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 AUGUST 5, 2025 QUESTIONS

NRG Energy, Inc. (NRG) appreciates the opportunity to provide comments in this project in response to the Staff's 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

NRG appreciates the Commission's thorough evaluation of the existing 4CP transmission cost allocation mechanism. NRG first formally raised concerns with the 4CP mechanism in the spring of 2017 as outlined in the report titled "Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT"[2] by Dr. William Hogan and Dr. Susan Pope. In their analysis and extensive critique of 4CP, they concluded:

> Demand reductions resulting from the 4CP transmission cost-recovery mechanism are not in response to high system marginal costs, but instead are in response to the allocation of sunk costs. On a net basis, there are no cost savings, only a reallocation of the costs to other customers.[3]

The 4CP mechanism is not just outdated, it has become an increasingly unreasonable method of allocating transmission costs because it is completely disconnected from the actual costs incurred to develop, maintain, and operate the ERCOT transmission system. Its protracted existence has resulted in significant transmission cost shifting benefitting some customer classes

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

[2] *See Project to Assess Price Formation Rules in ERCOT's Energy-Only Market*, Project No. 47199, William W. Hogan & Susan L. Pope, "Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT" (filed May 22, 2017) (hereafter, Hogan/Pope Paper), *available at* 47199_2_941113.PDF. NRG and Calpine Corporation supported the development of this paper.

[3] *Id.* at 78 (Bates page 83).

to the detriment of others. Therefore, this effort to update the transmission cost allocation mechanism so that it more equitably distributes the cost burden among customer classes is critically important, and NRG looks forward to participating in all aspects of the effort.

NRG offers that a meaningful analysis of the 4CP methodology should begin with a shared understanding of the mechanics by which transmission costs are allocated today (the "steps") and agreement on which steps of that process will be evaluated in this proceeding (the "scope"). The three steps of the 4CP method of allocating transmission costs are discussed in detail in Section II.A of these comments but can be briefly summarized as follows:

- **Step 1,** ***Allocation to DSPs***: ERCOT-wide transmission costs are allocated to distribution service providers (DSPs) (i.e., ERCOT transmission and distribution utilities, municipally-owned utilities, and electric cooperatives) based on 4CP.
- **Step 2**, ***Allocation to Rate Classes***: DSPs allocate their share of transmission costs to their rate classes (e.g., Residential, Secondary ≤ 10kW, Transmission). DSPs for the Investor-Owned Utilities (IOUs) allocate transmission costs to their rate classes based on 4CP.
- **Step 3**, ***Recovery from Customers***: DSPs recover transmission costs from customers in each rate class based on billing determinants that differ based on rate classes (e.g., Residential customers are billed on a volumetric (per kilowatt-hour (kWh)) basis; Transmission customers are billed on 4CP).[4]

The first two steps of this process involve cost allocation while the third step involves rate design. Regarding scope, NRG offers that it would be most effective for the Commission's focus in this proceeding to be on Steps 1 and 2 – changing the methodology to allocate transmission costs to all DSPs (including municipally-owned utilities and electric cooperatives) and among consumer classes for each DSP in the IOU service territories. The complexities of rate design (Step 3) are arguably best left to the side until the allocation issues attendant to Steps 1 and 2 have been fully re-examined.

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[4] In areas of the state open to retail competition, DSPs invoice retail electric providers (REPs) to recover their costs. REPs are the primary point of contact for end-use customers and are responsible for paying DSPs for all transmission and distribution charges applicable to customers the REP serves.

As more fully detailed below, NRG maintains that the allocation of transmission costs to DSPs (Step 1) and the allocation of costs from the IOU DSPs to their customer classes (Step 2)[5] should be changed from the current 4CP mechanism to something more equitable, so that the costs that are ultimately allocated to individual customers are more fairly split from the outset. NRG also suggests that should the Commission wish to pursue changes to the structure of transmission rates for the customer classes of DSPs within the Commission's ratemaking jurisdiction, one way to further accommodate the impacts of large loads, besides moving away from 4CP which should happen regardless, would be to create a new rate structure (e.g., a subclass) for loads greater than 75 MW within the transmission class for IOU territories for those customers.

II. BACKGROUND

A. Current Methodology for Allocating Transmission Costs in ERCOT and Context for SB6 Requirement for a Reevaluation of the 4CP Methodology

Transmission costs in ERCOT have been allocated based on the 4CP methodology since the implementation of restructured wholesale and retail competitive markets over 20 years ago.[6] Under this methodology, as noted above, transmission costs are allocated in three steps. In Step 1, transmission costs are allocated from the total ERCOT transmission cost-of-service revenue requirement (TCOS)[7] to each DSP on the basis of the DSP service territory's 15-minute peak load interval during each the four summer months of June, July, August, and September.[8] In Step 2, each DSP further allocates the transmission costs to each of its customer classes, again on the same

[5] NRG acknowledges that the Commission does not have jurisdiction to order a different cost allocation to customer classes for DSPs that are electric cooperatives and municipally owned utilities, as those entities set their own retail rates and customer class allocations. However, changing the customer class cost allocation just for the ERCOT TDUs would be meaningful—in the 2025 wholesale transmission cost matrix, those TDUs account for over 70 percent of the demand at the 4CP intervals. *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).

[6] The Commission established the customer classes and structure for transmission owners to recover their costs from distribution service providers in its 2000 to 2001 proceeding to implement the Texas Legislature's 1999 directive, in Senate Bill 7, to unbundle the investor-owned utilities and transition to a competitive retail electricity market. *See generally Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA Section 39.201 and Public Utility Commission Subst. R. 25.344*, Docket No. 22344, Order No. 40 (Nov. 22, 2000).

[7] *See, e.g.*, Docket No. 57491, Commission Staff's Final Transmission Charge Matrix, Attachment A, at 2 (Mar. 20, 2025) (calculating total ERCOT-wide TCOS for 2025 at ~$5.4 billion).

[8] 16 Tex. Admin. Code (TAC) § 25.192(d).

4CP basis.[9] Finally, in Step 3, rates are calculated to collect those costs from each customer class based on the approved tariffs of the applicable TSP.

It is at this last step that the recovery of costs from individual customers within each class deviates from a purely 4CP basis. For large industrial and commercial customers, 4CP is again used in the design of the rates facing those customers, consistent with the upstream allocation of costs. Meanwhile, residential customers—even though the costs were allocated to their class based on 4CP—pay rates that are based on energy consumption using a volumetric charge per kilowatt-hour.[10] Historically, this flattening of a demand-per-kW to a volumetric-energy charge for the residential class rate design was predicated on the limitations of metering, as explained in response to Question 1(b), although other sound reasons exist for this rate design also. Whatever the reason, large customers, unlike residential customers, pay rates that allow them to bypass the transmission costs allocated to their respective class, and large customers are thus incentivized to reduce their electricity consumption during those four 15-minute summer peak intervals. Their action both avoids costs to such customers themselves and, through subsequent ratemaking processes, reduces the allocation of costs at Steps 1 and 2, because their usage at the 4CP intervals affects the total demand (and thus allocation) to their corresponding DSP and class. These costs are shifted onto other customer classes, especially to residential customers, as the data NRG provides below in answer to Questions 1 and 3 demonstrates.

If the 4CP mechanism continues to be applied to all stages of TCOS allocation once the costs related to the Permian Basin Reliability Plan (PBRP) and the 765kV Strategic Transmission Expansion Plan (STEP) are included in the total TCOS, the current transmission cost recovery and rate design will allow new large loads to avoid the cost of building the very transmission that had

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[9] *See, e.g.*, *Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates*, Docket No. 49421, Commission Number Run Memo: Attachment C.3 at 1 (Dec. 5, 2019); *see also Application of AEP Texas Inc. to Update TCRF Allocators in Compliance with Docket No. 49494*, Docket No. 53236, Application of AEP Texas Inc. to Update TCRF Allocators in Compliance with Docket No. 49494 Attachment A (Feb. 16, 2022); *see also Application of Oncor Electric Delivery Company LLC for Authority to Change Rates*, Docket No. 53601, Finding of Fact No. 265 (Jun. 30, 2023); see *generally* Docket No. 22344, Direct Testimony of Kit Pevoto Class Classification & Rate Design Phase at 25 (Oct. 16, 2000) ("Once the transmission revenue requirement for each distribution utility is determined, the transmission revenue requirement for each distribution utility should be allocated among classes based on the 4-CP allocation method. This is because the 4-CP method is the same method used to determine each load entity's load share of the total ERCOT transmission costs.").

[10] This allocation methodology is reflected in the Commission-approved Retail Delivery Service tariffs for the individual TSPs, *available at*: Transmission and Distribution Rates for Investor Owned Utilities (texas.gov).

been justified by the emergence of these large loads. This is partly why the Legislature included the sections on transmission cost allocation in SB6 and directed the evaluation and, if deemed warranted following that evaluation, the modification of 4CP to a different mechanism to ensure transmission costs are equitably distributed among all customer classes. Before discussing the pros and cons of the existing 4CP mechanism on various parts of the ERCOT market as outlined in numerous questions, it would be helpful to elaborate on the incentives created by 4CP and the divergent impacts on the customer classes.

