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APPLICATION OF CENTERPOINT	§	**BEFORE THE STATE OFFICE**
ENERGY HOUSTON ELECTRIC, LLC	§	**OF**
FOR AUTHORITY TO CHANGE RATES	§	**ADMINISTRATIVE HEARINGS**

TEXAS INDUSTRIAL ENERGY CONSUMERS' INITIAL BRIEF

REDACTED

July 9, 2019

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1080

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PUC DOCKET NO. 49421

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TEXAS INDUSTRIAL ENERGY CONSUMERS' INITIAL BRIEF

I. Introduction/Summary [Preliminary Order (PO) Issues 1, 2, 3]

Context is critical in evaluating CenterPoint Energy Houston Electric, LLC's (CEHE's) requested rate increase. In 2015, the legislature passed Senate Bill 735, requiring all utilities in ERCOT to be placed on a regular rate review schedule.[1] Given the proliferation of piecemeal rate riders that allow ERCOT utilities to increase rates without a full rate review, certain utilities (including CenterPoint) have not filed a base rate case in nearly a decade.[2] The Commission implemented this legislation in PUC Subst. R. 25.247, requiring CEHE to file a rate case by July 1, 2019.[3] CEHE ultimately committed to file this case in April, before the July 1, 2019 deadline, as part of an agreement with stakeholders to reflect the impacts of the Tax Cuts and Jobs Act (TCJA) and to avoid a potential Commission order requiring them to come in earlier.[4]

Faced with an involuntary filing requirement, CEHE has somehow managed to manufacture a $149 million increase out of whole cloth. This is on top of CEHE's existing $2.1 billion annual revenue requirement,[5] and in spite of the myriad rate riders that provide nearly instant recovery for new investment between rate cases.[6] Yet, despite its efforts, the facts show overwhelmingly that CEHE should receive a rate ***decrease***—and given how this case came about, that outcome should surprise no one.

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[1] That legislation is now codified at PURA § 36.157.

[2] CEHE's last rate case used a 2009 test year. *See* Docket No. 38339, *Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates,* Order on Rehearing at Finding of Fact (FoF) 28 (Jun. 23, 2011).

[3] 16 TAC § 25.247(c)(2)(B).

[4] *See* Project No. 47945, *Proceeding to Investigate and Address the Effects of the Tax Cuts and Jobs Act of 2017 on the Rates of Texas Investor-Owned Utility Companies*, CEHE Letter to the Commissioners (Feb. 13, 2018).

[5] Tr. (Mercado Cr.) at 106:18-107: 5 (June 24, 2019).

[6] In fact, CEHE brags to its investors that it can recover ***approximately 95%*** of its capital expenditures without filing a rate case. *See* Tr. (Mercado Cr.) at 65:15–25 (Jun. 24, 2019); TIEC Ex. 8 (Investor & Analyst Day Presentation in Jun. 2014) at 7.

The main drivers of CEHE's requested rate increase are its proposal to increase its return on equity from 10% to 10.4%, and its request to increase the equity component of its current capital structure from 45% to 50%. However, the evidence demonstrates that CEHE's aggressive proposal is a result-oriented attempt to avoid a rate decrease, and is far out of line with prevailing ROEs and capital structures for similarly situated utilities, both in Texas and around the nation.[7]

CEHE has provided various, unpersuasive justifications in an attempt to support its requested ROE and capital structure; but the evidence shows that increasing CEHE's cash flows would have no impact on CEHE's stand-alone credit rating, which is dragged down substantially by CEHE's affiliation with its financially weaker parent, CenterPoint Energy, Inc. (CNP).[8] This is the paramount driver in CEHE's credit profile, not the factors alleged by CEHE. CEHE provides no credible justification for increasing its ROE or its equity percentage. For example, CEHE's regulatory risk has continuously been reduced with the implementation of new rate riders, such as the Distribution Cost Recovery Factor (DCRF),[9] and CEHE can point to no new regulatory risks. Further, contrary to CEHE's conclusory claims, the risk of serious storms and hurricanes is no greater now than it was ten years ago for a coastal wires utility.[10] And CEHE is not experiencing any extraordinary growth—it has been growing at a similar pace for years.[11] Even the Tax Cuts and Jobs Act (TCJA) presents no unique challenge to CEHE. In CEHE's own words, the TCJA is a "[redacted]"[12] and "[redacted]."[13]

Rather, if the Commission seeks to support CEHE's financial strength, there are simple ways to both lower CEHE's rates and improve its access to capital through reasonable ring fencing.

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[7] TIEC Ex. 5 (Gorman Dir.) at 8; TIEC Ex. 19, S&P Article: "Average U.S. Electric, Gas ROE Authorizations in H1'18 Down from 2017") at 2; Tr. (Hevert Cr.) at 714:25-715:6 (Jun. 26, 2019) (average awarded ROE for wires-only utilities was 9.18% in the first half of 2018, down from an average of 9.43% across all of 2017).

[8] *See* TIEC Ex. 4 (Griffey Dir.) at 9-11; TIEC Ex. 5 (Gorman Dir) at 27; *see also* CEHE Ex. 43 (McRae Reb.) at Ex. R-RBM-4, p. 5 (S&P Global Ratings – CenterPoint Energy Houston Electric LLC, March 22, 2019) ([redacted] (Confidential) (emphasis added).

[9] *See* Tr. (Gorman Re-Dir.) at 614:12-615:22 (June 26, 2019).

[10] Tr. (Mercado Re-Cr.) at 151:3–21 (June 24, 2019).

[11] *See* TIEC Ex. 13 (1st Quarter 2019 Earnings Transcript on May 9, 2019) at 6 (touting CEHE's consistent growth over the last ***30 years***); *see also* Tr. (Mercado Cr.) at 100:8-106:17 (June 24, 2019) (CEHE's annual capital expenditures have not grown significantly compared to its total rate base since its last rate case).

[12] *See* TIEC Ex. 4 (Griffey Dir.) at 28 (quoting CEHE Response to TCUC 1-02 in attachment SP 2018 CenterPoint Energy at 2-3. (HSPM)) (emphasis added).

[13] *Id.* (emphasis added).

If the Commission takes no other action besides insulating CEHE's revenue from CNP through appropriate ring-fencing, CEHE's credit would improve ***three notches***,[14] putting CEHE in the top 3% of utilities in the country.[15] CEHE's own witness admits that adopting TIEC witness Mr. Gorman's recommendations, including his 40% equity ratio and a 9.25% ROE with ring-fencing measures, would improve CEHE's S&P credit rating relative to CEHE's actual credit rating today.[16] Given CEHE's exposure to CNP, increasing CEHE's equity ratio and ROE would solely benefit CNP and its shareholders, allowing CNP to continue to use CEHE's inflated earnings to support CNP's other business activities. Such as result would be unjust and unreasonable for CEHE's captive customers.[17]

In addition to establishing a more reasonable ROE and capital structure and adopting appropriate ring-fencing, the Commission should:

- Continue to allocate wholesale transmission costs to CEHE's retail classes using the ERCOT 4CP, in line with decades of Commission precedent.[18]
- Prevent CEHE from over-recovering its wholesale transmission costs by requiring it to remove those costs from its base rates and recover them exclusively through the TCRF,[19] as has been done for Oncor,[20] TNMP,[21] and Sharyland,[22] and as AEP is proposing in its pending rate case.[23]
- Refine CEHE's proposed allocation of municipal franchise fee (MFF) expense to reflect each class's (a) in-city kWh deliveries, and (b) the specific MFF rates where that delivery occurs.[24]

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[14] TIEC Ex. 5 (Gorman Dir.) at 24-25.

[15] *See* TIEC Ex. 5 (Gorman Dir.) at 11, Table 1 (only 3% of electric utilities were rated A or higher by S&P in 2018).

[16] CEHE Ex. 43 (McRae Reb.) at 23-25.

[17] TIEC Ex. 4 (Griffey Dir.) at 9-11; TIEC Ex. 5 (Gorman Dir) at 27.

[18] *See* Section VII.B.1.

[19] *See* Section VIII.C.

[20] *Application of Oncor Electric Delivery Company LLC for Authority to Change Rates,* Docket No. 38929 at 8-9, FoF 39 (Aug. 26, 2011); *see also* Tr. (Abbott Cross) 916:24 – 917:4 (June 26, 2019).

[21] *Application of Texas-New Mexico Power Company for Authority to Change Rates,* Docket No. 38480 at 5, FoF 16 (Jan. 27, 2011); *see also* Tr. (Abbott Cross) 916:24 – 917:4 (June 26, 2019).

[22] *Application of Sharyland Utilities L.P. to Establish Retail Delivery Rates, Approve Tariff for Retail Delivery Service and Adjust Wholesale Transmission Rates,* Docket No. 41474 at 6, FoF 35 (Jan 23, 2014); *see also* Tr. (Abbott Cross) 916:24 – 917:4 (June 26, 2019).

[23] *See Application of AEP Texas, Inc. for Authority to Change Rates*, Docket No. 49494, Petition and Statement of Intent to Change Rates, at 3 (May 1, 2019); *see also id.*, *Direct Testimony of Jennifer L. Jackson* at 20-21, 41.

[24] *See* Section VII.B.2.

- Require CEHE to revise its proposed tariff to (1) ensure that CEHE will true up the cost of constructing transmission voltage facilities extensions against the contributions in aid of construction (CIAC) provided by customers and (2) ensure that transmission voltage customers will receive a credit if the facilities for which they paid a CIAC are later used to serve other customers.[25]
- Require CEHE to functionalize its Texas Margins Tax expense as suggested by Commission Staff witness Brian Murphy in order to ensure that CEHE does not uplift costs associated with serving its retail customers to TCOS.[26]
- Require CEHE to return to ratepayers all excess deferred income taxes (EDIT) related to its securitized transition and system restoration bonds (as recommended by GCCC witness Lane Kollen) or, in the alternative, open a separate proceeding to address the treatment of those amounts (as recommended by Commission Staff witness Darryl Tietjen).[27]
- Disallow all of CEHE's incentive compensation expenses related to financially-based goals, which amounts to 69% of CEHE's short-term incentive compensation costs and 100% of its long-term incentive compensation costs.[28]
- Require CEHE to return its entire unprotected excess deferred income tax (UEDIT) balance to customers through Rider UEDIT over the course of two years, and the $18.7 million of protected EDIT that CEHE proposes to return through that rider over the course of one year.[29]
- Reject OPUC witness Nalepa's baseless proposal to directly assign one-third of the expenses of CEHE's Transmission and Key Accounts Department ($678,154) to the transmission class.[30]

For these reasons, the Commission should reject CEHE's requested rate increase, and set its rates consistent with TIEC's recommendations, as discussed below.

II. Rate Base [PO Issues 4, 5, 10, 11, 12, 15, 16, 17, 18, 19]

A. Transmission and Distribution Capital Investment [PO Issues 4, 5, 10, 11, 12]

1. Capital Project Prudence

2. Capital Project Accounting/Capitalization Policy Changes

3. Land Costs

B. Line Clearance Project

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[25] *See* Section VIII.D.

[26] *See* Section VII.A.1.

[27] *See* Section II.D.

[28] *See* Section IV.B.1.

[29] *See* Section IX.A.

[30] *See* Section VII.B.3

C. Prepaid Pension Asset

D. Accumulated Deferred Federal Income Tax [PO Issue 17, 19]

Following the recent change in corporate federal income tax rates under the TCJA, CEHE now has substantial ***excess*** accumulated deferred income tax (EDIT) balances related to its securitized transition and system restoration bonds.[31] Accumulated Deferred Federal Income Tax (ADFIT) represents payments customers make through regulated rates to cover a utility's ***future*** income tax liabilities.[32] When the TCJA reduced the federal corporate income tax rate from 35% to 21%, a portion of the tax liability that CEHE's ADFIT balance was meant to cover was permanently eliminated, resulting in an excess balance.[33] These EDIT balances are ***ratepayer money***, paid in anticipation of taxes that will never be owed as a result of the TCJA, and they should be refunded to customers. Yet, CEHE is proposing to ***keep*** all of the EDIT for itself. Rather than granting CEHE this unjustified windfall, the Commission should either refund these amounts as proposed by GCCC witness Lane Kollen,[34] or, at a minimum, open a proceeding to account for and refund these EDIT balances, as recommended by Commission Staff witness Daryl Tietjen.[35]

CEHE's securitization EDIT balances relate to securitized bonds that were issued to recover the costs of electric deregulation within ERCOT (transition bonds), and to recover system restoration costs after major storms. When the electric market was deregulated, the Legislature allowed vertically integrated utilities to recover certain generation costs from customers as "stranded costs."[36] As part of the transition process, the statute allowed CEHE to securitize those costs and recover them through several transition bond issuances.[37] In addition, CEHE and its predecessor utilities were allowed to issue system restoration bonds to securitize the costs of restoring its system after major storms.[38] These bonds are held by wholly owned subsidiaries of

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[31] *See* GCCC Ex. 1 (Kollen Dir.) at Attachment D (Response to GCCC RFI No. 01-05).

[32] Staff Ex. 1A (Tietjen Dir.) at 19; TIEC Ex. 3 (LaConte Dir.) at 4.

[33] Staff Ex. 1A (Tietjen Dir.) at 22.

[34] GCCC Ex. 1 (Kollen Dir.) at 60-61.

[35] Staff Ex. 1A (Tietjen Dir.) at 25-26.

[36] *Application of CenterPoint Energy Houston Electric for a True-Up Filing,* Docket No. 29526, Order on Rehearing at 5 (Dec. 17, 2004).

[37] *See PURA* §§ 39.201, 39.301-39.303. *See also Application of CenterPoint Energy Houston Electric, LLC for a Financing Order,* Financing Order at 4-6 (Mar. 16, 2005).

