**PUC PROJECT NO. 58198**

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| **RULEMAKING TO IMPLEMENT FIRMING RELIABILITY REQUIREMENTS FOR ELECTRIC GENERATING FACILITIES IN THE ERCOT REGION UNDER PURA §39.1592** | **§**  **§**  **§**  **§** | **PUBLIC UTILITY COMMISSION**  **OF TEXAS** |

TCPA’s COMMENTS ON Proposal for publication (pfp) of new §25.65

Texas Competitive Power Advocates (“TCPA”) appreciates the opportunity to provide comments and recommended redlines to the proposed new §25.65 relating to Firming Reliability Requirements for Electric Generating Facilities in the ERCOT Region. TCPA represents thirteen companies in the ERCOT competitive market that are independent generation resource owners, independent power marketers, or both. The generation assets in our companies’ portfolios are primarily thermal dispatchable generation comprised of natural gas, nuclear, coal, and some energy storage resources. Our members own approximately 56,000 megawatts (MW) of generation capacity in ERCOT and represent approximately half of the MWs under development in the Texas Energy Fund (“TEF”). In addition, several TCPA member companies are also building new thermal generation resources in ERCOT through conventional market financing, outside of the TEF.

During the 2023 Legislative Session, the provisions enacted in HB 1500 that are the subject of this rulemaking were also contained in SB 7 and discussed in multiple public meetings. In each discussion, whether in committee or on the floor of the House or Senate, policymakers made it abundantly clear that the intent of the legislation was to require new renewable resources to contribute to available capacity during times of low reserves and support dispatchable thermal resources that provide reliability and address operational needs. TCPA’s comments and recommended changes to the PfP below are designed to more closely reflect the clear legislative intent of the firming statute. Specifically, the firming statute was enacted to ensure that the state attracts and retains thermal dispatchable resources in ERCOT. The Legislature has further indicated a desire to avoid negatively impacting thermal generation resources through the firming requirements, which would thwart the overall intent delineated by the Legislature and the Governor through multiple pieces of new legislation enacted over the three sessions from 2021 through 2025 that seek to increase the investment in natural gas generation to serve ERCOT.

As referenced in TCPA initial comments in this project filed on June 27, 2025, the collective message sent by the Legislature and the Governor through SB 3 (87th Regular Session) which required the Public Utility Commission of Texas (“Commission”) and ERCOT to establish a reliability standard for the ERCOT region, HB 1500 (88th Regular Session) which required the development of a dispatchable reliability reserve service (“DRRS”) with the eligibility criteria clearly indicating a desire to maintain and attract dispatchable resources that are capable of operating for a minimum of four hours at a time or longer if ERCOT deems it necessary, SB 2627 (88th Regular Session) which provides subsidized loans and completion bonus grants for development of up to 10,000 MW of new dispatchable thermal generation in ERCOT to help offset the impacts of federal renewable subsidies, and HB 14 (89th Regular Session) which establishes support for developing an advanced nuclear industry in Texas is that policymakers want more thermal dispatchable generation investment in ERCOT-- not less.

While TCPA agrees with the PfP’s definition of “low operation reserve hour” as falling below a physical responsive capability (PRC) of 3,000 megawatts (MW), there are several areas of concern in the PfP for which TCPA offers comments and recommends changes. The four primary areas of concern addressed are: 1. Seasonal Average Generation Capacity, 2. Lack of clarity regarding whether a firming contract can be met with either on-site or off-site resources, 3. Treatment of a co-located generator, and 4. Financial penalties and potential perverse incentives to be avoided. TCPA has no additional comment regarding staff questions regarding PRC or whether the low operation reserve hour should be tied to deployment of or a shortage in aggregate real-time awards relative to the Ancillary Service Plan for ERCOT Contingency Reserve Service (ECRS).

Recommended redlines will follow the comments provided.

