PROJECT NO. 58484

EVALUATION OF TRANSMISSION	**§**	**PUBLIC UTILITY COMMISSION**
	§	
COST RECOVERY	**§**	**OF TEXAS**

COMMENTS OF THE TEXAS ENERGY BUYERS ALLIANCE

I. INTRODUCTION

The Texas Energy Buyers Alliance (TEBA) represents the collective voice of more than 200 companies, representing some of the state's largest employers and energy customers. In total, TEBA members represent more than $36 trillion in market capitalization and hundreds of thousands of employees in Texas. Our organization is focused on helping to shape Texas' electricity market redesign in ways that propel Texas' economy forward, lower power bills for all energy customers, create jobs, spur innovation, strengthen the ERCOT grid, and extend Texas' energy leadership through the energy transition and for generations to come.

Because TEBA's membership represents such a unique cross-section of the businesses in Texas, we feel we are uniquely qualified to provide insight into this question. Hyperscaler data centers, retail businesses, petrochemical companies, technology companies, and manufacturers make up our membership and share a common purpose to protect the efficient, reliable, low-cost ERCOT market. While some of our membership will directly benefit from investment in significant new transmission upgrades, other members will have only indirect benefits. TEBA emphasizes that new large loads that directly benefit from transmission investment should contribute an appropriate amount for transmission service.

Many of our members are very cost-conscious and appreciate that ERCOT offers the opportunity to hedge against energy costs and respond to the 4CP signal to keep costs down. Changes to the transmission cost allocation should be within reason and should not unnecessarily increase the cost of doing business in Texas by broadening 4CP without proof of significant system benefit results. For these reasons, TEBA suggests that the Commission be very thoughtful in its approach to changes to transmission cost allocation.

II. RESPONSES TO COMMISSION STAFF'S QUESTIONS FOR COMMENT

TEBA appreciates the opportunity to provide comments in response to the Commission staff's second set of questions for comment for Project No. 58484. We respectfully submit the following responses for consideration by the Public Utility Commission of Texas.

Question 1: What cost assignment, allocation, and/or rate design methodologies would best implement PURA § 35.004(c-1):

a. Regarding wholesale transmission cost recovery?

b. Regarding retail transmission cost recovery, if any?

PURA § 35.004(c-1) is referencing the recovery of the interconnecting utility's costs to interconnect a large load. For this specific matter, TEBA recommends that a large load's contribution in aid of construction be used to determine the upfront interconnection cost.

In the context of this rulemaking, however, it can be assumed that this question was also intended to address cost recovery assignment through the existing coincident peak (CP) approach. TEBA believes that using coincident peaks provides system benefits and assists with incentivizing demand response during periods of high load. As noted by stakeholders in the November 10 PUCT workshop, the current approach was established over 20 years ago to address the growing issue of cost allocation.[1] With the growing introduction of large loads and ERCOT's

[1] PUCT 58484 Workshop Tr. at 3:48:48-3:49:03 (November 10, 2025).

changing landscape, it is important to consider ways that the current approach can be modified to address the current day needs of transmission cost allocation.

TEBA proposes the Commission keep 4CP but adopt a minimum demand ratchet requiring new loads to pay for a minimum portion of their total planned for the first few years of energization (this time period may be determined through further discussion at the Commission). In essence, a new large load would pay its transmission costs based on its requested capacity instead of its usage during one of the coincident peaks, preventing gaming but still enabling load curtailment during critical ERCOT intervals. Through this approach, new large loads would not be able to avoid the peaks and would be responsible for paying their fair share of transmission costs, which will safeguard ratepayers while still encouraging load to respond during critical peaks. It would also enable these loads to respond to real-time prices. While curtailment is allowed, it would not lower Transmission Cost of Service (TCOS) during this initial energization period.

This approach is not meant to be permanent; instead, it would be temporary for an appropriate number of years (determined by the Commission) to ensure transmission is being appropriately financed by the new loads in the first few years of energization. TEBA and its members believe that costs from transmission investment that directly benefits new large loads may be appropriately paid for by the customer.

TEBA emphasizes that new large loads that directly benefit from transmission investment should contribute an appropriate amount for transmission service.

Question 2: What methods of measurement, cost allocation, and rate design are

based on transmission capacity and scarcity, consistent with cost causation principles, and also minimize negative impacts on the energy market?