B. Financial Incentives Created by 4CP and Divergent Impacts on Customer Classes

The financial incentives created by 4CP are substantial, concentrated, and difficult to ignore by large loads that stand to benefit from it. ERCOT's transmission rate is currently $68.55[11] per kilowatt-year, which represents a 121% increase since 2013, before the Competitive Renewable Energy Zone (CREZ) rate impacts began.[12,13] Based on the range of 4CP rates in the tariffs for the investor-owned ERCOT transmission and distribution utilities (TDUs), a 500-megawatt large load could potentially avoid between ~$20.4 and $42.7 million annually in transmission costs by successfully removing their energy consumption from the grid, either through load curtailment or running backup generation, during each of the four 15-minute 4CP intervals.[14] Put another way, 4CP acts like a ~$10,000 to $21,000 per megawatt-hour (MWh) price

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[11] Docket No. 57491, Commission Staff's Final Transmission Charge Matrix, at Attachment A, at 2 (Mar. 20, 2025), *available at*: interchange.puc.texas.gov/Documents/57491_51_1481446.PDF.

[12] *Commission Staff's Application to Set 2013 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas*, Docket No. 40946, Commission Staff's Revised Final Transmission Charge Matrix, Attachment A, at 2 (Feb. 21, 2013) (reflecting an ERCOT transmission rate of $30.95 per kW-year), *available at* 40946_48_750608.PDF.

[13] This growth in the ERCOT transmission rate significantly exceeds inflation. If the rate had increased in line with inflation, it would be only $42.89 per kilowatt-year. Calculation derived from Bureau of Labor Statistics Consumer Price Index calculator. https://www.bls.gov/data/inflation_calculator.htm.

[14] This annual savings range is based on the highest and lowest monthly 4CP rates (each effective 9/1/2025) in the tariffs for the four investor-owned ERCOT TDUs (AEP Texas, CenterPoint, Oncor, and TNMP), converted from a per kW to a per MW charge, then multiplied by 12 months, and then multiplied by 500 MW. Specifically, the lowest rate is Oncor's transmission class at $3.395215 per kW ((($3.395215 x 1000) x 12) x 500) = $20,371,290); and the highest 4CP rate is TNMP's secondary class > 5 kW rate at $7.109469 per kW ((($7.109469 x 1000) x 12) x 500) = $42,656,814). *See Petition of AEP Texas Inc. to Update its Transmission Cost Recovery Factor*, Docket No. 58157, Clean Tariff (filed Jul. 8, 2025); *Petition of Texas-New Mexico Power Company to Update its Transmission Cost Recovery Factor*, Docket No. 58161, Clean Tariff (filed Jul. 3, 2025); *Petition of Oncor Electric Delivery Company LLC to Update its Transmission Cost Recovery Factor*, Docket No. 58164, Clean Tariff (filed Jul. 11, 2025); *Petition of CenterPoint Energy Houston Electric, LLC to Update its Transmission Cost Recovery Factor*, Docket No. 58178, Clean Tariff (filed Jul. 17, 2025).

signal,[15] substantially above the energy market's price cap. It is a hugely influential force on customer energy usage, indeed even more influential than scarcity energy pricing—at least for those customers exposed to it.[16] As transmission costs have continued to increase, ERCOT has reported that the number of large customers responding to 4CP has escalated rapidly, increasing from 418 in 2022 to 1,080 in 2024.[17]

The current participation in 4CP does not yet reflect the amplified incentive for cost avoidance because TCOS does not include the capital and expense of transmission projects approved for construction or in the process of being constructed, which is $14.90 billion.[18] Nor does it include the PBRP and yet to be approved 765kV STEP (and associated projects) with a capital cost between $30.75 billion and $32.99 billion.[19] NRG estimates that the $30 to $33 billion expenditure would nearly double the current annual TCOS, increasing it by more than $5 billion (from the current $5.4 billion to over $10 billion) per year based on a reasonable depreciation lifespan, a conservative estimate of the cost of capital, and an imputation of operating costs in line with current utility data.[20] This would cause 4CP-related cost shifting, described further below, to increase substantially.

Flowing transmission costs of this magnitude through the existing 4CP transmission cost mechanism will disproportionately impact residential consumers. Looking only at the CenterPoint

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[15] This number range was calculated by dividing $20,371,290 and $42,656,814, respectively, by 500 MW and then by four (for each of the 4CP intervals).

[16] Again, residential customers have no ability to pay lower TDU delivery rates by curtailing usage during 4CP, and though NRG is not advocating that residential customers be charged on a 4CP basis, NRG raises this fact to point out that residential customers are harmed by cost shifting, without any ability to avoid that harm by participating in their own cost shifting behavior. Moreover, ironically, since 4CP is calculated on the basis of gross peak load, when the energy price can be relatively low due to heavy renewable production, customer responsiveness at these hours offers little in the way of supplementary system reliability value.

[17] *See* ERCOT, "2024 Report on Demand Response in the ERCOT Region", at 17 (Feb. 2025), *available at*: 2024 Report of Demand Response in the ERCOT Region.

[18] ERCOT, System Planning and Weatherization Update, at slide 9 (Feb. 3, 2025), *available at*: PowerPoint Presentation (slide 9).

[19] *Reliability Plan for the Permian Basin under PURA § 39.167*, Project No. 55718, ERCOT, 2024 Regional Transmission Plan 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan Comparison, at iii (Jan. 24, 2025), *available at:* 55718_54_1462478.PDF; *see also* Project No. 55718, Order Approving the Reliability Plan for the Permian Basin (Oct. 7, 2024) (approving the PBRP but reserving a decision on the voltage level for the import paths) and Second Order Approving the Reliability Plan for the Permian Basin Region (Apr. 24, 2025).

[20] Specifically, NRG used conservative estimates of a 7.0% weighted average cost of capital (WACC), 30-year depreciation lifespan, and 2% rate of operational expenditures necessary to support the new capital expenditures.

service territory for 2023, residential consumers used 32% of the electricity but were allocated 49% of the transmission costs.[21] By comparison, the transmission connected class of consumers (the largest consumers of electricity) used 31% of the electricity in the CenterPoint territory in 2023 but were only allocated 18% of the transmission costs.[22] This gap will widen if more 4CP-responsive large loads are added to the system in tandem with escalating transmission costs.

Transmission expansion in ERCOT has historically been driven by non-coincident TDU system peak-demand (see NRG response to Question 6), not the four coincident summer peaks on the ERCOT system. As detailed further below, TDUs assess the needs for their individual transmission system based on their own peak demand (which is unlikely to align with the ERCOT-wide 4CP), which has been the case since before restructuring of the ERCOT wholesale market. The current ERCOT transmission planning process originated from this regionalized process but has remained consistent in this aspect. However, as the ERCOT system has evolved over the years, other needs have surfaced, and transmission expansion projects have been approved for policy reasons that have an even weaker association with ERCOT system peak demand. For example, CREZ transmission lines were built pursuant to a statutory mandate for the Commission to approve a plan to transfer renewable energy from remote locations to load centers in the most "beneficial and cost-effective" manner, not their ability to meet peak demand.[23] Many other major transmission projects recently have not correlated with ERCOT system peak demand such as

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[21] *Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates*, Docket No. 56211, Application at Schedule II-H-1.4: Adjusted Test Year Load Data (bates page 3509) (Mar. 6, 2024) (reflecting total adjusted electricity consumption, for all of 2023, by the residential class of 33,586,200 megawatt-hours (MWh) (at the source) out of an annual total (for all classes) of 106,616,630 MWh, which is approximately 32 percent); Docket No. 56211, Stipulation and Settlement Agreement, at Ex. B, Tab IV-J-7 TCRF (Jan. 29, 2025) (showing a proposed allocation factor of 49% for the residential class for future TCRF updates); Docket No. 56211, Order at 10 (Mar. 13, 2025) (approving the allocation factors proposed in the settlement).

[22] Docket No. 56211, Application at Schedule II-H-1.4: Adjusted Test Year Load Data (bates page 3509) (reflecting total adjusted electricity consumption, for all of 2023, by the transmission class of 33,429,590 MWh (at the source) out of an annual total (for all classes) of 106,616,630 MWh, which is approximately 31 percent); Docket No. 56211, Stipulation and Settlement Agreement, at Ex. B, Tab IV-J-7 TCRF (Jan. 29, 2025) (showing a proposed allocation factor of 18% for the transmission class for future TCRF updates); Docket No. 56211, Order at 10 (Mar. 13, 2025) (approving the allocation factors proposed in the settlement).

[23] *See generally Commission Staff's Petition for Designation of Competitive Renewable Energy Zones*, Docket No. 33672, Order on Rehearing (Oct. 7, 2008) (the designation of CREZ transmission plan was based on the statutory directive, in then-effective PURA § 39.904(g)(2), to identify the transmission plan that would deliver renewable energy from the areas designated as having the best renewable energy development potential in the state (i.e., the CREZ) to customers in the most beneficial and cost-effective manner).

projects in West Texas,[24] the Rio Grande Valley,[25] and Gulf Coast.[26] The demands on the ERCOT transmission system have changed given the evolution to a more dynamic supply mix and load growth pattern. The PBRP and 765kV STEP will serve large loads that mainly consume electricity at all hours of the day without correlation to system peak (and that were approved by the Commission based on statutory mandates unrelated to system peak).[27]

The demand response that 4CP produces is substantial, but it does nothing to support resource adequacy in ERCOT, nor has it avoided new transmission construction, nor is it related to the newest and most expensive transmission being constructed. In short, 4CP is a huge financial incentive—but it's an incentive to nowhere. The magnitude of transmission costs required to support the emergent growth of large loads is a tipping point and, without reform, residential customers will face substantial and disproportionate rate increases. Before any costs associated with new, large transmission projects are included in rates, a new approach to transmission cost allocation must be implemented, and NRG appreciates the efforts of the PUCT to do so expeditiously.