**COMMENTS ON APPLICABILITY AND DEFINITIONS**

1. Proposed Subsection (a) - Applicability

HB 1500 was signed into law on June 9, 2023 and written to only apply to generation resources that sign interconnection agreements on or after January 1, 2027 and thus that would not be online until even later (likely mid-2028 at the earliest), which is *five years* after the bill effective date. This substantially delayed effective date was designed to avoid imperiling the financial arrangements of generation resources that were already under development (or in operation) at the time, and to give would-be developers of new generation resources ample notice of the new policy. The delayed effective date demonstrates the legislature’s clear intent to impose the new firming requirements only on resources that sign an *original* standard generation interconnection agreement (SGIA) on or after January 1, 2027.

However, as the Commission and Commission staff are aware, SGIAs (including exhibits) must be amended from time to time to account for equipment repairs or replacements, change in ownership, or even a change to the contact information required for receipt of operational notices. Amended SGIAs are presumably “signed,” but such amendments do not constitute a new “signed” SGIA for purposes HB 1500’s firming policy. If the Legislature intended for SGIA amendments to trigger the firming requirements for existing resources, then it would not have gone to such lengths to shield at the outset not only existing resources, but resources that were merely under development (but would sign their original SGIA prior to the January 1, 2027 implementation date). In other words, if a simple amendment to an SGIA were intended to trigger the firming requirements for an existing resource eventually anyway, then it would not make sense for the Legislature to shield existing resource from the start and the January 1, 2027 date would effectively be read out of the statute.

TCPA believes that Commission staff agrees that amendments to SGIAs should not trigger the firming requirement for resources that are otherwise exempt. TCPA also believes that this was staff’s intent in drafting of 25.65(a)(1), but the section needs clarification to account for SGIA amendments. Therefore, to clearly implement the Legislature’s policy, section 25.65(a)(1) should state:

(a) Applicability. This section applies to an electric generating facility, other than a battery energy storage resource, settlement only generator, or self generator, in the ERCOT region:[[1]](#footnote-2)

(1) for which an original standard generation interconnection agreement is signed on or after January 1, 2027, and that has been in operation for at least one year;

TCPA would also suggest adding a new subsection “25.65(a)(3)” which explicitly states that amendments to SGIAs that were signed before January 1, 2027, do not constitute original SGIAs for purposes of the firming requirements.

With respect to proposed section 25.65(a)(2), TCPA strongly opposes subjecting existing generation resources to the firming requirements simply for adding more megawatts of capacity to the resource. TCPA understands staff’s desire to mitigate the eventual split treatment of generation resources by imposing some limit to the additions that existing resources can make (without being subject to the firming requirements), but this created exception is simply not authorized by the statute.

To the extent that the commission and commission staff disagree with TCPA’s statutory interpretation and intend to move forward with the 50% exception, TCPA requests that 25.65(a)(2) be clarified to state that the original capacity plus an additional 49.99 percent of capacity remains exempt from the firming requirements, and only the new capacity added beyond 49.99 percent is subject to the firming requirements.

In addition, the applicability of the rule to co-located facilities should align with its treatment of private use networks (PUNs), where capacity primarily dedicated to serving load is exempt from firming requirements. A co-located generating facility that provides fifty percent (50%) or more of its nameplate capacity to the host load should be considered primarily dedicated to that load, just as a private use network is recognized as primarily dedicated to serving its load. Like self-generators, co-located generators have operating characteristics that are dependent on the needs of the host load. Co-located generators may export a portion of their output to the grid, but the primary output from these facilities is used to serve the co-located PUN load. Ensuring a technology neutral baseline is essential to avoid putting pressure on thermal resources and to encourage renewable resource owners to increase their firming capabilities. Without that balance, there would be a substantial disincentive to invest in behind-the-meter interconnections, particularly those using thermal generation resources for such investment, which is counter to the overall policy goals aimed at increasing thermal generation in ERCOT. Given the minimal differentiation between co-located generation of this nature and self-generators or PUNs, there is no reasonable argument for including new co-located resources in the firming requirement, and doing so will only discourage new large loads from developing onsite generation at their locations. While there may be different scenarios, PUN and self-generator facilities connect to the grid and operate in similar ways, so they should have the same treatment for exemptions.