To the extent that this question is asking whether or not the CP method continues to be a viable approach to measuring transmission costs, TEBA believes that the CP method provides an array of benefits. CPs incentivize demand reduction for large loads during periods of high stress on the transmission grid.

Our proposed revision to the current 4CP methodology would result in a more appropriate split of TCOS as it would split the total TCOS among customers in a way that reflects who drives transmission investment.

Question 3: Are transmission-level thermal overloads and voltage limit violations primarily driven by system peak load or congestion? What ratemaking practice can be instituted to reasonably reflect the primary drivers?

TEBA has no formal response to this question at this time.

Question 4: Is the share of the total cost of transmission projects driven by off-peak conditions growing? If yes, what factors are driving this trend? Are those factors expected to continue? Are there reasonable ratemaking practices that can be instituted to reasonably reflect these conditions and factors?

TEBA has no formal response to this question at this time.

Question 5: Assume for purposes of cost recovery that transmission costs can be split into two categories. How could the Commission define the categories to clearly

delineate between those costs necessary to upgrade the transmission system and those related to costs specific to interconnecting loads or generation resources? Please explain how and why.

a. **What are the current contributions in aid of construction (CIAC) policies associated with transmission assets? Are any of the CIAC amounts refundable?**

b. **Should an ERCOT-wide policy be implemented for calculating required CIAC amounts or methodologies? If so, what should it be, and how should it be implemented?**

c. **Should some or all of the CIAC amounts be non-refundable?**

d. **Should the costs of radial lines that are used to interconnect transmission-level customers be included in the interconnection costs category, some or all of which should be paid for by the interconnecting entity?**

TEBA supports defining transmission cost categories into separate systemwide upgrades from costs tied directly to new interconnections. ERCOT-wide policy should be implemented to calculate the CIAC amount to ensure standardization and uniformity in costs across stakeholders. An initial, estimated CIAC should be assessed early, based on facility scale, redundancy, and known costs, with actual CIAC reconciled once construction is complete. Refunds should only apply if a project is canceled before construction begins.

TEBA does not support altering cost recovery in ways that undermine the "postage stamp" methodology, which ensures fairness and simplicity across ERCOT. CIAC amounts should remain nonrefundable beyond the limited case of project cancellation, and radial line costs should continue to be paid by ratepayers. TEBA reminds the Commission that we have proposed a methodology for large loads to contribute appropriately to TCOS, which would render separate charges for specific lines unnecessary because TCOS costs will be recovered broadly.

Question 6: Should existing generator or load interconnection allowances be modified? If so, how?

No, generator and interconnection allowances should not be modified. If stakeholders decide to modify the process, the only acceptable solution would be to standardize the allowances. Standardization is generally beneficial, and customers should pay when they interconnect. However, this process seems to be generally working and would take time to standardize across utilities. This right now would be a lower priority compared to other SB6 implementation activities. It is too early to weigh in on generator allowances, as that rule has only been recently written. However, increased costs for generators that might impact investment in new generation should remain under continuous scrutiny.

Question 7: If the Commission adopts a coincident peak (CP) rate design:

a. **What monthly CPs should be included?**
b. **Should "floating" CP intervals, not confined to specific months, be included? If so, how many floating intervals should be included, and should the floating intervals be confined to certain time periods (e.g. seasons)?**

c. **Should the peak intervals be broadened? If so, to how long, and what would be the likely negative effects of broadening the peak intervals (e.g., 30 minutes, 1 hour, 4 hours)?**

TEBA is not opposed to the solution posed by multiple stakeholders at the workshop to implement "5CP" (4CP plus 1 floating winter CP). 4CP would remain the same across June, July, August, and September, while the winter CP would occur in December, January, or February. This would provide an incentive for large loads to curtail in the instance of a high period of stress during the winter months. Historically, periods of high stress have materialized unpredictably across winter months. This floating CP would address any instance of grid stress related to winter weather without causing customers to reduce load if there is no reliability need to do so.

Our proposed solution of charging new loads based on their capacity instead of their demand during the peak (explained in our response to Question 1) could be implemented in tandem with 5CP.

