PROJECT NO. 58484

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

COMMENTS OF RETAIL ELECTRIC PROVIDERS FOR AFFORDABLE, INNOVATIVE RATES

I. INTRODUCTION

The Retail Electric Providers for Affordable, Innovative Rates ("REPAIR") appreciates the opportunity to comment on the Commission Staff's report ("Staff Report") on the above-captioned matter.[1] REPAIR was organized on an *ad hoc* basis to provide comments in this matter, because we are concerned that the Commission will overlook a critical opportunity to reform transmission rates in a manner that could materially reduce residential customers' rates while encouraging the adoption of demand-reducing technologies.

In particular, REPAIR is motivated by the Staff Report's conclusion that even a move to the farthest bookend considered in the Report, 12 Coincident Peak ("12CP"), would cause a meaningful but still relatively small reduction in the transmission costs paid by residential customers, versus commercial and industrial classes ("C&I"). We calculate the magnitude of this reduction, using the residential customer percentage cost allocation change results of the staff linear regression analysis along with 2025 TCOS rates, peak loads, and residential meter data, at $16.73 per residential customer in competitive territory annually, with lesser-reaching reforms, such as 6CP, *increasing* costs by $4.82. We believe that a change to the allocative factors from 4CP to 12CP can be an important step toward fairness for residential customers like those we serve, but it should be complemented by policies that allow residential customers to engage in the same kind of demand response that larger customers and Non-Opt-In Entities ("NOIEs") do. We estimate that such a reform, whether they were responding to 4CP or 12CP, would return more than $250 per residential customer annually.

As the Staff Report notes, when Texas first adopted the transmission ratemaking methodology it continues to this day, smaller customer classes had no exposure to demand-based transmission pricing because of technological barriers—namely, the lack of smart meter technology.[2] That

[1] For the purposes of these comments, REPAIR includes Base Power Company, Octopus Energy, and Tesla Energy Ventures, LLC.

[2] As the Staff Report described: "The Commission sought to match rate design with cost causation as much as possible while acknowledging the practical limitations of metering technology at that time. Therefore, the Commission adopted a rate design for each class that reflected the best-available metering data for that class at that time. For customers with an interval data recorder (IDR) meter, this meant that the retail transmission rate design should reflect how the DSP incurs transmission charges and how these transmission charges are allocated to the rate classes. … [F]or residential and other small secondary customers that did not have demand meters, transmission charges were to be

barrier no longer exists and, as the Staff Report implies, it is time for a "rate design approach" that "ensure[s] that rates [are] as cost-responsive as the available metering technology allow[s]."[3]

Notably, other markets expose Retail Electric Providers to demand-based cost allocation for their customers' transmission usage.[4] These markets essentially cause the same signal that C&I customers face to be replicated for residential customers, but add retailers as an intermediating function, to prevent residential customers from directly facing demand charges. If adopted in Texas, such a reform would create an equal playing field between residential customers in the ERCOT REP market and C&I customers.

To put the opportunity in clear terms, if a C&I customer reduces one megawatt of demand across demand intervals today, that load will save $68,550. If a REP, on behalf of its residential customers, does the same—through smart thermostats, batteries, or time-of-use pricing—it will save only $94.[5] That is not a typographical error. There is a **727:1 disproportionate benefit to C&I customers** undertaking *the same action* as residential customers. Unfortunately, the changes the Staff Report contemplates would do nothing to reform this structural disparity in the ability to respond to demand-based price signals.

Although much of the discussion in this proceeding has concerned the disparity between C&I and residential customers, it is worth noting that there exist massive disparities even among residential customers in ERCOT. Like C&I customers, municipal and member-owned electric co-operatives (NOIEs) face demand-based transmission-cost exposure directly and, in their case, for all their customers in aggregate. NOIEs have invested in demand response accordingly. CPS Energy's SmartHours and Energy Saver programs have enrolled over 180,000 residential customers with approximately 184 MW of demand response capability. Austin Energy's Power Partner program has enrolled more than 60,000 customers with approximately 45 MW in demand reductions. Together, these programs conservatively generate approximately $3.1 million per year in estimated transmission-cost savings.[6]

Comparable programs in REP territory are relatively undersubscribed because REPs are not exposed to transmission retail rates that provide a financial incentive to build equivalent demand response capabilities. According to ERCOT data, among residential customers, in NOIE territory 44.6% are enrolled in demand response programs, whereas in REP territory only 10.1% are enrolled.[7] This is not a difference in technology access, customer sophistication, or program design capability. It is a difference in incentives.