B. Proposed Subsection (b) - Definitions

The definition of “high-risk hour” in the PfP does not have a strong relationship to actual system risk. In contrast, ERCOT’s existing analyses in the CDR and the Ancillary Services methodology are intended to manage the grid in an effort to avoid defined and well-known risks. Under the provisions in PURA §39.1592(d)(3), ERCOT is prohibited from imposing penalties during the “hours outside a baseline established by the commission that includes morning and evening ramping period.” This language supports the use of existing risk assessment processes to determine high-risk hours that do not require additional calculations by either staff or stakeholders to validate the results. Put simply, incorporating the upcoming CDR data for peak load hour and net peak load hour or the changes to the ancillary services methodology with the probabilistic framework for the upcoming year would utilize publicly available and well-established tools to help predict when the tightest hours will occur. To determine the net load ramp hours, ERCOT could use the lowest predicted reserve values over each three-month period for the different seasons. If the highest risk hours of net load ramp, based on probabilistic modeling tools ERCOT has developed, are used, the result would not only include more historical hours but also more precisely pinpoint the highest risk hours in any particular season while accounting for the broader factors that impact uncertainty on the ERCOT grid. For example, the annual NERC probabilistic assessment provides a forward-looking analysis of the risk for loss-of-load hours looking ahead at two years and four years. The assessment, conducted by ERCOT and other NERC assessment hours, uses the same probabilistic reliability model, Strategic Energy and Risk Evaluation Model or SERVM, that will be used for the Reliability Assessment required for the Commission’s reliability standard. NERC expanded its reporting requirements, for the 2024 assessment, to provide hourly risk profiles along with the monthly profiles it already required. There’s an example of a heat rate map prepared by PowerGem for last year’s probabilistic assessment with graphical depictions that could clearly show the high-risk hours. Such a tool is already in existence, widely used and allows Commission staff, market participants, and ERCOT to clearly narrow down the high-risk hours that are concerning for the next few years.

Below is an example of the heat rate map referenced above:

A screenshot of a graph

AI-generated content may be incorrect.

TCPA supports the use of PRC below 3,000 MW for defining “low operation reserve hour” so long as the directive to ERCOT remains to operate the grid to avoid watches and the ancillary services methodology is also developed to ensure avoidance of watches.

Tying the definition of “seasonal average generating capacity” to telemetered high sustained limit (HSL) creates a requirement for thermal resources that is much higher than what can be achieved. This will result in significant penalties for the very resources the legislature is seeking to attract and retain and goes against the legislative intent of this statute as well as the multitude of other policies enacted over the past 4 years. Additionally, the use of telemetered HSL will result in intermittent resources having a very low performance requirement. This is counter to the Legislature’s desire for intermittent resources to pay for firming the grid. The increased volatility introduced by these resources, and the financial burden for ensuring dispatchable resources are available during times when intermittent generation is insufficient should fall on those contributing to the volatility. Similarly, by using the three prior years, resources that have performed poorly will actually be rewarded. TCPA recommends the seasonal rated capacity be revised to refer to the Capacity, Demand and Reserve (CDR) “Seasonal Net Max Sustainability Ratings” which relies on both the historical and upcoming seasonal values as the multiplier to set the “seasonal average generating capacity.” The Seasonal Net Max Sustainable Ratings should be reduced to 75% of that value which accounts for different ambient temperature conditions that impact resource output, without relation to actual performance of the resource, and accounts for reasonably expected derates associated with normal resource operations. A 75% value would establish a reasonable seasonal average generating capacity for resources. This is similar to the performance requirements that the Commission adopted for weatherization and is known to all market participants as well as to the PUC and ERCOT. The Staff memo on August 18, 2025, provides greater insight of these issues TCPA is laying out, primarily that the PfP appears focused on uprates at existing facilities, which are quite rare. Substantial capacity additions at an existing facility are more often achieved through adding a new resource unit than through uprates at existing units. It’s also important that uprated facilities are not measured on a lower historical rating that no longer represents an accurate performance capability. More importantly, the recommended approach is consistent with PURA §39.1592(b) which says “…The Commission shall determine the average generation capability based on expected resource availability and seasonal-rated capacity on a standalone basis.” The use of “based on” not “equal to” is a critical distinction and the approach recommended by TCPA accomplishes exactly what the statute contemplates. This recommendation also reflects a reasonable range while accounting for long-duration outages, like electrical equipment or turbine damage. It is important to remember the statutory intent that implementation of firming requirements provide incentives for renewable resources to contribute financially toward development of additional dispatchable generation that is necessary to mitigate volatility that results from the intermittent nature of renewable resources. While telemetered HSL moves up and down based on ambient temperature with greater output in lower temperatures and lower output in higher temperatures, net sustainable max rating for each season is a static number. It also does not account for the fact that solar telemeters zero during nighttime hours nor does it account for combined cycle gas turbine blocks in which units may be offline but are capable of coming on. Similarly, using effective load carrying capability (ELCC) will not accomplish legislative intent since solar goes to zero and the ELCC reflects the capacity of the resource without accounting for volatility for which firming is supposed to be mitigating. Using telemetered HSL creates a benchmark in higher temperatures that is physically impossible for thermal resources to meet and sets a lower average for renewable resources which, collectively, is entirely counter to the intent of the statute. The TCPA-recommended methodology would allow the rule to meet its intention and contribute to reliability. The TCPA-recommended methodology is also very transparent, stable, equitably applied across all technologies and verifiable by all resource owners.

