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Review of Market Reform Assessment Produced by Energy and Environmental Economics, Inc.

Public Utility Commission of Texas

Comments of Pine Gate Renewables, LLC

December 15, 2022

Pine Gate Renewables, LLC (Pine Gate) respectfully submits these comments in the above captioned proceeding in response to Public Utility Commission of Texas (Commission) staff's November 10, 2022, request for feedback on the report prepared by Energy and Environmental Economics, Inc. (E3).[1] Pine Gate is generally supportive of the Commission's efforts to improve reliability but believes that the Commission should take a more targeted approach that begins with clearly defining the reliability problem and adopting a reliability standard that would address this problem.

I. Introduction

Pine Gate originates, develops, finances, and operates utility-scale solar and energy storage projects that generate clean renewable power. With five large solar and hybrid projects in the Electric Reliability Council of Texas (ERCOT) queue totaling 830 MW, 1,600 MW of pending acquisition opportunity, and 3,000 MW sited and currently under review, Pine Gate has a large and growing portfolio of Texas projects. Pine Gate also works with energy buyers, corporations,

[1] E3, *Assessment of Market Reform Options to Enhance Reliability of the ERCOT System*, Docket No. 54335-2 (Nov. 10, 2022) (E3 Report).

utilities, local communities, and capital partners to develop and operate these projects across the country. Nationwide, Pine Gate currently has 1,200 megawatts (MW) of operational assets, over 900 MW in construction, and another 20 gigawatts (GW) in active development. With five large solar and hybrid projects in the ERCOT queue totaling 830 MW, 1,600 MW of pending acquisition opportunity, and 3,000 MW sited and currently under review, Pine Gate has a large and growing portfolio of Texas projects. Pine Gate is active in both the Independent System Operator/Regional Transmission Organization (ISO/RTO) markets and non-ISO/RTO markets.

II. Executive Summary

Pine Gate agrees with the Commission that ERCOT has a reliability problem. Recent assessments by ERCOT and independent third parties have revealed that the ERCOT grid faces operational challenges such as changes in demand, increased variable renewable generation, and unexpected thermal generation outages. Yet, despite these reliability concerns, Pine Gate maintains that the ERCOT market overall remains a robust source of affordable power and an attractive place to invest. Any market design that the Commission adopts should be carefully calibrated towards solving specific reliability issues while avoiding unnecessary disruptions to the market. This process should begin by carefully identifying the reliability problem that needs to be solved, as was required by Senate Bill 3 (SB3).

The Commission has not yet taken this important first step. The E3 Report does not define the nature of the reliability problem but nonetheless concludes that more money for new thermal generation is necessary to solve it. Notably, the E3 Report takes for granted that the same generation capacity that failed during Winter Storm Uri would perform perfectly in future extreme weather. Given these assumptions, it is not surprising that E3 only considered a limited number of market designs that mimic the capacity markets or bilateral capacity arrangements prevalent in the

Northeast and California. At the same time, E3 ignores recent experience from these other markets who are seeking to address the same operational challenges through different means. Pine Gate therefore urges the Commission to consider alternative market designs that are specifically aimed at solving operational challenges rather than building more new capacity.

III. Comments

Pine Gate submits these high-level comments in addition to detailed responses to Commission staff's questions in the following section. Before adopting any market design, Pine Gate urges the Commission to clearly identify the problem that it seeks to resolve. This exercise should begin by identifying the hours of highest reliability risk to better understand the causes of ERCOT's reliability problems. The Commission should use this analysis to adopt an appropriate reliability standard and compare different market designs for achieving it. Specifically, the Commission should evaluate the Performance Credit Mechanism (PCM) against other market designs that E3 did not consider, including the Independent Market Monitor's (IMM) recommendation to create a new reserve product such as the one proposed by the DRRS Coalition, and the Dispatchable Energy Credit (DEC) mechanism originally proposed by Commissioner McAdams. In the meantime, reforms that the Commission has already adopted, such as weatherization and changes to the operating reserve demand curve (ORDC), should be given time to work.

a. The E3 Report fails to adequately define the nature of ERCOT's reliability problem as required by SB3.