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recovered on a per-kWh basis. This metering-based rate design approach ensured that rates were as cost-responsive as the available metering technology allowed." Staff Report at 4.

3 Staff Report at 4.

4 These include major eastern retail markets in the United States, such as Pennsylvania, Illinois, and New Jersey among others.

5 Oncor Electric Delivery TCRF Rider (January 2026). Transmission-connected large load: full postage-stamp rate × 1 MW = $68,550/yr (727× vs. residential REP). Commercial/industrial demand-based: $3.395/kW-mo × 12 = $40,740/yr (432×). Residential REP flat-rate equivalent: ~$94/yr per MW (1× baseline). PUCT Dkt. 57491 (2025 TCOS).

6 CPS Energy FY2024 Annual Report (SmartHours / Energy Saver): 184 MW, 180,000+ customers. Austin Energy FY2024 Resource Guide (Power Partner): 45 MW, 60,000+ customers. EIA-861 (2024): NOIEs serve ~27% of ERCOT residential customers.

7 2024 Annual Report on Demand Response in the ERCOT Region.

To correct these inequities in Texas's retail market design—both between residential and C&I customers, and among residential customers—REPAIR proposes a straightforward remedy: During the annual update to Distribution Service Provider allocation-factor values proposed in the Staff Report's Recommendation No. 5, allow REPs to opt into demand-based transmission charges, rather than being subjected to non-demand-based transmission rates. This election would be compatible with whatever demand-based value the Commission chooses to succeed 4CP in this proceeding.

Under this approach, a REP opting into this demand-based treatment would receive invoices for transmission charges consistent with those received by C&I customers that are exposed to demand-based charges. This proposal allows REPs like ours the opportunity to act on behalf of our customers in the same way that C&I customers and their REPs and advisory services do. Importantly, the proposal is revenue-neutral for distribution and transmission service providers. Mechanically, it would work in tandem with the annual allocation update that the Staff Report identifies for comment, dovetailing with the regulatory process. There are a variety of permutations to this approach, tailored to scenarios that commonly present in the retail electricity market in Texas (such as how to incorporate the book in a REP acquisition) but all of these point in the same direction of giving customers on an opt-in basis exposure to demand charges that empower them to respond to that price signal on an equivalent basis to larger customers and NOIEs. We describe this proposal further herein.

For the same reasons that NOIEs in Texas and residential-serving REPs in markets outside Texas do not expose end-use residential customers to demand charges, we believe it unlikely that any REP serving residential customers would subject end-use customers to a demand charge for transmission. However, in an abundance of caution, our proposal includes a requirement that any REP that opts for demand-based treatment affirmatively intermediate the transmission demand pricing, rather than passing it through directly to the REP's residential customers; this practice has precedent in other retail markets in the United States.[8]

REPAIR urges the Commission to act on our request within the scope of the present rulemaking.[9] Alternatively, the Commission should in approving a change to upstream cost allocation be clear that this is only the first phase of its reforms, a second phase of which will encompass as a priority matter consideration of the proposal we are making here. Without the reform we identify, or something like it, the market will still be left with a robust price signal—equivalent to over $5,000 per MWh under 12CP—that some customers may engage in demand response to avoid, which is unavailable to most other customers. That is a structural inequity that requires reform.

Senate Bill 6 charged the Commission to evaluate "whether the Commission's retail ratemaking practices ensure that transmission cost recovery appropriately charges the system costs that are caused by *each customer class.*"[10] The Commission should therefore not focus exclusively on

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[8] See, for example, the Pennsylvania PUC's "fixed means fixed" regulation, codified at 66 Pa.C.S. §2807(d), which as interpreted has prevented the pass-through of demand charges that are inconsistent with the pricing of Provider of Last Resort rate design.