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[24] *See, e.g.*, ERCOT, "Long-Term West Texas Export Study" (Jan. 2022) (identifying long-term transmission improvement options to alleviate constraints in West Texas due to the substantial growth of inverter-based resources in the area), *available at*: https://www.ercot.com/files/docs/2022/01/14/Long-Term-West-Texas-Export-Study-Report.pdf; ERCOT, "Delaware Basin Load Integration Study" (Dec. 2019) (describing potential reliability transmission needs to meet higher-than-forecasted electric demand driven by the oil and gas industry and associated economic expansion in the Delaware Basin area in far West Texas), *available at*: https://www.ercot.com/files/docs/2019/12/23/ERCOT_Delaware_Basin_Load_Integration_Study_Public_Version.zip; ERCOT, "Combined Delaware Basin Stage 5 Project and Alternative – ERCOT Independent Review Study Status Update, at Appendix C (Mar. 18, 2025) (providing updates on status of projects identified in the Delaware Basin report, most of which have been endorsed and are in progress).

[25] *See Project for Commission Ordered Transmission Facilities*, Project No. 52682, Order (Oct. 14, 2021) (ordering two projects in the Rio Grande Valley under PURA §§ 35.005(b) and 39.203(e), in order to ensure "safe and reliable electric service").

[26] *See CenterPoint, "Freeport Master Plan Project"* (May 2017) (serving flat industrial load identified on slide 10 presented to the Regional Planning Group on 5/15/2017), *available at*: https://www.ercot.com/files/docs/2017/05/15/CNP_Freeport_Master_Plan_RPG_Presentation_05162017.pptx.

[27] *See generally* Project No. 55718, ERCOT Permian Basin Reliability Plan Study (Jul. 2024) and ERCOT 2024 Regional Transmission Plan 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan Comparison (Jan. 24, 2025). Under House Bill (HB) 5066, adopted by the 88th Texas Legislature in 2023, the PBRP must extend transmission service to areas where mineral resources have been found, address increasing available capacity to meet forecasted load, and provide available infrastructure to reduce interconnection times in areas without access to transmission service.

III. RESPONSES TO STAFF QUESTIONS

Question 1: What are the pros and cons of the existing four coincident peak (4CP) retail cost allocation and rate design? In your response, please address impacts to the following:

a. The Wholesale Market:

NRG response: The existing 4CP transmission cost allocation mechanism has evolved into the largest demand response "program" in the ERCOT market due to the steady increase in transmission costs which are up to nearly $5.5 billion per year.[28] At the current postage stamp rate of $68,500/MW (and current 4CP tariff rates ranging from ~$41,000/MW to $85,000/MW on an annual basis and ~$10,000 to $21,000/MW in a 4CP interval[29]), large electricity consumers have significant financial incentives to reduce consumption to avoid these costs. However, this reduction in electricity consumption has nothing to do with the price or cost of wholesale electricity, and those customers acting in relation to it do not appear to reduce or avoid future incremental transmission-related expenditures, based on how ERCOT and TDUs plan the transmission system. While the reduction in electricity consumption during periods when large electricity consumers "chase" 4CP intervals does (at present, slightly) lower the cost of electricity for the ERCOT market, the price of electricity should accomplish the same outcome, and do so consistently with market-based principles, by encouraging reduced consumption during times of high prices. In addition, the benefits of reduced electricity prices were more meaningful in the past when the highest wholesale prices were realized at the time of ERCOT summer peak demand. Those benefits are now muted since solar and battery production keep wholesale prices low during summer peak demand. Thus, the 4CP mechanism creates an out-of-market price signal that historically distorted wholesale energy pricing, but now largely has little to no impact on energy

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[28] Docket No. 57491, Commission Staff's Final Transmission Charge Matrix, Attachment A, at 2 (Mar. 20, 2025), *available at* 57491_51_1481446.PDF.

[29] These figures are based on the lowest and highest 4CP rates in the currently effective tariffs for the ERCOT TDUs. Specifically, the lowest rate is Oncor's transmission class at $3.395215 per kW, which equals $40,742.58 per MW per year (i.e., ($3.395215 x 1000) x 12 = $40,742.58) and $10,185.65 per 4CP interval (i.e., $40,742.58/4 = $10,185.65); and the highest 4CP rate is TNMP's secondary class > 5 kW rate at $7.109469 per kW, which equals $85,313.63 per year (i.e., ($7.109469 x 1000) x 12 = $85,313.63) and $21,328.41 per 4CP interval (i.e., $85,313.63/4 = $21,328.41). *See* Docket No. 58157, AEP's Clean Tariff (filed Jul. 8, 2025); Docket No. 58161, TNMP's Clean Tariff (filed Jul. 3, 2025); Docket No. 58164, Oncor's Clean Tariff (filed Jul. 11, 2025); Docket No. 58178, CenterPoint's Clean Tariff (filed Jul. 17, 2025).

prices, while acting to shift significant transmission costs on smaller customers.

b. <u>The Retail Market</u>:

<u>NRG response</u>: As background, the initial rate classes and the billing determinants to be used within each customer class were adopted by the Commission in the generic unbundling docket that was initiated to implement Senate Bill 7, adopted in 1999,[30] which enabled the transition to a competitive retail electricity market. In that docket, the Commission adopted six generic customer classes: (1) residential; (2) secondary less than 10 kW or kilovolt-ampere (kVA) (less than 5 kW for TNMP); (3) secondary greater than 10 kW or kVA (greater than 5 kW for TNMP); (4) primary; (5) transmission; and (6) lighting.[31] The Commission then approved billing determinants for each class (which is the way that transmission costs allocated to a class will be billed to an individual customer's retail electric provider (REP)) and decided that it was appropriate to establish those determinants based on the metering capabilities of the customers at that time—(a) customers without demand meters (i.e., residential and small commercial customers) would be billed on an energy basis (i.e., per kWh); (b) customers with non-interval data recorder (non-IDR) demand meters would be billed per non-coincident peak (NCP) demand; and (c) customers with IDR demand meters would be charged for distribution charges on an NCP basis and for transmission charges on a 4CP basis.[32] The Commission effectively determined that the metering capabilities at that time were a reasonable proxy for cost causation and maintained a continuity with past rate design methodology.[33] Following the generic unbundling docket in 2000, the individual ERCOT TDUs have generally adhered to the precedent from that docket and continue to bill REPs for their individual customer's use of the transmission system in the same manner as approved in that docket.[34]

In the past several years, NRG has observed a steady increase in the portion of the retail customer bill that is comprised of transmission and distribution charges, especially for residential

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[30] 76th Tex. Leg., R.S., Senate Bill 7 (eff. Sept. 1, 1999).

[31] Docket No. 22344, Order No. 40 at 3 (Nov. 22, 2000).

[32] *Id.* at 6-7.

[33] *Id.* at 7.

[34] *See supra* notes 14 and 29 for citations to the most recent TCRF cases and associated tariffs for the four ERCOT investor-owned TDUs.

customers. Since the 4CP mechanism is effective at shifting costs among classes (i.e., Step 2 of the cost allocation described in the Background section above), it has a significant impact on the retail market. NRG is concerned that if a transmission cost allocation mechanism is retained that continues to encourage cost shifting coupled with the magnitude of transmission cost increases coming to ERCOT consumers for the PBRP and 765kV STEP projects, it could overwhelm residential consumers' bills in the areas of the state open to competition, which would be detrimental to the options customers currently enjoy when choosing among retail offers. If a residential consumer's bill were mostly comprised of wires charges, they arguably would have less financial motivation to switch to other REPs based on energy prices.

With that said, the cost shifting to residential customers does not happen primarily at the stage at which TDUs bill REPs for their customers' individual transmission costs (i.e., Step 3, the billing determinant phase); at that point, the transmission costs have already been allocated to customer classes, and 4CP cost shifting within a particular customer class with 4CP-based billing determinants primarily impacts what an individual customer within that particular class pays (not what a customer in a different class pays – though there can be an upstream impact on future allocations to a class with 4CP billing if the customers within that class are particularly good at reducing consumption during the 4CPs). Thus, NRG contends that equitable outcomes between customer classes can result from changes to the upstream allocation of transmission costs, without modifying downstream rate design. As is discussed in more detail in the response to subparts (c) and (d) below, NRG supports the rate structures, particularly for residential and small commercial customers, within the existing TDU tariffs, with the exception of possibly creating a new class (or subclass) for transmission connected large loads (as discussed further under Question 10 below), due to complexity of transmission pricing and impacts to the billing processes for REPs and TDUs.

c. Ratepayers Generally; and

d. Specific Customer Classes (e.g., Residential, Small Commercial):

NRG response: Ratepayers are exposed to the impacts of 4CP in many ways. For the residential and small commercial customer classes, 4CP is employed only for allocation to those customer classes (and not, as noted above, for purposes of billing those specific classes). The actual transmission rate that any customer within those classes will be charged is generally derived by taking the customer class's total allocated costs, dividing it by the kilowatt-hours the class consumed, and deriving a cents-per-kilowatt-hour rate. For commercial and large industrial customers with IDR meters, 4CP is used as the billing determinant consistent with the upstream allocation of costs (and those without IDR meters are billed on an NCP basis). This contrast in approach for customer classes has positive impacts, most notably the mitigation in complexity of rates for smaller customers. However, this disparate rate treatment also results in negative consequences related to the ability of some customers classes to fully monetize the benefits from participation in demand response programs.

