PROJECT NO. 58484

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

COMMENTS OF NRG ENERGY, INC. IN RESPONSE TO STAFF'S SECOND SET OF QUESTIONS ON TRANSMISSION COST RECOVERY

NRG Energy, Inc. (NRG) appreciates the opportunity to provide comments in this project in response to the Staff's second set of questions regarding the directive in Senate Bill 6 (SB6)[1] for the Public Utility Commission of Texas (Commission or PUC) to evaluate various aspects of transmission cost recovery and allocation, including the existing four coincident peak (4CP) methodology. NRG is the parent company of well-established retail electric providers (REPs) and power generation companies (PGCs) in the competitive electricity markets in Texas.

I. INTRODUCTION AND SUMMARY OF COMMENTS

NRG strongly supports the Commission's efforts in this project to evaluate and implement changes to the current 4CP transmission cost allocation mechanism. As outlined in detail in prior comments,[2] the current 4CP mechanism results in significant cost shifting among customer classes that unfairly advantages larger consumers to the detriment of residential consumers in the competitive retail territories of the ERCOT region.

A. The Goal of the 4CP Review—Protect the Average Texan Against Inappropriate Cost Shifting

In implementing the statutory directive in SB6 to reevaluate 4CP, NRG urges the Commission to focus on the apparent Legislative goal of ensuring that the average Texan (i.e., the residential customer class) does not bear more than their fair share of the costs of transmission investment—i.e., that all loads are "*appropriately assigned*" and "*appropriately contribute*" to the recovery of those costs.[3] Notably, unlike the section in SB6 regarding large load interconnection

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[1] 89th Tex. Leg., R.S., Senate Bill 6, § 6 (effective June 20, 2025) (hereafter, SB6).

[2] *Evaluation of Transmission Cost Recovery*, Project No. 58484, Comments of NRG Energy, Inc. in Response to Staff's August 5, 2025 Questions (Sept. 9, 2025) (hereafter, NRG Initial 4CP Comments), *available at:* https://interchange.puc.texas.gov/Documents/58484_14_1537328.PDF.

[3] SB6, § 6 (emphasis added). SB6, §1 similarly reflects the Legislature's concern for protecting average Texans from bearing the brunt of costs associated with interconnecting large loads—i.e., by requiring that the

and forecasting criteria, the directive regarding 4CP review is not qualified by an instruction to balance objectives of supporting business development with avoiding stranded costs and ensuring reliability (as was implied to the contrary at the PUCT's recent workshop on 4CP review).[4] Instead, the directive for the review of 4CP is limited to ensuring that all classes are being appropriately assigned the costs of transmission infrastructure.[5]

This distinction in the statutory directive for 4CP is important considering the sheer magnitude of transmission infrastructure costs that are planned in the near term to support the anticipated boom of large loads locating in Texas—costs that could more than double the annual ERCOT-wide transmission cost of service (TCOS).[6] In this context, the continuation of the 4CP mechanism or implementation of a substantially similar transmission cost allocation approach that retains cost shifting incentives (such as adding one floating CP to the current 4CP) will exacerbate the financial harm to residential customers given the magnitude of transmission infrastructure development and the corresponding costs. Moreover, SB6 directs the Commission, by December 31, 2026, to "**amend commission rules** to ensure that wholesale transmission charges appropriately assign costs for transmission investment"[7]—clearly indicating that a rule change from 4CP to something else is contemplated. Maintaining the status quo, or implementing a similar methodology, is simply not consistent with the directive in SB6.

B. Satisfying the Goal: Increase the CP Intervals and the Interval Duration

To address the concerns of the Legislature in including the 4CP review provisions in SB6, the goal of this project should be to ensure an equitable allocation of transmission costs to consumers, and the best way to do that would be to increase the number of coincident peaks and the duration of the intervals used in the methodology. For example, a 365CP methodology with an hour duration interval or a 12CP methodology with a consecutive 4-hour duration interval would accomplish the goal without the need for an overly complicated methodology. Hybrid approaches

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Commission ensure that large loads contribute to the interconnecting utility's costs to interconnect the large load to the utility's system.

[4] SB6, § 2.

[5] SB6, § 6.