When measuring the performance of a resource relative to its seasonal average generation capability, combined cycle gas turbine (CCGT) resources should be appropriately benchmarked based on their combine cycle configuration of operations during the reliability requirement period. This is important when assessing performance during a lower operating reserve hour that occurs within a high-risk hour. For example, a CCGT that is operating under a 2x1 configuration with a HSL of 550 MW will have a different benchmark than if it is operating under a 1x1 configuration with a HSL of 350 MW.

**RELIABILITY REQUIREMENT**

While PURA §39.1592(b) states, “…The owner or operator must be allowed to meet the performance requirements described by this subsection by supplementing or contracting with on-site or off-site resources, including battery energy storage resources…” the provisions of the PfP in subsection (d)(1) does not make it completely clear if the owner or operator may fulfill its obligations by contracting with existing resources as well as new resources. This should be clarified and would best be handled by requiring the resource owner in its disclosure to ERCOT about the contract (subsection (d)(3)) to identify whether the firming resource is existing or a new resource. The ability to provide firming capacity in the future is an opportunity to not only support the construction of new dispatchable thermal resources but also to retain existing resources that are still needed in ERCOT to maintain reliability. Simply put, specifying the ability for a resource to contract with existing resources to provide firming services may provide a revenue stream that prevents or delays retirements and ensure market viability for these older but critical resources in the ERCOT fleet.

**FINANCIAL PENALTIES AND INCENTIVES**

TCPA has several concerns with the financial penalties and incentives, as well as some unintended perverse incentives, in the PfP. It’s important to note that firming is not a market design tool and does not provide a silver bullet to support dispatchable thermal generation. As constructed in the PfP, the financial penalties may actually cause significant financial harm to thermal dispatchable generation which runs counter to the collective legislative and commission message that ERCOT wants more investment in this type of generation not less. Tying penalties to the value of loss load (VOLL) is a moving target that inject unnecessary financial and regulatory instability into the ERCOT market which is already in a state of flux that is concerning to investors. Penalties should be predictable and high enough to incentivize resources that are volatile to enter into firming contracts but not so onerous that they risk avoiding investment. TCPA recommends the financial penalty be based on a fixed $1,000/MWh price since the value of lost load used to determine the ancillary serve demand curves is different for the various ancillary services after real-time co-optimization is implemented. This penalty amount is high enough to provide incentives to firm but not too high to deter future investment. A fixed price financial penalty will provide long-term certainty necessary to evaluate long lead time investments in future generation resources.

