Filing Receipt

Received - 2022-12-15 11:16:09 AM
Control Number - 54335
ItemNumber - 79

PROJECT NO. 54335

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

COMMENTS OF
SOUTHERN POWER COMPANY

Southern Power Company ("SPC") respectfully submits these comments in response to the Public Utility Commission of Texas ("Commission") Staff's ("Staff") questions regarding the Energy and Environmental Economics Assessment of Market Reform Options to Enhance Reliability of the ERCOT System report ("E3 report"). SPC, a subsidiary of Southern Company, is a leading wholesale energy provider meeting the electricity needs of municipalities, electric cooperatives, investor-owned utilities, and commercial and industrial customers. SPC and its subsidiaries own 55 facilities nationally—including natural gas (61.1% of generating capacity), wind (17.5%), solar (19.8%), battery storage and fuel cells (1.5%)—operating or under construction in 14 states with more than 12,500 megawatts ("MW") of generating capacity. SPC owns four wind and three solar generation facilities totaling approximately 1,100 MW of generating capacity in the Electric Reliability Council of Texas ("ERCOT") region. SPC has a unique perspective as a competitive generation company owning and operating a diverse fleet of generating facilities in multiple power markets across the country and as an affiliate of three retail electric operating companies in the Southeast.[1]

I. INTRODUCTION

SPC commends the Commission, the Legislature, and ERCOT stakeholders for the attention that has been devoted to improving the financial incentives provided for investment in new dispatchable resources and in encouraging the availability of dispatchable resources in times of scarcity. Like ERCOT, other Regional Transmission Organizations ("RTOs") have identified the need to ensure the availability of adequate dispatchable generation. Unfortunately, no market has found a "silver bullet" that simultaneously ensures timely investment in particular resources

[1] Alabama Power, Georgia Power, and Mississippi Power are vertically integrated electric utilities regulated by their respective state utility commissions tasked with ensuring reliable, clean, and cost-effective electric service for their citizens. Southern Company has a combined 42,000 MW of generating capacity, including natural gas, coal, nuclear, hydroelectric, wind, solar, battery storage, and fuel cells. Southern Company's 2020 total energy mix was: 51% gas, 17% coal, 17% nuclear, and 15% renewables and other.

and that mitigates resource scarcity on an interval-to-interval basis. That said, certain high-level concepts have emerged across markets. First, market designs that enable generators and load-serving entities ("LSEs") to easily enter long-term bilateral agreements can facilitate long-term investments in generating plants in addition to hedging risk for both parties. Second, day-to-day operational needs may be solved by different tools than long-term resource planning. For example, the Performance Credit Mechanism ("PCM") and the Independent Market Monitor's ("IMM's") proposed uncertainty product[2] focus on ensuring that committed resources are available in hours of scarcity. These tools, depending on implementation details, may need to be altered and/or layered with other tools to ensure the promotion of long-term investment in resource capacity that might be used in future non-triggered hours.

The ability to achieve longer-term revenue certainty is crucial for resource owners to manage the risk associated with incurring significant, long-term capital investments. SPC believes that LSE Obligations have market design elements (e.g., adoption of a reliability standard, incentive for LSEs to plan over a meaningful time horizon, ability for generation resources to sell attributes that meet LSEs' obligations, technology neutrality, etc.) that best provide appropriate long-term incentives for building new dispatchable resources in Texas. Ancillary services are a set of operational tools that support the reliable operation of the grid; however, ancillary services are not the appropriate mechanism to incentivize significant, long-term capital investments. As an owner of natural gas generating resources located in the multiple Southeastern states, SPC finds that sole reliance on volatile energy and ancillary services revenues is insufficient to justify the significant investment necessary to build a new dispatchable resource. While SPC believes that the LSE Reliability Obligation and Forward Reliability Market are the most proven solutions for long-term reliability planning considered in the E3 report, it recognizes that the PUCT is focusing its support on the PCM. SPC believes that PCM has some features that could incentivize desired performance from generation resources; however, the lack of design details makes it difficult to accurately assess, and SPC recommends that such design elements are further defined to confirm that PCM would achieve the Legislature's and Commission's desired goals. Thus, SPC is