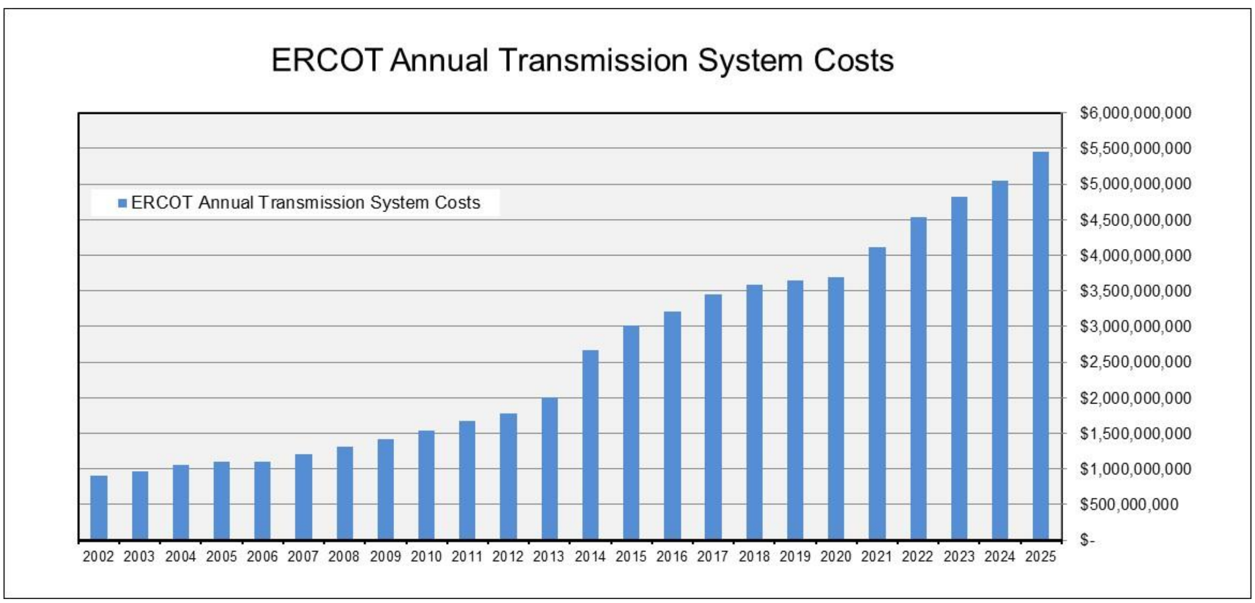
[6] NRG Initial 4CP Comments at 6 and note 20.

[7] SB6, § 6 (emphasis added).

that include monthly Non-Coincident Peaks (NCPs) along with increasing the interval duration could also accomplish this objective.

C. 4CP Cost Allocation and Rate Design *Do Not* Reduce Future Transmission Spend

At the PUCT transmission cost allocation workshop on November 10, 2025, there was discussion that implied that the existing 4CP mechanism has resulted in avoided transmission cost. The chart below shows the annual increase in the TCOS since the ERCOT wholesale market restructured over 20 years ago, including the entire time in which the 4CP mechanism has been in place. As the data demonstrates, there is no evidence of avoided transmission infrastructure or cost, even with record amounts of participation in 4CP response by large consumers.[8] This makes sense because the ERCOT transmission planning process, which results in most of the development of the transmission system, does not utilize ERCOT system summer coincident peak demand (as explained in prior comments from NRG).[9] So maintaining a transmission cost allocation mechanism with limited CPs based on an expectation that future transmission costs will be avoided is flawed and should be rejected.



[8] NRG Initial 4CP Comments at 13 and note 38.

[9] NRG Initial 4CP Comments at 7-8, 19-22.