Pros of consumption-based charges for smaller customers:

Consumption-based charges ($/kWh) for the residential and small commercial (typically less than 10 kW) rate classes to recover transmission costs have several positive attributes. They are simple and readily understood by end-use consumers. Relatedly, they have some degree of comparability to energy and other TDU charges that are usually billed on a volumetric-energy basis, allowing an apples-to-apples comparison between consumer-facing costs in the retail market. Finally, these charges are able to be passed through directly from REPs to end-use customers, without the possibility of any over- or under-recovery, such that the regulated charge propagates through to the customer at the Commission-approved level, no more and no less. The Commission has approved this method of recovery in TDU rate cases as a reasonable alternative variable for primary cost drivers of premise facilities size, maximum usage level, and coincidence with other users.[35] This methodology has long standing customer acceptance and understanding and does not expose less sophisticated customers directly to demand charges. Any changes to the current methodology would require changes to each TDU's Tariff for Retail Delivery Service and significant and costly changes to the TDU's, REPs', and ERCOT's IT systems at a time when ERCOT and the market are undertaking a number of other critical projects.

Cons for smaller customers resulting from 4CP allocation and rate design for larger customers

The current 4CP allocation and rate design methodology generally results in unfavorable rate impacts to residential and small customer classes in ERCOT. Commercial and industrial customers can reduce their share of total transmission costs by reducing their electricity

[35] *Supra* note 31 and accompanying text.

consumption during the four 15-minute summer peak intervals. Moreover, by collectively reducing their class's consumption of electricity during 4CP periods, the allocation of new transmission costs to the larger load classes is further reduced. This allows new large loads to potentially avoid the bulk of the cost of building the new transmission that had been justified by the emergence of these large loads.

As detailed above, based on the current ERCOT postage stamp rate of $68.55/kW and corresponding 4CP transmission rates billed by TDUs to customers in the competitive areas of ERCOT, large customers can reduce the transmission charge component of their bill by $10,000 to $21,000/MW by curtailing consumption during one of the peaks. If a customer can curtail consumption during all four peaks, they stand to benefit from savings of $41,000 to $85,000 per megawatt.[36] TDUs in the competitive areas of ERCOT have modified their tariffs such that all ESIIDs with peak demands over 700 kW (which is the threshold in ERCOT's Protocols that triggers a requirement to install an IDR meter) are billed on a 4CP basis and thus have the incentive and ability to avoid those charges by selectively reducing demand during the intervals they think will be included in the 4CP sample.[37] Active customer efforts to avoid these charges are responsible for most of the demand response achieved in ERCOT each year. In fact, ERCOT reported that over 4,000 unique ESIIDs responded to 4CP events in 2024.[38] Additionally, the current level of participation in 4CP does not yet consider the cost of pending transmission projects.

In contrast, while the existing 4CP structure allows and encourages larger commercial and industrial customers to "value stack" from demand response activities by avoiding both energy and transmission costs, residential and small commercial customers do not have that opportunity. Instead, those customers, to the extent they participate in retailer-offered demand response

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[36] *See supra* notes 28-29 and accompanying text.

[37] *See, e.g.*, Tariff for Retail Delivery Service (Tariff) for Oncor Electric Delivery Company, LLC, at Rider 6.1.1 (eff. May 1, 2023) ("Any Premises that has established an NCP kW of at least 700 kW in any previous billing month, or Retail Customers billed on 4CP kW prior to the effective date of this tariff, shall be billed on their 4CP kW pursuant to the Determination of 4CP kW provision shown below."). The Tariffs for each of the other ERCOT TDUs contain similar language and are available here: https://www.puc.texas.gov/industry/electric/rates/tdr/. ERCOT currently requires IDR meters to be installed for loads with peak demand greater than 700 kW (see ERCOT Protocols § 18.6.1(1)), and thus 4CP billing for such customers is consistent with the practice, since market open, of billing customers with IDR meters on a 4CP basis. *See supra* note 31 and accompanying text.

[38] *See* ERCOT, "2024 Report on Demand Response in the ERCOT Region", at 21 (Table 17) (Feb. 2025), *available at*: 2024 Report of Demand Response in the ERCOT Region.

programs (e.g., smart thermostats) will benefit only from the reduction in energy consumed without the potential for a reduction in the transmission charge. There is no further ability under the current rate design to benefit from exposure to ERCOT transmission costs, which are currently $68.55/kW.

<u>Question 2</u>: <u>How have congestion and wholesale market prices been impacted by the 4CP retail cost allocation and rate design?</u>

<u>NRG response</u>: With respect to wholesale market prices, because the 4CP transmission cost allocation mechanism creates a transmission price signal, and one that is meaningful and easy to respond to for the larger customer classes that are billed on that basis, it greatly distorted the pricing outcomes in the ERCOT wholesale market in the past. However, as indicated under Question 1(a) above and Question 4 below, with the substantial growth in renewable resources over the past decade, 4CP cost allocation now has little effect on wholesale energy prices based on when the 4CPs occur relative to scarcity pricing (i.e., at gross peak load when renewable penetration is high and thus prices are lower). Thus, while 4CP cost allocation no longer substantially distorts wholesale energy prices, it also has few benefits for smaller customer classes in terms of lowering their energy costs, while at the same time increasing the transmission portion of their bill.

With respect to congestion, while a reduction in load at the 4CP intervals could provide some benefits in the form of reduced congestion, it is likely minimal given that most congestion occurs in the shoulder seasons[39] during transmission outages or during periods of high renewable output and lower loads. During the summer peaks on the ERCOT system, most generation resources are online near the load centers, which reduces the most meaningful congestion patterns. The congestion that does occur in hot summer periods are within the load zones at lower voltage levels.[40] The 4CP transmission price signal is much higher than the shadow price for transmission constraints[41] so avoiding transmission costs is more economic for large loads than avoiding

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[39] *See* Potomac Economics, "2024 State of the Market Report for the ERCOT Electricity Markets," at 49, Figure 38 (May 2025) (reflecting congestion costs per month), *available at*: https://www.potomaceconomics.com/wp-content/uploads/2025/06/2024-State-of-the-Market-Report.pdf.

[40] *Id.* at 49, Figure 38, see "Cross-Zone" congestion (May 2025).

[41] As noted earlier, the 4CP transmission price signal ranges from $10,000 to $21,000/MW, *see supra* note 29, while the shadow price caps range from $2,800/MW to $5,251/MW. *See* ERCOT Protocols § 22, Attachment P, *Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints*.

congestion costs. But 4CP response is not regional, it is system wide. This limits any benefits of 4CP in reducing congestion. 4CP can actually exacerbate congestion due to its concentrated price signal. In situations where a load could balance the flow of power near a constraint by continuing to consume power, 4CP would encourage the load to do the opposite and cause congestion to persist or be more severe.

<u>Question 3</u>: <u>How has 4CP price response affected residential and small commercial customers? Is this quantifiable? If so, how?</u>

<u>NRG response</u>: As discussed at length above, the 4CP method allows large consumers of electricity to shift costs to residential and small commercial customers. As reflected in the chart below, NRG has attempted to quantify the impact and determined that residential customers consume about one-third of the load in the competitive areas in ERCOT[42] but are assessed almost one-half of the transmission costs. Utilizing transmission cost class allocation factors and adjusted test year load data from the most recent approved base rate proceedings of the largest three TDUs in the competitive area of ERCOT,[43] NRG has estimated the impact to residential customers of this

[42] This data point is reflected in the rate cases summarized above and is also consistent with the most recent report by the Energy Information Administration (EIA) regarding electricity consumption in Texas (not limited to ERCOT) for 2023, which indicates that residential customers in Texas consumed ~34.2% of all electricity consumed in Texas in 2023 (168,611,000 MWh out of 492,820,000 MWh total), *available at*: [Electric Power Annual - U.S. Energy Information Administration (EIA)].

[43] *Application of Oncor Electric Delivery Company, LLC for Authority to Change Rates*, Docket No. 53601, Application at Schedule II-H-1.4: Adjusted Test Year Load Data (bates 3133-39) (May 13, 2022) and Order on Rehearing at 48 (Jun. 30, 2023) (approving Oncor's proposed allocation factors); *Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates*, Docket No. 56211, Application at Schedule II-H-1.4: Adjusted Test Year Load Data (bates page 3509) (Mar. 6, 2024), Stipulation and Settlement Agreement, at Ex. B, Tab IV-J-7 TCRF (Jan. 29, 2025) (agreed allocation factors), and Order at 10 (Mar. 13, 2025) (approving agreed allocation factors); *Application of AEP Texas, Inc. for Authority to Change Rates*, Docket No. 56165, Application at Schedule II-H-1.4: Adjusted Test Year Load Data (bates page 2429) (Feb. 29, 2024), Unopposed Stipulation and Settlement Agreement, Exhibit G TCRF Baseline (Jul. 25, 2024) (agreed allocation factors), and Order at 12 (Oct. 3, 2024) (approving agreed allocation factors).