Another area that should be reconsidered involves the financial penalty exemption. The exemption for resources that offer into the day-ahead market (DAM) and are awarded may offer a perverse incentive that yields unintended consequences for both the market and the reliability of the grid. There could be a significant uptick in renewable resources participating in the day-ahead market, hedging the risk that they will not be able to perform if awarded and will have to replace those MWs in real-time as being a less costly alternative to potentially having a high-risk hour in which they owe a financial penalty for firming requirements. The exemption afforded DAM awardees should be tightened up to prevent this type of behavior. Additionally, the ability for renewable resources to offer into the DAM at significantly lower prices, whether from less overhead or the federal tax credits, may depress prices in the DAM and forward prices that create a disincentive for dispatchable resources that have a solid history of being available when cleared from participating in that or the ancillary services markets. The final rule should take great care to ensure this outcome is avoided. Otherwise, it may further jeopardize market stability for the very resources the state is trying to attract and retain.

Finally, the incentive for providing firming to intermittent resources should be available to existing as well as new resources. Older resources are disproportionately deployed under Reliability Unit Commitment (RUC) and may be a viable tool for firming until additional new dispatchable resources are built and brought into service. If those resources are contracted to provide firming, they will remain in the market longer with lower costs to consumers by potentially avoiding more frequent RUCing of those units or likely RMR situations. Requiring resources awarded in the DAM to perform in real-time in order to get the exemption is one way to solve for this potential.

**REDLINES TO PFP**

**§25.65. Firming Reliability Requirements for Electric Generating Facilities in ERCOT.**

(a) **Applicability.** This section applies to an electric generating facility, other than a battery energy storage resource, settlement only generator, self generator, or generating facility within a private use network (PUN) that will provide more than 50 percent of its nameplate capacity to the load within the PUN (with the load capacity measured based on the final amount to be interconnected under the agreement with the utility), in the ERCOT region:

(1)for which a standard generation interconnection agreement is signed on or after January 1, 2027, and that has been in operation for at least one year; ~~or~~

~~(2) completes upgrades resulting in an increase of the nameplate capacity by 50 percent or more and requires a new or amended standard generation interconnection agreement after January 1, 2027.~~

(b) **Definitions.** The following words and terms, when used in this section, have the following meanings unless the context indicates otherwise.

(1) **Electric generating facility** -- A generation resource, as defined in ERCOT protocols.

(2) **High-risk hour** -- A daily hour encompassing all seasonal morning and evening ramp hours, as determined by ERCOT in its annual NERC Probabilistic Assessment, and any hour where at least 5% of the highest decile of net load hours occurred during that season in the prior three years.

(3) **In operation** -- The resource commissioning date, as defined in the ERCOT protocols.

(4) **Low operation reserve hour** -- An hour when the physical responsive capability (PRC) falls below 3,000 megawatts (MW) for at least 15 minutes.

(5) **Owner or operator** -- A resource entity that owns an electric generating facility represented by a qualified scheduling entity.

(6) **Season** -- Winter (December 1 through February 29), Spring (March 1 through May 31), Summer (June 1 through September 30), and Fall (October 1 through November 30).

(7) **Seasonal average generation capability** -- For each season, the seasonal net max sustainable rating for the electric generating facility multiplied by 0.75 .  The resource level capability shall be based on owned resources.  The portfolio level capability shall also include any affiliates of the generation entity. ~~the average of the ratio of real-time telemetered high sustained limit (HSL) to the seasonal rated capacity of an electric generating facility across all intervals during the prior three years multiplied by the seasonal rated capacity of the electric generating facility at the beginning of the relevant season. For an electric generating facility that has been in operation for less than three years, ERCOT will use the operational data that is available for each season.~~

(c) **Notice of seasonal average generation capability.** Prior to each season, ERCOT will:

(1) notify an electric generating facility of its seasonal average generation capability; and

(2) release the high-risk hours for the upcoming season.

(d) **Reliability requirement.** Each season, an electric generating facility, must operate or be available to operate when called on for dispatch at or above the seasonal average generation capability during a low operation reserve hour that occurs within a high-risk hour.

(1) **Firming.** The owner or operator of an electric generating facility may meet the requirements under this subsection by supplementing with its portfolio or contracting with:

(A) another electric generating facility that is either on-site or off-site; or

(B) an on-site or off-site battery energy storage resource.

