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TEXGEN POWER'S[1] COMMENTS IN SUPPORT OF THE PERFORMANCE CREDIT MECHANISM (PCM)

I. INTRODUCTION

Texas is a challenging place for those looking to invest in new dispatchable power generation. Over the past twenty years, the ERCOT market has created significant challenges for financing and building new dispatchable generation. Most thermal generation owners have gone bankrupt.[2] And given the notoriously boom-bust structure of the ERCOT energy-only market, it is not surprising that Texas has failed to attract the investment it needs. A market littered with bankruptcies does not instill much confidence in investors or lenders. Consequently, all Texans suffer from a lower reliability level than in other states. While some large businesses can avoid costs associated with emergencies and extreme pricing, residential and small commercial customers generally end up bearing these costs in the form of power outages and higher electricity rates.[3]

But the issue is not merely a lack of new dispatchable generation sufficient to meet growing demand. It is also that the current market cannot sustain the *existing* dispatchable generation that is currently needed to keep the grid reliable. Older and economically challenged assets, like TexGen's Mountain Creek facility, are no longer viable in ERCOT and will likely retire without near-term, meaningful

[1] TexGen owns over 2,000 MW of gas-fired generation in ERCOT. Its owners include numerous investment firms that are active in the energy infrastructure space.

[2] See, for example, Talen Energy (filing for bankruptcy in 2022); Ector County Energy Center (filing for bankruptcy in 2022); ExGen Texas Power LLC (filing for bankruptcy in 2017); Panda Power Funds (filing for bankruptcy in 2017); Vistra Corp. (emerging from Chapter 11 bankruptcy in 2016); Dynegy, Inc. (various units filing for bankruptcy in 2011); Calpine Corp. (emerging from bankruptcy in 2008); NRG Energy (filing for bankruptcy in 2003)

[3] Most small business and residential customers ultimately pay higher rates because of such events. But some large and sophisticated industrial consumers can avoid extreme electricity pricing during scarcity events (and indeed often profit from these events).

market reform.[4]

Some states and countries have addressed reliability concerns by using a capacity market. But E3 and the Commission have offered a different solution that perfectly fits Texas. The proposed PCM design is not a capacity market. And if implemented correctly, it will (i) meaningfully reduce the cost of capital associated with an investment in dispatchable generation assets, (ii) send appropriate market and pricing signals for the necessary investment, and (iii) benefit consumers through enhanced reliability and increased avoidance of extreme pricing events and grid emergencies. TexGen encourages the Commission to adopt the PCM market design and implement it quickly, with a phased approach starting within the next six months.

II. DISCUSSION

A. The ERCOT market is on an unsustainable path

Texas currently faces the prospect of not having sufficient reliable electricity to support the state's continued economic growth. As explained in the E3 Report, over 11,000MW of legacy thermal generation will likely retire over the next few years.[5] The margins these generation units can eke out in the current ERCOT energy-only market are unlikely to sufficiently cover their fixed and variable operating costs, let alone result in a reasonable return. However, while these generation units likely cannot afford to stay in business, ERCOT apparently cannot afford for them to retire. This is not a sustainable path.

[4] Mountain Creek Unit 8, a 568 MW gas-fired steam unit, plans to enter seasonal mothball status on March 1, 2023 and will accordingly be available only from June through September.

[5] E3 Report at 46 (finding that "[a]djusting the 2026 portfolio into market equilibrium requires a reduction in 11,560 MW of firm capacity, which the Consulting Team assumed to be split equally between coal and steam gas turbine units.").

1. The ERCOT market creates significant challenges for older dispatchable assets

The headwinds for ERCOT's legacy, dispatchable generation are significant. First, the market no longer values what these units have to offer. The state's regulated utilities constructed and designed these units—in the 1950s through 1970s—to run as "baseload" units, meaning that they would run 24 hours a day and start/stop infrequently. Unlike the last century's regulated market, today's market results in these units earning profits only during a few hours or days throughout the year. Units run at a loss for many hours or days, hoping they can make enough profit during a few essential hours to justify incurring all those losses. Often the gamble fails: generators come online in response to forecasted tight conditions during a tight time window, but the pricing does not materialize and the day turns into a total loss. This is not sustainable.