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[2] SPC supported the adoption of an uncertainty product in comments filed in Project 52373 and believes it does a better job of addressing net load uncertainty than the overreliance of Reliability Unit Commitment and the over-procurement of Non-Spin reserves. For further details on the IMM's proposal, *see* 2021 State of the Market Report for the ERCOT Electricity Markets at xviii, available at https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-the-Market-Report.pdf

concerned that near-term adoption of the PCM may introduce regulatory uncertainty. SPC encourages the Commission to engage with stakeholders to more fully define crucial elements of the PCM before adopting such a proposal.

Regardless of the tool that is adopted to address the need to incentivize long-term capital investment in dispatchable resources, the usefulness of the tool largely depends on the details of implementation, underlying assumptions and other specifics. These implementation details can also materially affect the costs of one tool versus another. This is why, for example, it is possible for E3, using one set of assumptions about the PCM program's details can estimate that it might cost ERCOT consumers approximately $460 million per year and others, using different assumptions can reach estimates that are materially higher. Because the PCM has not been used by any other wholesale market in the country, assumptions about the design can be even more varied. However, this variation in plausible models creates uncertainty for would-be project developers and investors. ERCOT needs to incentivize a broad range of potential investors, ideally stable and creditworthy generation owners. Uncertainty can be fatal to investment in expensive, long-duration projects like power plants.

The Commission can mitigate the regulatory uncertainty problem by: (1) using tools that have been implemented in other RTOs, (2) providing as much detail as possible regarding whatever tools are adopted, and (3) adopting a solution that is agreeable to a broad consensus of decision makers as doing so will increase the likelihood that the adopted solution will remain in place for a long time. No option, in its current form, in the E3 report is fully capable of meeting these goals in the near future. As emphasized throughout the E3 report, significant stakeholder engagement is necessary for thoughtfully and effectively designing and implementing the details of any selected option. Stakeholder engagement beyond this set of comments should be utilized before any design is selected.

II. RESPONSE TO STAFF 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?

Obstacles will exist with the implementation of any market tool, and PCM is no different in this regard; however, the fact that E3 could not identify any market that has adopted the PCM does present additional obstacles to its successful implementation and achievement of desired goals—e.g., ensuring effective operations in the ERCOT market and effectively promoting investment in dispatchable generation.

ERCOT's experience implementing the nodal market, which had meaningful precedent in markets around the world, spotlights the risk that implementation of the PCM may be slow, and its early use may encounter unanticipated events. The nodal market emulated other markets in the United States, relied on existing computer coding from those markets, and still had a multi-year delay. It took about seven years from the date of the Commission order to implement the nodal market to its first operation in ERCOT.[3] By comparison, the PCM has nothing to emulate and cannot borrow existing computer coding. This increases the risk of a long implementation timeline. It also increases the risk of bugs and glitches in the implementation of the PCM as ERCOT would be the first trial of the computing coding to effectuate it. There is no way to predict whether such bugs and glitches might occur, but if they do, they can be enormously problematic.

Similarly, when ERCOT first opened the competitive retail market, the systems suffered significant problems. There were prolonged periods where manual workarounds were needed and there were severe limitations on the number of customer switches submitted to ERCOT. "Collaboration among stakeholders was essential to the resolution of many difficult technical and operational issues. Not all issues were resolved prior to full market opening and market gaps remain."[4] Operational and implementation risks can add uncertainty and potential delay that can ripple into delays in private investment. Existing designs, whether in ERCOT or elsewhere, should have less operational and implementation risk than a heretofore unused design.