Question 8: If the Commission adopts a non-coincident peak (NCP) rate design:

a. **What values should be used (e.g., distribution service provider (DSP) NCP values or retail customer-level NCP values)?**
b. **If customer-level NCP or other load data should be used for wholesale transmission cost recovery, how should DSP-level customer data be collected and provided to the Commission? How should disputes associated with such data be addressed?**

The Commission should not adopt a non-coincident peak (NCP) rate design. The systemwide benefits that CPs provide through demand response have been critical over recent years through monetarily rewarding loads that reduce their demand during ERCOT's periods of highest usage.

Question 9: If the Commission adopts a hybrid NCP and CP rate design, what monthly CPs should be included?

TEBA has no formal response to this question at this time.

Question 10: For each of the following methodologies, what are the pros and cons, and potential impacts to the wholesale market:

a. **Coincident peak (365CP; 12CP; 7CP; 6CP; 5CP)**
b. **Non-coincident peak (DSP NCP; A "dual rate/hybrid" Wholesale Transmission Service rate design where some X% of Transmission Cost of Service is recovered via 4CP or other CP rate design, with the remaining % recovered via DSP NCP)**
c. **DSP total energy usage**

Overall, TEBA is not in favor of the adoption of 12CP for multiple reasons. As the number of coincident peaks increases, the likelihood that large loads will respond and reduce their demand decreases. The reduction in curtailment during high-stress periods must be considered as a cascading impact of increasing the number of CPs across the year that could negatively impact the ERCOT system. 12CP would also force weather-sensitive loads to pay CP charges for months that do not cause new transmission to be built. Additionally, creating a CP across all months, particularly the shoulder months when demand is manageable, risks discouraging economic activity without providing any reliability benefit. Load reductions during periods of genuine grid stress more clearly support system needs, but incentivizing customers to curtail operations during low-stress conditions leads to unnecessary economic tradeoff for no meaningful gain. Texas is the fifth-largest economy in the world and continues to lead the nation in industrial growth and new capital business. Rate structures should not undermine the state's competitive advantage.

As stated above, TEBA does not support the adoption of an NCP rate design. In a similar vein, 365CP is not preferable as it would ultimately have the same impact on demand response as NCP.

TEBA supports transmission costs being appropriately allocated and believes new large loads should pay their fair share of transmission built for their benefit. It is essential, however, to implement a methodology for capturing transmission costs without disincentivizing critical curtailment during periods of high stress, charging loads that did not require new transmission to be built, or discouraging economic activity. TEBA's energization proposal strikes this balance by preserving the integrity of the TCOS framework while ensuring that new large loads contribute to TCOS allocations for an appropriate period of time.

Question 11: Should regulated wholesale and retail transmission ratemaking policy and practice be based on a methodology that incorporates ERCOT's modeling for transmission planning?

a. If so, how specifically could such policy and practice be translated into reasonable ratemaking practice?

b. If so, how should cost recovery be addressed for projects that do not go through ERCOT independent review?

c. **If so, how can stable and predictable ratemaking practice be instituted in light of potentially evolving transmission planning practices and changing needs and priorities of the planning process?**

d. **Would doing so have any unintended consequences or required additional staff or stakeholder processes?**

TEBA has no formal response to this question at this time.

III. CONCLUSION

TEBA appreciates the opportunity to submit these comments and looks forward to continuing to work with Commission staff on this matter.

Respectfully submitted,

/s/ Bryn Baker

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<u>EXECUTIVE SUMMARY OF TEXAS ENERGY BUYERS ALLIANCE</u>

- TEBA proposes the Commission keep 4CP but adopt a minimum demand ratchet requiring new loads to pay for a minimum portion of their total planned capacity for a predetermined number of years after energization to ensure transmission is being appropriately financed by new loads.
- TEBA believes that using coincident peaks incentivizes critical demand response for large loads during periods of high stress, and changing the methodology could threaten the resilience of the grid.
- TEBA supports defining transmission cost categories into separate systemwide upgrades from costs tied directly to new interconnections. TEBA does not support altering cost recovery in ways that undermine the "postage stamp" methodology.
- TEBA believes generator and interconnection allowances should not be modified.
- TEBA supports the "5CP" (4CP across the summer months and 1 floating CP in the winter) in tandem with our proposal to assess new large loads based on their requested capacity.
- TEBA is opposed to the adoption of NCP and 365CP as it threatens critical demand response.
- TEBA is opposed to 12CP as it would incentivize unnecessarily curtailment and discourage economic activity without providing any reliability benefits.