[38] *Id.*

CEHE, and include ADFIT balances to account for prospective tax liabilities.[39] When the TCJA took effect, $158 million of the ADFIT related to those bonds became EDIT.[40]

Rather than returning the EDIT balances related to its securitized transition[41] and system restoration[42] bonds to ratepayers, CEHE unilaterally removed those amounts from its balance sheet and recorded it as ***income*** in 2017.[43] CEHE should have brought this issue to the Commission's attention and obtained approval before taking a windfall at ratepayers' expense. CEHE now contends that its treatment of these EDIT balances was proper because the Commission considered treatment of ADFIT associated with its competitive transition and system restoration charges when those amounts were securitized.[44] This argument is misleading at best. While the Commission set CEHE's rates in its last rate case under the assumption that the federal corporate tax rate was and would remain 35%, there is no dispute that the Commission has the authority to order CEHE to refund EDIT now. Similarly, the Commission did not anticipate or address the effects of the TCJA when determining the appropriate level of ADFIT related to the securitization bonds.[45] Moreover, CEHE's treatment of the EDIT associated with these securitized bonds is inconsistent with how the Commission has addressed EDIT amounts associated with non-securitized assets following the TCJA. As a result, the Commission is not bound by its prior treatment of these balances given the change in tax rates, and CEHE should not be entitled to permanently keep $158 million that its ratepayers were charged in anticipation of tax liabilities that have now been

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[39] GCCC Ex. 1 (Kollen Dir.) at 56.

[40] Staff Ex. 1A (Tietjen Dir.) at 17, 23-24; GCCC Ex. 1 (Kollen Dir.) at 56.

[41] *Compliance Filing of CenterPoint Energy Houston Electric, LLC for a Standard True-up of Transition Charges Under Schedule TC2*, Docket No. 48838, Notice of Approval (Nov. 20, 2018); *Compliance Filing of CenterPoint Energy Houston Electric, LLC for a Standard True-up of Transition Charges Under Schedule TC3*, Docket No. 49049, Notice of Approval (Feb. 4, 2019); *Compliance Filing of CenterPoint Energy Houston Electric, LLC for a Standard True-up of Transition Charges Under Schedule TC5*, Docket No. 48884, Notice of Approval (Dec. 12, 2018).

[42] *Compliance Tariff Filing of CenterPoint Energy Houston Electric, LLC for a Standard True-up of System Restoration Charges Under Schedule SRC*, Docket No. 48685, Notice of Approval (Oct. 16, 2018); *Compliance Filing of CenterPoint Energy Houston Electric, LLC for a Standard True-up of ADFIT Credit Charges Under Schedule ADFITC*, Docket No. 48686, Notice of Approval (Oct. 16, 2018).

[43] GCCC Ex. 1 (Kollen Dir.) at 56 (citing CenterPoint Energy, Inc. 2018 10-K at 151).

[44] CEHE Ex. 13 (Pringle Dir.) at 29; Tr. (Tietjen Cr.) at 789:21 – 810:7 (June 26, 2019).

[45] Mr. Tietjen notes that the relevant securitization transactions are: *Application of CenterPoint Energy Houston Electric, LLC for a Financing Order*, Docket No. 30485 (Order, March 16, 2005); *Application of CenterPoint Energy Houston Electric, LLC for a Financing Order*, Docket No. 34448 (Order, September 18, 2007); *Application of CenterPoint Energy Houston Electric, LLC for a Financing Order*, Docket No. 37200 (Order, August 27, 2009); *Application of CenterPoint Energy Houston Electric, LLC for a Financing Order*, Docket No. 39809 (Order, October 27, 2011). Staff Ex. 1A (Tietjen Dir.) at 18.

eliminated. For these reasons, TIEC believes that this EDIT should be returned to ratepayers, as recommended by Mr. Kollen. In the alternative, TIEC would support Staff's recommendation to require CEHE to file a separate proceeding to account for and return the EDIT amounts related to CEHE's securitization bonds.[46]

E. Cash Working Capital [PO Issue 15]

F. Other Prepayments

G. Regulatory Assets and Liabilities [PO Issues 18, 19, 59]

1. Unprotected Excess Deferred Income Tax (UEDIT)

2. Hurricane Harvey

3. Medicare Part D

4. Texas Margin Tax

5. Smart Meter Texas

6. REP Bad Debt

7. BRP Pension and Postretirement

8. Other Regulatory Assets and Liabilities

H. Capitalized Incentive Compensation

III. Rate of Return [PO Issues 4, 5, 7, 8, 9]

Mr. Gorman's recommended capital structure of 60% debt and 40% equity, with a 9.25% return on equity (ROE) and an embedded cost of debt of 4.38%, is reasonable, supported by the evidence, and should be adopted.[47] Compared to CEHE's request, Mr. Gorman's recommendation would save ratepayers ***$104.1 million per year***[48] while allowing CEHE to preserve its financial integrity and maintain access to capital markets. In stark contrast to Mr. Gorman's recommendation, and the recommendations of every other party to this case, CEHE seeks a 10.4% ROE and a capital-rich 50% equity ratio.[49] CEHE's request is facially unreasonable, unsupported

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[46] Staff Ex. 1A (Tietjen Dir.) at 26.

[47] TIEC Ex. 5 (Gorman Dir.) at 7, Ex. MPG-6.

[48] TIEC Ex. 5 (Gorman Dir.) at 37, Ex. MPG-6.

[49] CEHE Ex. 6 (Mercado Dir.) at 2.

by the record in this case, and would represent a dramatic departure from recent Commission precedent (at ratepayers' expense). As discussed further below, the Commission should reject CEHE's proposal and adopt Mr. Gorman's recommended return on equity and capital structure.

The Commission should also adopt Mr. Griffey's ring fencing proposal to ensure that CEHE's customers receive the benefit of CEHE's ***actual*** financial strength. Today CEHE's stand-alone credit is dragged down significantly[50] by the speculative business activities of its parent, CNP, which harms both CEHE and its ratepayers. As Mr. Griffey and Mr. Gorman demonstrate, CEHE and its customers would both be better off if CEHE were financially insulated from CNP. The Commission should adopt appropriate ring-fence measures, as discussed below, in combination with a more reasonable ROE and capital structure.

A. Return on Equity [PO Issue 8]

The Commission should grant CEHE an ROE that will provide reasonable access to capital—no more and no less. As illustrated at the hearing, CEHE's current ROE is already excessive. CEHE's proposed ROE is even more out of line with current market conditions and unsupported by the record.

[50] By ***three notches*** according to S&P. TIEC Ex. 5 (Gorman Dir.) at 24-25.

The parties' recommendations regarding CEHE's ROE are:

Party	Recommendation
TIEC[51]	9.25%
Staff[52]	9.45%
OPUC[53]	9.15%
TCUC[54]	9.00%
CEHE[55]	10.4%

The intervenors' and Staff's ROE recommendations are much closer to current market conditions, and similar ROEs have allowed Texas utilities to attract capital and successfully fund substantial infrastructure programs.[56] CEHE's requested 10.4% ROE, on the other hand, is excessive compared with recent Commission awarded ROEs, and those that have been awarded across the country. As Mr. Gorman notes, the principal flaws in CEHE witness Mr. Hevert's analysis are as follows:

- Mr. Hevert's constant growth discounted cash flow (DCF) model is based on unsustainably high growth rates.[57] The long-term growth rate applied to CEHE exceeds the long-term growth rate for the entire U.S. economy, and it is widely accepted that a utility cannot sustain growth rates that are higher than the economy that it serves.
- Mr. Hevert's CAPM is based on inflated market risk premiums.[58]

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[51] TIEC Ex. 5 (Gorman Dir.) at 5.

[52] Staff Ex. 3A (Ordonez Dir.) at 28.

[53] OPUC Ex. 3 (Winker Dir.) at 40.

[54] TCUC Ex. 1 (Woolridge Dir.) at 49.

[55] CEHE Ex. 26 (Hevert Dir.) at 3.

[56] For example, in late 2017, Oncor was awarded a 9.8% ROE, and last December, TNMP was awarded a 9.65% ROE. *See Application of Oncor Electric Delivery Company LLC for Authority to Change Rates*, Docket No. 46957, Order at FoF 32 (Oct. 13, 2017); *Application of Texas-New Mexico Power Company to Change Rates*, Docket No. 48401, Order at FoF 47 (Dec. 20, 2018).

[57] TIEC Ex. 5 (Gorman Dir.) at 71.

[58] TIEC Ex. 5 (Gorman Dir.) at 71.

- Mr. Hevert's Bond Yield Plus Risk Premium studies are based on inflated utility equity risk premiums.[59]

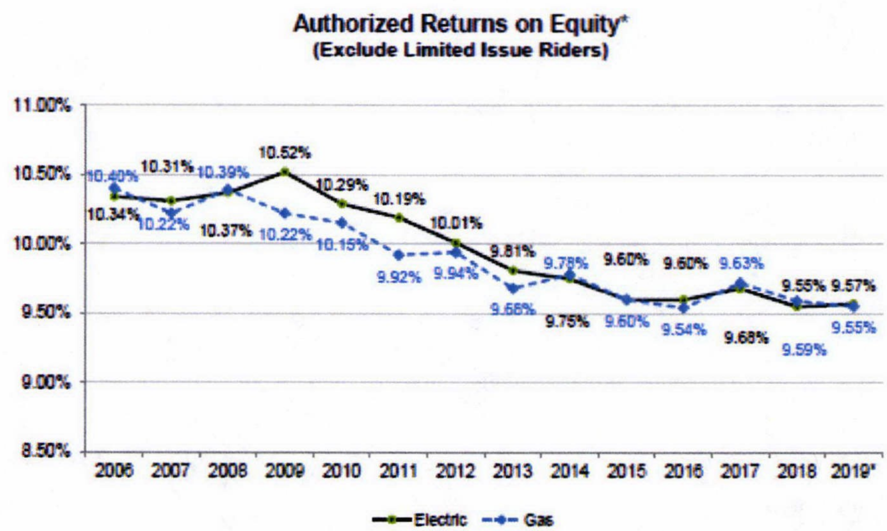
Due to these errors, Mr. Hevert's recommendation significantly overstates CEHE's market cost of equity and results in an excessive, unjustified ROE recommendation.

1. Observable market evidence does not support CEHE's requested ROE.

a. Utilities have maintained access to external capital and stable credit ratings despite lower ROEs.

CEHE's requested 10.4% ROE is unjustified in the current market environment, where utilities have maintained or improved their credit quality, access to capital, and stock valuations[60] at much lower authorized ROEs on average. Mr. Gorman's Figure 1 shows that awarded utility ROEs have fallen significantly since 2009:[61]

FIGURE 1



Source and Notes:
* S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions – January - March 2019, April 11, 2019 at pages 8 and 9.
* Data includes January - March, 2019.
* Electric Returns exclude Limited Issue Riders.
* RRA excludes the 2017 Alaska ENSTAR decision from its calculations.

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[59] TIEC Ex. 5 (Gorman Dir.) at 71.

[60] TIEC Ex. 5 (Gorman Dir.) at 8.

[61] TIEC Ex. 5 (Gorman Dir.) at 8.

This trend holds true today. CEHE witness Mr. Hevert admits that since February of 2018, ***no electric utility in the country has been awarded an ROE of greater than 10.0%.***[62] Additionally, the record shows that awarded ROEs have fallen even more for low-risk utilities like CEHE. The average awarded ROE for wires-only utilities was 9.18% in the first half of 2018—***122 basis points*** below CEHE's request—which was down from an average of 9.43% across all of 2017.[63]

Despite the steady decrease in authorized returns illustrated in Figure 1, utility credit ratings have improved over the same period, with credit upgrades significantly outpacing downgrades for the period 2011 through 2017,[64] and the industry average credit rating trending upward, as shown in Mr. Gorman's Table 1:[65]

TABLE 1

S&P Ratings by Category
(Year End)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Regulated											
A or higher	8%	7%	9%	8%	6%	3%	3%	3%	6%	6%	3%
A-	10%	15%	14%	14%	17%	20%	21%	22%	28%	34%	32%
BBB+	23%	22%	17%	19%	14%	17%	32%	33%	36%	29%	32%
BBB	23%	27%	31%	35%	36%	49%	37%	33%	22%	20%	21%
BBB-	23%	20%	17%	14%	17%	6%	3%	3%	8%	11%	12%
Below BBB-	13%	10%	11%	11%	11%	6%	5%	6%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source:
EEI 2018 Q4 Credit Ratings. Tab V. S&P Rating by Comp. Category

This downward trend in utility ROEs has not impaired the credit quality of utilities, or their ability to access capital. To the contrary, as shown in an *RRA Financial Focus* report cited by Mr. Gorman, utilities have continued to access significant amounts of capital to support construction programs over the past decade.[66] This trend is shown in Mr. Gorman's Figure 3:[67]

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[62] CEHE Ex. 42 (Hevert Reb.) at 73; Tr. (Hevert Cr.) at 741:3-17 (Jun. 26, 2019).

[63] TIEC Ex. 19 S&P Article: "Average U.S. Electric, Gas ROE Authorizations in H1'18 Down from 2017") at 2; Tr. (Hevert Cr.) at 714:25-715:6 (Jun. 26, 2019).

[64] TIEC Ex. 5 (Gorman Dir.) at 9.

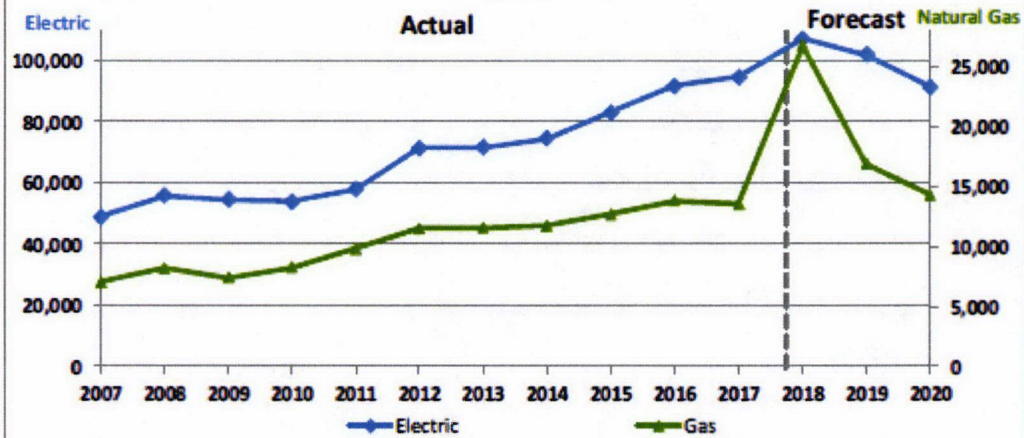
[65] TIEC Ex. 5 (Gorman Dir.) at 10-11.