[9] Various commentators in this rulemaking previously raised the prospect of innovations that allowed smaller customer classes to participate around demand-based price signals. See the comments of Base Power Company, Enchanted Rock, and TAEBA filed earlier in Project No. 58484. REPAIR's proposal is meant to be an implementable reform of those previously stated ambitions.

[10] Senate Bill 6 (2025), Sec. 6(4).

reforms for only one customer class. It should consider proposals to empower the residential customer class to lower their transmission rates. REPAIR respectfully submits that it would be unreasonable for the Commission to reaffirm that transmission costs should be allocated on a demand basis for only *certain* customers, while closing off the opportunity that REPAIR presents for residential customers to participate in the same sort of demand response and cost allocation.

II. COMMENTS ON COMMISSION STAFF'S DRAFT RECOMMENDATIONS

REPAIR supports a wholesale CP methodology that retains demand-based pricing, but which broadens the allocative base. The following comments are offered from the perspective of ensuring that any wholesale reform is accompanied by a corresponding update to the REP billing structure, so that the demand-based cost signals available to certain customers may be allowed to propagate downstream to REPs across all customer classes they serve.

Draft Recommendation 1 — *"Change the methodology for assessing wholesale transmission costs on distribution service providers to a coincident peak (CP) methodology with a greater number of CPs."*

As the Staff Report notes, there is a significant gap between the energy that customer classes consume and the transmission costs that they are allocated on the basis of their registered demand. In the CenterPoint service territory, residential customers used 33% of electricity in 2023 but were allocated 49% of the transmission cost of service: a 16-percentage-point gap, widened from 12.6 points in 2018, as large-load curtailment has grown.[11]

The Staff Report considers a variety of demand-based allocative methodologies. REPAIR supports broadening the base of peaks that are the basis for this allocation, which better reflects cost causation around a transmission system that is planned and used across multiple seasons but which still generally is sized to meet demand-based considerations. Under Staff's 12CP simulation—the most expansive methodology examined—the residential class's estimated share of costs decreases by approximately 3.1 percentage points relative to the 4CP baseline, from approximately 46.3% to approximately 43.1%.[12]

However, we note that expanding the number of coincident peaks will not by itself correct the REP billing asymmetry. A system with more CPs remains structurally inequitable if REPs continue to receive billing that provides no demand-based signal for the residential portion of their load. The Commission should ensure that any expansion of the CP methodology at the wholesale level is accompanied by a parallel update to the REP billing structure. So long as demand-based pricing remains available only to certain customers, an entire class of residential customers remains unable to share in substantial cost savings from reducing demand during peak intervals, instead absorbing

[11] CenterPoint Energy Houston Electric, PUCT Dkt. 56211 (Rate Case, 2023). ERCOT-wide: Staff Draft Report, Table 4 (34.5% residential consumption / 46.7% WTSC, 2024).

[12] Staff Draft Report, Table 12 (Cost Assessment Methodology Regression Analysis): 12CP case estimated effect on residential share = −3.137 percentage points (statistically significant at $p < 0.01$), relative to 4CP baseline residential share of ~46.3% (Table 12 intercept). Combined with the 34.5% residential consumption share (Table 4), the gap between residential cost share and consumption share under 12CP remains approximately 8 to 9 percentage points. Staff Draft Report, Table 11 also confirms that each additional CP beyond baseline is associated with a 0.417 percentage point increase in the CP customer (large-load) share of costs, demonstrating that gaming behavior adapts to any fixed-interval methodology.

additional costs from customers that are exposed to CP price signals. A narrow focus on the number of upstream cost-allocation intervals ignores the more material differences that exist downstream, in retail rate design. Such a focus will maintain discrepancies in the benefits a customer enjoys by undertaking the same demand-responsive activities, as shown in the table below.

Customer / Entity Type	Transmission Cost Billing Mechanism	Value of 1 MW CP Reduction
Transmission-Connected Large Load	Direct 4CP or 12CP contribution — full postage-stamp rate	$68,550/yr (727×)
Residential (REP customer, competitive territory)	Flat $/kWh — no demand signal to REP	$94/yr (1×)

Table 1. Coincident-peak demand reduction incentives by customer/entity type (Oncor territory, January 2026 rates). Sources: Oncor TCRF Tariff (January 2026); PUCT Docket 58484.

