52373, that report is plagued by errors in its fundamental assumptions rendering its conclusions and recommendations unusable. Generally speaking, the ICF report makes many “free lunch” assumptions, such as assuming that Dispatchable Energy Credits (DECs) would not result in any retirements (despite acknowledging the error in this simplification) and incorrectly modeling Backstop Reliability Service (BRS) as having no impact on energy and ancillary services costs, while also choosing only to highlight outlier modeled first-year costs of the Load-Serving Entity Obligation (LSEO) and assuming away its ability to “attract more risk-averse capital” (while failing to acknowledge the same logic under its flawed assumptions for DECs and BRS) - and most critically, ignoring the reliability and market impacts of a mandatory reliability standard on the LSEO’s long-term effects. *See Review of Wholesale Electric Market Design*, Project No. 52373, ICF Report, *Assessment of ERCOT Market Structural Changes* (Oct. 26, 2022). [↑](#footnote-ref-4)
4. Pub. L. No. 117-169, H.R. 5376 (2022). [↑](#footnote-ref-5)
5. *See* U.S. Environmental Protection Agency, Docket No. EPA-HQ-QAR-2021-0668, *Comments of the Public Utility Commission of Texas Regarding the United States Environmental Protection Agency’s (EPA’s) Proposed Federal Implementation Plan (FIP) Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (NAAQS)* (Jun. 21, 2022) *, available* *at*: <https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0333>. [↑](#footnote-ref-6)
6. 87th Tex. Leg., R.S., Senate Bill 3, Section 18 (2021) (requiring the Commission to direct ERCOT to “establish[] requirements to meet the reliability needs of the power region”). [↑](#footnote-ref-7)
7. E3 Report at 7-9, 76 (while the Backstop Reliability Service (BRS) is also projected to meet the 0.1 LOLE standard at a comparable cost, it is characterized by E3 as the “least competitive” option with “less stable costs and revenues,” and TCPA has concerns with this option as set out further below). [↑](#footnote-ref-8)
8. E3 Report at 5. [↑](#footnote-ref-9)
9. *E.g.*, ECCO International Inc., *2012 ERCOT Loss of Load Study Assumptions and Methodology*, at 2 (Mar. 7, 2013) (“The electric power industry has generally adopted the criteria of 1 loss of load event every 10 years (a 0.1 LOLEV per year) as this level, and this level has also been used historically for the ERCOT System.”), *available at*: <https://www.ercot.com/files/docs/2013/03/08/ercot_loss_of_load_study_2013.pdf>. [↑](#footnote-ref-10)
10. Tex. Util. Code §§ 11.001-66.016 (PURA). [↑](#footnote-ref-11)
11. PURA § 39.159(b)(1) (“The commission shall ensure that the independent organization certified under Section 39.151 for the ERCOT power region: (1) establishes requirements to meet the reliability needs of the power region….”). [↑](#footnote-ref-12)
12. E3 Report at 5. [↑](#footnote-ref-13)
13. PURA § 39.159(b)(2), (3) (“The commission shall ensure that the independent organization certified under Section 39.151 for the ERCOT power region: …(2) periodically, but at least annually, **determines the quantity and characteristics of ancillary or reliability services necessary to ensure appropriate reliability during extreme heat and extreme cold weather conditions and during times of low non-dispatchable power production** in the power region; (3) procures ancillary or reliability services **on a competitive basis to ensure appropriate reliability during extreme heat and extreme cold weather conditions and during times of low non-dispatchable power production** in the power region; (4) develops **appropriate qualification and performance requirements** for providing services under Subdivision (3), including appropriate penalties for failure to provide the services; and (5) **sizes the services** procured under Subdivision (3) to prevent prolonged rotating outages due to net load variability in high demand and low supply scenarios.) (emphasis added). [↑](#footnote-ref-14)
14. *E.g.*, E3 Report at 47 (indicating that loss of load events (i.e., by definition, the highest risk hours) are most likely to occur in the seasons with extreme heat and cold (i.e., summer and winter) and at night (i.e., which would coincide with low intermittent power in a solar heavy grid)—“Loss of load events are most likely to occur during **summer evenings and winter nights**, as illustrated in Figure 23. Nearly all of these high-risk hours occur **outside of daylight hours**, which aligns with **expectations of a system with significant quantities of solar energy**.”) (emphasis added); *id.* at 14 (explaining that the 30 hours of highest reliability risk were assumed to be during peak net load, i.e., during times with low non-dispatchable production). [↑](#footnote-ref-15)