NRG has not included Texas-New Mexico Power Company in the chart below because it has not had a base rate case since 2018 (but is due to file one in December 2025). However, the allocation factor from its most recent TCRF update and the adjusted load data from its most recent base rate case are consistent with the other ERCOT TDUs, with a ~42 percent current allocation factor for residential customers, who consumed ~32 percent of total electricity in the most recent test year (2017). *See Application of Texas-New Mexico Power Company for an Extension of Rate Filing Requirement Under 16 TAC § 25.247*, Docket No. 56249, Order (Aug. 29, 2024); Docket No. 58161, Petition of Texas-New Mexico Power Company to Update its Transmission Cost Recovery Factor at Attachment A, Tab 1 (May 27, 2025); *Application of Texas-New Mexico Power Company for Authority to Change Rates*, Docket No. 48401, Application at Schedule II-H-1.4: Adjusted Test Year Load Data (bates 3228) (May 30, 2018) (reflecting adjusted total load for the residential class of 3,118,080,674 kWh (at the source) out of 9,750,797,569 kWh total load, or ~32 percent).

shifting of costs:

Oncor
Docket #53601

Rate Class	RES	SEC <10	SEC > 10	PRI	TRAN
Transmission Cost Allocation	45.88%	1.28%	33.35%	11.15%	8.34%
Energy Consumption (kWh)	47,769,624,698	1,949,367,342	47,439,931,656	23,879,475,042	21,076,754,598
Energy Consumption %	33.52%	1.37%	33.29%	16.76%	14.79%
Differential[1]	**12.36%**	-0.09%	0.06%	**-5.61%**	**-6.45%**

CenterPoint
Docket #56211

Rate Class	RES	SEC <10 KVA	SEC >10 KVA	PRI	TRAN
Transmission Cost Allocation	48.92%	0.65%	29.03%	3.08%	18.32%
Energy Consumption	33,586,200,000	944,620,000	33,554,400,000	4,864,370,000	33,429,590,000
Energy Consumption %	31.50%	0.89%	31.47%	4.56%	31.35%
Differential[1]	**17.42%**	-0.24%	-2.44%	-1.48%	**-13.03%**

AEP Texas
Docket #56165

Rate Class	RES	SEC <10 KVA	SEC >10 KVA	PRI	TRAN
Transmission Cost Allocation	48.48%	1.92%	28.55%	8.09%	12.97%
Energy Consumption	13,539,159,700	722,776,454	9,899,118,521	4,727,025,597	11,257,072,832
Energy Consumption %	33.51%	1.79%	24.50%	11.70%	27.86%
Differential[1]	**14.97%**	0.13%	4.05%	-3.61%	**-14.89%**

Reflects difference between percentage of transmission costs allocated to the customer class and the energy consumed by the customer class.

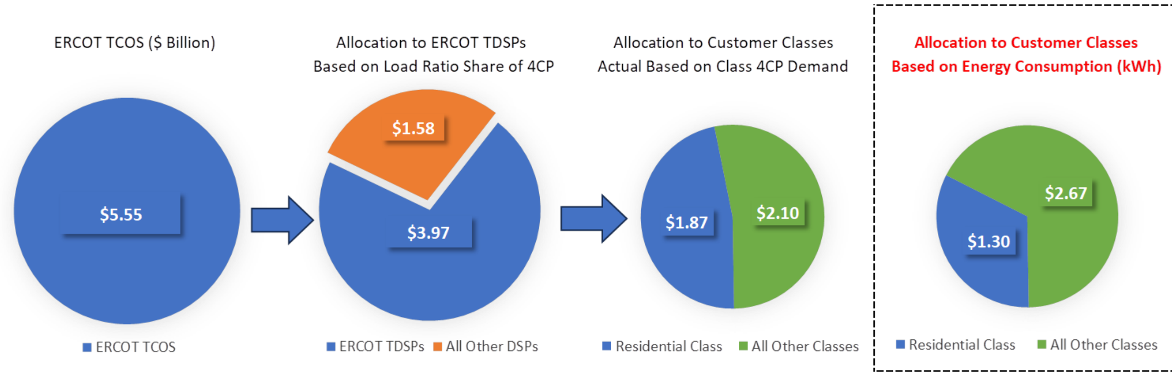
For simplicity and due to relatively small load, lighting class excluded from the table but is included in the total for calculation of consumption %

Source: Schedule II-H-1.4 Adjusted Test Year Load Data from most recent rate case.

The chart above demonstrates the concerns NRG has discussed throughout these comments about whether the current 4CP methodology used to allocate transmission costs ensures that all loads appropriately contribute to the recovery of a TDU's costs to provide access to the transmission system, especially considering the substantial increase in total transmission costs coming in the next 5 to 10 years.

In terms of real costs, for 2025, residential customers in the ERCOT TDUs (CenterPoint, Oncor, AEP Texas, and TNMP) will be allocated and pay ~$568M more in transmission costs than if the allocation had been based on energy consumption:[44]

[44] This is calculated by multiplying the average 4CP load from Staff's wholesale transmission matrix for 2025 in Docket No. 57491 (or, 81,042,657) by the ERCOT postage stamp rate for 2024 ($68.547301) to arrive at a total TCOS for 2025 of $5,555,255,403 (note that, due to regulatory lag, that total TCOS actually collected using the postage stamp rate is higher than the total TCOS calculated in Staff's matrix using the latest TDU rate filings, which is closer to $5.4 billion). *See* Docket No. 57491, Commission Staff's Final Transmission Charge Matrix (Mar. 20, 2025). The total TCOS is then multiplied by the sum of the 4CP allocation percentages for the four ERCOT TDUs (Oncor, CenterPoint, AEP, and TNMP) (from the same matrix) to arrive at an allocation of ~71.47 percent of the total TCOS to the ERCOT TDUs (or, $3,970,258,819). Then, that total is multiplied by the average 4CP allocation for the residential class for the ERCOT TDUs (47.05%), as reflected in the immediately preceding chart and accompanying footnotes, to calculate what the allocation to the residential class is for those TDUs based on 4CP (or, $1,868,159,131), and then, an alternate calculation is performed to determine what the allocation to the residential class would be for



The current cost shifting impacts addressed above do not yet include the significant transmission investments in ERCOT already approved by the Commission. This will further strengthen the 4CP-related cost shifting outcomes.

Question 4: What potential harms to ratepayers might occur if the demand-response signal provided by the status-quo 4CP pricing is diluted?

NRG response: The 4CP intervals tend to occur for the ERCOT system when solar output is robust, during summer peak demand, and consequently wholesale energy prices are low. Any value of lower energy consumption related to 4CP is no longer meaningful, compared to the situation one or two decades ago when wholesale energy prices were closely correlated to gross peak demand and 4CP might have had an amplifying effect on demand response in relation to energy pricing. For example, during the summers of 2024 and 2025, the average prices for the

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those TDUs, if based on the average energy consumption (also from the immediately preceding chart) (or, 32.76%), which would have resulted in an allocation of $1,300,539,770. The difference between the two allocations is roughly $568 million. NRG performs these calculations to provide estimates for discussion purposes.

2025	
TCOS	$5,555,255,403
Allocation to ERCOT TDSPs (Based on 4CP)	71.47%
ERCOT TDU's Share of TCOS	$3,970,258,819
Resi Class Actual % Allocation (Based on 4CP)	47.05%
Resi Actual Allocation	$1,868,159,131
Resi Class % Allocation (If Based on Consumption)	32.76%
Resi Allocation if Based on Consumption	$1,300,539,770
Difference	14.30%
Residential Impact	**$567,619,360**

highest ERCOT system peak demand hours (coincident with the 4CP intervals) were $25.71/MWh and $24.56/MWh respectively.[45] Any 4CP responsive effect relative to this price would be *de minimis* in terms of the total energy cost to consumers. Meanwhile, there are dozens of intervals each summer where per-MWh pricing exceeds $100/MWh, and usually many of intervals where per-MWh pricing exceeds $1,000/MWh. Through this energy pricing, REPs have a natural incentive to avoid usage during high-priced intervals, which reduces both short-run and long-run incremental costs in the system. By contrast, and as explained above and below, 4CP does not avoid any substantial costs; it merely shifts costs. In NRG's view, the reform of 4CP would tend to encourage firms in the demand-response business that currently focus on what is essentially regulatory arbitrage, through 4CP, to a more economically efficient model of demand response focusing on energy pricing.

Question 5: Do the risks of cost-shifting associated with 4CP price response exceed the benefits of cost avoidance or other savings that are associated with 4CP price responses during the months of June, July, August, and September? Please provide all relevant data and analyses.

NRG response: Yes. As explained in responses to Questions 1 and 3, the cost shifting that occurs as a result of 4CP allocation greatly disadvantages the residential class of consumers, especially in light of the substantial increase in transmission costs projected to occur in the next 5 to 10 years from the PBRP and STEP-765 kV project. The benefits of energy or ancillary service cost avoidance related to 4CP are no longer meaningful or relevant since the ERCOT system has evolved to one with high renewable penetration. Meanwhile, there appears to be no evidence that any transmission costs have been avoided as a result of 4CP.

[45] NRG calculated this number using ERCOT price data and taking the average of the North Hub Real-Time Settlement Point Prices for the highest peak demand hour for June, July, August, and September for 2024 and June, July, and August for 2025 (with highest demand measured as of the time these comments were drafted, which did not include the entirety of September so it was excluded). That data can be found on ERCOT's website in a few places. *E.g.*, https://www.ercot.com/mktinfo/rtm; https://www.ercot.com/mp/data-products/data-product-details?id=NP6-905-CD; https://www.ercot.com/gridinfo/load; https://www.ercot.com/content/cdr/html/actual_loads_of_forecast_zones.html; https://www.ercot.com/mp/data-products/data-product-details?id=NP6-346-CD.