(2) **Disclosure to ERCOT.** An owner or operator that meets the requirements under this subsection by supplementing from its portfolio or contracting with another electric generating facility or battery energy storage resource must disclose the arrangement to ERCOT and provide ERCOT with any additional information reasonably required for ERCOT to perform its duties under this section, including confirmation of the arrangement by both parties to a trade.

(e) **Financial penalty and financial incentive.**

(1) **Financial penalty.** ERCOT must impose a financial penalty on an electric generating facility if the electric generating facility fails to operate or is unavailable to operate when called on for dispatch at or above the seasonal average generation capability during a low operation reserve hour that occurs within a high-risk hour, as required under subsection (d) of this section, and did not supplement effectively from its portfolio or by contractual arrangement disclosed to ERCOT for any shortages. A financial penalty imposed must be $1000/~~MWh20 percent of the effective value of lost load used to determine the ancillary service demand curves for the day-ahead market and real-time market~~ and applied to the shortage megawatt hours (MWh). In seasons where more than 15 low operation reserve hours occur during the seasonal high-risk hours, only the 15 low operation reserve hours with the lowest levels of PRC will be subject to this penalty.

(2) **Financial penalty exemption.** An electric generating facility is exempt from a financial penalty under this section if the electric generating facility is:

(A) unavailable during the applicable hour due to:

(i) a planned, maintenance, or opportunity outage or derate that was approved by ERCOT, or

(ii) a transmission outage;

(B) a switchable generation resource that is committed to a neighboring independent system operator or regional transmission operator for the applicable season;

(C) awarded energy or ancillary services in the day ahead market rules for the duration of the applicable hour; or

(D) awarded an ancillary service or reliability service that has an associated penalty for failure to perform for the duration of the applicable hour.

(3) **Financial incentive.** ERCOT must provide a financial incentive to an electric generating facility if the electric generating facility operates or is available to operate when called on for dispatch above the seasonal average generation capability during a low operation reserve hour that occurs within a high-risk hour, as required under subsection (d) of this section.

(A) The total financial incentives provided under this subsection each season must not exceed the total financial penalties imposed each season for low operation reserve hours occurring within high-risk hours.

(B) The financial incentives payable under this subsection must be equal to the total financial penalties imposed under this subsection divided by the total MWs that exceeded the seasonal average generation capability.

(C) A financial incentive provided to an eligible electric generating facility must be calculated based on the total financial penalties imposed divided by available MWh and allocated to an eligible electric generating facility based on the percentage of MWh that exceed the performance requirements.

~~(D) An electric generating facility that is not required to operate or be available to operate under subsection (d) of this section is not eligible to receive a financial incentive under this subsection.~~

(f) **Settlement.** After each season, ERCOT must:

(1) notify each electric generating facility if it was long or short net of trade arrangements disclosed to ERCOT during the low operation reserve hours that occurred within the high-risk hours in the prior season;

(2) impose financial penalties to those electric generating facilities that are net short; and

(3) provide financial incentives to those electric generating facilities that are net long.

(g) **Protocols.** ERCOT must develop protocols in consultation with commission staff to implement this rule by December 1, 2026.

**CONCLUSION**

TCPA appreciates the opportunity to provide these comments and looks forward to continuing to work with the Commission, Staff and other stakeholders throughout this project to ensure the Legislature’s goals of a firm, reliable and balanced grid are achieved.