Pine Gate generally agrees with the Commission and SB3 that ERCOT has a reliability problem that needs to be addressed. This past summer, ERCOT repeatedly came close to experiencing outages and, as recently as November 26, 2022, experienced tight operating

conditions.[2] The NERC's 2022-2023 WRA recently warned that under above-average peak load and/or outage conditions, ERCOT would need to turn to operating mitigations to meet load requirements.[3] In its own SARA, ERCOT found that another extreme weather event comparable to Winter Storm Uri could lead to a 12,900 MW shortfall in generating capacity.[4] Multiple short-term and long-term factors contribute to the dim outlook for reliability in Texas, including planned and forced outages, fuel supply disruptions, demand volatility, extreme heat and cold events, generator retirements, and insufficient ramp capability.

Given the myriad sources of potential operational and planning challenges that ERCOT faces, the Commission must clearly define the reliability problem it seeks to address before crafting a solution. Otherwise, the Commission risks implementing a costly market design that causes unnecessary disruptions and leaves Texans no less vulnerable to prolonged outages from Winter Storm Uri-type events. This is not merely a matter of adopting a reliability standard or metric. Reliability targets are useful tools to help assess the effectiveness of a given policy or plan in solving a particular problem. For example, if the Commission concluded that ERCOT faced a capacity shortfall due to increasing generator retirements, it might adopt a Loss of Load Expectation (LOLE) target like the industry standard 1-day-in-10-years (0.1 days per year) that measures the frequency of outages in days. On the other hand, if the Commission concluded that ERCOT faced a risk of prolonged outages due to fuel supply disruptions, it might adopt an

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[2] Commission and ERCOT Press Conference (Nov. 29, 2022), available at: https://www.kcbd.com/2022/11/29/live-officials-discuss-ercot-winter-power-grid-preparations/ .
[3] NERC, *2022-2023 Winter Reliability Assessment* (Nov. 2022) at 26, *available at*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf (WRA).
[4] ERCOT, *Seasonal Assessment of Resource Adequacy for the ERCOT Region Winter 2022/23* (Nov. 29, 2022) at 4, *available at*: https://www.ercot.com/files/docs/2022/11/29/SARA_Winter2022-23.pdf (SARA).

Expected Unserved Energy (EUE) target that measures the duration of outages in addition to their frequency. But neither metric by itself would enable the Commission to define the specific reliability problem that it needs to address; they simply measure different aspects of reliability.

Unfortunately, the E3 Report did not consider this important threshold question. Instead E3 merely adopted, at the direction of the Commission, a LOLE target of 0.1 days per year with little discussion about how that standard would help resolve the unique reliability challenges that ERCOT faces. But E3's own assessment of the status quo demonstrates that the LOLE metric is *not* the appropriate target. According to E3, the energy-only market in Texas in 2022 achieves a LOLE target of 0.03 days per year, remarkably better than the industry standard of 0.1 days per year.[5] Yet, as described above, ERCOT operated on the brink of power outages multiple times in 2022, a situation that the LOLE metric fails to capture. The Commission cannot expect a market design aimed solely at achieving this arbitrarily selected metric to improve reliability when the same metric indicates that there is no reliability problem to begin with, despite evidence to the contrary.

Most notably, E3 did not consider how each market design would fare during a severe storm like Winter Storm Uri. During Winter Storm Uri, thermal generation failed at several times the rate of renewables.[6] For this reason, the Commission wisely adopted weatherization standards and firm fuel requirements for thermal generators aimed at increasing performance during cold snaps. These policies rightly acknowledge the strong correlation among extreme weather events, fuel shortages, and thermal outages. The Commission and Texas Legislature have both recognized that

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[5] E3 Report at 126.

[6] University of Texas at Austin Energy Institute, *The Timeline and Events of the February 2021 Texas Electric Grid Blackouts* (July 2021), available athttps://energy.utexas.edu/sites/default/files/UTAustin%20%282021%29%20EventsFebruary2021TexasBlackout%2020210714.pdf.

this is a significant problem in ERCOT that needs to be addressed. In contrast, the E3 Report assumes "unlimited access to fuel when needed,"[7] an unrealistic assumption that renders E3's analysis meaningless for understanding the likelihood of repeating the biggest electric reliability failure in the history of Texas. While the weatherization standards and other post-Uri reforms, albeit untested by abnormally cold winter conditions, have undoubtedly improved reliability, they certainly have not created "unlimited access to fuel when needed." But without a precise definition of the reliability problem, it is impossible to assess to what extent these reforms have already solved it.