Question 6: What are the primary drivers of transmission cost incurrence?

a. **Are the costs for transmission network upgrades primarily driven by customer load at the time of the transmission system peak load? If not, what share of transmission network upgrades is primarily driven by peak load?**

NRG response: No, the ERCOT transmission system is not designed to meet the coincident summer peak demand of the ERCOT system. It is designed to meet multiple reliability and economic transmission planning criteria in the ERCOT Protocols[46] based on North American Electric Reliability Corporation (NERC) Reliability Standards,[47] PUCT Substantive Rules,[48] and the Public Utility Regulatory Act (PURA).[49]

Specifically, under ERCOT's Planning Guides, "ERCOT employs reliability, economic, and resiliency criteria in evaluating the need for transmission system improvements."[50] The processes that allow ERCOT to meet this planning criteria include ERCOT's annual Regional Transmission Plan (RTP), the TDUs' System Resiliency Plans,[51] Commission directed transmission projects such as the CREZ, PBRP, Rio Grande Valley transmission upgrades, and the 765kV STEP.[52] Most of the transmission projects constructed and approved in the ERCOT region follow the criteria used to develop the RTP including the PBRP and STEP:

> The Regional Transmission Plan addresses regional and ERCOT-wide reliability and economic transmission needs and the planned improvements to meet those needs for the upcoming six years starting with the SSWG base cases.[53]

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[46] ERCOT Protocols § 3.11.2; ERCOT Planning Guides, Section 4.

[47] *E.g.*, NERC Reliability Standard TPL-001-5.1.

[48] 16 TAC § 25.101.

[49] Tex. Util. Code §§ 11.001-66.016 (PURA), at § 37.056.

[50] ERCOT Planning Guides § 4.1(1).

[51] *See* PURA § 38.078; 16 TAC § 25.62 (allowing TDUs to file for approval of costs related to improving the resiliency of the TDU's system). The Commission has approved applications for Oncor, TNMP, and AEP in the past year, and CenterPoint's case is still pending. *Application of Oncor Electric Delivery Company, LLC for Approval of a System Resiliency Plan*, Docket No. 56545, Order (Nov. 21, 2024); *Application of Texas-New Mexico Power Company for Approval of a System Resiliency Plan*, Docket No. 56954, Order (Mar. 26, 2025); *Application of AEP Texas, Inc. for Approval of a System Resiliency Plan*, Docket No. 57057, Order (Apr. 24, 2025); *Application of CenterPoint Energy Houston Electric, LLC for Approval of its 2026-2028 Transmission and Distribution System Resiliency Plan*, Docket No. 57579 (pending); *see also Electric System Resiliency Plan Annual Reports*, Project No. 57941.

[52] *See supra* notes 23-27 and accompanying text.

[53] ERCOT Planning Guides § 3.1.1.2(1) (emphasis added).

The Steady State Working Group, composed of representatives from transmission and distribution service providers (TDSPs) and ERCOT, create the SSWG cases annually and update them throughout the year. The load information to build the SSWG cases for transmission planning are submitted by TDSPs through the Annual Load Data Request (ALDR) process.

> The Transmission and/or Distribution Service Provider (TDSP) or its Designated Agent must provide Load data each year to allow necessary ERCOT System reliability analysis and planning and to meet requirements of North American Electric Reliability Corporation (NERC). Each TDSP or its Designated Agent is responsible for providing historical and <u>forecasted Load data</u> to ERCOT for all Loads connected to <u>its system</u> as outlined in the Annual Load Data Request Form Instructions.[54]

The load forecast information submitted by TDSPs in the ALDR process is "***non-coincident load data***"[55] meaning it is not coincident with ERCOT summer peak demand. In other words, the ERCOT transmission is designed and built to serve the **<u>annual</u>** peak demand for **<u>each separate TDU system</u>**. The peak demand for each separate TDU system rarely, if ever, occurs when the overall ERCOT transmission system is peaking. When examining historical data of peak demand, as reflected in the table below,[56] the ERCOT system has never peaked when all of the various regional areas in ERCOT have peaked. As a result, the four (4) coincident summer peak intervals for June, July, August, and September have very little relationship to the actual transmission system upgrades and costs.

[54] ERCOT Planning Guide § 6.5(1) (emphasis added)

[55] *See* ERCOT Steady State Working Group Procedure Manual at § 4.2 (ROS Approved on June 5, 2025) (emphasis added), *available at*: https://www.ercot.com/files/docs/2024/07/12/SSWG_Procedure_Manual_ROS_Approved_06052025.docx

[56] *See* ERCOT Demand & Energy Reports from 2008 through 2024 for regional zones and ERCOT system. Reports for 2023 and 2024 can be found here: https://www.ercot.com/news/presentations/2024. A drop-down menu on that page can be used to access reports for prior years.

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

b. <u>What portion of non-interconnection transmission costs are primarily driven by customer non-coincident peak demand, or other measures of demand?</u>

<u>NRG response</u>: As NRG explained in the response to Question 6.a, the ERCOT transmission system is primarily designed to serve the non-coincident peak demand of each TDU system, and it appears, historically, that this has been the case since at least 2005. The earliest version of the SSWG Procedure Manual available on the ERCOT website is from November of 2005 and it outlines the process of load data submission for each TDU system similar to what occurs today.[57] Historical documentation on transmission planning in ERCOT prior to the early-2000's is difficult to find, making further evidence scarce. Other large transmission projects that are not closely related to TDUs' non-coincident peaks include CREZ and more recently the PBRP. These transmission expenditures have an extremely attenuated relationship with system peak demand that would not justify an allocative basis thereupon.[58]

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[57] ERCOT Steady State Working Group Procedural Manual (Nov. 2005), *available at*: https://www.ercot.com/files/docs/2006/01/31/SSWGProcedureManual_ROSapproved_1_06.doc

[58] *Supra* notes 23-27.

c. **Quantify the absolute and relative magnitudes associated with the various categories of primary transmission cost drivers, including the amounts of transmission costs incurred by category in recent years.**

NRG response: As explained in the responses to Question 6.a and 6.b, most of the transmission costs are related to non-coincident peak demand for each TDU system. The remaining costs are related to serving other purposes such as renewable integration and system resiliency, of which the latter have been approved only recently (within the past year).

d. **How stable is the relative relationship between the primary transmission cost drivers over time?**

NRG response: Based on historical documentation of the transmission planning process described in the response to Question 6.b, the primary transmission cost driver of non-coincident peak demand for each TDU system has remained consistent.

Question 7: What alternative methods to 4CP should the commission consider? In your response, please distinguish between 4CP for wholesale cost recovery and 4CP for retail cost recovery.

NRG response: The goal of designing a transmission cost allocation mechanism should be to ensure a fair and equitable distribution of costs among all customer classes with the elimination of the ability to shift costs among consumer classes. As explained in Dr. Hogan's report, the ERCOT transmission system costs subject to allocation are sunk costs and cannot be avoided.[59] Therefore, any methodology that allows for some consumers (but not others) to alter their consumption patterns to substantially reduce their share of those sunk costs will only result in the inefficient outcome of shifting those costs to others while the consumers altering their consumption are incurring real costs to do so. One clear example of this inefficient outcome is a manufacturing plant reducing output of the production of goods to reduce their share of transmission costs. In whole, the total amount of transmission costs incurred by the system are not changed at all, but real economic activity and production is reduced in the process. The current 4CP mechanism produces especially inefficient outcomes as it impacts transmission cost allocation at every stage (from the ERCOT wide costs down to the customer), and the 4CP intervals occur only 4 times a year, for 15 minutes, which allows large customer classes to very effectively shift their costs onto

[59] Project No. 47199, Hogan/Pope Paper at 83-84 (bates) (filed May 22, 2017).

other classes. If there were any record of deferred or avoided transmission spending as a result of the application of the 4CP methodology, one might optimistically credit 4CP as an effective demand-side tool to reduce additional transmission spending. But there is no such record. Thus, as discussed throughout these comments, that mechanism does not result in a fair and equitable allocation of transmission costs and should be changed.

As an initial matter, for the reasons detailed throughout these comments (and particularly under Question 1), NRG is not recommending that the Commission alter the billing determinant stage (i.e., Step 3) of the transmission cost recovery within particular classes, which, as noted above, includes 4CP billing for some but not all classes. Retaining the existing 4CP structure at the billing determinant stage for the larger customers (if the Commission decides to do so) would not preclude the Commission from largely addressing the inequities that exist under the allocation system today. With respect to Steps 1 and 2 of the allocation process, NRG does recommend that the Commission move away from the current method of allocating transmission costs on the basis of 4CP.

In determining what a more equitable allocator could look like, the Commission should consider that (1) PURA requires a "postage stamp" rate for ERCOT-wide costs to DSPs (Step 1), which requires only a methodology in which the divisor is *any* measure of "total demand placed on the combined transmission systems [in ERCOT]" and the dividend is the TCOS;[60] (2) PURA requires that rates be "just and reasonable" and not discriminatory[61]; and (3) SB6 requires the Commission to determine if the 4CP allocation "ensures that all loads appropriately contribute to" the recovery of utility's costs to provide access to the transmission system. The Commission has extensive latitude to determine what methodology to use. The most cabining element of this three-part formulation is the fact that rate must be a uniform, postage-stamp rate, which diverges from the test that governs the differential allocation of costs for types of transmission in certain other markets (as NRG explains in response to Question 11). Even so, by selecting an appropriate divisor for demand, ratemaking can select an appropriate balance between peak-demand and average-

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[60] PURA § 35.004(d) ("postage stamp method of pricing" calculates "a transmission-owning utility's rate . . . based on the ERCOT utilities' combined annual costs of transmission . . . divided by the total demand placed on the combined transmission systems of all such transmission-owning utilities within a power region").