[66] TIEC Ex. 5 (Gorman Dir.) at 11 (citing S&P Global Market Intelligence, RRA Financial Focus: "Utility Capital Expenditures Update," (Oct. 30, 2018)).

[67] TIEC Ex. 5 (Gorman Dir.) at 12.

FIGURE 3

Utility Capital Expenditures
Dollars (in millions)



Source: *S&P Global Market Intelligence, RRA Financial Focus*, Utility Capital Expenditures, October 30, 2018, Table 1.

Finally, as demonstrated in Mr. Gorman's Exhibit MPG-2, utility stocks are currently receiving robust valuations relative to the past several years, demonstrating that utilities are still able to access sufficient capital on reasonable terms at these lower ROEs—even with substantial capital expenditure programs.[68] In sum, the business environment for utilities has continued to improve in recent years, despite lower awarded ROEs.

b. CEHE's requested ROE would provide a disproportionately high premium above the risk-free rate.

There are many indicators that investors view Texas utilities as a strong investment opportunity, including the high level of interest in acquiring utilities in Texas,[69] the multiples of book value that have been offered to buy Texas utilities, and various utilities' efforts to secure additional endpoints to build transmission facilities in the state.[70] Investors' focus on the Texas utility industry is attributable to growth potential and the historically rich risk-adjusted returns. Figure 3 from Mr. Griffey's testimony uses data provided by CEHE witness Mr. Hevert to compare

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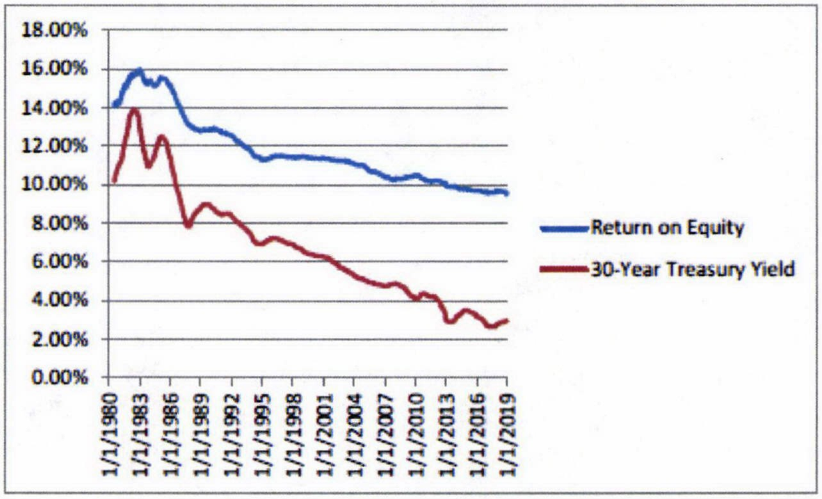
[68] TIEC Ex. 5 (Gorman Dir.) at 13, Ex. MPG-2.

[69] *See e.g. Joint Report and Application of Oncor Electric Delivery Company LLC and Sempra Energy for Regulatory Approvals Pursuant to PURA §§ 14.101, 39.262 and 39.915,* Docket No. 47675, Joint Report (Oct 5, 2017); *Joint Report and Application of Oncor Electric Delivery Company LLC, Sharyland Distribution & Transmission Services LLC, Sharyland Utilities LP, and Sempra Energy for Regulatory Approvals Under PURA §§ 14.101, 37.154, 39.262, and 39.915,* Docket No. 48929, Joint Report (Nov. 30, 2018).

[70] TIEC Ex. 4 (Griffey Dir.) at 25-27.

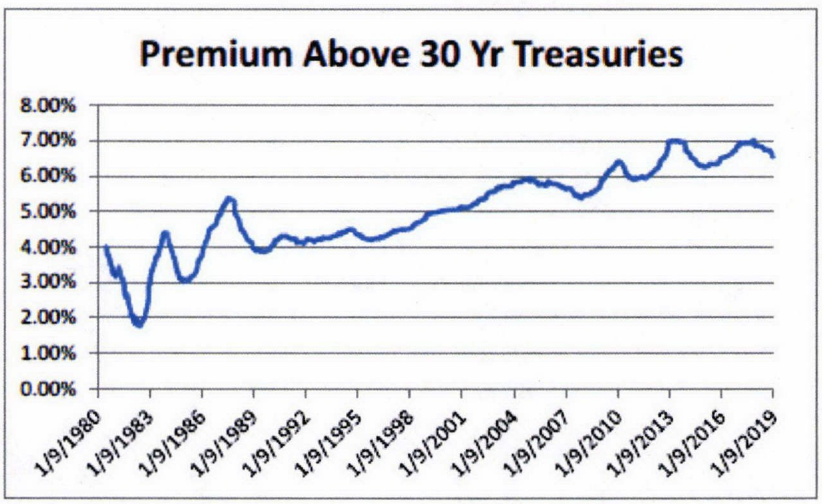
utility ROEs to long-term treasury yields since 1980. The chart shows how the gap between the two metrics has grown over time:

Figure 3: Utility ROEs and 30 Year Treasury Yield[71]



Mr. Griffey's Figure 4 demonstrates that utility risk premiums have grown steadily over time, and now sit near their all-time high at approximately 650-700 basis points above treasuries.[72]

Figure 4: Premium Above 30 Year Treasury Yield[73]



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[71] TIEC Ex. 4 (Griffey Dir.) at 26 (based on data from CEHE Ex. 26 (Hevert Dir.) at Ex. RBH-5).

[72] The reasons for this trend are discussed in a whitepaper that Mr. Griffey attached to his testimony as Exhibit CSG-3. TIEC Ex. 4 (Griffey Dir.) at Ex. CSG-3 (Griffey, Charles, Whitepaper: "When 'What Goes Up' Does Not Come Down: Recent Trends in Utility Returns." (Feb. 15, 2017)).

[73] TIEC Ex. 4 (Griffey Dir.) at 26 (based on data from CEHE Ex. 26 (Hevert Dir.) at Ex. RBH-5).

Mr. Griffey described the implications of this phenomenon in a 2017 whitepaper, where he stated:

> The "risk premium" being granted to utility shareholders is now higher than it has ever been over the last 35 years. Excessive utility ROEs are detrimental to utility customers and the economy as a whole. From a societal standpoint, granting ROEs that are higher than necessary to attract investment creates an inefficient allocation of capital, diverting available funds away from more efficient investments. From the utility customer perspective, if a utility's awarded and/or achieved ROE is higher than necessary to attract capital, customers pay higher rates without receiving any corresponding benefit.[74]

As Mr. Griffey explains, awarded ROEs are often based primarily on a comparison with other awarded ROEs around the country.[75] The backward-looking nature of this analysis means that average awarded utility returns have failed to timely reflect changing market conditions.[76] Despite CEHE's complaints, utility stocks are still vastly less risky than the average stock in the market, and thus, awarded ROEs have been higher than necessary to attract capital.[77] This has been borne out in practice: CEHE has had no difficulty making necessary capital investments in recent years.[78]

Even compared to historically high risk premiums for regulated utilities, CEHE's rate request is ***disproportionately*** high. Since 1980, utility ROEs have been above 30-year treasury yields by an average of 467 basis points.[79] CEHE's requested ROE of 10.4% would be ***730 basis points*** above long-term treasury yields, which is well above the all-time high for utility risk premiums shown in Mr. Griffey's Figure 4.[80] And as Mr. Griffey explains, these risk premiums are "allowing equity investor returns equivalent or superior than what is available in the markets generally, but for ***a lower level of risk***. This runs completely counter to reasonable economics or

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[74] TIEC Ex. 4 (Griffey Dir.) at Ex. CSG-3 (Griffey, Charles, Whitepaper: "When 'What Goes Up' Does Not Come Down: Recent Trends in Utility Returns." at 2 (Feb. 15, 2017)).

[75] *See id.*

[76] *See id.*

[77] *See id.*

[78] CEHE Ex. 43 (McRae Reb.) at 32 ("CenterPoint has been able to attract capital at reasonable terms since the enactment of the TCJA.").

[79] TIEC Ex. 4 (Griffey Dir.) at 26-27.

[80] *Id.* at 27.

market theory. As one observer colorfully put it, '. . . if you want actionable [investment] intelligence up front, here it is: invest in regulated utilities.'"[81]

This excessive risk premium is particularly unjustified for CEHE, which is a low-risk transmission and distribution utility (TDU) serving the ERCOT market. The historical premium over treasuries described above includes vertically integrated utilities that bear commodity risk and have to fund significant generation construction.[82] TDUs like CEHE do not bear those risks, and further benefit from the various rate riders, such as the TCRF and DCRF, that are available to ERCOT utilities.[83] CEHE has bragged that 95% of its capital expenditures are in rates without a rate case.[84] These advantages have led Moodys to indicate that CEHE enjoys a [redacted]" and has "[redacted]"[85] Additionally, as Mr. Gorman noted at the hearing,

> [C]redit rating agencies distinguish the credit metric targets for utilities with no commodity risk. And they establish a level of financial risk credit metric targets that are more lenient; that is, the utility can finance with greater amounts of financial risk or financial leverage and still maintain their bond rating because of the existence of the favorable regulatory treatment in Texas and importantly because Texas TDUs do not have commodity risk.[86]

Accordingly, due to the nature of CEHE's business model and regulatory environment, empirical evidence establishes that it merits a lower risk premium than others, and certainly less than what CEHE is requesting.

2. The Commission should adopt Mr. Gorman's ROE recommendation.

As described in detail below, Mr. Gorman used widely accepted methods to estimate CEHE's market cost of equity. Throughout his analysis, he applied conservative assumptions to

[81] TIEC Ex. 4 (Griffey Dir.) at Ex. CSG-3, p. 8 (quoting Huntoon, S., "Nice Work If You Can Get It," Public Utilities Fortnightly (Aug. 2016)).

[82] TIEC Ex. 4 (Griffey Dir.) at 27-28.

[83] *Id.*

[84] Tr. (Mercado Cr.) at 65:15–25 (Jun. 24, 2019); TIEC Ex. 8 (Investor & Analyst Day Presentation in Jun. 2014) at 7.

[85] TIEC Ex. 4 (Griffey Dir.) (citing Moody's Credit Opinion (Jun. 19, 2018), included in Schedule II-C-2.10 of the rate filing package) (Confidential).

[86] Tr. (Gorman Cr.) at 562:18-563:1 (Jun. 26, 2019).

data drawn from widely accepted sources. His resulting ROE recommendation of 9.25% is reasonable, in line with the recommendations of the other intervenors and Staff, and represents a fair outcome for both CEHE and its customers.

a. Mr. Gorman's proxy group is reasonable.

Mr. Gorman used the same proxy group as Mr. Hevert, with one exception. He removed one of Mr. Hevert's selected companies because less than 20% of its stock is publicly traded, which means its valuation is not comparable to the other proxy companies.[87] Mr. Hevert did not criticize this adjustment in his rebuttal testimony.[88]

b. Mr. Gorman's Discounted Cash Flow (DCF) analysis is reasonable.

The discounted cash flow (DCF) model is based on the principle that a company's stock price can be valued by summing the present value of expected future cash flows (dividends), discounted at its investors' required rate of return.[89] This is represented by the following equation:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \;\ldots\; \frac{D_\infty}{(1+K)^\infty} \qquad \text{(Equation 1)}$$

P_0 = Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

That equation can be rearranged as follows in order to use a company's current stock price, its expected dividend, and an expected dividend growth rate to estimate the return on equity that investors will demand in order to invest in that company:[90]

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend in first year
P_0 = Current stock price
G = Expected constant dividend growth rate

Mr. Gorman used three different DCF models to estimate the return that investors would demand in order to invest in CEHE: the constant growth DCF, the sustainable growth DCF, and

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[87] TIEC Ex. 5 (Gorman Dir.) at 39-40.

[88] *See generally*, CEHE Ex. 42 (Hevert Reb.).

[89] TIEC Ex. 5 (Gorman Dir.) at 40.

[90] *Id.* at 41.

the multi-stage growth DCF.[91] As discussed below, the primary difference between these models is their growth rate assumption.

i. Constant growth DCF

Mr. Gorman's constant growth DCF model used the proxy group's 13-week average stock price and most recently reported quarterly dividends, along with a 5.38% growth rate, which was based on a consensus, or mean, of professional securities analysts' growth estimates for those companies.[92] The resulting average and median constant growth DCF returns for the proxy group were 9.31% and 9.57%, respectively.[93]

Importantly, Mr. Gorman questioned the results of his constant growth DCF model because it is widely accepted that over the long term, utility stocks cannot grow faster than the economy in which they provide goods and services, and consensus economists predict that the US GDP will grow at approximately 4.00% per year.[94] In light of this issue, Mr. Gorman considered the results of his constant growth DCF analysis to be a reasonable high-end return estimate.[95]

ii. Sustainable growth DCF

Mr. Gorman's sustainable growth DCF model is based on the principle that a utility's earnings will grow over time as it invests in additional utility plant and equipment, which enables it to earn its authorized return on a larger total rate base. To estimate the sustainable growth in CEHE's rate base, Mr. Gorman looked to the proportion of total earnings that his proxy group retained for reinvestment rather than paying out in dividends.[96] He found that, on average, the sustainable growth rate for CEHE's proxy group is 4.23%,[97] which is much more in line with the projected GDP growth rate of 4.00%. Performing a DCF analysis using this more conservative sustainable growth rate resulted in proxy group average and median ROE requirements of 8.11% and 8.20%, respectively.[98]

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[91] *Id.* at 40-54.

[92] *Id.* at 42-43, Ex. MPG-8.

[93] *Id.* at 43, Exhibit MPG-9.

[94] *Id.* at 44.

[95] *Id.*

[96] *Id.* at 45, Ex. MPG-10.

[97] *Id.* at 45, Ex. MPG-11.