With the explosion in renewable resources, the grid and market need to prioritize units that can start and ramp quickly in response to potentially drastic weather-driven changes in output from wind and solar units. Units designed to start infrequently and run at constant "base load" levels are generally not what the market values, both now and in the future. Instead, the market (correctly) favors units that can respond quickly to changing demand for dispatchable generation. In other words, the economic cards are stacked against older units, making them increasingly unprofitable.

2. Older assets <u>should</u> be retiring, but ERCOT still relies on them to provide reliability

Importantly, these older and inefficient units *should* be on a path to retirement. And they would be if ERCOT had a well-functioning market. As these plants have continued to age and the market/grid has evolved, it is time for many of these older units to cease operations and be replaced by newer, more efficient, and more flexible generating capacity. Again, the ERCOT grid will be much better served by assets (like gas peakers or batteries) that can respond quickly to periods when ever-increasing wind and solar resources are not producing electricity.

Unfortunately, the status quo energy market has resulted in a grid that relies on outdated plants from a different era because it has not attracted enough of the assets needed for the future. One example is TexGen's Mountain Creek Unit 8, a 568 MW steam unit located in Dallas. It began operations in 1967, and it initially provided energy very efficiently (compared with technology at the time) and served as a baseload foundation for Dallas Power & Light's electricity needs. Fast forward fifty-five years, however, and you will see a relatively inefficient unit with high fixed costs, aging equipment with high maintenance costs, and a long and complicated 18-hour starting process. These attributes make the unit ill-suited to generate much, if any, profit in the current ERCOT market.

Additionally, as an aging and complex unit, Mountain Creek Unit No. 8 is susceptible to unexpected, forced outages that further limit its ability to collect revenue in an ERCOT market premised on high pricing during just a few hours throughout the year. And ERCOT's persistent RUC instructions exacerbate the problem by potentially subjecting the unit to significant, costly, and time-consuming maintenance costs that ERCOT's make whole payments will not cover.

Even worse, the site's new post-Uri gas transportation costs, which have increased by almost 300%, make starting, ramping, and running the unit prohibitively expensive.[6] Mountain Creek Unit 8 now incurs exorbitant "imbalance" penalties whenever it does not run "ratably" (i.e., consuming the same amount of gas for all twenty-four hours in a single day). This leaves Mountain Creek Unit 8 in an untenable position. It can either (i) incur significant losses by running at full output all day even when its marginal operating costs exceed its marginal revenue, or (ii) incur significant losses by increasing/decreasing its output throughout the

[6] Importantly, this nearly 300% cost increase is separate and apart from the recent underlying increases in the price of natural gas. This increase is due *only* the cost of transportation and delivery of the natural gas.

day and paying the resulting massive imbalance penalties to pipeline operators.[7] And Mountain Creek is not alone in this regard. With limited or no other options for gas transportation, other similarly situated plants in ERCOT now face the same difficulties and pressures.

In the future, Mountain Creek Unit 8 is expected to be uneconomic for most, if not all, of the year. TexGen has accordingly notified ERCOT that the unit will be entering seasonal mothball status outside of June through September (the minimum amount of time allowed under the ERCOT protocols), effective March 1, 2023. Importantly, it is certainly possible that the market continues to impose unsustainable economic pressures and that there is no material change from Phase II that changes the economic outlook for such units. In that case, it will likely be prudent to retire the unit or to mothball it indefinitely. One could also reasonably assume that other owners of aging thermal generation would make similar economic choices in the coming years.

Again, assets like Mountain Creek Unit 8 (built more than a half-century ago) *should* be on a path to retirement. But for now, *ERCOT still relies on these aging, increasingly unprofitable units nearly daily to provide the necessary grid reliability*. For example, ERCOT routinely RUCs older and inefficient units, forcing otherwise unprofitable plants to come online as critical support to the grid.[8] The question is *why* these units (most constructed in the 1950s, 60s, and 70s) are still considered essential for reliability. The answer is that capital investment in ERCOT dispatchable resources has not kept up with the state's growth. While other ISOs add dispatchable capacity (and retire older assets), ERCOT does not.[9]

[7] While a gas storage contract could presumably help to avoid such imbalance penalties, the fixed and variable costs of such a contract are at least as high as the penalties themselves. So a storage contract would not change the fundamental economic dilemma.

[8] While these units are allegedly made whole, there are often many costs that go unrecovered.