D. Eliminating Cost Shifting Aligns with Cost Causation

Eliminating cost shifting aligns with cost causation principles. Cost causation principles are foundational to rate design in the Public Utility Regulatory Act (PURA),[10] which requires "just and reasonable" rates and precludes unreasonable allocations among customer classes.[11] SB6 effectively requires the Commission to reevaluate whether the existing 4CP allocation methodology is still accomplishing this objective of allocating costs based on cost causation by requiring that the Commission review 4CP and ensure that transmission cost allocation still "appropriately assigns costs for transmission investment."[12] Based on how the transmission system is designed and built, which NRG describes in initial comments,[13] the costs of the ERCOT transmission system are caused by a myriad of reasons unrelated to system demand at the 4CPs, including to serve non-coincident peak demand of each disparate TDU system, resolve renewable resource export constraints, manage clearance of transmission outage needs, and improve system resiliency. Using an allocation methodology (like the current 4CP mechanism) that encourages and rewards loads for reducing their use of the transmission system to lower their allocation of costs is thus actually inconsistent with cost causation. Instead, a methodology that allocates costs based on loads' typical (rather than distorted) use of the transmission system would more appropriately reflect cost causation principles. In other words, although there is no "perfect" cost causation model, avoiding cost shifting is an important part of achieving cost allocation because it better aligns with the principles of cost causation by reflecting a more accurate use of the transmission system by consumers, rather than a brief distortion of large consumer's usage patterns.

E. The Commission Need Not Modify Retail Rates to Satisfy SB6's Directive

It is notable that Section 6 of SB6, which directs the Commission to evaluate and modify the current 4CP methodology, focuses on equitable transmission cost allocation among consumer classes. Section 6(a)(1) requires the Commission to evaluate whether the current methodology

[10] Tex. Util. Code §§ 11.001-66.016 (PURA).

[11] *E.g.*, PURA § 36.003 (requiring just and reasonable rates and prohibiting utilities from establishing or maintaining an "unreasonable difference concerning rates between localities or between classes of service").

[12] SB6, § 6.

[13] NRG Initial 4CP Comments at 7-8, 19-22.

"ensures that all loads appropriately contribute to the recovery" of transmission costs, and Section 6(a)(2) directs the Commission to evaluate alternative methods that "more appropriately assign the costs" using "multiple seasonal peak demands" and "different length daily intervals" consistent with the design principles that NRG is proposing.[14] The Commission can accomplish these goals of SB6 by increasing the number of CPs used in the methodology and expanding the length of the duration used to measure peak demand for the allocation of transmission costs to distribution service providers (DSPs) and the consumer classes. The Commission does not need to modify the design of retail rates to accomplish these goals.

II. RESPONSES TO STAFF QUESTIONS

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?

NRG response: PURA § 35.004(c-1) states that "the commission by rule shall ensure that a large load customer contributes to the recovery of the interconnecting electric utility 's costs to **interconnect** the large load to the utility 's system."[15] Therefore, this section of PURA added by SB6 is focused on interconnection facility costs. As explained by NRG in comments filed in Project No. 58481,[16] large loads subject to the interconnection standards in PURA § 37.0561 should be required to pay for all their interconnection facility costs through the contribution in aid of construction (CIAC) as part of their interconnection agreement with their interconnecting utility. This will ensure other consumers do not have to pay for the interconnection costs of large load customers.

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[14] SB6, § 6.

[15] Emphasis added.

[16] *Rulemaking to Implement Large Load Interconnection Standards under PURA 37.0561*, Project No. 58481, NRG Energy, Inc.'s Comments on PUCT Staff Questions (Oct. 10, 2025) (hereafter, NRG LL Interconnect Comments).

<u>Question 2</u>: <u>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?</u>

<u>NRG response</u>: As explained in prior comments, the capacity and scarcity of the ERCOT transmission system is evaluated in ERCOT's transmission planning process based on a non-coincident basis relative to the peak demand of each disparate TSP's system.[17] And historical data demonstrates that scarcity of transmission capacity, as measured by non-coincident peak demand, on each TSP's system collectively does not occur at the same day and time as the ERCOT system coincident peak demand:

Day and Time of Regional Peak Demand vs. ERCOT System Peak

Year	North	South	Houston	West	ERCOT System
2008	8/4/2008 5:45:00 PM	6/18/2008 5:00:00 PM	8/1/2008 4:45:00 PM	6/4/2008 4:45:00 PM	8/4/2008 5:00:00 PM
2009	7/13/2009 5:00:00 PM	7/8/2009 4:45:00 PM	6/24/2009 4:45:00 PM	8/25/2009 4:45:00 PM	7/13/2009 5:00:00 PM
2010	8/23/2010 4:00:00 PM	8/23/2010 4:45:00 PM	8/16/2010 3:00:00 PM	8/17/2010 4:45:00 PM	8/23/2010 5:00:00 PM
2011	8/3/2011 4:00:00 PM	8/28/2011 5:00:00 PM	8/18/2011 4:45:00 PM	8/10/2011 5:00:00 PM	8/3/2011 5:00:00 PM
2012	8/1/2012 4:45:00 PM	6/26/2012 4:30:00 PM	6/26/2012 4:15:00 PM	8/1/2012 4:30:00 PM	6/26/2012 5:00:00 PM
2013	8/7/2013 5:00:00 PM	8/8/2013 4:00:00 PM	8/13/2013 4:45:00 PM	8/6/2013 4:15:00 PM	8/7/2013 5:00:00 PM
2014	8/25/2014 5:00:00 PM	8/26/2014 4:00:00 PM	8/11/2014 4:00:00 PM	8/7/2014 5:00:00 PM	8/25/2014 5:00:00 PM
2015	8/10/2015 4:30:00 PM	8/12/2015 4:30:00 PM	8/11/2015 4:00:00 PM	8/5/2015 4:45:00 PM	8/10/2015 5:00:00 PM
2016	8/12/2016 3:00:00 PM	8/12/2016 4:00:00 PM	8/9/2016 3:45:00 PM	8/4/2016 4:00:00 PM	8/11/2016 5:00:00 PM
2017	7/28/2017 5:30:00 PM	8/18/2017 4:00:00 PM	8/18/2017 4:00:00 PM	6/23/2017 3:00:00 PM	7/28/2017 5:00:00 PM
2018	7/19/2018 4:30:00 PM	1/17/2018 7:30:00 AM	8/21/2018 4:45:00 PM	7/19/2018 4:30:00 PM	7/19/2018 5:00:00 PM
2019	8/26/2019 5:30:00 PM	8/14/2019 4:45:00 PM	8/14/2019 4:30:00 PM	8/12/2019 4:45:00 PM	8/12/2019 5:00:00 PM
2020	8/14/2020 4:45:00 PM	8/27/2020 4:45:00 PM	9/2/2020 3:45:00 PM	7/17/2020 4:30:00 PM	8/14/2020 5:00:00 PM
2021	2/14/2021 6:45:00 PM	2/14/2021 8:45:00 PM	8/10/2021 2:45:00 PM	8/9/2021 4:00:00 PM	8/24/2021 5:00:00 PM
2022	7/20/2022 5:00:00 PM	12/23/2022 10:00:00 AM	6/20/2022 3:30:00 PM	12/22/2022 7:15:00 PM	7/20/2022 5:00:00 PM
2023	8/25/2023 4:15:00 PM	8/14/2023 3:30:00 PM	8/14/2023 4:30:00 PM	8/5/2023 2:45:00 PM	8/10/2023 6:30:00 PM
2024	8/19/2024 5:30:00 PM	1/16/2024 6:30:00 AM	8/21/2024 4:00:00 PM	8/23/2024 1:45:00 PM	8/20/2024 6:00:00 PM

Thus, there is merely a loose relationship between the ERCOT-wide coincident peak demand currently used for cost allocation and cost causation on the transmission system.

[17] NRG Initial 4CP Comments at 7-8, 19-22. While the methodology summarized above and detailed in NRG's prior comments describes the planning process for "TSPs," that methodology is relevant because TCOS is allocated to DSPs, ERCOT TSPs are also DSPs, and the bulk of TCOS (over 70 percent) was allocated to them in the most recent wholesale transmission cost matrix. *Commission Staff's Petition to Set 2025 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas, Inc.*, Docket No. 57491, Commission Staff's Final Transmission Charge Matrix, Attachment A, at 2 (Mar. 20,2025).

NRG recommends a transmission cost allocation mechanism that equitably distributes costs among customer classes. This can be accomplished by increasing the number of CPs and increasing the duration of the interval used to measure demand. NRG would also support evaluation of including monthly non-coincident peak demands in the calculation as a hybrid approach.