[98] *Id.* at 46.

iii. Multi-stage growth DCF

Mr. Gorman's multi-stage growth DCF model reflects the reality that while a utility may experience periods of high or low short-term growth, its growth rate will eventually regress toward a long-term sustainable rate.[99] To model this expectation, Mr. Gorman performed a multi-stage growth DCF analysis that starts with the consensus economists' growth rate projections that were used in his constant growth DCF (5.38%), which represent reasonable investor expectations for the next five years.[100] Then, for years six through ten, he adjusted the proxy group's growth rates either upward or downward (as applicable), halfway toward the long-term sustainable growth rate of 4.00%, which mirrors economists' projections for total GDP growth.[101] For years eleven and after, Mr. Gorman projected growth at the long-term sustainable rate of 4.00%.[102] The resulting DCF analysis resulted in average and median DCF ROEs of 8.21% and 8.17%, respectively.[103]

iv. DCF model results

The results of Mr. Gorman's various DCF models are summarized in his Table 9:[104]

TABLE 9

Summary of DCF Results

Description	Proxy Group Average	Proxy Group Median
Constant Growth DCF Model (Analysts' Growth)	9.31%	9.57%
Constant Growth DCF Model (Sustainable Growth)	8.11%	8.20%
Multi-Stage Growth DCF Model	8.21%	8.17%

Mr. Gorman's DCF cost of equity estimate for CEHE is 9.45%, which is the midpoint of his reasonable range of 9.3% to 9.6%.[105] As discussed above, Mr. Gorman determined that his estimate is likely near the higher end of a reasonable range because it is based primarily on his

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99 *Id.*

100 *Id.* at 47.

101 *Id.* at 47-53, Ex. MPG-13 (demonstrating reasonableness of 4.00% long-term sustainable growth rate estimate).

102 *Id.* at 48.

103 *Id.* at 53.

104 *Id.* at 54.

105 *Id.*

Constant Growth DCF Model (Analysts' Growth), which applied a long-term growth rate assumption of 5.38%—well in excess of the long-term sustainable growth rate of 4.0%, as represented by projected U.S. GDP growth. As explained further below, CEHE witness Mr. Hevert also constructed a Constant Growth DCF model that (in his "Mean" result) used a similar growth rate assumption (5.79%).[106] However, unlike Mr. Gorman, Mr. Hevert failed to acknowledge that his results should serve as a high-end ROE estimate because they were based on an unsustainable growth rate.[107] Worse, Mr. Hevert went on to deliberately inflate his ROE result by conducting another DCF analysis (his "Mean High" result) using the ***highest available*** analyst growth projections rather than the average.[108] Additionally, unlike Mr. Gorman, Mr. Hevert did not balance the results of his Constant Growth DCF model against more conservative DCF projections that slowly adjust expected growth toward the maximum long-term sustainable rate (again, 4%). Accordingly, the Commission should place substantially more weight on Mr. Gorman's conclusions, which are based on sound reasoning and analysis and not artificially inflated.

c. Mr. Gorman's Bond Yield Plus Risk Premium (Risk Premium) analysis is reasonable.

Mr. Gorman also conducted a bond yield plus risk premium (Risk Premium) analysis, which is based on the principle that investors will require a higher return for investments that pose a greater risk.[109] Equity investments are riskier than bonds because bondholders are paid out before equity holders in bankruptcy and bond coupon payments are contractually required, whereas stock dividends are discretionary.[110]

Mr. Gorman's Risk Premium analysis separately estimates the additional return that has historically motivated investors to hold utility stock instead of (1) risk-free U.S. Treasury bonds and (2) "A" rated utility bonds.[111] These analyses are based on a comparison of historically awarded utility ROEs to Treasury bond yields and "A" rated utility bond yields, respectively, over

[106] CEHE Ex. 26 (Hevert Dir.) at 61, Ex. RBH-1.

[107] TIEC Ex. 5 (Gorman Dir.) at 74.

[108] CEHE Ex. 26 (Hevert Dir.) at 61 ("I calculated the high DCF result by combining the maximum EPS growth rate estimate as reported by Value Line, Zacks, and First Call with the subject company's dividend yield.").

[109] TIEC Ex. 5 (Gorman Dir.) at 54.

[110] *Id.*

[111] *Id.*

the period from 1986 through 2019.[112] This time period was chosen because electric utility stocks consistently traded at a premium to book value over that span, meaning that awarded ROEs for electric utilities were generally high enough to support market prices in excess of book value and provide utilities with an opportunity to access equity markets.[113] As shown in Exhibit MPG-16 to Mr. Gorman's testimony, he calculated average indicated equity risk premium that utility investments demanded over U.S. Treasury bond yields and "A" rated utility bond yields over the last 33 years.[114] Additionally, to reflect the dynamic nature of utility risk premiums and mitigate the impact of anomalous market conditions, Mr. Gorman also calculated five- and ten-year rolling average risk premiums.[115] Those results are as follows:

Electric Utility Equity Risk Premium Over U.S. Treasury Bond Yields: 1986-2019[116]	
Average Indicated Risk Premium	5.57%
Five-Year Rolling Average Risk Premium	4.25% to 6.72%
Ten-Year Rolling Average Risk Premium	4.38% to 6.57%
Electric Utility Equity Risk Premium Over "A" Rated Utility Bond Yields: 1986-2019[117]	
Average Indicated Risk Premium	4.21%
Five-Year Rolling Average Risk Premium	2.88% to 5.57%
Ten-Year Rolling Average Risk Premium	3.20% to 5.41%

Rather than just applying these risk premiums to recent Treasury bond levels, Mr. Gorman analyzed empirical data to determine how the market is currently pricing investment risk.[118] By comparing historical and recent yield spreads for utility bonds and general corporate bonds, Mr. Gorman concluded that today, the market is paying a premium for access to lower-risk utility securities—a premium that is not reflected in higher-risk bond offerings.[119] As a result, Mr. Gorman applied an ***above-average*** risk premium by weighting his high-end risk premium estimates (70% weight) significantly higher than the low-end estimates (30% weight).[120] This had the effect of increasing the ROE recommendation based on his Risk Premium analysis.

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[112] *Id.* at 54-55.

[113] *Id.* at 55-56.

[114] *Id.* at 55-56, Ex. MPG-16, Ex. MPG-17.

[115] *Id.*

[116] *Id.* at Ex. MPG-16.

[117] *Id.* at Ex. MPG-17.

[118] *Id.* at 57-58.

[119] *Id.* at 59.

[120] *Id.* at 60.

After appropriately weighting his historical risk premiums, Mr. Gorman concluded that the risk premium that an investor will demand for holding utility stock instead of Treasury bonds is approximately 6.0%, which is considerably higher than the 5.57% historical average premium.[121] Combined with the current 3.2% projected U.S. Treasury bond yield, this results in a Risk Premium ROE estimate of 9.20%. Similarly, his weighted Risk Premium over utility bonds is 4.80%, compared to the historical average of 4.21%.[122] This results in a Risk Premium ROE estimate of 9.40%.[123] Accordingly, Mr. Gorman's Risk Premium analysis indicates a return in the range of 9.20% to 9.40%, with a midpoint at 9.30%.[124]

d. Mr. Gorman's Capital Asset Pricing Model (CAPM) analysis is reasonable.

The Capital Asset Pricing Model (CAPM) posits that in order to hold a security, the market requires a rate of return equal to the risk-free rate, plus a premium called "beta" that represents the risks of holding that security that cannot be eliminated by asset diversification.[125] The CAPM theory suggests that the market will not compensate investors for assuming risks that can be diversified away by holding a balanced portfolio. Beta is a measurement of the systematic, non-diversifiable market risks of holding a particular security.[126] A beta of less than 1.0 indicates that a company is less risky than the market as a whole.[127] The risk/return relationship underlying the CAPM can be expressed as follows:[128]

$R_i = R_f + B_i \times (R_m - R_f)$ where:

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock

[121] *Id.*

[122] *Id.*

[123] *Id.*

[124] *Id.*

[125] *Id.* at 61.

[126] *Id.*

[127] *Id.*

[128] *Id.*

Using the CAPM to determine an appropriate ROE for CEHE requires an estimate of the market risk-free rate, CEHE's beta, and the market risk premium.[129]

As mentioned above, Mr. Gorman uses consensus economists' projected 30-year Treasury bond yield of 3.20% as a proxy for the risk-free rate.[130] This is a conservative approach in the context of this analysis because, as Mr. Gorman describes, Treasury bonds do include some systemic market risks related to unanticipated inflation and interest rates, meaning that using them as a proxy for the risk-free rate has a tendency to ***overstate*** the CAPM return for companies (like CEHE) that have betas below 1.0, which indicates that they are less risky than the market as a whole.[131]

Mr. Gorman reviewed data from *Value Line* to determine that the current average beta for his proxy group is 0.60, compared to the group's historical average beta of 0.70.[132] Mr. Gorman explains that this discrepancy is likely due to the market paying a premium for low-risk utility securities as a hedge against uncertainty. For purposes of his CAPM analysis, he applied the higher historical average utility beta, which, like his risk free rate assumption, has the effect of ***increasing*** the estimated ROE.[133]

For the next component of the CAPM analysis, Mr. Gorman derived two risk premium estimates. His forward-looking estimate projected the returns of the S&P 500 into the future by adding an expected inflation rate to the long-term arithmetic average real return on the market (as determined by Duff & Phelps), which represents the market's achieved return above inflation.[134] This forward-looking method produced an expected market return of 11.1%.[135] Subtracting the estimated forward-looking risk-free rate of 3.2% results in a forward-looking risk premium of 7.9%. Mr. Gorman also determined a historical estimate of the market risk premium by reviewing data from Duff & Phelps, which shows that the historical arithmetic average of the achieved total return on the S&P 500 was 11.9%. By subtracting out the historical total return on long-term

[129] *Id.* at 62.

[130] *Id.*

[131] *Id.* at 63.

[132] *Id.* at 63, Exhibit MPG-20.

[133] *Id.* at 63.

[134] *Id.* at 63, 64.

[135] *Id.* at 64.

Treasury bonds of 5.9%,[136] he determined that the historical market risk premium was 6.0%.[137] Based on this analysis, Mr. Gorman found that his market risk premium falls in the range of 6.0% to 7.9%, which is consistent with (and toward the higher end of the range for) forward-looking market risk premium estimates made by Duff & Phelps, which predicts a market risk premium in the range of 5.5% to 6.9%.[138]

Combining all of the aspects of Mr. Gorman's CAPM analysis results in an expected ROE of 7.40% to 8.73%. While Mr. Gorman's CAPM range is lower than his DCF analysis, recent market data supports the reasonableness of ROEs in this range.[139] Based on his assessment that the market is currently paying premiums to hold low-risk investments as a hedge against uncertainty, Mr. Gorman determined that investors will require somewhat higher risk premiums relative to risk free securities to invest in the current market.[140] Accordingly, he recommends the higher end of his CAPM indicated ROE range (8.70%) as his CAPM return.[141]

e. The Commission should adopt the reasonable and conservative conclusions that Mr. Gorman draws from his various models.

Based on his analyses, Mr. Gorman concluded that a reasonable market cost of equity for CEHE is ***9.25%***, which is the midpoint of his estimated range of 9.00% to 9.5%.

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[136] As Mr. Gorman notes in his testimony, the historical return for Treasury bonds is significantly higher than the projected return because the historical period saw inflation of approximately 3.0%, which implies that the total real return on long-term government bonds is about 2.9%. *Id.*

[137] *Id.*

[138] *Id.* at 66.

[139] *See* TIEC Ex. 4 (Griffey Dir.) at Exhibit CSG-3 (Whitepaper: "When 'What Goes Up' Does Not Come Down: Recent Trends in Utility Returns." Griffey, Charles S. (Feb. 15, 2017)).

[140] TIEC Ex. 5 (Gorman Dir.) at 67.

[141] *Id.*

Gorman: Cost of Equity Summary

Analysis	**Results**
DCF	9.45%
Risk Premium	9.30%
CAPM	8.70%
Estimated Range: 9.00% - 9.50%	
Recommended ROE: 9.25%	

This ROE recommendation is very conservative, as Mr. Gorman made numerous judgments that actually increased the output of several of his model runs. Moreover, this ROE reflects observable market evidence, the impact of Federal Reserve policies on current and expected long-term capital market costs, an assessment of the current risk premium built into market securities, and a general assessment of the current investment risk characteristics of the electric utility industry and the market's demand for utility securities. In sum, it is a fair assessment of CEHE's market cost of equity, and will allow CEHE to access capital and earn a fair return on its investments.

3. The Commission should reject Mr. Hevert's inflated ROE recommendation.

a. Mr. Hevert's analysis is unreliable.

Mr. Hevert's analysis is not credible, and unnecessarily inflates CEHE's requested ROE. As explored in detail at the hearing, Mr. Hevert regularly testifies on behalf of utilities, and consistently recommends unreasonably high ROEs. In fact, Mr. Hevert has only recommended an ROE lower than 10.0% in ***three out of 143 cases*** over the last five years,[142] and during that time period, his recommended ROE has ***never*** been adopted by a regulator.[143] Further, utility commissions throughout the country often find that Mr. Hevert's analysis is unreliable for exactly

[142] Tr. (Hevert Cr.) at 724:5-24 (Jun. 26, 2019); TIEC Ex. 22 (Entergy New Orleans RFI Response from Docket No. UD-18-07 RE: Hevert Prior Testimony).