[9] For example, PJM Interconnection added over 50% of capacity to their gas-fired fleet over the past 10 years vs approximately 11% increase for ERCOT over the same time span. *see* PJMs Capacity by Type report; *see also* ERCOT's Capacity Changes by Fuel Type report.

Fortunately, Senate Bill 3 (S.B.3) created a framework for ERCOT to continue integrating intermittent generation while ensuring that sufficient dispatchable generation remains in the market until developers construct new dispatchable generation. Phase I of the Commission's blueprint stabilized the post-Uri grid, and phase II should create the right market design that keeps existing generation viable while new generation is developed. But if Phase II fails to accomplish the necessary changes, the status quo energy-only market will result in additional retirements, and the grid will be persistently unreliable due to a lack of dispatchable generation.

B. PCM is the right market design for ERCOT

1. PCM benefits consumers

The primary benefit of PCM's enhancements to the ERCOT energy-only market is for consumers. By creating a market that retains existing generation and incentivizes new generation, PCM will enhance reliability and reduce the instances of extreme pricing, physical scarcity, conservation notices from ERCOT, and having the lights go out. And just as avoiding a boom-bust market makes ERCOT a more attractive destination for capital investment, avoiding crisis and extreme pricing creates a more attractive environment for most consumers.[10] As shown in the E3 report, PCM's primary impact on costs is to shrink the range of outcomes: average costs are slightly (2%) higher than the status quo, but the grid can avoid scenarios where costs explode to extreme levels.

2. PCM helps keep existing generation temporarily in the market while providing a pathway for newer and better assets

As discussed above, ERCOT has many economically challenged resources that remain essential for ongoing system reliability. ERCOT does not just need

[10] Some large and sophisticated users might actually welcome instances of extreme pricing because they can economically benefit from such events. But the majority of consumers (small business and residential customer) eventually incur the costs from extreme pricing in the form of higher rates going forward.

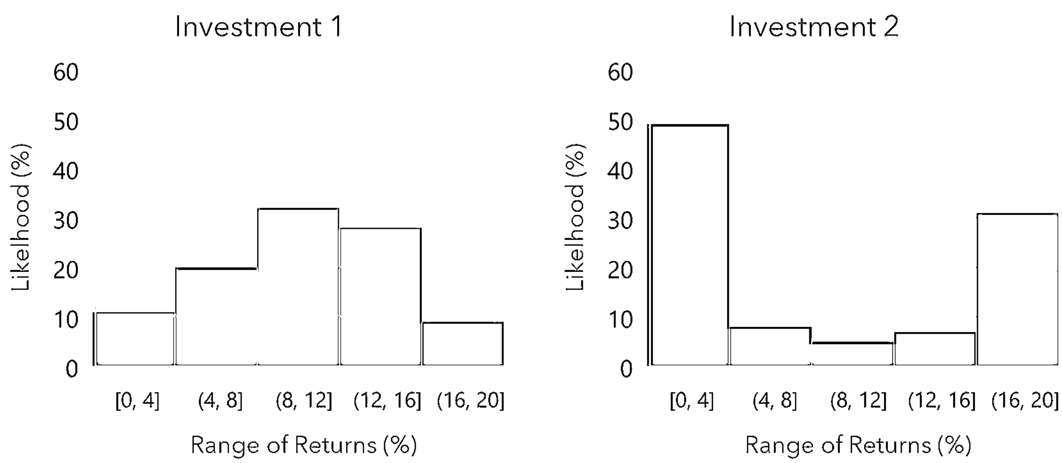
incremental capacity; it also needs legacy assets due for retirement to be replaced. These legacy resources generally cannot afford to remain in the market, but ERCOT still uses them to keep the grid reliable. Fortunately, PCM helps to delay the inevitable retirement of legacy assets while giving sufficient time for new investments to take their place.

PCM allows legacy units to remain in the market, at least temporarily, because the generators know that running during tight conditions comes with a financial reward (in the form of performance credits). This contrasts with the current market, in which legacy generators often incur significant losses in trying to capture a limited period of extreme pricing (which may never materialize). Under PCM, ERCOT gets the confidence that legacy generation has the appropriate incentive to self-commit resources, and the resources get the certainty that performing reliably during periods of low intermittent generation output will not be a losing endeavor.