So long as smaller classes of REP customers face no meaningful demand-based signal, even while C&I and NOIEs do, any methodology change upstream may dampen the magnitude of demand response to the underlying asymmetry, but not eliminate it. The conclusion from Staff's own data is clear: Methodology reform at the wholesale level is a necessary but insufficient condition for compliance with SB 6's mandate. Consumer empowerment—giving REPs a demand-based billing signal so smaller customers can respond—is a complementary reform that makes any methodology change meaningful for all customer classes.

Draft Recommendation 2 — *"Lengthen the interval over which a coincident peak period is measured."*

REPAIR believes that the window of measurement, currently 15 minutes, could be as long as 1 or 2 hours. Like our response to Draft Recommendation No. 1, we recommend that whatever interval structure the Commission selects should also define the interval used for REP demand billing, so that the retail signal is consistent with the wholesale methodology the Commission adopts.

Draft Recommendation 3 — *"Eliminate cost allowances related to interconnecting large load customers."*

REPAIR takes no position on this recommendation.

Draft Recommendation 4 — *"Require large load customers to pay a portion of system upgrade costs."*

REPAIR generally supports this recommendation, which by directly assigning costs can reduce the amount of costs that are subject to broader allocation to all other consumers. Like the proposal we raise in response to Draft Recommendation No. 5, we see this as a complement to a reform around expanding the base of allocative factors from 4CP to 12CP. See also our comment on Draft Recommendation No. 6.

Draft Recommendation 5 — *"Require annual updates to allocation factor values."*

REPAIR supports the proposal to undertake an annual update to allocation factor values, with one essential additional feature, which we describe in some detail below. Specifically, during the annual allocation procedures, any REP should have the option to be billed, on a portfolio basis, for transmission charges based on demand, on the same basis as transmission-connected customers. This election would remove from the billing determinants the cumulative, flat-rate value of the REP's customer loads and have them separately billed on a demand basis in an equivalent manner to C&I customers. The regulatory approach proposed by REPAIR achieves parity between residential and C&I customers and provides a more complete policy solution to the issues presented by SB 6 and considered in this proceeding.

REPAIR's proposed reform also moves the competitive retail market closer to the original ambitions of Texas's restructuring law. As the Staff Report notes, the current billing structure is a relic of Order No. 40 in Docket 22344, issued in 2000 as part of the electric deregulation proceeding under Senate Bill 7. That Order explicitly conditioned per-kWh residential billing on the absence of demand meters — a practical accommodation of the metering technology available at the time.[13] That condition no longer holds. As of 2025, the four competitive-territory TDUs have collectively deployed approximately 7.1 million interval data recorder (IDR) meters, effectively representing 100% of their retail delivery points in ERCOT's competitive territory.[14] The technological impediment underlying Order No. 40's accommodation has been resolved; the billing structure that resulted from it should be updated accordingly.

More recently, in Docket No. 58923, Commission Staff separately petitioned the Commission to require annual updates to class allocation factor values under 16 TAC §25.193(c).[15] As Staff's Draft Report explains, TCRF class allocation factors are currently fixed between comprehensive rate proceedings on approximately a four-year cycle, albeit sometimes more frequently. Because transmission-voltage class load has been growing disproportionately relative to other classes, the failure to update allocation factors annually results in the same outdated class shares being used to apportion costs in each biannual TCRF filing—generating systematic, inequitable cost shifts between customer classes. Staff's Docket 58923 petition would use AMS metering data to update those factors annually, without the contentious load research studies that formerly made such updates impractical. Base Power supports this reform.

REPAIR urges the Commission to expand Draft Recommendation No. 5 and Docket 58923 to include a direct REP billing election mechanism, the vehicle by which the REP billing reform described in these comments would be implemented. Specifically, the annual allocation factor update filing should serve as the proceeding in which a REP declares its election to receive demand-based billing for its total coincident-peak load contribution in a given DSP territory. This

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13 PUCT Docket No. 22344, Order No. 40 (2000): "Residential and small commercial customers without demand meters shall be billed on a per-kWh basis."