[143] Tr. (Hevert Cr.) at 723:13-724:4 (Jun. 26, 2019); TIEC Ex. 22 (Entergy New Orleans RFI Response from Docket No. UD-18-07 RE: Hevert Prior Testimony).

the same reasons discussed in Mr. Gorman's testimony and described below. For example, here are just a few of the findings that other regulators have made about Mr. Hevert's analysis:

- "Specifically, in this Cause, the Commission did not find Mr. Hevert's opinions persuasive. His recommended ROE of 10.25 percent was excessive in that ***each of his methods and the inputs he used appear to have been biased upward, resulting in a significantly inflated recommendation***."[144]

- "KCPL's expert witness, ***Robert Hevert, supports an increased return on equity at 10.3 percent. The Commission finds that such a return on equity would be excessive***. Hevert's return on equity estimate is high because 1) his constant growth DCF results are based on ***excessive and unsustainable long-term growth rates***, 2) his multi-stage DCF is based on a ***flawed accelerated dividend cash flow timing and an inflated gross domestic product growth estimate as a proxy for long-term sustainable growth***, 3) his CAPM is based on ***inflated market risk premiums***, and 4) his bond yield plus risk premium is based on ***inflated utility equity risk premiums***."[145]

- "Ameren Missouri's expert witness, Robert Hevert, supports an increased ROE at 10.4 percent. The Commission finds that such an ROE would be excessive. In large part, Hevert's ROE estimate is high because he based his multi-stage DCF analysis calculations on an ***optimistic nominal long-term GDP growth rate*** outlook of 5.71 percent. ***As Gorman explains, that growth rate is substantially higher than consensus economists' forward-looking real GDP growth outlooks.*** Adjusting Hevert's optimistic growth rate outlook to the consensus economist level reduces his multi-stage growth DCF return from 10.02 percent to 8.80 percent for his proxy group. Similarly, if Hevert's CAPM analysis is ***adjusted to use more reasonable projected returns*** on the market, that analysis would result in a range of 8.80 percent to 9.52 percent."[146]

- "Pepco witness ***Hevert has relied on growth rates and risk premiums that are too high to be consistent with actual current or predicted versions of those indicators***. We also have reservations about Mr. Hevert's asymmetric elimination of mean and median low DCF results. ***Mr. Hevert also appears to have overestimated other numbers that biased his ROE to too high a level. His long-term earnings growth rates and market risk premium estimates are significantly higher than most estimated and historical growth rates for electric utilities. Further, many of Mr. Hevert's comparable companies, and his reliance on the average returns of all S&P 500 companies, contribute to a higher ROE than is realistic for a stable monopoly*** such as Pepco. We are not persuaded that any changes in

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[144] TIEC Ex. No. 27 (Oklahoma Corporation Commission Final Order in Docket No. PUD 201500273 (Feb. 2, 2017)) at 5 (emphasis added).

[145] TIEC Ex. No. 26 (Missouri Public Service Commission Report and Order in Docket No. ER-2014-0370 (Sept. 2, 2015)) at 19–20, FoF 33 (emphasis added).

[146] TIEC Ex. No. 25 (Missouri Public Service Commission Report and Order in Docket No. ER-2014-0258 (April 29, 2015)) at 66, FoF 15 (emphasis added).

Pepco's service territory, or the riskiness of Pepco's business monopoly, justify an ROE in the range Mr. Hevert proposes."[147]

- "WGL Witness ***Hevert utilizes an inflated U.S. GDP growth rate*** for the long-term growth rate as part of his Multi-Stage DCF. We do not believe that a 5.27% growth rate is justified at this point in time for ratemaking purposes and we must set his Multi-Stage DCF results aside. Additionally, with regard to the CAPM presented by Witness Hevert, the Commission finds that ***the use of forecasted U.S. Treasury Yields is speculative*** and so we will disregard his CAPM results based on those projections."[148]

In short, Mr. Hevert has shown a consistent pattern of ***overestimating*** long-term growth rates and using ***excessive*** risk premiums to support unreasonably high utility ROEs. As demonstrated below, this case is no exception.

Also casting doubt on his credibility, Mr. Hevert refused to revise his 10.4% ROE recommendation downward in response to new information. As shown during cross-examination, Mr. Hevert substantially adjusted the results of his various models between his direct and rebuttal testimony.[149] Every result from his Constant Growth DCF model fell by around 0.5%.[150] Additionally, all of his CAPM results fell by between 0.27% and 1.34%.[151] Even his Bond Yield Plus Risk Premium results dipped.[152] Despite this, Mr. Hevert's ROE recommendation remained unchanged.[153] This is simply not credible, and the Commission should take it into account when assessing Mr. Hevert's recommendations.

b. Mr. Hevert used unreasonably high estimated growth rates in his constant growth DCF analysis and did not balance that analysis with more conservative DCF models.

In his direct testimony, Mr. Hevert performed a constant growth DCF analysis that, like Mr. Gorman's analysis described above, generally supports an ROE of no higher than 9.30%.[154]

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[147] TIEC Ex. No. 24 (Maryland Public Service Commission Order in Docket No. 9336 (July 2, 2014)) at 86–87 (emphasis added).

[148] TIEC Ex. No. 28 (District of Columbia Public Service Commission Opinion and Order in Docket No. FC1137-2017-G-280 (March 3, 2017)) at 27, ¶ 65 (emphasis added).

[149] *Cf.* CEHE Ex. 26 (Hevert Dir.) at 7 (Table 1A) *with* CEHE Ex. 42 (Hevert Reb.) at 177 (Figure 53).

[150] *Cf.* CEHE Ex. 26 (Hevert Dir.) at 7 (Table 1A) *with* CEHE Ex. 42 (Hevert Reb.) at 177 (Figure 53); *see also* Tr. (Hevert Cr.) at 742:10-745:10 (Jun. 26, 2019).

[151] *Cf.* CEHE Ex. 26 (Hevert Dir.) at 7 (Table 1A) *with* CEHE Ex. 42 (Hevert Reb.) at 177 (Figure 53); *see also* Tr. (Hevert Cr.) at 742:10-745:10 (Jun. 26, 2019).

[152] *Cf.* CEHE Ex. 26 (Hevert Dir.) at 7 (Table 1A) *with* CEHE Ex. 42 (Hevert Reb.) at 177 (Figure 53).

[153] CEHE Ex. 42 (Hevert Reb.) at 7.

[154] TIEC Ex. 5 (Gorman Dir.) at 74.

As shown on page 61 of Mr. Hevert's testimony, the mean results of his Constant Growth DCF model using average projected growth rates for his proxy companies ranged between 9.22% and 9.32%,[155] which is very close to Mr. Gorman's results.[156] In his rebuttal testimony, Mr. Hevert revised that "Mean" Constant Growth DCF Result downward to a range of 8.71% to 8.9%.[157] As Mr. Gorman explains, these DCF projections likely ***overstate*** the required ROE for CEHE because they are based on average growth projections for the proxy group that are substantially higher than a reasonable long-term GDP estimate of 4.0%.[158]

Not satisfied with his "Mean" Constant Growth DCF results, Mr. Hevert then performed what he calls a "Mean High" analysis that used the ***maximum EPS growth rate estimate*** for each of his proxy companies.[159] In other words, he inflated the growth rate as much as he possibly could based on the available data. This approach is not credible because it pushes the expected growth rate even further above the long-term sustainable growth rate.[160] Even with the most inflated possible assumptions, Mr. Hevert's "Mean High" constant growth DCF results ranged from 10.09% to 10.20%.[161] Then, in his rebuttal testimony, he revised that estimate downward to a range of 9.53% to 9.73%,[162] which is still well below his requested ROE of 10.4%. Notably, Mr. Hevert's corresponding "Mean Low" results are substantially lower, and produced a range of of 8.43% to 8.53% in his direct testimony,[163] and 7.95% to 8.14% on rebuttal.[164]

As mentioned above, Mr. Hevert's average constant growth DCF model was based on a proxy group average growth rate of 5.80%, which is higher than Mr. Gorman's average growth rate of 5.3%, and well above consensus economists' projected long-term sustainable growth rate

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[155] CEHE Ex. 26 (Hevert Dir.) at 61.

[156] TIEC Ex. 5 (Gorman Dir.) at 74.

[157] CEHE Ex. 42 (Hevert Reb.) at 177.

[158] TIEC Ex. 5 (Gorman Dir.) at 44.

[159] CEHE Ex. 26 (Hevert Dir.) at 61 ("I calculated the high DCF result by combining the ***maximum EPS growth rate estimate*** as reported by Value Line, Zacks, and First Call with the subject company's dividend yield.") (emphasis added).

[160] In fact, while Mr. Hevert does not list the average expected growth rate for his "Mean High" analysis, taking the average of the highest number from each row of columns 4, 5, and 6 of Mr. Hevert's Exhibit RBH-1 (the Zacks, First Call, and Value Line growth projections, respectively) results in a "High" average earnings growth rate of ***6.65%***. This is even more out of line with the long-term sustainable growth rate of 4.0%.

[161] CEHE Ex. 26 (Hevert Dir.) at 61

[162] CEHE Ex. 42 (Hevert Reb.) at 177.

[163] CEHE Ex. 26 (Hevert Dir.) at Ex. RBH-1, p. 1-3.

[164] CEHE Ex. 42 (Hevert Reb.) at 177.

of 4.00%.[165] However, unlike Mr. Gorman, Mr. Hevert does not acknowledge that the DCF model should represent a high-end estimate of CEHE's current market cost of equity.[166] Nor does he balance the results of that constant growth model against other, more conservative DCF models that are based on sustainable growth estimates. For example, even though he has done so in prior cases, Mr. Hevert did not perform a multi-stage growth DCF analysis to estimate CEHE's market cost of equity using a more realistic long-term growth rate that matches the long-term GDP growth rate of 4.00%.[167] While he claimed in a discovery response that a multi-stage DCF model would not add significantly more information relative to the models he included,[168] he likely omitted this model because it results in a very low estimated cost of equity for CEHE. To demonstrate this, Mr. Gorman performed a multi-stage growth DCF analysis using Mr. Hevert's dividend and stock price inputs, along with a growth rate equal to consensus economists' long-term GDP growth outlook of 4.00%.[169] The resulting ROE estimate was 8.0%.[170]

After Mr. Hevert's constant growth DCF analysis—which applied an unsustainable long-term growth rate that would inflate CEHE's estimated ROE—proved too low, he attempted to discredit the results of the DCF model entirely. Mr. Hevert claimed that current market conditions reflect a low interest rate environment, which affects security valuation and yields relative to historical levels, and that the market has an expectation of higher interest rates, which will in turn increase the return that investors will demand on their equity investments.[171] However, as Mr. Gorman points out, economists have been consistently predicting that interest rates would rise over the last five years, and were even making such predictions at the time of CEHE's last rate case.[172] Nevertheless, interest rates have remained stable, and consensus economists have moderated their projections for interest rates over the next five to ten years,[173] which is evidence that the market is embracing the sustainability of low interest rates.[174] Despite this shift in economists' predictions,

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[165] TIEC Ex. 5 (Gorman Dir.) at 74.

[166] TIEC Ex. 5 (Gorman Dir.) at 74.

[167] *Id.* at 75.

[168] *Id.* at 75.

[169] *Id.* at 75, Ex. MPG-23.

[170] *Id.* at 76.

[171] CEHE Ex. 26 (Hevert Dir.) at 5, 9, 12, 61-63.

[172] TIEC Ex. 5 (Gorman Dir.) at 76.

[173] *Id.* at 76-77.

[174] *Id.* at 77.

Mr. Hevert has repeatedly testified in other Texas proceedings that interest rates were about to rise.[175] However, those predictions have been consistently wrong, as interest rates have actually fallen since Mr. Hevert anticipated otherwise in Atmos Energy, SPS, and Oncor's recent rate cases.[176] Worse, Mr. Hevert's prediction of rising interest rates is directly contradicted by statements from the Federal Reserve Board, which has recently revised its interest rate projections significantly downward ***twice***,[177] and currently projects that rates will ***fall*** from their current 2.4% to 2.1% in 2020, and will only rebound to their current levels in 2021.[178] Mr. Hevert himself even admits that there is a "zero" chance of the Federal Reserve increasing the federal funds rate before April of 2020.[179] Accordingly, Mr. Hevert's projection of increasing interest rates, as well as his criticism of the DCF model's results, is simply not credible.

Mr. Hevert also claimed that the DCF analysis is not producing reasonable results because the growth outlook for utility stocks is depressed. However, Mr. Gorman's Exhibit MPG-2 demonstrates that there is a robust outlook for utility securities, with analysts' current predictions for utility dividends and earnings growth at 6.59% and 5.26%, respectively.[180] This compares to a historical 4.3% annual growth rate for utility earnings and dividends over the past 13 years,[181] and an average projected growth rate for Mr. Gorman's proxy group of 5.38%.[182] Given that all of these growth projections are substantially higher than projected U.S. GDP growth of 4.0% (which represents a long-term maximum growth rate for utility companies),[183] the growth rate component of the DCF analysis should, if anything, ***overstate*** the return that investors will require to invest in utility stocks.[184] Accordingly, Mr. Hevert's claim that his DCF results are too ***low*** is not credible, and the Commission should instead rely on Mr. Gorman's analysis.

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[175] Tr. (Hevert Cr.) at 748:12-750:12 (Jun. 26, 2019); TCUC Ex. 92-94.

[176] Tr. (Hevert Cr.) at 748:12-750:12 (Jun. 26, 2019); TCUC Ex. 92-94.

[177] *See* TIEC Ex. 20 (March 20, 2019 Federal Reserve Board Press Release) (revising December projections downward); TIEC Ex. 21 (June 19, 2019 Federal Reserve Board Press Release) (revising March projections further downward); Tr. (Hevert Cr.) at 718:17-721:23 (Jun. 26, 2019).

[178] *See* TIEC Ex. 21 (June 19, 2019 Federal Reserve Board Press Release); Tr. (Hevert Cr.) at 718:17-721:23 (Jun. 26, 2019).

[179] *See* Tr. (Hevert Cr.) at 750:22-753:7 (Jun. 26, 2019); TCUC Ex. 97.

[180] TIEC Ex. 5 (Gorman Dir.) at 78.

[181] *Id.*

[182] *Id.* at 78, Ex. MPG-8.

[183] *Id.* at 74.

[184] *Id.* at 78.

c. Mr. Hevert based his CAPM analysis on inflated market risk premiums.

Mr. Hevert also performed a CAPM analysis. As described above, the CAPM analysis is based on the theory that the market required rate of return for a security is equal to the risk free rate, plus a risk premium that can be calculated by multiplying a stock's "beta," which is a measure of its riskiness, by the difference between the expected return of a market portfolio minus the risk-free rate (in other words, beta multiplied by the non-diversifiable risk of the market).[185]

There are two major issues with Mr. Hevert's CAPM analysis. First, he used extraordinarily high market risk premiums, which bias his ROE result upward. In his direct testimony, Mr. Hevert based his market risk premium on assumed market growth of ***11.63% to 14.82%***,[186] which is two to three times the long-term sustainable growth rate, and far out of line with the actual capital appreciation of the S&P 500 between 1926 and 2018, which is between 5.8% to 7.7%.[187] Not only is Mr. Hevert's projection far too high, but as demonstrated by Mr. Gorman, it does not take into account the fact that market growth has generally tracked historical U.S. GDP growth, and because G.D.P growth is currently lower than its historical average, the assumed market growth premium should be as well.[188]

Mr. Hevert also failed to appropriately set his market risk premium in relationship to the projected risk-free rate.[189] He calculated his market risk premiums by conducting a DCF analysis for the entire market using risk premium estimates from Bloomberg (10.72%) and *Value Line* (14.10%).[190] Those risk premium estimates used a risk-free rate of 3.03%.[191] Later, however, Mr. Hevert plugged those same risk premium estimates into his CAPM along with a ***higher*** risk-free

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[185] *Id.* at 79.