While PCM encourages legacy units to remain in the market, it also puts them at a competitive disadvantage versus more flexible and efficient dispatchable resources. Resources that can start quickly, run efficiently, ramp quickly, and cycle easily will be best positioned to succeed under the PCM. A legacy steam unit, for example, might need to run at a loss for many hours (if not days) to ensure that it is online and available during the designated hours. But a modern peaking unit or combined cycle gas turbine (and especially a battery) will be able to respond to changing market conditions quickly, and such units are significantly more likely to be online/available when necessary. So PCM has placed a natural competitive pressure on legacy units and favors newer, more efficient, and more flexible resources. In other words, while PCM provides near-term stability for legacy existing resources to keep them in the market for now, it also provides longer-term signals for investment in the right types of *new* dispatchable generation that will eventually displace these legacy assets.

3. *PCM creates the right type of market to attract new investment*

Imagine that you are an investor who is presented with two investment opportunities. The first opportunity is one where you can expect to achieve a reasonable rate of return and where the range of outcomes is relatively stable. The second opportunity offers more risk—there is a good chance that you will achieve meager returns, but also a chance that you will achieve high returns. Which investment is preferable? Which investment are you more likely to be able to get a loan for?



Investing in dispatchable power plants offers the same kind of choice. Some markets, particularly those that offer a capacity market, are like Investment 1. ERCOT's scarcity-driven model, on the other hand, offers a boom-bust proposition that is more like Investment 2. In ERCOT, a generator's returns are premised not on consistent revenue streams but on rare periods of physical scarcity on the grid—when the grid approaches emergency conditions and power prices rise to extreme levels. This is a crisis-based business model, where profits largely depend on a scarcity event.

The scenarios presented above are certainly simplified. Actual investment decisions depend on many factors, including the investor's cost of capital, ESG requirements, credit rating, financing options, investment horizon, etc. It also depends on the ability to hedge future output in the forward markets (power purchase agreements, call options, financial swaps, derivatives, etc.). But the illustrations are instructive in laying out the fundamental reasons why investment in ERCOT has lagged that of other ISOs, to the detriment of reliability for Texas consumers.

How can the Commission achieve a market design that makes investment in dispatchable generation a less risky and more certain proposition? A capacity market has undoubtedly been proven to result in a sufficient investment in dispatchable generation and reliability benefits. Yet some have pointed to the economic downsides of such a market design. On the other hand, merely tinkering with the ERCOT energy-only market by duct-taping it with a new "Uncertainty Product" does not change the investment profile for dispatchable generation. Such changes mostly perpetuate the status quo, continuing the crisis-based business model, grid emergencies, and extreme pricing events. With the continued explosion of renewable resources projected over the next five years, something should be done now to encourage the type of investment needed for more reliability. Maintaining the status quo while waiting for the next emergency is not what Texas needs.

Fortunately, the PCM enhances the current energy-only market and *fundamentally changes the investment profile* for dispatchable generation in ERCOT. Currently, a generator must hope it is online during the rare and brief periods of scarcity pricing. Under PCM, a generator can have more stable revenue streams and move away from a crisis-based business model. PCM will enable generators to make a reasonable return without requiring a grid emergency.

Additionally, the forward-looking component of PCM (i.e., tradable credits) will increase the ability of investors to raise the debt needed for new investment. Rather than having to point merely to energy market volatility or having to lock in future hedges at depressed forward prices for energy, investors will be able to rely on future PCM hedges to support the necessary debt. Ultimately, attracting investment requires an investor to have confidence in a return on (and certainly a return of) their investment. PCM's enhancements and changes to the forward price signals for new investments will help create that confidence in a market that desperately needs it.

When private capital views the investment profile for dispatchable generation in ERCOT, it will see a reasonable investment opportunity with a strong expectation of a reasonable return on investment, albeit at a reduced chance of significant profits resulting from a crisis. PCM would convert ERCOT from a risky, boom-bust, speculative market to a more stable and less risky destination for capital investment.

4. PCM is consistent with Senate Bill 3

Furthermore, the PCM fits squarely within the precise language of the last session's legislation. Tex. Util. Code § 39.159(b)(3), for example, says that ERCOT shall procure "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 case of PCM, ERCOT is procuring "reliability services" (i.e., performance credits) on a "competitive basis" (i.e., only from those generators who choose to be online/available) during times of "low non-dispatchable power production" (i.e., during the tightest hours of the month/year). In developing PCM, the Commission has designed a solution that accomplishes the explicit goals of the 87th Legislature: create the necessary market changes to ensure that Texans have sufficient dispatchable generation.