Given the lack of attention devoted to identifying the reliability problem in ERCOT, the E3 Report cannot satisfy the Commission's statutory obligations under SB3. SB3 directs the Commission to ensure that ERCOT (1) determines the quantity and quality of ancillary or reliability services needed and (2) procures those ancillary or reliability services to ensure appropriate reliability during times of low non-dispatchable power production.[8] For these reasons, Pine Gate urges the Commission to conduct further analysis of the reliability threats that ERCOT faces as described further below.

b. Recent assessments of ERCOT's grid reveal operational problems rather than resource adequacy ones.

As discussed above, ERCOT faces several threats to the short- and long-term reliability of the grid. The Brattle Group recently explained that these threats can broadly be divided into two categories: *resource adequacy*, which means having enough supply always available to meet

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[7] E3 Report at 56.
[8] PURA 39.159(b).

demand, and *operational responsiveness*, which means having the ability to manage changes in supply and demand.[9] SB3's directive to improve reliability could be interpreted to encompass either category. However, the E3 Report adopted a reliability target and recommended a market design that primarily focused on improving resource adequacy through the retention and procurement of capacity.

While ERCOT may need additional capacity in the future, the E3 Report has not demonstrated this need. In fact, its assessment of the LOLE in 2022 demonstrates the opposite—ERCOT has more than enough existing capacity to satisfy the one day in ten years LOLE standard. When modeling the status quo energy-only market in 2026, however, E3 identifies a severe capacity shortfall of 11,560 MW that results in a substantially worse LOLE of 1.25 days in ten years.[10] This capacity shortfall—representing the retirement of nearly 20% of the ERCOT thermal fleet in the next three years—would be alarming if it were not so unbelievable. In fact, this capacity shortfall is an *output* of the model, which achieves equilibrium by reducing the number of thermal resources based on whether they earned a certain amount of revenue (the amount of revenue equal to the cost of building a new gas plant) that E3 estimates is $93.5/MWh.[11] While this may make sense in the context of the model E3 used, it makes for an extremely crude forecast of retirements. Existing thermal generators in the ERCOT market today do not immediately retire when they fail to earn revenues equal to the cost of new entry, despite the fact that generators frequently earn less than $93.5/MWh. On the contrary, there are three GW of new gas-fired generation in the ERCOT

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[9] The Brattle Group, *Market Design Option for Managing Reliability in Texas* (Nov. 2021) at 2, available at https://interchange.puc.texas.gov/Documents/52373_255_1168764.PDF.
[10] E3 Report at 46.
[11] E3 Report at 56.

interconnection queue today demonstrating that the market can attract new investment even with energy-market revenues below what E3 assumes.

Even if one assumes that ERCOT faces a future capacity shortfall, additional capacity would not improve reliability in the face of fuel scarcity and weather-related outages. Nor will additional capacity necessarily help ERCOT manage other reliability challenges. The NERC WRA and ERCOT's SARA both reveal the risks to ERCOT's reliability during extreme weather events: outages, fuel disruption, and demand volatility creating significant reserve shortages in extreme cold weather. NERC's 2022-2023 WRA found that under normal peak-demand scenarios, Texas is expected to have sufficient resources to meet the operating reserve requirements. However, should there be an above average peak load and/or outage conditions, ERCOT would need to turn to operating mitigations to meet load requirements.[12] NERC's assessment estimates generation deficit, with ERCOT's project reserve margin at -21.4% due to outages, fuel disruption, and volatile demand in extreme cold weather events.[13] This assessment emphasizes that ERCOT's main challenge is not its resource adequacy, but rather its operational response capability in times of constraint.

This should lead the Commission to adopt reliability metrics aimed at addressing operational challenges and tailor market designs to achieve those metrics, as discussed more in the next section of these comments.

c. Any market design that the Commission adopts should address ERCOT operational reliability and avoid unnecessary disruptions to ERCOT's energy market.

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[12] WRA at 26.
[13] *Id* at 3.

Despite recent failures, ERCOT's energy-only market has provided Texans with affordable and reliable electricity for decades. This market, unique in the country, has attracted billions of dollars in investment due to low barriers to entry, healthy competition, and transparent price signals. The market is supported by solid transmission infrastructure that is growing and improving at a time when other regions are marred by stagnation in transmission planning and development.