[61] *Id.* § 36.003.

energy usage on the transmission system; probably, the best approach lies somewhere in the middle but at their extremes, one measure of demand is 1CP, and another measure of demand is 8,760CP, and either of these would be legally compliant with at least the first element above, regarding formulaic postage-stamp calculation.[62]

As described at length above, the ERCOT transmission system was primarily designed and built to serve non-coincident TDU system peak demand, meaning that demand during the 4CP intervals is not what drives transmission investment, and 4CP, due to its very limited 15-minute window that occurs only four times a year, can be avoided by large customers, to the significant detriment of smaller customers. Further, other transmission upgrades are entirely unrelated to system peak demand, such as CREZ, the PBRP, and System Resiliency. For example, it would not make practical or economic sense for consumers to curtail when wind production is peaking in the areas traversed by CREZ transmission lines because wholesale prices would be low.

NRG recommends the Commission implement a transmission cost allocation mechanism to replace 4CP that is based on overall system utilization and that eliminates the ability to shift costs to the greatest extent possible. As explained above, it is not possible to design a methodology that lowers future transmission costs or assigns costs purely based on causation. But a more equitable allocation can still be accomplished simply by increasing both the number of intervals and the duration of those intervals. FERC Order 888[63] established a measurement that balances demand and energy by adopting an annual average across monthly peaks (12CP) based on an hourly measurement. This would produce a gradualist approach that departs from 4CP but without radical change, although in NRG's view the base should further be broadened to a wider temporal sample of the peak (e.g., four-hour versus the 15-minute interval) or across a broader sampling (e.g., an annual average across daily peaks, 365CP). Any of the approaches suggested above (i.e., 12CP with four-hour interval or annual average across daily peaks) would accomplish the goal of reducing cost shifting among customer classes with less complexity than the status quo.

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[62] Notably, there are transmission systems in the United States which are planned and cost-allocated based on either of these extremes, as described in response to Question 11.

[63] *See infra* response to Question 11.

Question 8: At what times is the transmission system most congested, excluding discretionary outages (i.e. planned outages)?

NRG response: As explained in the response to Question 2, the transmission system experiences the most congestion during the spring and fall due to transmission outages, along with periods of high renewable output and low load. And the congestion that occurs during the summer peak demand periods is not typically major import constraints that 4CP response would be effective at resolving.[64] The top transmission constraints on the ERCOT system have been related to high renewable output in West Texas.[65]

Question 9: Section 6(a)(3) of SB6 requires the commission to evaluate the portion of the costs related to access to and wholesale service from the transmission system that should be nonbypassable, consistent with Section 35.004(c-1). Does the language regarding "nonbypassable" costs in section 6(a)(3) of SB6 refer to costs other than the interconnection costs described by new PURA § 35.004 (c-1)? If so:

a. **What non-interconnection costs are referred to?**
b. **How is "nonbypassable" to be properly interpreted?**

NRG response: The emergence of large loads has precipitated a different kind of transmission planning, one that is predicated on the prospective accommodation of them. Consequently, Section 6(a)(3) of SB6 arguably should be interpreted as referring to costs not merely to directly interconnect large load customers to the grid, but also to the necessary and upstream costs that interconnecting them will entail. This seems supported by Section 6(a)(3), which states:

> The commission shall also evaluate: … the portion of the costs **related to access to and wholesale service from** the transmission system that should be nonbypassable, **consistent with Section 35.004(c-1)**, Utilities Code, as added by this Act.[66]

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

[65] *See* ERCOT, "Report on Existing and Potential Electric System Constraints and Needs" at 25 (Dec. 2024), *available at*: https://www.ercot.com/files/docs/2024/12/20/2024-report-on-existing-and-potential-electric-system-constraints-and-needs.pdf.

[66] 89th Tex. Leg., R.S., SB6 at Section 6(a)(3) (eff. June 20, 2025) (emphasis added).

In turn, PURA § 35.004(c-1), which is newly added by SB6, states:

> The commission by rule shall ensure that a large load customer who is subject to the standards adopted under Section 37.0561 **contributes to the recovery of the interconnecting electric utility 's costs to interconnect the large load to the utility 's system**.[67]

While PURA § 35.004(c-1) is focused only on "interconnecting" large load customers to the grid, Section 6(a)(3), in its reference to "wholesale service," seems to suggest something incremental to those directly allocable costs of interconnection, which will already largely (if not fully) be addressed in the implementation of new PURA § 37.0561, which requires the Commission to adopt numerous standards to ensure that large loads appropriately contribute to the costs to interconnect them to the system.

To give effect to the broader reference in Section 6(a)(3) to "wholesale service" costs and the reference to "nonbypassable," the Commission should not limit its focus to the costs simply to interconnect to the grid. Section 6(a)(3) arguably reflects the Legislature's broader intent for the Commission to ensure that large load customers also pay an equitable portion of the costs of transmission service, consistent with the overarching exercise that the Commission is undertaking in this project to ensure that all customers (including new large load customers) appropriately contribute to the payment of transmission costs. If the Commission replaces the existing 4CP allocation at Steps 1 and 2 of the allocation (and particularly Step 2, the allocation to customer classes), as NRG has recommended, then larger customer classes will already be allocated a more equitable portion of transmission costs. The Commission could take an additional step to ensure that new large load customers are paying their fair share of costs, by creating a sub-class for new large load customers that receives a separate allocation of transmission costs that has an even broader base for the purposes of rate design. Notably, other jurisdictions that are the focus of data-center development, including Virginia, Ohio, and Illinois have considered or adopted tariffs that require large loads to enter into take-or-pay contracts of a long tenor for transmission service, thereby ensuring their contributions to the transmission revenue requirement regardless of their peak demand (or even their continuing presence as a customer on the system). The Commission

[67] *Id.* at Section 1 (emphasis added).

should carefully balance the Legislature's requirements in SB6 with the competitiveness of Texas as a jurisdiction conducive to data-center development in this regard.

<u>Question 10</u>: <u>What data can transmission and distribution service providers (TDSPs) (or other stakeholders) provide to aid the commission in evaluating the appropriateness of the existing transmission cost recovery methods and alternative transmission cost recovery methods?</u>

<u>NRG response</u>: TDSPs and ERCOT could aid the Commission in a couple ways.

First, implementing alternative transmission rate methodologies would require a comprehensive assessment of existing infrastructure, billing systems, regulatory frameworks, and stakeholder coordination. Thus, the TDUs and ERCOT could assist the Commission by providing data on potential system modifications and integration software upgrades, which could include estimated costs and timelines for implementation.

Second, ERCOT's peak load forecasts incorporate a 50% reduction for Large Flexible Loads (LFLs) over the coincident peak hours for the months of June, July, August, and September and a reduction of 85% over the net-load peak hours for the months of June, July, August, and September.[68] This assumption reflects expected load management behavior during peak periods for flexible loads. However, with the emergence of new data center loads, there is an underlying expectation that these customers will consume energy during the 4CPs and thus pay transmission charges based on their full peak demand. Whether this assumption holds true remains uncertain, particularly considering the substantial incentives available to these customers to reduce or shift load during 4CP intervals. This uncertainty introduces potential variability in transmission cost recovery outcomes.

Consequently, to support a more robust evaluation of the appropriateness of current transmission cost recovery mechanisms — as well as potential alternatives — ERCOT could provide scenario-based analyses. These analyses would model a range of LFL reduction

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[68] See ERCOT 2025 Long-Term Load Forecast Report (page 7) at: https://www.ercot.com/files/docs/2025/04/08/2025_LTLF_Report.docx.

percentages during 4CP months, offering insight into the financial and operational impacts of different customer behaviors under varying incentive structures.

<u>Question 11</u>: <u>How have other areas of the country (i.e., other Regional Transmission Operators and Independent System Operators) addressed wholesale transmission cost recovery? Are there lessons to be learned from these other areas?</u>

<u>NRG response</u>:

Transmission rates elsewhere in the contiguous United States are regulated by the Federal Energy Regulatory Commission (FERC) or by state public utility commissions, depending on the underlying state regulatory policy that governs the organization of the jurisdiction's utilities.[69] By and large, the transmission revenue requirement is paid for by the demand side of the market. In RTOs/ISOs, transmission cost allocation and rate design generally follow the precepts established by FERC Order 888, which established a *pro forma* tariff for a twelve coincident peak (12CP) allocation and rate design for wholesale purposes. This is the methodology that governs the majority of grids in the United States today. As FERC explained at the time:

> Network service permits a transmission customer to integrate and economically dispatch its resources to serve its load in a manner comparable to the way that the transmission provider uses the transmission system to integrate its generating resources to serve its native load. Because network service is load based, it is reasonable to allocate costs on the basis of load for purposes of pricing network service. This method is familiar to all utilities, is based on readily available data, and will quickly advance the industry on the path to non-discrimination. We are reaffirming the use of a twelve monthly coincident peak (12CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks. Utilities that plan their systems to meet an annual system peak (e.g., ConEd and Duke) are free to file another method if they demonstrate that it reflects their transmission system planning.[70]

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[69] In states that have adopted a policy of restructuring and which have unbundled transmission rates from distribution and transmission rates, FERC regulates those rates comprehensively; in other jurisdictions, and in particular those that have fully vertically integrated electric utility monopolies that are not in regional transmission organizations, State Commissions exercise a full range of authority around transmission ratemaking, including both cost allocation and rate design.