Dated: September 2, 2025

Respectfully submitted,

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**EXECUTIVE SUMMARY OF TCPA COMMENTS**

* Firming statute was enacted specifically enacted to ensure the state attracts and retains thermal dispatchable resources in ERCOT.
* TCPA agrees with the PfP definition of “low operation reserve hour” as falling below a PRC of 3,000 MW.
* The applicability of the rule to anything beyond a new SGIA executed on or after January 1, 2027 goes beyond the statutory scope which specifically applies these new requirements only to new SGIAs on or after January 1, 2027 and after they have been operating for a year. The application to uprates or capacity additions of existing resources is not contemplated in the statute and TCPA recommends striking the provision in the PfP that applies the requirements to capacity additions of existing resources.
* Co-located facilities providing 50% or more of their capacity to a host load is no different in operating characteristics to a self-generator or a private use network and should be exempted just as self-generators and PUNs are. Otherwise the rule is discriminating based on technology and will create a disincentive to invest in behind-the-meter interconnections, particularly using thermal resources.
* “High-risk hour” definition in the PfP does not have a strong relationship to actual system risk.
* TCPA recommends instead using analyses in the CDR and AS methodology which are intended to manage the grid to avoid defined and well-known risks and the statutory language supports the use of existing risk assessment processes to determine high-risk hours. Utilizing CDR data for peak load hour and net peak load hour or the probabilistic framework of the AS methodology would use publicly available and well-established tools to predict the tightest hours.
* For the highest risk hours of net load ramp, probabilistic modeling tools ERCOT has developed or NERC’s probabilistic assessment could be used and is using the same SERVM reliability model required for the Commission’s reliability standard.
* PfP definition of “seasonal average generating capacity” tied to telemetered HSL and establishes a standard for thermal resources that does not account for the ambient temperature impacts on generation output, without bearing on actual performance, creating a standard (especially in hot temperatures) that is physically impossible for a thermal generator to achieve.
* Use of telemetered HSL will also result in a very low performance requirement for intermittent resources.
* An unattainable performance level for thermal resources and a low performance level for intermittent resources run counter to the Legislature’s desire for intermittent resource to pay for firming the grid and for more investment in thermal dispatchable resource in ERCOT.
* Using three prior years performance will actually reward resources that have poorly performed rather than holding them accountable to an acceptable standard by requiring them to firm.
* TCPA recommends seasonal rated capacity be revised to refer to the CDR “Seasonal Net Max Sustainability Ratings” which rely on both historical and upcoming seasonal values as the multiplier to set the “seasonal average generating capacity” and reduce to a 75% value to account for different ambient temperature conditions that impact resource output without relation to performance.
* The recommended 75% value establishes a reasonable seasonal average generating capacity and is similar to the performance requirements adopted by the Commission for weatherization so the standard is known to all market participants as well as ERCOT and the PUC.
* Measuring performance of a resource relative to its seasonal average generation capability should also include appropriately benchmarking combined cycle gas turbine resources (CCGTs) based on their combine cycle configuration of operations during the reliability requirement period.
* PfP should clarify that resources may fulfill their performance obligations with existing or new resources and require disclosure of which type of resource to ERCOT. This would ensure compliance with the statutory provisions.
* The PfP links the firming penalties to VOLL and also creates some unintended perverse incentives with regard to the day-ahead market.
* Firming is not a market design tool and the financial penalties may actually cause significant financial harm to thermal dispatchable generation, which is counter to legislative and commission objectives to attract more investment of this type of generation in ERCOT.
* VOLL is a moving target and tying penalties to it injects unnecessary financial and regulatory instability into the market which is concerning to investors.
* TCPA recommends a financial penalty of $1,000/Mwh which is high enough to provide an incentive to firm but not so high that it deters future investment.
* The exemption for DAM participation has the potential to depress DAM prices by increased participation in the DAM by intermittent resources in an effort to find a lower cost alternative to firming requirements and resulting penalties.
* Such a potential could lead to less participation in the energy or ancillary services DAM by dispatchable resources that have a solid history of being available in real-time when cleared in the DAM. TCPA recommends requiring resources that clear in the DAM to actually perform in real-time in order for the exemption to apply.
* The incentive for providing firming should be available to existing and new resources that provide those services. Older resources that are disproportionately RUC’d could provide firming until new dispatchable resources are built and the older resources would potentially stay in the market longer with lower consumer costs by avoiding more frequent RUC’ing of those units or potential RMR situation.

1. TCPA recommends additional edits to subsection (a) in the proposed redline at the end of these comments, related to the suggestion on private use networks (PUNs) that is detailed on the next page of the comments. [↑](#footnote-ref-2)