[186] *Id.* at 81.

[187] *Id.* (citing Duff & Phelps, *2019 SSBI Yearbook* at 6-17).

[188] *Id.* at 81.

[189] *Id.* at 79.

[190] *Id.* at 79-80.

[191] *Id.* at 80.

rate of 3.33%.[192] By using market risk premiums derived using a risk-free rate of 3.03%, but then calculating his CAPM with a risk-free rate of 3.33%, Mr. Hevert biased his analysis upward.[193]

Mr. Gorman performed an appropriate CAPM analysis using his calculated high-end market risk premium of 7.9% combined with Mr. Hevert's risk-free rates of 3.03% and 3.33%, and the average Bloomberg and *Value Line* beta estimates for the proxy group of 0.497 and 0.582, respectively. This analysis resulted in an ROE estimate of 7.9%.[194]

d. Mr. Hevert based his Bond Yield Plus Risk Premium studies on inflated utility equity risk premiums.

Mr. Hevert's Bond Yield Plus Risk Premium (BYP) analysis is based on the premise that equity risk premiums are inversely related to interest rates, with no regard to any differences in perceived investment risk.[195] This view is overly simplistic and unnecessarily inflates his ROE result. In particular, various academic studies have proven that there has been an inverse relationship between interest rates and equity risk premiums in the past, the market's perception of investment risk influences the relationship between those variables over time.[196] For instance, in the 1980s, there was an inverse relationship between equity risk premiums and interest rates because high interest rate volatility increased the perceived risk of bond investments compared to stock.[197] Today, however, interest rate volatility is much lower, and changes in equity risk premiums are not directly related to interest rate swings.[198] Additionally, changes in nominal interest rates are heavily influenced by changes to inflation outlooks, which also change investors' equity return expectations.[199] As a result, it was inappropriate for Mr. Hevert to ignore differences in perceived risk between debt and equity investments when performing his CAPM analysis.[200]

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[192] *Id.* at 81-82; *see also* CEHE Ex. 26 (Hevert Dir.) at Ex. RBH-4 (*cf.* Column 1, which applies different risk-free rates of 3.03% and 3.33% *with* Columns 3 and 4, which apply risk premium estimates derived using only a 3.03% risk-free rate assumption).

[193] *Id.* at 82.

[194] *Id.*

[195] *Id.* at 83.

[196] *Id.* at 83-84.

[197] *Id.* at 84.

[198] *Id.*

[199] *Id.*

[200] *Id.*

Mr. Hevert attempts to prove the strength of the relationship between interest rates and risk premiums by performing a regression analysis using data from 1980-2019.[201] However, that regression collapsed when Mr. Gorman modified it to measure the post-recession period from 2010-2019.[202] In other words, Mr. Hevert's proposed relationship between interest rates and risk premiums no longer holds, and is unduly weighted by historical results from prior decades when financial conditions were substantially different than they are now. This indicates the flawed nature of Mr. Hevert's simplistic assumption that interest rates and risk premiums continue to be inversely related to one another.

Finally, as Mr. Gorman explains that Mr. Hevert should have used observable current bond yields when performing his analysis, rather than more uncertain five to ten year bond yield projections.[203]

Mr. Gorman corrected the flaws in Mr. Hevert's BYP analysis, and re-ran it using a weighted average equity risk premium over Treasury bonds of 6.1% (as derived above in Mr. Gorman's Risk Premium analysis), along with Mr. Hevert's assumed Treasury yields of 3.03% and 3.33%.[204] The resulting BYP result ranged from 9.13% to 9.43%.[205]

e. Mr. Hevert's Expected Earnings analysis should be rejected entirely because it does not measure the market required return.

Mr. Hevert applied an Expected Earnings analysis in an attempt to bolster the outputs of his other models. That analysis used Value Line's projected returns on "book equity" to show that analysts expect the proxy group to actually earn returns in excess of 10%.[206] However, the Expected Earnings analysis only says what a proxy group of utilities' earnings (likely) ***will*** be, and that information is not helpful in utility ratemaking, which attempts to ***determine*** a fair market return on equity rather than just awarding returns based on other utilities' expected performance.

As Mr. Gorman explains, projected book accounting return is a useful only in determining whether utilities' rate revenues are generally too high or too low ***to achieve a valid market return***

[201] *Id.* at 85.

[202] *Id.* at 85-86.

[203] *Id.* at 86.

[204] *Id.* at 87.

[205] *Id.*

[206] *Id.*; CEHE Ex. 5 (Hevert Dir.) at 73.

on equity.[207] In other words, the Expected Earnings analysis will show whether the proxy group utilities are generally projected to over- or under-earn. However, it could just be the case that analysts' projected earnings for the proxy group are high because, on average, their rates are simply set too high and/or they are expected to earn in excess of a fair market return. In fact, Mr. Hevert's result is easily explained by Mr. Griffey's analysis that regulators have been slow to decrease utility ROEs to market levels in response to changing market conditions.[208] Just because the proxy group is projected to earn a high actual return does not mean that regulated rates should be set at that level. It could simply mean that in general, the proxy group utilities are projected to earn more than is fair to ratepayers.

Further, using Expected Earnings to set utility rates simply perpetuates those projections: if a proxy group of similar utilities is generally expected to over-earn, then the Expected Earnings analysis would suggest that their rates should be increased, and if rates are increased in response to that analysis then the group's expected earnings would increase even further. And vice versa in the event they were expected to under-earn. As such, the Expected Earnings analysis is meaningless in the context of a proceeding that is designed to ***develop*** a fair market return, and the Commission should disregard the results of that analysis.

f. Mr. Hevert's flotation cost adjustment should be disregarded because is not based on CEHE's known and measurable cost of issuing equity.

Mr. Hevert also considered a nine-basis-point "flotation cost adjustment" that, unsurprisingly, would only serve to ***increase*** CEHE's ROE.[209] He did not explicitly include in the adder his DCF, CAPM, or Risk Premium results.[210] However, he did consider it to gauge where his recommended ROE would be within his market-based model return estimates. Flotation cost adjustments of this type are rarely proposed in Commission proceedings, and are almost never adopted.[211] For instance, in Docket No. 40443, the Commission rejected a flotation cost

[207] TIEC Ex. 5 (Gorman Dir.) at 88.

[208] TIEC Ex. 4 (Griffey Dir.) at 26-27.

[209] TIEC Ex. 5 (Gorman Dir.) at 89.

[210] *Id.* at 72.

[211] *See Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Proposal for Decision at 140 (May 20, 2013) ("Flotation cost adjustments are not common in Commission proceedings. There is a reason for the almost consistent refusal of the Commission to grant such an adjustment–it is by no means clear whether SWEPCO's parent company will procure the capital used to make equity infusions through retained earnings of the parent company, debt issuances of the parent company, or a stock

adjustment proposed by Mr. Hevert because he did not prove that the adjustment represented known and measurable costs that the utility would actually incur to issue equity.[212]

Mr. Hevert's flotation cost adjustment should also be rejected in this case because it is not based on CEHE's known and measurable costs to conduct equity issuances.[213] Rather than looking at CEHE's actual flotation costs, Mr. Hevert derived his flotation cost adder based on his proxy group, and there is no way to verify that the results are reasonable and appropriate as applied to CEHE.[214] Additionally, there is nothing in the record to support Mr. Hevert's assumption that CEHE would obtain equity by issuing common stock rather than receiving an infusion from its parent. In fact, the record indicates that if CEHE were to issue common stock to any entity other than its parent company, that would trigger an "Event of Default" under its credit agreement,[215] so it seems exceedingly unlikely that CEHE would ever incur the flotation costs estimated by Mr. Hevert's adder. The Commission should disregard that adder when determining CEHE's ROE.

4. Conclusion: Return on Equity

For the foregoing reasons, the Commission should adopt Mr. Gorman's recommended 9.25% ROE and reject Mr. Hevert's excessive and unjustified recommendation of 10.4%.

B. Cost of Debt [PO Issue 8]

Mr. McRae proposes an embedded cost of debt of 4.38% in Schedule II-C-2.4a.[216] TIEC did not challenge CEHE's cost of debt.

C. Capital Structure [PO Issue 7]

The parties' capital structure proposals are as follows:

Party	**Recommendation (Debt%/Equity%)**
TIEC[217]	60%/40%

issuance. To grant it an adjustment on the possibility that it might fund such an infusion through a stock issuance violates the known and measurable standard.").

212 Docket No. 40443, Order on Rehearing at 11-12 (Mar. 6, 2014).

213 TIEC Ex. 5 (Gorman Dir.) at 90.

214 *Id.* at 89-90.

215 *See* TIEC Ex. 4. (Griffey Dir.) at 21.

216 *See* TIEC Ex. 5 (Gorman Dir.) at 38.

217 *Id.* at 37.

Staff[218]	60%/40%
OPUC[219]	54.5%/45.5%
TCUC[220]	Primary: 60%/40% Alternate: 56.38%/43.62%
CEHE[221]	50%/50%

The Commission should set CEHE's ratemaking capital structure at 60% debt/40% equity, which is consistent with the prevailing capital structure of many ERCOT TDUs.[222] As discussed in detail below, Mr. Gorman's analysis shows that along with his recommended 9.25% ROE, a 60% debt/40% equity capital structure will be sufficient to support an A- stand-alone credit rating for CEHE while producing significant savings for ratepayers.[223] Mr. Griffey notes that "if a higher credit rating could be achieved or maintained ***without*** increasing costs to customers—for example, through financial or governance protections at the utility—then absent some other compelling reason, increasing the equity component of a utility's rates would be unreasonable."[224] As described below, CEHE's own witness agrees that CEHE's credit rating from S&P would actually ***increase*** by one notch on a stand-alone basis if the Commission adopts Mr. Griffey's and Mr. Gorman's recommendations. Accordingly, there is no reason to reward CEHE's shareholders with the equity-heavy capital structure CEHE is requesting.

CEHE's requested 50% debt/50% equity capital structure[225] would do nothing but benefit the shareholders of CEHE's parent, CNP, at ratepayers' expense. To illustrate this point, based on its own stand-alone metrics, CEHE would be rated a+ by S&P ***but for its affiliation with its parent***, which drags its rating down to BBB+.[226] CEHE's credit rating is being determined by the riskier

[218] Staff Ex. 39 (Ordonez Dir.) at 8.

[219] OPUC Ex. 3 (Winker Dir.) at 43.

[220] TCUC Ex. 1 (Woolridge Dir.) at 20, Ex. JRW-3.

[221] CEHE Ex. 26 (Hevert Dir.) at 52.

[222] Staff Ex. 39 (Ordonez Dir.) at 37, n. 41 ("The following TDUs are operating in Texas with authorized capital structures comprising 60% long-term debt and 40% equity: Cross Texas Transmission, LLC (Docket No. 43950), Electric Transmission Texas, LLC (Docket No. 33734), AEP Texas Central Company (Docket No. 33309), AEP Texas North Company (Docket No. 33310), Wind Energy Transmission Texas, LLC (Docket No. 44746).").

[223] TIEC Ex. 5 (Gorman Dir.) at 36-37.

[224] TIEC Ex. 4 (Griffey Dir.) at 9 (emphasis added).

[225] CEHE Ex. 27 (McRae Dir.) at 14.

[226] TIEC Ex. 5 (Gorman Dir.) at 24-25.

business activities of its parent. As such, increasing the equity component of CEHE's rates does nothing except provide additional revenues for its parent (so that it can continue to engage in other business activities) and provides no benefit to CEHE or its customers.[227]

Further, CEHE has not shown that the substantial costs of increasing its equity component for customers would be justified by avoided debt costs. Mr. Gorman's testimony showed that, even taking CEHE's claimed increases in borrowing costs at face value, authorizing additional equity to avoid a higher debt interest rate would cost customers ***$39.2 million per year.***[228] Accordingly, ratepayers would be better off even if there is were a credit downgrade. In other words, it is not economic for customers to be charged more to maintain the current credit rating when the actual consequences of a downgrade are quantified and considered.

Nor has CEHE shown that it faces business risks that will require it to maintain a higher equity percentage. CEHE witness McRae presents four justifications for CEHE's requested increase in the common equity ratio: (1) elevated capital expenditures over the next five years; (2) risks caused by the TCJA; (3) the risk of catastrophic damage from hurricanes; and (4) regulatory risk.[229] Mr. McRae's testimony on this point is not credible. It contradicts CNP's and CEHE's own statements to investors and regulators, and, as described below, does not justify CEHE's request.

1. CEHE's growth and capital expenditures are in line with its historical experience.

Mr. McRae first claims that CEHE needs additional equity in its capital structure to manage risks associated with rapid expansion of its service area. As evidence of this, he states that in recent years, CEHE's load growth has averaged 2% per year, and is expected to continue on that trajectory for several more.[230] However, significant load growth is nothing new for CEHE. The Commission has previously recognized that CEHE's industrial and residential load has been

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[227] *See* TIEC Ex. 4 (Griffey Dir.) at 12 ("Even if a utility would have a higher credit rating on a stand-alone basis, it may be notched downward if its parent has a lower credit rating and is depending on dividends from the utility. In such cases, a utility's ratepayers are paying for the equivalent of a higher rated entity, but higher financial and/or business risk at the parent prevents ratepayers from getting the full benefit of what they are paying for in rates (e.g., increased equity that should give rise to lower debt costs).").

[228] TIEC Ex. 5 (Gorman Dir.) at 30-31.

[229] *See* CEHE Ex. 27 (McRae Dir.) at 15.