[70] *Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities*, 61 F.R. 21540-01 at 21599, Order No. 888 (1996).

In general, SPP, MISO, ISO-NE, and numerous non-RTO transmission utilities follow the 12CP *pro forma* approach that FERC elucidated in Order 888. However, various points of departure exist.

More similar to ERCOT, PJM allocates the transmission costs of its system to the seasonal peak, using a five coincident peak (5CP) methodology. Like ERCOT, it concentrates billing determinants in summer but, unlike ERCOT, it assigns transmission costs to the five highest peaks regardless of month. Typically, these costs are then directly "tagged" to load-serving entities (the equivalent of REPs) in the restructured jurisdictions, and those REPs then must decide how to price their retail offers so to collect the transmission costs they are assigned. The difference between REPs in Texas and their approximate equivalent in PJM is that the latter typically must, as a matter of law or business practice, intermediate the demand-based transmission rate and convert it into a volumetric-energy price that their retail customers will understand and accept. States such as Pennsylvania have formalized this by adopting regulations that ratify the PJM practice of facing REPs with a demand-based allocation of transmission costs, while mandating a retail-pricing obligation where REPs face demand-based transmission rates but effectively must offer their residential customers a volumetric-energy (or other) price with no opportunity for true up. On one hand, this creates an incentive for demand response on the part of REPs, who might offer innovative products to induce their customers to manage their transmission costs through automated smart devices, but on the other it creates the opportunity for mark-ups to (or losses on) regulated costs, rather than simply passing through a regulated-cost element to end-use customers.

In PJM, states also are allowed to opt-out of an LSE-based allocation, and instead re-bundle transmission costs as a regulated service, which is something that Ohio, for example, has done. This creates Ohio into a jurisdiction that, like Texas, uniformly flattens the wholesale transmission cost into a retail rate element, and then passes it through directly to end-use retail customers. Most PJM end-use retail customers, however, pay an intermediated retail transmission rate as described above that is, in effect, repackaged from the upstream wholesale transmission cost. This confers on the PJM market at least an opportunity to allow all customer classes to activate demand response in response to wholesale transmission price signals, which is not the case in ERCOT as described in NRG's answers above. The actual levels of demand response for residential customers in the PJM market, however, significantly depend upon retail billing practices and the state of advanced metering, both of which tend to lag behind the practices of ERCOT, where REPs bill their customers directly, and interval data from TDUs, including through a central repository of data (Smart Meter Texas), exists.

MISO generally follows a 12CP allocation of costs, but MISO also, like ERCOT, has approved a substantial package of transmission expenditures designed to broadly expand its transmission grid, known as Multi-Value Projects (MVP). In an exception to Order 888's 12CP approach, MISO filed at FERC and was approved to allocate these costs apart from demand on an energy-only basis, on a load-ratio basis across its footprint, in recognition that the portfolio of transmission projects were not being undertaken for the sake of serving peak demand in its system.[71] MISO thus uses a two-part transmission cost allocation methodology, something that while perhaps more precise is not legally permitted in a jurisdiction that requires a pure "postage stamp" approach like ERCOT. It could be possible to approximate a MISO-style approach by assessing the degree to which ERCOT transmission provided peak-demand versus hourly-demand services, then averaging those factors to create a billing determinant that presumably would be somewhere between 1CP and 365CP.

CAISO does use a postage stamp methodology and perhaps has the simplest allocation to billing determinants in its footprint: the megawatt-hours of load served.[72] As CAISO explains, its transmission cost allocation follows from the fact that is "is an energy market, not a capacity market."[73] The transmission rates charged by CAISO follows the volumetric energy design of the underlying system, rather than being based on a demand factor that is not in use in the corresponding energy market that CAISO administers.

As summarized above, other retail markets do expose load-serving entities to demand-based transmission charges, but then essentially require simpler, volumetric-energy pricing to end-use retail customers. This provides a substantial incentive for demand response to retailers who may, in offering retail products, seek to intermediate the wholesale transmission pricing and retail

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[71] https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MVPAnalysis.aspx.

[72] *See generally* Section 26.1 of the CAISO tariff; CAISO Background White Paper, "How Transmission Cost Recovery through the Transmission Access Charge Works Today," https://www.caiso.com/Documents/BackgroundWhitePaper-ReviewTransmissionAccessChargeStructure.pdf.

[73] CAISO, *Transmission Access Charge Structure Issue Paper*, (June 30, 2017) at 12.

customer behavior. However, significant differences between those markets and Texas exist. For example, in all of the states noted above, the utility bills end-use customers even if they have a retailer and, in some states, the utility may purchase the retailer's unpaid customer debt, which reduces the retailer's exposure. By contrast, in Texas, REPs are responsible for all aspects of the customer's retail electric experience, including billing, and must pay the TDU's invoices for electric delivery service even if the customer fails to pay the REP.

IV. CONCLUSION

NRG appreciates the Commission's consideration of its comments as the Commission undertakes the evaluation of transmission cost recovery and allocation in ERCOT. NRG expects this will be an iterative process and looks forward to assisting the Commission's analysis as it moves through the process.

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- The 4CP mechanism has become an increasingly unreasonable method of allocating transmission costs because it is completely disconnected from the actual costs incurred to develop, maintain, and operate the ERCOT transmission system, and it results in significant cost shifting benefitting some consumer classes to the detriment of other classes (primarily the residential class in competitive territories).
- Transmission costs in ERCOT are allocated to consumers in a three-step process:
  - **Step 1,** ***Allocation to DSPs***: ERCOT-wide transmission costs are allocated to distribution service providers (DSPs) (i.e., ERCOT transmission and distribution utilities, municipally-owned utilities, and electric cooperatives) based on 4CP.
  - **Step 2**, ***Allocation to Rate Classes***: DSPs allocate their share of transmission costs to their rate classes (e.g., Residential, Secondary ≤ 10kW, Transmission). DSPs for the Investor-Owned Utilities (IOUs) allocate transmission costs to their rate classes based on 4CP.
  - **Step 3**, ***Recovery from Customers***: DSPs recover transmission costs from customers in each rate class based on billing determinants that differ based on rate classes (e.g., Residential customers are billed on a volumetric (per kWh) basis; Transmission customers are billed on 4CP).
- Given the complexities of rate design, the Commission should focus on modifying the allocation of transmission costs in Step 1 and Step 2, which will resolve the cost shifting issues with the current 4CP mechanism, if modified properly, without having to go through the complicated process of changing transmission rates and without implementing changes to billing that could be confusing for residential customers.
- With a current postage stamp rate of $68.55/kWh-Yr, the financial incentives created by 4CP are substantial, concentrated, and difficult to ignore by large customers that stand to benefit from it. The number of large customers participating in 4CP has increased substantially in the past few years, and that participation does not yet reflect the amplified incentives from including the costs of large transmission projects such as the Permian Basin Reliability Plan and the 765kV Strategic Transmission Expansion Plan. Flowing transmission costs of this magnitude through the existing 4CP transmission cost mechanism will disproportionately impact residential consumers.
- Transmission expansion in ERCOT has been, and continues to be, driven by non-coincident TDU system peak-demand, not the four coincident summer peaks on the ERCOT system. TDUs assess the needs for their individual transmission system based on their own peak demand (which is unlikely to align with the ERCOT-wide 4CP). The current ERCOT transmission planning process originated from this regionalized process before restructuring of the wholesale market but has remained consistent in this aspect.
- Because 4CP is not aligned with how the transmission system is designed and built, it has no relationship to future transmission costs and only serves to allow large consumers to shift sunk costs to smaller consumers, particularly the residential class of consumers.
- Further, although 4CP cost shifting behavior used to benefit consumers by lowering energy prices during the 4CPs (with a corollary negative effect on the wholesale market), that impact

has been largely eliminated due to the substantial increase in the penetration of renewable resources in ERCOT (especially solar) and associated reduction in scarcity pricing. 4CP cost shifting behavior also does not alleviate congestion on the system (because it is a system-wide activity) and can even exacerbate it.

- The goal of designing a transmission cost allocation mechanism should be to ensure a fair and equitable distribution of costs among all customer classes with the elimination of the ability to shift costs among consumer classes to the greatest extent possible.
- NRG recommends the Commission implement a transmission cost allocation mechanism to replace 4CP that is based on overall system utilization and that eliminates the ability to shift costs. This can be accomplished by simply increasing both the number of intervals used in the methodology and the duration of those intervals such as a 365CP method or a 12CP method with a 4-hour measurement duration.
- Finally, in implementing Section 6(a)(3) of SB6, the Commission should focus more broadly than just on the costs of interconnecting new large loads to the system (which are addressed elsewhere in the bill, namely in new Section 37.0561) and instead should seek to ensure that new large loads (like all loads) appropriately contribute to the upstream costs of transmission service. This can largely be accomplished by modifying the 4CP cost allocation mechanism at Steps 1 and 2 of the allocation to something more equitable (as recommended above), but the Commission also might consider creating a new subclass in the transmission class of customers for large load customers.