<u>Question 3</u>: <u>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?</u>

<u>NRG response</u>: While congestion could lead to transmission-level thermal overloads and voltage limit violations, system peak load is unlikely to coincide with congestion on the system—meaning that 4CP allocation and related cost shifting behavior is unlikely to impact congestion or thermal overloads/voltage limit violations. As discussed in NRG's prior comments in this project,[18] most congestion occurs during the spring and fall outage seasons due to planned transmission outages. Further, the top transmission constraints in recent years have been related to high renewable output in West Texas.[19] Congestion usually subsides during peak demand since all generation resources are incentivized to be online, and most dispatchable generation resources are located near load centers. When congestion has occurred during the summer months, it has been at lower voltage levels that 4CP response would not be effective at resolving.[20] In evaluating what TCOS allocation would "appropriately" assign costs to customer classes, NRG encourages the Commission to avoid trying to design an allocation that attempts to address or reduce congestion on the transmission system, given that the causes of congestion are generally unrelated to peak demand and unrelated to how the transmission is built.

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[18] NRG Initial 4CP Comments at 14-15, 25.

[19] *Id.*

[20] *Id.* at 25 (citing Potomac Economics, "State of the Market Report" for 2024 (Value of Real-time Congestion, "Cross Zone" at 49, *available at*: https://www.potomaceconomics.com/document-library/?filtermarket=ERCOT).

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?**

NRG response: No, NRG is not aware of any approved or constructed transmission projects based primarily on serving off-peak demand—unless by off-peak demand, Staff is referring to anything outside the 4CPs, in which case, transmission projects (as noted above) are not currently, and have never been, planned based on the ERCOT-system 4CP (but rather are generally planned on utility-specific non-coincident peak). But there have been many transmission projects approved and built to resolve renewable export constraints (such as CREZ), and those conditions may occur during times that are not related to system peak demand.

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?

NRG response: NRG views the costs necessary to interconnect specific loads or generation resources as the "driveway" as compared to the costs necessary to upgrade the transmission system, which is the "highway." NRG generally defers to the utilities to distinguish which costs are appropriately classified as specific to an interconnection facility (and thus part of the "driveway" that the interconnecting load should fund) versus those costs that are appropriately classified as system upgrades (and thus part of the "highway" that should be socialized through a fair and appropriate allocation of TCOS to DSPs and ultimately to customer classes). NRG would expect the "driveway" costs to be identified in the relevant interconnection agreement and would not generally expect system upgrades, which typically would benefit more than just the interconnecting customer, to be included in those costs.

As NRG commented in Project No. 58481,[21] the "driveway" costs should be assigned to large loads, in their entirety, through a contribution in aid of construction (CIAC), as part of the Commission's implementation of the section in SB6 related to interconnection standards that will require large loads to meaningfully commit financial resources to demonstrate "skin in the game" and to dissuade speculative loads.[22] That would differ somewhat from the process in place today, which NRG defers to the utilities to describe in their comments, but which generally involves a CIAC for non-standard interconnection facilities, but varies by utility in terms of how much is required. NRG supports a standardization of the CIAC process for large loads in order to implement the interconnection standards in SB6, by requiring large loads to fund the entire CIAC. In addition, a reasonable financial security (in dollars per megawatt) should be required to demonstrate financial commitment by large loads (e.g., $10,000/MW). The CIAC should not be refundable, as it would be assessed and paid as costs are incurred by the utility. However, the $/MW financial security should be refundable if the large load takes service for at least three years or if the large load withdraws its request before the load has signed an interconnection agreement and its project has been included in planning models (otherwise, the security would be forfeited and could be used to offset the costs included in the utility's rate base). More detail on this proposal is provided in NRG's comments in Project No. 58481, where the Commission is separately evaluating interconnection standards (including financial commitment and CIAC requirements) for large loads. NRG posits that issue is more appropriately addressed in Project No. 58481.

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

NRG response: The recently adopted rule for generation interconnection allowance in 16 Tex. Admin. Code (TAC) §25.195(f) was thoroughly vetted in response to House Bill 1500 adopted

[21] NRG LL Interconnection Comments at 3-7.