5. PCM has been mischaracterized

Some were quick to criticize PCM when the E3 Report was first released. It has already variously been referred to as a "capacity market," an "energy tax," and even a "socialist wealth transfer." But these characterizations are wholly inaccurate.

PCM is not a capacity market. Instead, it is purely a pay-for-performance market design. Resources are not paid for merely having steel in the ground or simply sitting on the sideline; they are paid only if/when they are online when the grid most needs them. PCM is purely a pay-for-performance proposition. And loads are not charged based on an estimate of their expected demand; they are charged only for what they *actually consume* during the tightest grid conditions.

Calling PCM a "tax" might be good rhetoric, but it is highly inaccurate. If PCM is an energy tax, then *every* ERCOT ancillary service (and indeed the cost of the electricity itself) could be called a "tax." PCM is designed to reflect the costs associated with providing the reliable dispatchable generation necessary to support the ERCOT grid. And it essentially moves some costs from the energy market into a new reliability service. Providing reliable dispatchable generation does indeed come at a cost, and simply labeling such costs as a "tax" is an attempt to sidestep this fundamental issue and score political points.

Likewise, calling PCM a "wealth transfer" might provide a good sound bite, but it is not a reasonable way of describing the market design. As described in the E3 report, the PCM is expected to raise total system costs by only around 2%. It is not primarily designed to increase revenues for dispatchable generation, but rather to *stabilize* the revenue streams by moving away from the current boom-bust, crisis-based design.

Some have disparaged PCM for not "guaranteeing" that dispatchable generation will be built. However, nothing in S.B.3 gives the Commission the authority to command new generation to be built, nor will any market design "guarantee" new generation. Guaranteeing new generation is undoubtedly (and rightfully) not the Commission's task under S.B.3. The Commission's job is to create the right market design to retain existing generation and to construct new generation. But it certainly cannot command private businesses to build power plants. Conversely, a state procurement of new generation using taxpayer money is not a market design authorized by S.B.3. (and is not even a market). Likewise, using state funds to subsidize only new generation (but not existing generation) will certainly lead to the "crowding out" of existing generation and ultimately result in little or no gain of dispatchable generation. State subsidization of new generation is the antithesis of ERCOT's free market design and would be the first step towards a full re-regulation of the market.

Nor should there be a "will NRG and Vistra build new plants?" litmus test for the market design. The question is not whether NRG and Vistra—both public companies with complicated and nationwide portfolios of retail, thermal, and renewable assets—will build in response to a change in market design. Instead, the question is whether the market will create the right investment profile for those seeking to make capital investments in energy infrastructure. PCM accomplishes this objective, regardless of whether NRG and Vistra ultimately decide to make such an investment decision. With the right market signals, the investment will come.

III. ANSWERS TO SPECIFIC COMMISSION QUESTIONS

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

No. PCM has three main facets: (i) a look-back settlement mechanism that calculates the generation that qualifies for PCM and the load-ratio share during the same intervals, (ii) the demand curve, and (iii) the voluntary forward market. These three components have well-established precedents in the ERCOT or similar markets. For example, there are numerous examples where ERCOT's settlement function is tied to a look back on what happened in real-time. Load-ratio share is a standard settlement mechanism, and ERCOT is readily capable of evaluating online generation in the past. The demand curve is not dissimilar from (and is substantially less complex) than the ORDC curve process. And the voluntary forward market is not dissimilar from the current CRR forward auctions. With a helpful precedent for all the main components of PCM, the implementation should not present significant obstacles for ERCOT.

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 peak net load and extreme power consumption conditions? Why or why not?

Yes. As discussed on pages 6 through 10, PCM is designed to achieve the Legislature's and Commission's goals and creates the right market structure for retaining and developing new dispatchable generation.

3. What is the appropriate reliability standard to achieve the goals stated in Question 2? Is 1-in-10 loss of load expectation (LOLE) a reasonable standard to set, or should another standard be used, such as expected unserved energy (EUE). If recommending a different standard, at what level should the standard be set (e.g., how many MWh of EUE per year)?

The 1-in-10 LOLE is an appropriate standard because it is consistent with the standard in other dynamic economies and is widely recognized as being correct. Texans should not have to suffer under a lower standard than other states.

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?