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?**

SPC believes that PCM has some features that could incentivize desired performance from generation resources; however, the lack of design details makes it difficult to accurately assess, and SPC recommends that such design elements are further defined to confirm that PCM would achieve the Legislature's and Commission's desired goals. As noted in Staff's Question 1, there is no precedent for the PCM. Consequently, especially for market entry, lenders and investors

[3] 2011 Report on the Scope of Competition in Electricity Markets at 24-25, available at https://ftp.puc.texas.gov/public/puct-info/industry/electric/reports/scope/2011/2011scope_elec.pdf

[4] 2003 Report on the Scope of Competition in Electricity Markets at 71, available at https://ftp.puc.texas.gov/public/puct-info/industry/electric/reports/scope/2003/2003scope_elec.pdf

have no experience financing new power plants in markets with a PCM. Likewise, essential details regarding the PCM have not been addressed and these details are likely critical to determine whether the PCM can incentivize the desired resources. For example, the E3 report is silent regarding the potential treatment of force majeure and fuel interruptions caused by third parties. Risk averse power plant owners may be less likely to participate in a PCM market if they must indemnify the market and find replacement resources in the event that a hurricane strikes their plant, a pipeline fails to deliver contracted fuel for whatever reason, etc. However, to the extent that power plants are allowed force majeure-like exemptions from PCM bids, then the PCM market offers the same incentive as the existing scarcity market, *i.e.*, higher revenues for operating in periods of relative resource scarcity.

Similarly, the E3 report seems to assume that the PCM market would not distinguish resources based on location, but this is uncertain. In operation, location and deliverability are fundamental in determining scarcity. That is exactly why the Commission approved the nodal market almost two decades ago. It is also why the existing ERCOT Protocols allow for the contracting of Reliability Must Run ("RMR") units in transmission-constrained areas. In actuality, PCM-participating plants are not always equal. A plant in a constrained area or that is particularly quick ramping likely will help the system more than a slow-ramping plant. Further, with limited exceptions, periods of extreme power consumption are localized to particular parts of ERCOT as opposed to being system-wide. Additionally, a slow ramping plant that otherwise is eligible for PCM credits may make operations more difficult in the hours before and after the PCM-triggered hours because its slow ramp will squeeze quicker, more agile resources out of the energy bid stack. The E3 report assumes that all generators can bid into the PCM market without regard for ripple effects. If the PCM market were implemented to grant credits to these slow ramping plants, it could serve as a disincentive at some level for new investment in quick start and fast ramping resources. In such a scenario, in order to receive the PCM credit for being available at the right time, the slow ramping resource will bid extremely low prices so it can guarantee dispatch—without regard to heat rate, fuel cost, etc. When these slow ramping plants run, they displace other units, including newer, more nimble plants that may actually be more cost-effective in the operating interval. These types of details are essential to assessing whether the PCM might incentivize, discourage, or simply not affect the addition and retention of resources available in periods of extreme power consumption.

The PCM is designed to make payments to generators both unknown in amount and payable long after the operating day. This lack of revenue certainty and likely inter-year revenue volatility will likely not provide the predictable revenues needed to incentivize new market entry from a broad range of stable and creditworthy investors for new dispatchable resources. As described above, SPC has found as a broader matter, whether in ERCOT or elsewhere, that large capital investments benefit from predictable, preferably steady revenue streams. The revenues from the PCM are neither unless a secondary forward market emerges. It is currently unclear whether such a forward market can effectively result from the PCM.

While the E3 report contemplates a voluntary forward market being established, it does not address how and why parties could effectively use the forward market to hedge their positions in a significant way. For LSEs, the PCM creates significant timing and forecasting challenges that could limit their ability to participate in a forward market. The triggered hours are unknown until well after, potentially months, after they occur. Consequently, an LSE cannot anticipate how much load it will be serving at the specific time that a PCM triggered hour occurs. This affects the quantity that might be procured in the forward market. It also effectively makes the forward market sell a call option for PCM credits for many hours in the year. The likely scope of a forward bilateral transaction would require over-procurement when compared to paying for the triggered hours retroactively. This could make a forward market a less cost-effective option for LSEs, and without willing buyers, leaves generators without the predictable revenues that a forward market could provide.