14 PUCT Substantive Rule 25.130 (Advanced Metering Systems); TDSP Annual AMS Implementation Reports on file with PUCT. Competitive-territory IDR deployments as of 2024: Oncor (PUCT Dkt. 39346): ~3.4 million meters; CenterPoint Energy (PUCT Dkt. 38444): ~2.3 million; AEP Texas: ~1.1 million; Texas-New Mexico Power: ~260,000. Combined: ~7.1 million IDR meters, substantially 100% of retail delivery points in ERCOT competitive territory.

15 Docket No. 58923, Commission Staff's Petition to Require Annual Updates to Class Allocation Factor Values Under 16 TAC §25.193(c) (pending). As described in Staff Draft Report at 38–39, the TCRF class allocation factor values are currently fixed between comprehensive rate proceedings (typically on a four-year cycle). Staff's petition would require annual updates to those allocation factors to reflect current customer class 4CP demand, using AMS data that is now available without contentious load research studies.

uses the existing administrative infrastructure Staff is already proposing, without requiring a separate tariff docket or rulemaking proceeding.

The mechanics of this election, and how it interacts with the allocation factor calculation, are illustrated in the figure below. The left column shows the current TCRF annual update process as Staff's Docket 58923 petition would implement it. The right column shows the same process with a REP direct billing election added, using a hypothetical "REP A". All figures are illustrative.

Step	Current Mechanics (Without REP Opt-In)	With REP A Opt-In (Proposed Expansion)
DSP Annual TCRF Update Filing (Annual Allocation Factor Update)		
1. Total DSP 4CP demand	25,000 MW (illustrative)	25,000 MW **(unchanged)**
2. TCOS postage-stamp rate	\$68.76/kW-yr (2025)	\$68.76/kW-yr **(unchanged)**
3. Total DSP wholesale WTSC	\$1.719B	\$1.719B **(unchanged)**
4. Residential class 4CP demand	10,000 MW	10,000 MW (gross)
5. REP A residential 4CP demand	500 MW — included in residential class; no separate tracking	500 MW — **REP A files opt-in election; load removed from DSP calculation**
Cost Allocation Calculation		
6. DSP residential allocation factor	10,000 / 25,000 = 40.0%	9,500 / 24,500 = 38.7% **(down 1.3 pp)**
7. Residential class revenue requirement	40.0% × \$1.719B = \$687.6M	38.7% × \$1.719B = \$665.3M **(down \$22.3M)**
8. Residential TCRF rate (\$/kWh)	\$687.6M ÷ total residential kWh	\$653.2M ÷ non-REP A residential kWh (≈ same per-kWh rate; non-REP A customers unaffected)
REP A's Billing and Incentive Transformation		
9. REP A TCRF obligation	~\$34.4M embedded in \$/kWh billed to REP A's customers; REP has no direct demand liability	\$34.4M direct demand bill from DSP (500 MW × \$68.76/kW-yr × 1,000 kW/MW)
10. REP A financial stake in customers' 4CP behavior	None — REP billed \$/kWh regardless of when customers use power	Full, every MW of 4CP reduction saves REP \$68,760/yr
11. Individual customer billing	Flat \$/kWh retail rate (no change to customer's relationship with DSP)	REP-designed rate subject to legislative and PUCT regulation, gives flexibility to end customer

Figure 1. Illustrative flow of the TCRF annual allocation factor update with REP opt-in election. Steps 5-7 (shaded green) shows the key modification: the electing REP's 4CP load is removed from the residential class denominator and billed directly to the REP on a demand basis. All other residential customers are unaffected. Figures are illustrative based on 2025 postage-stamp rate of \$68.76/kW-yr.

A REP making such an election would receive demand-based invoices from the DSP for its total coincident-peak load contribution across all customer classes served in that territory in a manner consistent with the manner in which DSPs bill their largest customers. The election would be portfolio-wide for the REP in that DSP territory. The REP would manage its total demand exposure and price its retail products as it sees fit within applicable retail market rules, but would not be permitted a direct passthrough of demand charges to residential customers.

There are permutations of this approach that might be considered by the Commission as well, to accommodate the buying and selling of REP portfolios for example. In this scenario, it may be advisable to allow a REP that acquires another REP book not to incorporate those customers into demand-based pricing.