For at least two reasons, the reliability risk should focus on peak net load instead of the hours with the smallest number of reserves. First, peak net load is more consistent with S.B.3. Second, peak net load is determined independently from the commitment decisions made by generators (which increase online reserves). Using the highest peak net load hours, which are independent of the commitment decisions of thermal generators, will lead to greater certainty around which hours are designated under PCM and will eliminate the potential for manipulation of the specific hours due to commitment decisions from dispatchable generation. As discussed below, the number of hours should be changed from 30 to 48.

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 hours of highest reliability risk should be determined monthly, four times per month. Like TexGen's 12CNP proposal,[11] having PCM settled monthly recognizes system reliability is a year-round problem.[12] Focusing the reliability risk hours during the highest thirty hours (regardless of month or season) will likely result in the hours occurring on just a few (potentially consecutive) days during an extreme summer or winter peak. Those days/hours will likely coincide with high energy prices (or even scarcity pricing). This could have the unintended effect of exacerbating (not reducing) the boom-bust nature of the ERCOT market. Specifically, a generator that is not available (forced outage, trip, gas curtailment) for that tight window of hours would get hit "twice" for the same event (once in the PC market and again in the energy market).

Additionally, assigning PCs during only the highest hours of the year (as opposed to a more seasonal or monthly procurement) will have two potentially negative impacts. First, it will tend to increase the number of PCs awarded because the target hours will likely occur only during periods where significant generation is already online (like a peak summer day). Second, it will tend to exert downward pressure on the clearing price of PCs and ultimately reduce the program's overall effectiveness.

A better solution would be to spread the measures throughout the year and focus on four hours each month. Identifying the peak net load hour each month as PCM's "target" hours will help ensure reliable year-round operations, recognizing that reliability issues can (and do) occur during times of high planned thermal generation outages.

[11] Project No. 52373, Review of Wholesale Electric Market Design, TexGen Power's Proposal for Market Reform (Doc 166), 12CNP: A Hybrid of the Phase II Market Design Proposals (Doc 273).

[12] TexGen also recommends that PCM be settled monthly (as a monthly product) as opposed to after the calendar year is complete.

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?

Yes. These concepts would establish a forward market that can allow sophisticated market participants to assess, allocate, and manage risk. In fact, a viable forward market is a critical driver in providing the right investment signals for new dispatchable generation.

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

Yes. Central procurement will sufficiently mitigate the concern that a large "gentailer" can exercise market power in otherwise opaque bilateral markets. Additionally, targeting the PCM hours based on peak net load (as opposed to reserves) will reduce the likelihood that large generators can profitably impact the selection of PCM hours through self-commitment decisions.

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?

TexGen believes PCM can be designed and implemented relatively quickly and would not be a "multi-year" implementation. However, assuming there is such a long implementation timeline, it *does* make sense to implement a short-term bridge. The bridge should be a phased-in implementation of PCM.

Broadly speaking, PCM has three main facets that need to be developed (i) a look-back settlement mechanism that calculates the generation that qualifies for PCM and the load-ratio share during the same intervals, (ii) the demand curve, and (iii) the voluntary forward market. But these components should not be viewed as the proverbial stool's three legs. In particular, the first component (the look-back settlement function) can likely be implemented quickly and independently.

The Commission need not wait for the details of the demand curve and forward voluntary market to be fully litigated and implemented. Instead, it can immediately prioritize and begin implementing the look-back mechanism. Specifically, the Commission could instruct ERCOT to develop the necessary systems to begin calculating (after the fact) the generation that was online/available during the designated tightest hours. This implementation should take a matter of months.

With the look-back mechanism in place, ERCOT could assign a fixed price for PCs to be in place on an interim basis until the demand curve is developed and implemented. If, as TexGen recommends, PCs are awarded for four hours each month, then all dispatchable units (including legacy steam units) would have appropriate incentives to self-commit during high peak net load periods. This would immediately (i) reduce the need for incessant RUCs, (ii) provide more stable energy prices, and (iii) provide the right economic incentives for legacy dispatchable assets to remain in operation. As a form of a circuit breaker, the price for PCs could be reduced if/when the peaker net margin is reached.