The PCM includes a penalty risk for generators. Even dispatchable generators with high availability rates still experience unplanned outages. Existing dispatchable generators have identified an increasing risk of unplanned outages resulting from increasing regulatory interference in scheduling planned outages. Increased regulatory command and control of planned outage schedules has a direct effect on the risk of a generator incurring an unplanned outage penalty because the generator's ability to plan for scarcity hours is impeded, and as the characteristics of ERCOT's supply and demand continue evolving in the future, there is risk that thirty scarcity hours will become increasingly difficult to predict.

For existing dispatchable generators with high forced outage rates, bidding capacity into the PCM creates an even greater risk. The PCM would make the generator financially responsible for outages; so, plants prone to unplanned outages incur higher risk than others. Consequently, it is unlikely that revenues from the PCM would help retain these likely older thermal units as they are less likely to bid.

The PCM as crafted in the E3 report does not actually trigger for scarcity but triggers for *relative* scarcity when compared against the 8,730 hours each year that do not trigger PCM credits. In theory, the PCM credits could be paid in an environment with large reserve margins. While in the short run large reserve margins are unlikely, whatever design(s) is chosen should be intended for the long-term when large reserve margins are possible. The PCM nonetheless would pay credits to well-timed capacity availability without accounting for net peak margin or other signs of true operational scarcity. In this regard, there is a logical disconnect between the PCM and operational need.

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)?**

SPC believes that adopting a reliability standard is a crucial first step in defining the desired reliability goals that the Commission wants to achieve. SPC recommends utilizing the 1-in-10 LOLE threshold, which is a well-established industry planning standard, as a reliability floor. However, LOLE by itself does not paint a full picture of resource adequacy health because it only describes the frequency of a loss of load event but not the magnitude (*i.e.*, the LOLE standard measures a 10 MWh loss of load event equally to a 1,000 MWh loss of load event).[5] Therefore, SPC recommends pairing the 1-in-10 LOLE standard with an EUE metric, which describes the expected unserved energy during load shed events. The two reliability standards complement each other by measuring the impact of load shed events differently, one focused on frequency and the other on magnitude. ERCOT should conduct detailed analysis to help the Commission determine an appropriate EUE standard, which should balance sufficient reliability and expected cost to ensure such reliability. A starting point in this analysis should be to determine the economic value of lost load ("VOLL"). Once established, the VOLL can be used as an effective economic metric for cost-benefit analysis of optimal reserve margin calculations. SPC also recommends studying

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[5] This is similar logic as why the Commission measures *both* System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") for assessing reliability and continuity of service on distribution systems. *See* 16 TAC § 25.52.

and updating VOLL on a regular basis, perhaps every 3 to 5 years to maintain accuracy. Working in concert, these metrics will allow the market to respond and achieve the desired reliability goals from both a frequency ("LOLE") and duration ("EUE") of event perspective.

4. **The E3 report examines 30 hours of highest reliability risk over a year. Is 30 the appropriate number of hours for this purpose? Should the reliability risk focus on a different measure?**

The 30-hour size seems arbitrary and to our knowledge is not a threshold used for resource planning in other regions. There is no connection between the 30-hour threshold and the traditional 1-in-10 LOLE. Even E3 in its recent technical conference recognized that the 30-hour threshold is fluid and could be set at a different level. However, if the PCM were adopted, the hour threshold should not be changed often. Frequent resetting, for example, could materially impair the ability for loads and resources to enter longer term bilateral agreements because it makes the product within the longer-term agreement unpredictably change.