As the figure shows, the election is revenue-neutral for the DSPs and TSPs and does not alter the total transmission costs collected system-wide. It changes only who bears the financial responsibility, and thus the financial incentive in relation to a price signal, for managing a specific portion of 4CP load—shifting it from the DSP's class-based cost allocation to the REP that serves those customers and is best positioned to act on the price signals. This change would replicate the conditions that exist for other REP customer classes, as well as for NOIEs, which all face either directly or through an intermediary a demand-based charge that allows those customers to be empowered to react to a price signal on a basis consistent with how they are allocated that cost. This is the only change that affirmatively prevents a unidirectional cost shift between some customers exposed to such a price signal and those who are not.

Draft Recommendation 6 — *"Require large load customers to pay a minimum demand charge that is based on the large load customer's contracted peak demand for a 10 to 15 year period."*

REPAIR generally supports this recommendation, but notes that experience from other regions suggests that this style of take-or-pay contract for transmission access sometimes can send poor signals about efficient siting of new loads on the transmission system, if applied without regard to the actual incremental system costs resulting from the addition of a new large load. This concern should be balanced against the benefit of making a direct assignment or guarantee of new large customers relative to rising transmission costs, which otherwise would recirculate to all other customers. As the Staff Report notes, Texas once had a policy that attempted to bifurcate a postage-stamp transmission rate and an access charge relating to particular loads, which was discontinued during the legislative activity that accompanied restructuring.

III. CONCLUSION

REPAIR appreciates the opportunity to comment on the Staff Report and respectfully urges the Commission to incorporate our targeted proposal in Draft Recommendation 5 to ensure that residential and other small customers have an equal opportunity to respond to the price signals that emerge from the cost allocation framework the Commission establishes in this proceeding.

[*signature page follows*]

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EXECUTIVE SUMMARY

The Retail Electric Providers for Affordable, Innovative Rates ("REPAIR") is an *ad hoc* coalition of REPs serving residential customers. We support the expansion of demand-based allocative factors for transmission costs from 4 to 12 Coincident Peaks ("4CP" and "12CP"). However, we note that such a reform by itself will not address a major structural inequity that would continue to exist in the ERCOT market, absent a further, complementary reform. Namely, changing the allocative factors alone would continue to maintain a robust price signal, the equivalent of more than $5,000 per MWh, to large customers ("C&I") and Non-Opt-In Entities ("NOIE"), while providing no opportunity for smaller customers of REPs to engage in the same behavior for the same reward. At present, a large customer who reduces demand during 4CP intervals obtains *727x* the benefits that a portfolio of residential REP customers who do exactly the same thing.

This inequity all but guarantees a unilateral cost shift that would continue to exist even with a change to 12CP, *unless* other customers also have the ability to respond to demand-based price signals. Notably, residential customers whose utilities do face a demand-based price signal on their behalf convey much more substantial incentives for distributed energy resource adoption, as shown in a comparison between NOIE and REP programs for residential customers within ERCOT. As the Staff Report demonstrates, this inequity was never meant to exist; it is a relic of the technological limitations associated with metering when the Commission first established retail rate design at the beginning of restructuring. Those limitations no longer exist with the advent of smart meters.

REPAIR proposes a straightforward, complementary reform to fix this. A REP would be allowed to opt-in to exposure to demand-based transmission charges, allowing the REP to face a financial incentive to flex consumer demand in the same way C&I and NOIE customers do. The REP would be required to intermediate the demand-based charge on behalf of its residential customers. Meanwhile, the proposal is revenue-neutral for transmission and distribution service providers. REPs would receive an invoice on an equivalent basis to C&I customers from the relevant distribution service provider. During an annual update to allocation factor value raised in Staff Recommendation No. 5, the direct assignment of costs to opting-in REPs would reduce the ultimate amount of costs due to be allocated to other customers.

In summary, REPAIR urges the Commission to consider the reforms within this proceeding as a suite of complementary mechanisms to both broaden the base of cost allocation and to empower customers to respond to a retail price signal that corresponds to the upstream allocative factor. A focus on only one element of reform will miss the forest for the trees on this important topic.