Nonetheless, Winter Storm Uri revealed that the Texas energy-only market urgently needs improvements. In Uri's aftermath, the Commission and ERCOT adopted a number of new measures as part of the first phase of reforms. Many of these have already been successful at improving reliability. ORDC improvements and increases in ERCOT Contingency Reserve Service (ECRS) and non-spin reserves are providing more revenue to dispatchable generators. Weatherization and firm fuel service, although largely untested, provide a bulwark against future extreme cold snaps. However, some problems with these reforms remain unresolved. Without sufficiently flexible generation on its system, ERCOT must rely on inflexible generation that has lengthy start-up and minimum run times and must be committed through out-of-market reliability unit commitments (RUCs). Because they occur out-of-market, RUCs degrade the price signals the energy market would otherwise send and prevent needed investment in more flexible generation. Moreover, these operations are requiring older thermal units to run more often, causing wear and tear on these facilities that will likely increase forced outage rates.

As the Commission enters the next phase of further improving the ERCOT grid, it should give earlier reforms time to work (and be improved), while also ensuring that the benefits of Texas energy-only market persist through the next phase. The Commission should be skeptical of capacity market-like solutions given the experience of other regions with similar constructs.

Some RTOs with capacity markets are looking to procure ancillary services to address similar operational problems faced by ERCOT. Experience from these markets indicates that capacity market constructs are not a generic remedy for all reliability problems but rather, operational challenges are often better solved with ancillary service solutions. In the ISO New England (ISO-NE) region, for example, grid operators face a persistent threat of fuel supply shortages during periods of extreme cold, as Texas experienced in 2021. And, as in Texas, renewables are quickly outstripping conventional thermal generation in the ISO-NE region. After multiple iterations of measures to establish performance incentives and penalties[14] and manage the retirement of thermal resources through the Competitive Auctions with Sponsored Policy Resources (CASPR) program, ISO-NE ultimately sought to implement new ancillary service products to manage operational reliability. [15] In PJM, grid operators face a similar threat of weather-correlated outages of PJM's existing thermal fleet while having to manage a large influx of new renewable resources. PJM operates the largest capacity market in the country but does not rely on its capacity market to procure operational flexibility. PJM's *Renewable Integration Study* reaffirmed the need for operational flexibility to address the rise in uncertainty, as the study found the system would face 50% steeper net-load ramping periods, frequent dispatch of generators to their economic minimum, and lower capacity factors for thermal resources.[16] PJM's subsequent study, *Emerging Characteristics of a Decarbonizing Grid*, highlighted the need for increased operational flexibility

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[14] ISO-NE, Market Rule 1 Section 13.7.2.1, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.
[15] *ISO-NE*, 173 FERC ¶ 61,106 (2020).
[16] Energy Transition in PJM: Frameworks for Analysis, 2 (Dec. 15, 2021), *available at:* https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211215-energy-transition-in-pjm-frameworks-for-analysis.ashx (RIS 2021).

due to the variability of intermittent generation.[17] These studies indicate that PJM will reform and expand ancillary service products that would enhance ramping and reserves to complement growing variable renewable generation.[18]

Solutions to Texas grid reliability problems can be found without establishing a capacity market or a capacity market-like solutions. The solution that the Commission adopts in this proceeding should preserve the benefits of Texas's energy-only market: competition, transparency, and low consumer costs. The solution should also be narrowly tailored to solve the specific reliability problem of the reserve shortage period and should be easily implemented to provide consumers with reliable and affordable energy.

d. The Commission should consider adopting a new ancillary service product to address operational reliability and a targeted backstop reliability service or bridge mechanism if it finds it necessary to address resource adequacy in the short-term.

Based on its analysis of the current state of the energy market, the IMM recommends an ancillary service product procured day-ahead and deployed during constrained real-time conditions to address supply uncertainty.[19] This product would increase reliability by accurately valuing the flexible generating resources that could be dispatched in real time, and thus providing signals for investment into more flexible dispatchable generation. Such a construct is also aligned with SB3, which requires the Commission to ensure ERCOT determine and procure the necessary

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[17] Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, 5 (May 17,2022), *available at*: https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220517-energy-transition-in-pjm-emerging-characteristics-of-a-decarbonizing-grid-white-paper-final.ashx (RIS 2022).

[18] *See e.g., id* at 4, 5.

[19] Independent Market Monitor for ERCOT, *2021 State of the Market Report for the ERCOT Electricity Markets* (May 2022) at 23, *available at*: https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-the-Market-Report.pdf (IMM State of the Market Report).

quantity of ancillary or reliability services to ensure reliability during shortage periods.[20] The E3 Report did not evaluate this construct.