SPC recommends that the Commission, ERCOT, and interested parties examine historic, multi-year datasets to identify and declare hours of the day for critical seasons instead of using a retroactively-set 30 hours per year set for assigning revenues and costs. Doing so would significantly help predictability for market participants and therefore would make forward market transactions significantly more efficient. Consequently, it would mitigate the risk that PCM charges could cause volatility in retail rates.

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?**

SPC recommends using seasonal periods for assessing reliability risk. Seasonal intervals will increase the confidence of generators to bid in larger portions of their capacity and improves an LSE's ability to anticipate the amount of its load-ratio share. Additionally, a seasonal assessment strikes an appropriate balance between simplicity and accuracy in modeling electric grid reliability risks that are unique to seasonal system conditions. A seasonal view would allow the Commission to assess various factors (*e.g.*, changing resource mix, increasing electric demand, flexible load participation, transmission transfer capability, resource forced outage risk, fuel supply during extreme winter conditions, etc.) that will impact the ability to serve load differently throughout the year. It is critical that the Commission consider these various factors and plan the system accordingly to ensure reliable outcomes.

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?**

Possibly, although it is unclear how generators would elect to participate given non-performance risk during the defined high-risk hours. There is a significant potential that generators will materially underestimate their expected availability in forward market offers in order to avoid potentially costly failures to perform that manifest as charges in the residual settlement process. If this underestimation holds true, then the economic incentives to improve availability come not from the PCM but from the already existing sources of revenue from selling electricity and ancillary services.

Last summer and even Winter Storm Uri show that resource availability rates in ERCOT have not been a major problem for the grid. Uri showed significant problems with real-time physical fuel supply but this problem is not resolved by the addition of the PCM. More recently, there have been increased challenges in the delivery of coal from the Powder River Basin. To the extent that a coal-fired plant worries about maintaining its coal stack, it may be hesitant to offer into a forward market and then to risk costs in the residual market caused by coal delivery issues outside of its control. Again, existing economic incentives encourage reliability as manifested in the rather low outage rates in ERCOT plants in the past few years.

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

While a centrally cleared market provides a solid framework for market power risk monitoring and mitigation, it does not, by itself, sufficiently mitigate market power risk. Likewise, compelling each generator to make an offer does not resolve the market power risk. As can be seen in bidding in ERCOT today, generators that do not want to be dispatched offer at extremely high prices. The proposed PCM would allow this as well. Thus, the use of a centrally cleared market should not be the only tool used to mitigate market power abuse.

Before adopting any market design, the Commission and the IMM should assess the market share of each resource owner not only in generic generation capacity but also in the capacity reasonably capable of participating in a particular market or product. The PCM seems designed with the expectation that intermittent generation will offer little or no capacity into the PCM. This means that the traditional analysis of capacity market share does not match the PCM. A large market share by itself does not mean that market power is being abused, but it can identify which market participants have the means to affect the supply and price in forward offers. Especially with an untested market design, the risk of market manipulation may be acute and ultimately could unnecessarily increase the costs borne by consumers.

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?**

A short-term "bridge" product should not be adopted. Adding a "bridge" by definition will not offer economic incentives for new dispatchable resources because the bridge should not exist for the preponderance of the economic life of the new dispatchable resource. Further, adding the implementation of a "bridge" product while simultaneously trying to implement another product only increases the risk of implementation delays or other problems. A "bridge" of indeterminate duration also would add another layer of regulatory risk for all market participants.

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?**

There may be the need to delay approval of an ultimate solution in order to attain needed information, to further debate the merits of the various plans, and to address underlying details, but a "bridge" should not be the sole basis for a delay. The proposal that ERCOT enter a multi-year commitment to buy 5,630 MW of ancillary services has the same effect for the selling generator as when a hedging LSE procures the same. In application, it is not clear how ERCOT would distinguish buying from a QSE with a long-term contractual right to ancillary services from a power plant that might retire absent entering a long-term contract. Moreover, if QSEs/power marketers forecast future scarcity in the ancillary services market, they already have incentive to enter long-term contracts with generators, and these long-term contracts would provide comparable revenue certainty to the proposed procurement of additional ancillary services by ERCOT.