[22] SB6, § 2.

in the 88th Legislative Session[23] and should not be revisited at this time (as it is unrelated to the implementation of SB6). The ERCOT system and consumers in general benefit from the interconnection of generation resources, and therefore it makes sense for a portion of the interconnection costs to be socialized. With respect to large loads, as explained in response to Question 5, NRG would support standardization of CIAC policies among utilities to allow for all of the costs of interconnection (i.e., the "driveway") to be paid by the interconnecting large load as CIAC (which NRG understands from the November 10, 2025 PUCT workshop is the policy of some, but not all, ERCOT TSPs today).

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)?

NRG response: As discussed at length in the introduction and NRG's prior comments in this project,[24] the goal of this project should be to ensure an equitable allocation of transmission costs to consumers by eliminating cost shifting to the greatest extent possible, and the best way to do that would be to increase the number of coincident peaks and the duration of the intervals used in the methodology. A 365CP methodology with an hour duration interval or a 12CP methodology with a consecutive 4-hour duration interval would accomplish the goal without the need for an overly complicated methodology. A hybrid methodology using monthly NCPs could also be evaluated as an option and should reduce cost shifting to some extent, as the peak in each month presumably would be more difficult to predict and avoid than the 4CP, especially with longer duration intervals.

[23] *See Generation Interconnection Allowance*, Project No. 55566, Order Adopting Amendments to 16 TAC §25.195 (Feb. 15, 2024).

[24] *See generally* NRG's Initial 4CP Comments.

The data provided by the ERCOT Transmission and Distribution Service Providers (TDSPs) in this project demonstrates the cost shifting that occurs through the current TCOS allocation that uses demand during the 4CP 15-minute intervals. For example, the chart below shows the historical allocation of TCOS in each TDSP's territory using current 4CP intervals compared to what would have been allocated based on the average peak demand throughout the summer months (i.e., outside but inclusive of the 4CP fifteen-minute intervals):[25]

ERCOT TDSP Data from Project No. 58484 on Demand at 4CP vs. Demand During Summer Peak Months:

Oncor	**Current**	**Ave Summer Peak Interval**	**Ave 4CP Interval**
Residential	45.88%	42.21%	45.51%
Non-Residential, Non-4CP[26]	26.31%	22.64%	23.49%
4CP[27]	27.80%	35.15%	31.00%
CenterPoint	**Current**	**Ave Summer Peak Interval**	**Ave 4CP Interval**
Residential	47.61%	44.50%	47.50%
Non-Residential, Non-4CP	22.14%	19.15%	19.65%
4CP	30.25%	36.35%	32.85%
AEP	**Current**	**Ave Summer Peak Interval**	**Ave 4CP Interval**
Residential	49.30%	43.95%	46.81%
Non-Residential, Non-4CP	29.18%	25.36%	27.12%
4CP	21.52%	30.69%	26.06%

[25] Project No. 58484, Oncor's Response to Staff's Request for Information Related to Wholesale Transmission Service Charges (Nov. 14, 2025); CEHE's Updated Response to Commission Staff's Request for Information Issued October 17, 2025, Regarding Wholesale Transmission Service Charges (Nov. 20, 2025); AEP Texas, Inc.'s Response to Commission Staff's Request for Information Issued on October 17, 2025 Related to Wholesale Transmission Service Charges (Nov. 12, 2025) and Supplemental Response (Nov. 17, 2025); and TNMP Response to Staff Request for Information (Nov. 13, 2025). The calculation of the average includes all of the years provided in the responses.

[26] The rate classes included in this category differ slightly for each TDSP, but generally include the following classes that are billed either on a volumetric or NCP basis: Secondary Less Than or Equal to 10 kW (5 kW for TNMP), Secondary Greater Than 10 kW (5 kW for TNMP) (NCP-billed), and Primary (NCP-billed).

[27] The rate classes included in this category differ slightly for each TDSP, but generally include the following classes that are billed on a 4CP basis: Secondary Greater Than 10 kW (5 kW for TNMP) (4CP-billed), Primary (4CP-billed), Substation, and Transmission.