[230] *Id.*

growing rapidly for many years.[231] In fact, in its Q1 2019 Earnings Call with investors, CEHE's parent bragged that CEHE has experienced consistent customer growth over the last ***30 years***.[232] Further, consistent growth represents an ***opportunity*** for CEHE, rather than a risk.[233] In that same investor presentation, CNP emphasized its prospects for additional growth and capital investment (in particular, the Bailey to Jones Creek transmission line), and even listed "Customer Growth" as a positive driver for 2019.[234]

Additionally, while it is true that CEHE's capital investment has grown over time, CEHE earns a return on all of that investment, which increases revenues.[235] This growth in rate base has allowed CEHE to support additional (and growing) investment without the need for additional equity in its capital structure. As Mr. Mercado acknowledged, CEHE's ratio of capital expenditures to net electric plant in service has been nearly flat since its last rate case. In Docket No. 38339, CEHE's 2010 net electric plant in service totaled $4.189 billion,[236] and according to Mr. Mercado, CEHE had $463 million of capital expenditures in that year.[237] So, CEHE's 2010 capital expenditures were about 11% of its net plant in service. According to Mr. Mercado's testimony, CEHE's capital expenditures grew to $952 million in 2018.[238] However, its net electric plant in service also grew to approximately $7.716 billion,[239] so CEHE's capital expenditures now

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[231] Tr. (Mercado Cr.) at 51:6–52:7 (June 24, 2019); *Application of Cross Texas Transmission, LLC to Amend a Certificate of Convenience and Necessity for the Limestone to Gibbons Creek 345-KV Transmission Line in Brazos, Freestone, Grimes, Leon, Limestone, Madison, and Robertson Counties*, Docket No. 44649, Final Order at 16–17, FoF 137 & 139 (Jan. 13, 2016).

[232] Tr. (Mercado Cr.) at 87:25–88:8 (Jun. 24, 2019); TIEC Ex. 13 (1st Quarter 2019 Earnings Transcript on May 9, 2019) at 6.

[233] *See* TIEC Ex. 4 (Griffey Dir.) at 24-25 ("Given current prevailing utility returns on equity, including those awarded in Texas, capital expenditures are more of a business opportunity than a business risk. . . . If additional capital expenditures were a burden and not an opportunity, management would be seeking to *limit* capital expenditures, not grow them.").

[234] Tr. (Mercado Cr.) at 84:9–16 (June 24, 2019); TIEC Ex. 12 (1st Quarter 2019 Earnings Presentation on May 9, 2019) at 5.

[235] Tr. (Mercado Cr.) at 62:12–19 (June 24, 2019); TIEC Ex. 8 (Investor & Analyst Day Presentation in Jun. 2014) at 2.

[236] Tr. (Mercado Cr.) at 100:8–101:18 (June 24, 2019); TIEC Ex. 16 (Texas Public Utility Commission Order on Rehearing in Docket No. 38339 at 19, FoF 54 (Jun. 23, 2011)).

[237] Tr. (Mercado Cr.) at 104:8–10 (June 24, 2019); CEHE Ex 6 (Mercado Dir.) at WP KMM-10 (09 to 18 10K CEHE CapEx).

[238] Tr. (Mercado Cr.) at 106:4–5 (June 24, 2019); CEHE Ex 6 (Mercado Dir.) at WP KMM-10 (09 to 18 10K CEHE CapEx).

[239] Tr. (Mercado Cr.) at 101:19–102:8 (June 24, 2019); TIEC Ex. 17 (Schedule II-B).

represent approximately 12.3% of its net plant in service.[240] This is not a material increase. As a result, CEHE's testimony on this issue is misleading. What may appear to be a dramatic increase in capital expenditures when described as nominal dollars is really just the natural consequence of CEHE becoming a larger utility, with more rate base and correspondingly ***greater revenues and returns*** from its customers. While CEHE may have more capital expenditures in absolute terms, the growth is not outpacing its ability to fund those expenditures. Therefore, CEHE's alleged need for more equity is not supported by the increase in its capital expenditures.[241]

2. The TCJA does not justify increasing CEHE's equity percentage.

Mr. McRae also claims that the Commission should authorize CEHE to carry more equity to mitigate the impacts of the Tax Cuts and Jobs Act (TCJA) on CEHE's credit quality.[242] However, once again, CenterPoint is talking out of both sides of its mouth. As Mr. Griffey points out, if the TCJA really were a problem for CenterPoint, it would be constraining its capital expenditures rather than touting their expansion, as discussed above.[243] Additionally, contrary to CEHE's claims in this proceeding, CNP stated in a presentation to S&P that the TCJA is a "[redacted]"[244] and went on to call the TCJA "[redacted]."[245] CNP also noted that tax reform was [redacted].[246] This is hardly the message that CNP would be sending if the TCJA posed the type of challenge that would support CEHE's capital structure request. Similarly, in its first quarter earnings call with investors, CNP listed "Reduced Income Tax Expense" as a ***positive*** driver for 2019.[247] CEHE witness Mr. Mercado also testified that growth in rate base increases earnings.[248] Since bonus depreciation increases ADFIT, which is an offset

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[240] Tr. (Mercado Cr.) at 106:6–17 (June 24, 2019).

[241] *See* Tr. (Mercado Cr.) at 106:18 – 107:17.

[242] CEHE Ex. 27 (McRae Dir.) at 17, 21.

[243] TIEC Ex. 4 (Griffey Dir.) at 28.

[244] *See* TIEC Ex. 4 (Griffey Dir.) at 28 (quoting CEHE Response to TCUC 1-02 in attachment SP 2018 CenterPoint Energy at 2-3. (HSPM)) (emphasis added).

[245] *Id.* (emphasis added).

[246] *Id.* at 28.

[247] Tr. (Mercado Cr.) at 84:9–16 (June 24, 2019); TIEC Ex. 12 (1st Quarter 2019 Earnings Presentation on May 9, 2019) at 5.

[248] Tr. (Mercado Cr.) at 62:12-19 (June 24, 2019); *see also* TIEC Ex. 4 (Griffey Dir.) at 24-25.

to rate base, decreasing ADFIT will actually increase rate base, which increases earnings.[249] This additional return mutes the impacts of the TCJA.

Providing further context on the actual impacts of the TCJA, CNP told its investors that for the first quarter of 2019, the TCJA decreased CEHE's revenues by just $6 million (on a $2.1 billion revenue requirement), and that decrease was offset by a corresponding decrease in federal income tax.[250] In contrast, CNP also apparently allocated CEHE $10 million in "Merger related expenses" attributable to CNP's acquisition of Vectren Corp.[251] Based on the foregoing, the TCJA is no justification for increasing CEHE's equity above the 40%, recommended by Staff and TIEC, and adopted by the Commission for numerous other utilities in ERCOT.[252]

Finally, the credit effects of the TCJA are a mixed bag and benefit utilities in some respects. As Mr. Gorman described in his direct testimony, the TCJA actually has the effect of ***reducing*** a utility's cost of equity capital because it decreases the income tax cost of a utility dividend.[253] In any event, as described elsewhere in this brief, Mr. Gorman's calculations of CEHE's prospective credit rating show that, even incorporating the effects of the TCJA, CEHE will be able to achieve a strong rating on a stand-alone basis even at Mr. Gorman's proposed capital structure of 60% debt/40% equity. Accordingly, it is not credible that CEHE would need to increase the amount of equity in its capital structure to maintain its financial quality.

Instead, it is clear that CEHE is trying to force its ratepayers to support ***its parent company's*** credit rating so CNP can continue to expand and make risky investment decisions. The Commission should reject this outcome. As Mr. Gorman and Mr. Griffey show, it would be much more effective, and much better for ratepayers, if CEHE were instead to financially separate itself from its financially weaker parent company. CEHE's request for a richer capital structure at substantial cost to ratepayers is unjustified when the only beneficiary will be CEHE's parent,

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[249] Tr. (Tietjen Cr.) at 786:25-787:10 (June 26, 2019); *see also* TIEC Ex. 4 (Griffey Dir.) at Ex. CSG-3, p. 7.

[250] TIEC Ex. 13 (1st Quarter 2019 Earnings Transcript on May 9, 2019) at 10; TIEC Ex. 12 (1st Quarter 2019 Earnings Presentation on May 9, 2019) at 13.

[251] TIEC Ex. 13 (1st Quarter 2019 Earnings Transcript on May 9, 2019) at 11; TIEC Ex. 12 (1st Quarter 2019 Earnings Presentation on May 9, 2019) at 13.

[252] Staff Ex. 39 (Ordonez Dir.) at 37, n. 41 ("The following TDUs are operating in Texas with authorized capital structures comprising 60% long-term debt and 40% equity: Cross Texas Transmission, LLC (Docket No. 43950), Electric Transmission Texas, LLC (Docket No. 33734), AEP Texas Central Company (Docket No. 33309), AEP Texas North Company (Docket No. 33310), Wind Energy Transmission Texas, LLC (Docket No. 44746).").

[253] TIEC Ex. 5 (Gorman Dir.) at 10.

whose non-Texas activities are dragging CEHE's credit rating. The superior approach is to adopt Mr. Griffey's ring fencing recommendations, along with the more reasonable capital structure proposed by Mr. Gorman.

3. CEHE's exposure to hurricanes and other storms has not changed.

Contrary to its claims, CEHE is facing no new natural disaster risk that would justify increasing the amount of equity in its capital structure. CEHE has always faced risks from hurricanes and serious storms, and Mr. Mercado admits as much.[254] Additionally, CEHE has shown that it is able to successfully prepare for and deal with large storm events when they do occur, and as CEHE acknowledges, the risk of storm events are largely mitigated by CEHE's ability to securitize storm restoration costs.[255] The risk of future storms does not justify increasing the proportion of equity in CEHE's capital structure.

4. CEHE does not face any increased "regulatory risk" that would justify an increased equity percentage.

Mr. McRae's final argument in favor of increasing the amount of equity in CEHE's capital structure relates to alleged regulatory risk, which he defines as "the possibility that a utility may not be able to recover its costs in a timely fashion, including the costs necessary to service debt and issue dividends."[256] This argument is baseless. As CEHE itself admits, and the credit rating agencies recognize, CEHE is an extremely low-risk "wires-only" utility, meaning that unlike most utilities, it is not exposed to the environmental and financing risks associated with constructing generation projects, or the commodity risks associated with procuring fuel.[257] Further, CEHE enjoys prompt and nearly dollar-for-dollar capital recovery through various rate riders, such as the TCRF and DCRF, that are available to ERCOT utilities.[258] These advantages have led Moodys to indicate that CEHE enjoys a [redacted]" and has "[redacted][259] Similarly, Fitch notes that

[254] Tr. (Mercado Re-Cr.) at 151:3–21 (June 24, 2019).

[255] TIEC Ex. 4 (Griffey Dir.) at 28; CEHE Ex. 27 (McRae Dir.) at 27-28.

[256] CEHE Ex. 27 (McRae Dir.) at 29.

[257] *See* TIEC Ex. 5 (Gorman Dir.) at 26.

[258] TIEC Ex. 4 (Griffey Dir.) at 27.

[259] *Id.* (citing Moody's Credit Opinion (Jun. 19, 2018), included in Schedule II-C-2.10 of the rate filing package) (Confidential).

providing T&D service in Texas is a "[redacted]," and CEHE has "[redacted]"[260]

Additionally, CEHE's claims with respect to regulatory risk are contradicted by statements that it has made to its investors and credit ratings agencies. For instance, in a presentation to its investors from 2014, CNP described the "***Supportive Cost Recovery and Regulatory Environment***" in which CEHE operates, emphasizing that ***"~95% of [CEHE's] capital plan [is] eligible for recovery through [capital recovery] mechanisms"*** like the TCRF and DCRF, which "[r]educes recovery lag and frequency of general rate cases."[261] In that same presentation, CNP listed the factors underlying CEHE's "***Low Business Risk***" as follows: (1) it holds only poles and wires assets; (2) it does not have generation assets, which reduces its business, environmental, and regulatory risks; (3) its direct customers are ~70 REPs (which decreases its bad debt risk); and (4) it has regulatory protections from REP bad debt.[262] On cross, Mr. Mercado confirmed that that all of those factors are still true for CEHE today.[263] In fact, since CEHE's last rate case, the Commission implemented the Distribution Cost Recovery Factor (DCRF) through PUC Subst. R. 25.243, further reducing CEHE's already-low regulatory risk.[264] As such, there is no indication that CEHE faces some new regulatory risk that would justify putting its equity percentage above 40%.

D. Overall Rate of Return [PO Issue 8]

As discussed in Mr. Gorman's testimony, an overall rate of return of 6.33% should be used to set CEHE's revenue requirement,[265] based on CEHE's actual cost of debt, Mr. Gorman's 60% debt, 40% equity capital structure, and his recommended 9.25% ROE.

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[260] *Id.* at 27-28 (citing Fitch Report (Apr. 13, 2018), included in Schedule II-C-2.10 of the rate filing package) (Confidential).

[261] TIEC Ex. 8 (Investor & Analyst Day Presentation in Jun. 2014) at 7 (emphasis added).

[262] *Id.* at 6.

[263] Tr. (Mercado Cr.) at 69:8–13 (June 24, 2019).

[264] Project No. *39465, Rulemaking Related to Periodic Rate Adjustments,* Order Adopting New § 25.243 (Sept. 22, 2011).

[265] TIEC Ex. 5 (Gorman Dir.) at 7 and Ex. MPG-1.

E. Financial Integrity [PO Issue 9]

CEHE's unnecessarily rich rate of return proposals are unsupported, and, at most, driven by the credit linkage between CEHE and its financially weaker parent company, which uses CEHE's cash flows to support its own credit rating.[266] CEHE's credit linkage with CNP forces CEHE, and by extension, its customers, to subsidize CNP's business decisions—such as CNP recent $6 billion leveraged acquisition of Vectren Corp., which caused both CNP ***and CEHE*** to be downgraded from A- to BBB+ by S&P.[267] This Commission and CEHE had absolutely nothing to do with this merger, yet somehow CEHE's customers are being asked to pay for its consequences. The Commission should reject this outcome.