15. PURA § 39.159(c) (“(c) The commission shall ensure that: (1) resources that provide services under Subsection (b) are dispatchable and able to meet continuous operating requirements for the season in which the service is procured; (2) winter resource capability qualifications for a service described by Subsection (b) include on-site fuel storage, dual fuel capability, or fuel supply arrangements to ensure winter performance for several days; and (3) summer resource capability qualifications for a service described by Subsection (b) include facilities or procedures to ensure operation under drought conditions.”). [↑](#footnote-ref-16)
16. E3 Report at 101 (“E3 believes that either a properly implemented annual construct that accounts for risks across all seasons or a full seasonal construct would be consistent with the directive of Senate Bill 3 and yield similar economic outcomes.”). [↑](#footnote-ref-17)
17. *Supra* note [9](#note3). [↑](#footnote-ref-18)
18. December1989; February 2011; and February 2021. *See* U.T. Austin Energy Institute, *The Timeline and Events of the February 2021 Te**xas Electric Grid Blackouts* (July 2021), *available at*: <https://www.puc.texas.gov/agency/resources/reports/utaustin_(2021)_eventsfebruary2021texasblackout_(002)final_07_12_21.pdf>. ERCOT also experienced an Energy Emergency Alert, Level 3, with a brief period of rotating outages in April 2006 due to, among other things, higher-than-expected temperatures. *See* Public Utility Commission of Texas, *Investigation into April 17, 2006 Rolling Blackouts in the Electric Reliability Council of Texas Region*, Preliminary Report (Apr. 24, 2006), *available at*: <https://www.ercot.com/files/docs/2006/04/27/10._rollblackouts_april_17_200.pdf>. [↑](#footnote-ref-19)
19. *E.g.*, E3 Report at 43 (explaining that LOLH is “better at capturing the length of events but does not capture the frequency of events like LOLE” and explaining that EUE is “better at capturing the magnitude of events but does not capture the frequency of events like LOLE”). [↑](#footnote-ref-20)
20. *Supra* note [18](#note14). [↑](#footnote-ref-21)
21. These tools include, for example, the ability to delay or recall planned outages by generation resources. [↑](#footnote-ref-22)
22. E3 Report at 76. [↑](#footnote-ref-23)
23. See Project No. 54335, TexGen Power’s Comments in Support of the Performance Credit Mechanism (PCM) (Dec. 1, 2022). [↑](#footnote-ref-24)
24. For example, the BRS is projected to take at least 1 year to implement. E3 Report at 82. TexGen suggests that its interim PCM proposal could be put in place in a matter of months. [↑](#footnote-ref-25)
25. ERCOT Protocols §§ 4.4.9.2.1(4) (“The Resource’s Startup Offer must not be greater than 200% of the Resource Category Generic Startup Cost for that type of Resource listed in Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, unless ERCOT has approved verifiable Resource-specific startup costs for that Resource, under Section 4.4.9.2.4, Verifiable Startup Offer and Minimum-Energy Offer Caps, in which case the Resource’s Startup Offer must not be greater than 200% of those approved verifiable Resource-specific Startup Costs.”); 4.4.9.2.1(5) (“The Resource’s Minimum-Energy Offer must not be greater than 200% of the Resource Category Generic Minimum-Energy Cost for that type of Resource listed in Section 4.4.9.2.3 unless ERCOT has approved verifiable Resource-specific minimum-energy costs for that Resource, under Section 4.4.9.2.4 in which case the Resource’s Minimum Energy Offer must not be greater than 200% of those approved verifiable Resource-specific minimum-energy costs.”). [↑](#footnote-ref-26)
26. ERCOT Protocols § 4.4.9.4.1. [↑](#footnote-ref-27)
27. *E.g.*, NERC, *2022 State of Reliability* (Jul. 2022), *available at*: <https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf>. [↑](#footnote-ref-28)
28. *Id.* at 2. [↑](#footnote-ref-29)
29. E3 Report at 2; *see* The Brattle Group, *Estimating the Economically Optimal Reserve Margin in ERCOT* (Jan. 31, 2014) (using the SERVM model). [↑](#footnote-ref-30)
30. *E.g.*, ERCOT, *Study Process and Methodology Manual: Estimating Economically Optimum and Market Equilibrium Reserve Margins (EORM and MERM)* (2017) (directing that the SERVM model be used). [↑](#footnote-ref-31)
31. *Commission Proceeding to Ensure Resource Adequacy in Texas*, Project No. 40000, Brattle Group “Customer Cost Comparison” Analysis (Sept. 4, 2012) (finding that achieving a reserve margin of 14 percent, consistent with a 1 in 10 LOLE, would result in ~$400 million more of system costs than the status quo energy-only market, equivalent to a 2.4% increase in costs). [↑](#footnote-ref-32)
32. *Review of Wholesale Electric Market Design*, Project No. 52373, The Brattle Group, *Market Design Options for Managing Reliability in ERCOT* (Nov. 2021) (projecting a 7% increase on the generation portion of the bill from the LSERO option). [↑](#footnote-ref-33)