TNMP	Current	Ave Summer Peak Interval	Ave 4CP Interval
Residential	41.64%	34.93%	39.33%
Non-Residential, Non-4CP	25.18%	22.01%	23.06%
4CP	33.17%	43.06%	37.61%

As is evident from the chart above, in each of the ERCOT TDSP's territories, the loads that are billed on a 4CP basis (i.e., at step 3 of the transmission cost allocation[28]) are consuming significantly less (26 to 37 percent) on average during the 4CP intervals, compared to their consumption on average throughout the summer peaks (30 to 43 percent). This demonstrates the need to increase the duration of the measurement interval well beyond 15 minutes. It is clear that the loads billed on a 15-minute 4CP basis are successfully distorting their consumption pattern and reducing their load during those brief intervals while consuming more during the summer peak hours and thereby shifting costs onto smaller customer classes. The data in the chart above also demonstrates the need to update the class allocation factors on an annual basis as the Commission Staff is proposing to do in Docket No. 58923[29] since the allocators in some TDSP territories deviate considerably from the actual 4CP data.

In sum, the data provided by TDSPs in Project No. 58484[30] demonstrates that the Commission can substantially reduce cost shifting and accomplish the goal of ensuring an equitable and "appropriate" allocation of transmission costs as the transmission system is substantially expanded to accommodate large loads simply by moving from 4CP to a greater number of CPs, potential inclusion of monthly NCPs, and a longer interval duration (e.g., 4 hours). There are multiple options for the Commission to evaluate and consider, but NRG encourages the Commission to focus on the broader objectives of SB6 and avoid getting bogged down attempting

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[28] As discussed in NRG's Initial 4CP Comments, transmission cost allocation occurs in three steps—step 1 is the allocation of system-wide TCOS to the DSPs in ERCOT (which occurs based on demand in that DSP's territory at the 4CP 15-minute intervals), step 2 is the allocation by DSPs to their customer classes (which also occurs based on 4CP), and step 3 is the billing of individual customers according to the billing determinants in the DSP's tariff, which varies by class, with only certain larger customers with interval data recorder (IDR) meters and transmission level customers continuing to be billed, individually, based on their demand at 4CP. *See* NRG Initial 4CP Comments at 3-5.

[29] *Commission Staff's Petition to Require Annual Updates to Class Allocation Factor Values Under § 25.193(c)*, Docket No. 58923 (pending), *available at*: 58923_2_1554372.PDF.

[30] *Supra* note 25.

to overengineer a methodology that perfectly aligns with cost causation (which, as noted above, is not possible given the myriad of causes that prompt transmission buildout).

<u>Question 8</u>: **<u>If the Commission adopts a non-coincident peak (NCP) rate design:</u>**

<u>a. What values should be used (e.g., distribution service provider (DSP) NCP values or retail customer-level NCP values)?</u>

<u>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?</u>

<u>NRG response</u>: As explained in response to Question 2 above (and NRG's prior comments), NCP is more consistent with cost causation than the current 4CP methodology. The Commission could incorporate into the TCOS allocation a monthly transmission and distribution utility (TDU) system NCP based on DSP monthly NCPs. Customer-level NCP would be overly complex and is not necessary to accomplish the goals of SB6. Further, no change to rate design (i.e., the billing determinant phase of cost allocation as set out in individual utility tariffs) is needed to accomplish the objectives of SB6, though the Commission could add a new transmission subclass for large loads if the Commission wanted to ensure some minimum amount of transmission costs were allocated to large loads as a class (e.g., based on their 12CP, 365CP, or whatever allocation methodology the Commission moves to).

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

<u>NRG response</u>: A hybrid NCP and CP rate design, while more complicated than a pure CP rate design, could be a good way to further eliminate cost shifting incentives and more accurately capture each rate class's demand on the system. If the Commission decides to adopt such an approach, then NRG would recommend that the NCPs and CPs should be at least monthly (i.e., 12CP+12NCP).