Pine Gate encourages the Commission to consider the comments submitted by the DRRS Coalition.[21] The DRRS Coalition proposes a new four-hour reserve product, Dispatchable Reliability Reserve Service (DRRS), that would provide a market mechanism to address ERCOT's real-time operational uncertainty problem. As described above, this operational uncertainty is caused by issues that typically have a two to four-hour duration: unexpected demand shifts, variable renewable generation, insufficient ramp capability, and unexpected thermal outages. The DRRS product could improve reliability by providing ERCOT a tool to address these issues. Here, the experience in other markets may again be instructive. PJM recently analyzed various scenarios of renewable penetration and their findings show four-hour energy storage and hybrid resources as a promising potential solution to reliability concerns. Their analysis indicated that storage resources would provide up to 80% of reserves in the ancillary service market and complemented all generation portfolios studied in terms of resource adequacy.[22]

Because the product has a limited time duration and a transparent market price, it would avoid disrupting the existing energy market on which generators and investors currently rely to make business decisions in Texas. As a backstop measure, the DRRS Coalition also proposes an interim transition mechanism that would utilize ERCOT's existing reliability must-run (RMR) to manage retirements on a temporary basis if they present a problem for reliability.

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[20] Texas State Senate, 87th Legislature 2021-2022, Texas Senate Bill 3, *available at:* https://legiscan.com/TX/bill/SB3/2021 .

[21] Shell Energy North America, DRRS Coalition Comments (Dec. 15, 2022), Case No. 54335-105, available at https://interchange.puc.texas.gov/search/documents/?controlNumber=54335&itemNumber=105 .

[22] RIS 2022 at 4.

IV. Response to Commission Questions

Pine Gate generally supports the comments filed by the DRRS Coalition, Texas Solar Power Association (TSPA) and Solar Energy Industries Association (SEIA) (Solar Associations), and the Advanced Power Alliance (APA) and American Clean Power Association (ACP). Below, Pine Gate responds to certain of the Commission questions where Pine Gate wishes to supplement the responses made by those groups.

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?

Many design details will need to be developed and finalized before the PCM design can be implemented in ERCOT. The fact that the PCM design is entirely novel will require the Commission to develop this design without reference to the experience in other markets or regions. While this is not an insurmountable obstacle, it will require a significant amount of time for analysis and feedback on the framework of the design and further analysis, feedback, and decision-making before final implementation. According to E3's own assessment, the PCM will require two-to-four years to develop, several additional years to implement, and only then will the market begin to respond.[23] If the Commission seeks to implement a design that addresses the reliability challenges that ERCOT faces today, the PCM would not be the best choice because it would not be implemented until many years in the future when the ERCOT grid may look very different than it does today.

In addition, the lack of precedent for the PCM compounds the uncertainty already inherent in the market design's approach to setting performance credit hours. Before building new capacity, project developers must secure financing from investors. These investors will look at potential

[23] E3 Report at 91.

future revenue streams when making decisions on whether to finance a particular project. Not all future revenue streams are treated equally; revenue streams that are uncertain are discounted at a higher rate than revenues that are certain. The fact that no one knows how the market participants will behave under a PCM construct will add to the uncertainty of future performance credit hours, which may dampen the signal to invest in new generation that the PCM is intended to send.

2. Would the PCM design incentivize generation performance, retention, and market entry consistent with the Legislature's and the commission's goal to meet demand during times of net peak load and extreme power consumption conditions? Why or why not?

As discussed above, ERCOT's existing energy-only market already attracts significant investment in new dispatchable generation and provides sufficient revenues to retain existing dispatchable capacity. Recent changes to the ORDC, ancillary services products, and ERCOT's conservative operations have provided even more revenue opportunities for dispatchable generation. While the PCM design would provide additional revenue streams, E3 has not demonstrated that those streams are needed to attract new capacity or improve reliability. In addition, as discussed above, the PCM's uncertainty would undermine its ability to incentivize market entry.

For these reasons, Pine Gate does not recommend the Commission adopt the PCM design at this time. However, if the Commission chooses to proceed with adopting this design, Pine Gate urges the Commission to adopt the improvements recommended by the Solar Associations and APA and ACP. In particular, Pine Gate urges the Commission to use ERCOT's existing ORDC to deliver, as much as possible, the Commission's desired reliability standard on its own. This will help ensure the PCM has minimal impact on the existing energy and ancillary services markets.