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

It is impossible to know what impact the PCM might have on consumer costs until details regarding implementation are established. Third party estimates regarding the cost of the PCM seem to vary wildly. This does not necessarily mean that any forecast is flawed or that its arithmetic is incorrect. The variation highlights the amount of uncertainty in the details that currently exists in regard to the PCM. One cannot make assumptions based on its implementation in other markets because no such data exists. The inability to accurately estimate the consumer costs of the PCM also means that it is difficult, if not impossible, to opine on whether it can pass a cost-benefit test. Ultimately, the cost of the PCM will be borne by Texas consumers. This underscores the need for additional deliberation before any market tool is adopted.

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.**

A "bridge" product cannot send meaningful market signals for investment in new dispatchable generation unless the bridge lasts for a long period of time. In order for the "bridge" to affect the investment incentives for a new generation resource, that bridge must be expected to affect the economics of that project. In other words, it ceases serving as a bridge and becomes a long-term device.

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?**

The DEC should not be applied in combination with the PCM as they would double count dispatchable characteristics. Any market design approved by the Commission should be technology neutral. First, technologies change over time—sometimes quickly. This means that a technology-based rule is likely to focus on outmoded technologies in the future. Secondly, the fundamental goals of a resilient and reliable grid capable of delivery to end-use customers can be achieved by a multitude of different technologies. Southern Company has invested considerably in new nuclear capacity and anticipates the new capacity serving Georgia well for decades to come. Nuclear capacity is part of an energy strategy to develop and maintain a diversified energy portfolio which is essential to maintaining reliability and affordability. A diversified portfolio of technologies shaped by competitive wholesale forces in Texas can reliably provide service in a cost-efficient manner.

SPC opposes the current DEC qualification proposal that only allows new generation resources to participate, as this is inherently discriminatory and treats resources providing an equivalent service differently based on the timing of resources' commencement of commercial operations. As proposed, DECs will subsidize a particular subset of new generators and make existing DEC-ineligible generators with the same desired operational capabilities less economic, possibly even forcing their retirement over the long-term.

III. CONCLUSION

SPC greatly appreciates the opportunity to provide these comments as ERCOT prepares for the future. The problems facing ERCOT are not unique; RTOs across the nation are experiencing similar challenges and are grappling for solutions in much the same way. Whatever solutions ultimately may be adopted need to be well-vetted, generally accepted by market participants, and capable of fitting into a model with robust forward markets. This goal, while daunting, must be achieved. Robust discourse among the Commission, the Legislature, market participants, and would-be investors are essential to the development of the tools needed for long-term reliability, resiliency, and operational efficiency.

Dated: December 15, 2022

Respectfully submitted,

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

EXECUTIVE SUMMARY OF COMMENTS OF
SOUTHERN POWER COMPANY

- LSE Obligation market designs have elements that best provide long-term incentives for building new dispatchable resources in Texas.
- Ancillary services are a set of operational tools that support the reliable operation of the grid; however, they are not the appropriate mechanism to incentivize significant, long-term capital investments.
- SPC encourages the Commission to engage with stakeholders to define important elements of the PCM more fully before adopting such a proposal. Near-term adoption of the PCM may introduce regulatory uncertainty. Whatever solutions are ultimately adopted need to be well-vetted, generally accepted by market participants, and capable of fitting into a model with robust forward markets.
- ERCOT should use a combination of LOLE and EUE metrics to ensure reliability against both the frequency and magnitude of loss of load events. ERCOT should also quantify the value of lost load to improve analysis of optimal economic reserve margins and understand the cost-benefit tradeoffs as the system evolves in the future.
- Bridge products should not be adopted due to their temporary nature and potential to interfere with implementation of longer-term market design methodologies.
- Any market design approved by the Commission should be technology neutral and open to all technologies that can satisfy technical requirements.