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

a. Coincident peak i. 365CP ii. 12CP iii. 7CP (current 4CP + December through February CPs) iv. 6CP (current 4CP + 1 floating winter CP + 1 additional floating summer CP) v. 5CP (current 4CP + 1 floating winter CP)

b. Non-coincident peak i. DSP NCP ii. 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

NRG response: As stated above, NRG supports a simple approach to meeting the goals of the statute and encourages the Commission to avoid temptations to overengineer rate design to perfectly match cost causation, which is an impossible task. The data filed in this project to date indicates that simply moving to a 12CP or 365CP would go a long way toward satisfying this goal. Increasing the interval from 15-minutes to something longer (e.g., 4 hours if fewer CPs, such as 12, are used, or 1 hour if 365 CPs are used) would also reduce the ability to engage in cost shifting behavior. Again, the overarching goal of this project should be to ensure that the allocation of transmission costs is "appropriate" and equitable and that the average Texan is not unduly saddled with the billions of dollars of investment in transmission infrastructure that will need to be made to accommodate the large loads that plan to locate in the state.

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 require additional staff or stakeholder processes?

NRG response: Again, NRG does not recommend attempting to overcomplicate transmission cost allocation by trying to exactly match it to the complex transmission modeling and planning processes at ERCOT. It's not clear that the modeling data used by ERCOT could be used for allocation of transmission costs since the load data provided by TDUs to ERCOT in the transmission planning process is not separated by customer class. Instead, the Commission should focus on reducing or eliminating cost shifting to the greatest extent feasible by increasing the number of CPs and the duration of the interval that is measured for purposes of transmission cost allocation.

III. CONCLUSION

NRG appreciates the Commission's consideration of its comments as the Commission undertakes the evaluation of transmission cost recovery and allocation in ERCOT.

Respectfully submitted,

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- The Legislative goal of including transmission cost allocation in Senate Bill 6 (SB6) was to ensure that the average Texan (i.e., the residential customer class) does not bear more than their fair share of the costs of transmission investment—i.e., that all loads are "*appropriately assigned*" and "*appropriately contribute*" to the recovery of those costs.[31]
- The costs of the ERCOT transmission system are caused by a myriad of reasons unrelated to system demand at the four coincident peaks (4CPs), including to serve non-coincident peak (NCP) demand of each disparate transmission and distribution utility (TDU) system, resolve renewable resource export constraints, manage clearance of transmission outage needs, and improve system resiliency.
- Based on historical transmission cost of service (TCOS) data, there is no evidence of avoided transmission cost due to 4CP, even with record amounts of participation by large consumers in the past 5 years.
- The data provided by the ERCOT Transmission and Distribution Service Providers (TDSPs) in this project demonstrates the cost shifting that occurs through the current TCOS allocation that uses demand during the 4CP 15-minute intervals.
- The TDSP data also clearly demonstrates the need to update the class allocation factors on an annual basis as the Commission Staff is proposing to do in Docket No. 58923 since the allocators in some TDSP territories deviate considerably from the actual 4CP data.
- There is no "perfect" cost causation model, but avoiding cost shifting is an important part of achieving "appropriate" cost allocation because it better aligns with the principles of cost causation by reflecting a more accurate use of the transmission system by consumers, rather than a brief distortion of large customer's usage patterns.
- Large loads subject to the interconnection standards in PURA § 37.0561 should be required to pay for all their interconnection facility costs through the contribution in aid of construction (CIAC) as part of their interconnection agreement with their interconnecting utility. This will ensure other consumers do not have to pay for the interconnection costs of large load customers. The Commission is already considering this issue in the pending project on large load interconnection standards (Project No. 58481) and need not add it to the issues under evaluation in this project (58484).
- Consistent with the Legislative directive for the PUC to reevaluate 4CP, the goal of this project should be to ensure an equitable allocation of transmission costs to consumers by eliminating cost shifting to the greatest extent possible, and the best way to do that would be to increase the number of coincident peaks and the duration of the intervals used in the methodology. The Commission does not need to change retail rate design to accomplish this goal.
- A 365CP methodology with an hour duration interval or a 12CP methodology with a consecutive 4-hour duration interval would accomplish the goal without the need for an overly complicated methodology. The PUC could also evaluate a hybrid methodology using monthly NCPs.

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[31] SB6, § 6 (emphasis added). SB6, §1 similarly reflects the Legislature's concern for protecting average Texans from bearing the brunt of costs associated with interconnecting large loads—i.e., by requiring that the Commission ensure that large loads contribute to the interconnecting utility's costs to interconnect the large load to the utility's system.