The Commission could, for example, target the PCM design so that the PCM market does not exceed 10% of the combined energy, ancillary services, and PCM markets.

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 goals expressed in Question 2, i.e., to meet demand during times of net peak load and extreme power consumption conditions, need to be more clearly defined as Pine Gate explains in its comments above. Pine Gate notes that different reliability metrics serve different purposes. While the industry widely uses the one day in ten years LOLE standard, the standard has lost some of its usefulness as the grid has evolved. Whereas LOLE helps identify the amount of capacity needed to meet a given target, EUE can identify the amount of energy needed at specific times. A recent study performed by Southwest Power Pool showed that under certain conditions, the number of outages (i.e., LOLE) could remain low even as the magnitude of those outages (i.e., EUE) increased exponentially, concluding that the one day in ten years metric might not be appropriate to apply to a system with a high penetration of renewables.[24] To further understand the problem with relying exclusively on LOLE, the Commission should consider that ERCOT expected a reserve margin of 16.2% immediately prior to Winter Storm Uri, but, on February 15,

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[24] Southwest Power Pool, *Expected Unserved Energy (EUE),* November SAWG Meeting, available at https://spp.org/Documents/68194/sawg%20agenda%20&%20background%20materials%20220221109-10.zip.

2021, experienced a -21.1% reserve margin instead.[25] Pine Gate urges the Commission to carefully consider a variety of metrics rather than adopting and relying upon a single metric.

The Commission should also consider other metrics besides LOLE and EUE including the economically optimal reserve margin as described by the Brattle Group and supported in the comments of the Solar Associations comments in this docket. According to the Brattle Group, the economically optimal reserve margin minimizes total system costs by weighing: (1) increasing capital costs of building more generation plants to achieve the higher reserve margins, against (2) decreasing scarcity-event-related costs as higher reserve margins help to avoid load shedding, reserve shortages, demand-response calls, and other emergency event costs.[26]

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?

It is unclear whether the PCM design, absent further refinement, would provide sufficient revenue to incentivize new generation. Project financing requires revenue certainty. Investors typically discount future revenues streams by substantial amount (50% or more) based on how much uncertainty they face. If revenues are uncertain, project developers will not be able to attract sufficient capital to build a project. The uncertainty of the PCM revenue stream would also result in a significant coverage ratio of that revenue that would have to be paid by the developer. While the revenue awarded to generators running during the 30

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[25] Patrick Milligin, *Winter Storms Wreak Havoc on ERCOT Grid*, ICF Insights / Energy, (Feb. 23, 2021), available at https://www.icf.com/insights/energy/winter-storms-ercot-grid .

[26] The Brattle Group, *Estimating the Economically Optimal Reserve Margin in ERCOT* (Jan. 31, 2014), available at https://www.brattle.com/wp-content/uploads/2017/10/7641_estimating_the_economically_optimal_reserve_margin_in_ercot.pdf .

hours of lowest reserve would be significant, investors will drastically discount that revenue stream because they are not certain that the generator will be earning those credits.

8. If the commission adopts a market design with a multi-year implementation timeline, is there a need for a short-term "bridge" product or service, like the Backstop Reliability Service, to maintain system reliability equivalent to a 1-in-10 LOLE or another reliability standard? If so, what product or service should be considered?

As discussed above, the ERCOT market provides sufficient revenue to incentivize investment in new capacity. However, the ERCOT market faces several operational challenges that could be addressed by adopting a new reserve product, the DRRS, which could be implemented much more quickly than the multi-year time horizon required for more complex market design changes like the PCM. Therefore, Pine Gate does not believe that a bridge product is needed. However, if the Commission concludes that there is insufficient capacity on an interim basis, then Pine Gate believes that the RMR construct described by the DRRS Coalition is preferable the BRS construct modeled by E3 because the DRRS RMR proposal would be more limited and temporary, and thus have a more limited impact on the ERCOT market.

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?

Pine Gate supports the comments made by APA and ACP regarding the DEC design and reiterates that the dispatchable energy credit design should be evaluated with eligibility criteria that reflect all of the dispatchable resources on the system include batteries. Pine Gate also adds that the E3

Report demonstrated a high loss of load probability on some winter mornings and therefore, the eligibility criteria that limits DECs the evenings is overly restrictive.[27]

Respectfully submitted,

_/s/ Frank Swigonski_____

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[27] E3 Report at 126.