The BRS solution is likely not the best "bridge" for the market. BRS, by design, keeps existing capacity out of the generation stack until there is an emergency. As evidenced by ERCOT's conservative operations over the past 18 months, the goal is to ensure that generation is committed and dispatched before an emergency occurs. ERCOT needs more dispatchable generation online during tight conditions, not less. Earlier formulations of BRS suggested that legacy steam generation units would be the target resources for the program. More recent formulations appear to indicate that the program would target gas peakers. Either way, intentionally holding generation capacity out of the market would increase market volatility, raise energy costs, and create increased uncertainty around emergency conditions. It would likely be good for speculative power traders but bad for the market.

The apparent problem ERCOT has experienced in recent months is a perceived need for additional generation to come online. But there is likely no economic incentive to do so, particularly in light of the excessive gas costs that many gas generators now incur daily. When these generators do come online (or are RUC'd), it is often the case that they lose money. And as with Mountain Creek Unit 8, these units are economically challenged and likely to retire soon without significant market changes. A phased-in approach to PCM, starting with the look-back settlement mechanism, would be an effective bridge in preserving reliability.

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?

The bridge solution proposed by TexGen—a phased implementation of PCM—is unlikely to delay a full PCM implementation materially. It could arguably speed up the ultimate implementation, as it is often easier to implement a large project in phases than to try to finalize everything simultaneously.

However, short-term solutions like procuring additional NSRS will likely not fix ERCOT's retirement problem. Procuring additional NSRS benefits gas peakers and combined cycle units but tends not to benefit the legacy generation units that generally cannot profitably sell NSRS. In other words, it likely does not serve the goal of forestalling the retirement of legacy resources and would not materially improve the achievement of the 1-in-10 LOLE standard.

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

The impact on consumer costs appears to be addressed in the E3 report.

11. What is the fastest and most efficient manner to build a "bridge" product or service, such as the BRS, in order to start sending market signals for investment in new and dispatchable generation, while a multi-year market design is implemented by ERCOT? Please provide specific steps.

As discussed above, the fastest and most efficient way to build a bridge product would be to phase in PCM's development. The first step would be to direct ERCOT to develop the look-back settlement mechanism and to assign an interim fixed price for the PCs. The Commission and ERCOT could then create the demand curve and the forward market in later phases.

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?

TexGen has no comments in response to this question.

IV. CONCLUSION

The Commission has the opportunity to implement a market design that changes ERCOT from a boom-bust market littered with bankrupt generators, to a viable and attractive place for capital investments. It can do this by implementing a PCM market design that provides a more reliable and sustainable profile for investment, one that eschews the crisis-based business model of the past. And in light of looming retirements of the assets ERCOT continues to need for reliability, the Commission must act. PCM is the right solution for ERCOT, and the Commission should implement it quickly.

Respectfully submitted,

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Executive Summary

- Texas is a challenging place for those looking to invest in new dispatchable power generation. Federal and state regulations have created significant challenges for financing and building new dispatchable generation. As a consequence, **Texas has failed to attract the investment it needs.**

- The issue is not merely a lack of new dispatchable generation sufficient to meet growing demand**. It is also that the current market cannot sustain the existing dispatchable generation that (unfortunately) remains essential for keeping the grid reliable.**

- Some states have addressed reliability concerns by using a capacity market. But E3 and the Commission have offered **a different structure that perfectly fits Texas**. The proposed PCM design enhances the current energy-only market and fundamentally changes the investment profile for dispatchable generation in ERCOT. **PCM would convert ERCOT from a risky, boom-bust, speculative market to a more stable and less risky destination for capital investment**.

- PCM will **benefit consumers by creating a more reliable grid with more stable costs**. By creating a market that retains existing generation and incentivizes new generation, PCM will enhance reliability and reduce instances of extreme pricing and physical scarcity with minimal increases in cost.

- PCM helps **keep legacy generation temporarily in the market** while providing a pathway for newer and better assets. It supports aging (but still critical) plants while simultaneously **providing the right signals for investment in new generation.**

- The forward-looking component of PCM (i.e., tradable credits) will **increase the ability of investors to raise the debt needed for new investment**. Rather than having to point merely to energy market volatility or having to lock in future hedges at depressed forward prices for energy, investors will be able to rely on future PCM hedges to support the necessary debt. PCM's enhancements and changes to the forward price signals for new investments will help create that confidence in a market that desperately needs it.

- **The Commission should approve moving forward with a PCM structure and immediately begin a phased implementation**. The first phase, which could serve as a "bridge," would be implementing the look-back settlement mechanism using an administratively set price. The subsequent steps (demand curve; voluntary forward markets) should be implemented shortly thereafter.