It is clear that CEHE is a much less risky business than CNP, and would be able to support a stand-alone credit rating that is ***three notches higher*** than the rating that is currently foisted upon it due to its affiliation with CNP.[268] De-linking CEHE's credit from that of its parent by adopting reasonable ring-fencing proposals will ensure that customers are no longer subsidizing the financial risks taken by CNP, and will allow customers to enjoy the benefits of CEHE's superior stand-alone credit rating, which customers are paying for today (and not receiving the benefit of). Critically, CEHE's own testimony demonstrates that even if the Commission adopted Mr. Gorman's capital structure and ROE proposals, CEHE's stand-alone credit rating would still be ***significantly higher*** than the BBB+ group rating at which it currently borrows.[269] In other words, if CEHE's credit rating were not dragged down by its association with CNP, it could achieve equal or lesser borrowing costs at significantly lower rates to its customers. Additionally, even in the unlikely event that CEHE did experience a credit downgrade as a result of the Commission adopting Mr. Gorman's recommended ROE and capital structure, its ratings would still be investment grade, and the small increase to its borrowing costs would be far outweighed by the savings that customers would receive compared to CEHE's proposed capital structure and ROE proposal. These issues are explored in detail below.

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[266] *Id.* at 5; TIEC Ex. 4 (Griffey Dir.) at 7-8.

[267] TIEC Ex. 4 (Griffey Dir.) at 10.

[268] *Id.; see also* TIEC Ex. 5 (Gorman Dir.) at 24-25.

[269] CEHE Ex. 43 (McRae Reb.) at 23-25.

1. The Commission should take steps to separate CEHE's credit from its parent company's in order to protect CEHE's financial integrity.

a. CEHE's credit rating and financial integrity are negatively impacted by its relationship with its parent company and affiliates.

CEHE's credit rating is dragged downward by its association with CNP, which is dependent on dividends from CEHE to maintain its cash flows and support its credit rating.[270] It is undisputed that CEHE's stand-alone credit quality is significantly better than CNP's. Recently, S&P indicated that it would assign CEHE an a+ bond rating on a stand-alone basis[271]—a rating that would place CEHE in the ***top 3%*** of all electric utilities with respect to credit quality.[272] However, when S&P considers CEHE along with its parent (and by extension, the other subsidiaries of CNP), its bond rating drops ***three notches*** to BBB+.[273] To justify notching CEHE down by three ratings, S&P notes that "[redacted][274]

CEHE has admitted to its investors that its linkage with CNP is a liability. In its 2017 Form 10-K filing with the SEC, CEHE admitted that:

- "***The creditworthiness and liquidity of our parent company and our affiliates could affect our creditworthiness and liquidity.***"[275]
- "***CenterPoint Energy can exercise substantial control over our dividend policy and business and operations and could do so in a manner that is adverse to our interests.***"[276]
- "***Our management could decide to increase our dividends to CenterPoint Energy to support its cash needs. This could adversely affect our liquidity.***"[277]

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[270] TIEC Ex. 4 (Griffey Dir.) at 10.

[271] CEHE Ex. 43 (McRae Reb.) at 23.

[272] *See* TIEC Ex. 5 (Gorman Dir.) at 11, Table 1 (only 3% of electric utilities were rated A or higher by S&P in 2018).

[273] *Id.* at 25.

[274] CEHE Ex. 43 (McRae Reb.) at Ex. R-RBM-4, p. 5 (S&P Global Ratings – CenterPoint Energy Houston Electric LLC, March 22, 2019) (Confidential) (emphasis added).

[275] TIEC Ex. 6 (2017 10-K) at 8 (emphasis in original).

[276] *Id.* at 7 (emphasis in original).

[277] *Id.* at 7 (emphasis added).

It is apparent from these statements that CEHE's relationship with CNP drags down CEHE's credit rating because CNP uses CEHE's cash flows[278] to finance risky acquisitions and support various unregulated businesses.[279] Illustrating this point, Commission Staff Exhibit 13 shows that CEHE's 2018 net income of $336 million represented ***91.3%*** of CNP's consolidated net income for that year, even though CEHE represents just over a third of CNP's total assets.[280] The fallout from CNP's recent $6 billion leveraged acquisition of Vectren Corp. shows the kind of risks that CEHE is forced to bear due to its credit linkage with CNP. As Mr. Gorman explained, that acquisition was funded primarily by existing or new debt, and was viewed as credit negative for CNP and, by extension, CEHE, both of which were downgraded to BBB+ from A- as a result of the transaction.[281] Explaining the downgrade, S&P Global noted that "[CNP's] financial measures will deteriorate after using a disproportionate amount of debt to fund the Vectren acquisition."[282] This result was not a surprise to CNP, which expected the acquisition to hurt its credit metrics. On its Q3 2018 earnings call, it told its investors that the Vectren "[f]inancing plan [was] designed to achieve anticipated consolidated FFO/total debt of 15% or better by 2020 as determined by the ratings agencies' methodology."[283] That metric is consistent with a BBB+ rating for a company with CNP's business and financial profile.

b. The Commission should insulate ratepayers from the activities of CEHE's parent by adopting reasonable financial ring-fencing measures.

TIEC witness Charles Griffey explained that rather than increasing the equity component of its return, which would solely benefit the parent CNP, CEHE should adopt financial protections to insulate itself from the financial and business risks of its parent company.[284] Such ring-fencing

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[278] For example, when analyzing CEHE, S&P assumes that it will pay [redacted] per year in dividends to CNP. CEHE Ex. 43 (McRae Reb.) at Exhibit R-RBM-4, p. 3 (S&P Global Ratings – CenterPoint Energy Houston Electric LLC, March 22, 2019) (Confidential).

[279] For example, over 25% of Vectren Corp.'s earnings come from unregulated businesses. TIEC Ex. 4 (Griffey Dir.) at 11.

[280] *See* Commission Staff Ex. 13 (Excerpts from 2019 Annual Report). Put differently, while CNP's regulated subsidiaries, CEHE and CenterPoint Energy Resources Corp. (CERC), contributed earnings of $336 million and $208 million, respectively, ***CNP's other businesses lost $176 million***. *See id.* Accordingly, CEHE's earnings accounted for nearly all of CNP's profits.

[281] TIEC Ex. 5 (Gorman Dir.) at 22-23.

[282] *Id.* at 23 (quoting *S&P Global Ratings:* "CenterPoint Energy Inc. And Subsidiaries Still CreditWatch Negative: Senior Unsecured Debt Rated 'BBB+', Watch Negative," at 2).

[283] *Id.* at 24 (quoting CenterPoint Energy Investor Update at 12 (Oct. 2, 2018)).

[284] TIEC Ex. 4. (Griffey Dir.) at 12.

protections would help ensure that captive utility customers are getting what they are paying for, and are not forced to subsidize risks and business ventures undertaken by CEHE's parent.[285] Additionally, ring-fencing would provide some measure of protection in the event that CNP falls into financial distress.[286] Such measures have proven invaluable for other regulated wires utilities in the state.

Mr. Griffey describes in his testimony, CEHE should take three critical precautions to insulate itself from CNP:[287]

- First, CEHE should adopt a "dividend stopper" that will prevent CNP from accessing CEHE's revenues if CEHE's financial situation begins to deteriorate.[288] A dividend stopper is important to assure credit ratings agencies that there is a limit on the amount of cash that CNP can pull from CEHE, and to prevent CEHE from losing the cash flow necessary to support safe and reliable electric service in the event that its parent experiences credit issues.[289] To the extent that there are provisions in CNP's credit arrangements that promise it will maintain unrestricted access to CEHE's cash flow, those provisions should be removed as soon as they can be renegotiated.[290]

- Second, CEHE should obtain a non-consolidation opinion that indicates that it will not be consolidated with its parent or non-subsidiary affiliates in the event of their bankruptcy.[291] This will provide assurance of CEHE's financial separation and place CNP's creditors on notice that they will not be able to access CEHE's assets.[292]

- Third, CEHE's credit agreement should be amended to change the current definition of an "Event of Default." Currently, that term is defined to include (i) a change in control of CNP or (ii) CNP ceasing to own and control 100% of the outstanding common Capital

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[285] *Id.* at 13.

[286] *Id.*

[287] *Id.* at 21.

[288] *Id.*

[289] *Id.*

[290] *Id.* at 22.

[291] *Id.*

[292] *Id.*

Stock of CEHE.[293] This provision weakens CEHE's separation from CNP and makes CEHE subject to forces beyond its control.[294]

Also, Mr. Griffey's Figure 2 includes a number of ring-fencing protections that CEHE is already observing informally.[295] In order to truly separate CEHE from its parent, those protections should be formalized and made permanent. Those additional ring-fencing protections are as follows:

- CEHE shall not include in its debt or credit agreements any financial covenants or rating-agency triggers related to any other entity.
- CEHE shall not guarantee the debt of or pledge any assets for entities other than CEHE.
- CEHE shall not share credit facilities with CNP or any affiliate.
- CEHE shall maintain its registrations with all three major credit rating agencies.
- CEHE shall maintain a stand-alone credit rating.

Taken together, these ring-fencing provisions, which Mr. Griffey modeled after selected provisions from the Oncor ring-fence, should be sufficient to ensure CEHE's financial separation from its parent, and insulate CEHE from corresponding risks associated with CNP.

2. Mr. Gorman's recommended 9.25% ROE and 60/40 capital structure are sufficient to support CEHE's financial integrity.

a. CEHE would maintain an investment grade bond rating if the Commission were to adopt Mr. Gorman's proposed 9.25% ROE and 60/40 capital structure.

i. Mr. Gorman's calculations indicate that, under his recommended rate of return, S&P would assign CEHE an A- rating on a stand-alone basis.

S&P has indicated that because CEHE is a low-risk wires utility with stable cash flows and a supportive regulatory environment, its stand-alone credit rating is set using S&P's "Low Volatility" financial ratio benchmarks instead of the "Medial Volatility" benchmarks used to

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[293] *Id.* at 21.

[294] *Id.* at 22.

[295] *Id.* at 19-20.

evaluate CNP and set the BBB+ "group" credit rating at which CEHE currently borrows.[296] Mr. Gorman's Table 6 compares S&P's ratings criteria for companies with Low and Medial Volatility:[297]

TABLE 6

S&P Credit Metrics

Low Volatility			
Description	Intermediate	Significant	Aggressive
Debt to EBITDA	3.0x-4.0x	4.0x - 5.0x	5.0x - 6.0x
FFO to Total Debt	13% - 23%	9% - 13%	6% - 9%
Credit Rating	A	A-	BBB

Medial Volatility			
Description	Intermediate	Significant	Aggressive
Debt to EBITDA	2.5x - 3.5x	3.5x - 4.5x	4.5x - 5.5x
FFO to Total Debt	23% - 35%	13% - 23%	9% - 13%
Credit Rating	A	A-	BBB

Sources and Notes:
Standard & Poor's: "Criteria: Corporate Methodology," November 19, 2013.
Business Risk: Excellent
Financial Risk: Intermediate

As this table illustrates, if CEHE were considered on a stand-alone basis, it would receive a stronger credit and lower borrowing costs while ***also*** providing service to customers at lower rates.

Based on his proposed equity return of 9.25%, Mr. Gorman calculated that CEHE will have the opportunity to produce a Debt to Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) ratio of 4.6x, and a ratio of Funds From Operations (FFO) to total debt coverage of 16%.[298] For a company like CEHE that is judged on S&P's "Low Volatility" scale, those metrics are consistent with an A- rating.[299] Such a rating would ***increase*** CEHE's rating by one notch, because CEHE is currently borrowing at its "group" rate of BBB+.

[296] *See* TIEC Ex. 5 (Gorman Dir.) at 35-36; CEHE Ex. 43 (McRae Reb.) at Ex. R-RBM-4, p. 4 (S&P Global Ratings – CenterPoint Energy Houston Electric LLC, March 22, 2019) (Confidential) ("[redacted] (emphasis added).

[297] TIEC Ex. 5 (Gorman Dir.) at 34.

[298] *Id.* at 70.

[299] *Id.* at 70-71, Exhibit MPG-22.

ii. CEHE admits that Mr. Gorman's recommended 9.25% ROE and 60/40 capital structure would result in investment-grade credit ratings for CEHE on a stand-alone basis.

(a) Mr. McRae confirms Mr. Gorman's finding that S&P would assign CEHE an A- rating if the Commission adopts Mr. Gorman's rate of return recommendation.

CEHE witness Robert McRae confirms that if the Commission adopts TIEC's ring fencing and rate of return recommendations, CEHE's credit rating from S&P will actually ***increase*** compared to today. In Mr. McRae's Exhibit R-RBM-7, he calculates CEHE's stand-alone credit rating assuming Mr. Gorman's 9.25% ROE and 60/40 capital structure.[300] His results, which are very similar to Mr. Gorman's,[301] indicate that in that scenario, CEHE would enjoy an FFO/Debt ratio of 12.7% and a Total Debt/EBITDA ratio of 5.08.[302] As Mr. McRae admits, ***if the Commission adopts Mr. Gorman's 9.25% ROE and 60/40 capital structure, S&P would assign an A- rating to CEHE on a stand-alone basis.***[303] While Mr. McRae misleadingly refers to that rating as a "two-notch downgrade from [CEHE's] current position," it is critical to remember that CEHE is currently borrowing at its "group" rating of BBB+, meaning that an A- rating would actually represent a ***one-notch upgrade***. Additionally, an A- rating is a strong investment-grade rating that would ensure CEHE's ability to access the capital markets at reasonable rates.

In an attempt to deflect the results of his own analysis, Mr. McRae makes the extremely misleading claim that "S&P's targeted FFO/Debt ratio for CenterPoint Houston is 18%-20%, and its targeted Debt/EBITDA is roughly 3.5x. Thus, the credit metrics produced by Mr. Gorman's ROE and capital structure recommendations are far below the S&P benchmarks."[304] However, it is clear from the S&P report that Mr. McRae references that those numbers represent S&P's ***expected***[305] results for CEHE in its base case projections with its current credit being determined

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[300] CEHE Ex. 43 (McRae Reb.) at Ex. R-RBM-7, p. 5.

[301] *See* TIEC Ex. 5 (Gorman Dir.) at Ex. MPG-5 (Errata 1), p. 2.

[302] CEHE Ex. 43 (McRae Reb.) at 23 and Ex. R-RBM-7, p. 5.

[303] *Id.* at 24-25.

[304] *Id.* at 23.

[305] In fact, the numbers are clearly marked as [redacted]." *Id.* at Ex. R-RBM-4, p. 3 (S&P Global Ratings – CenterPoint Energy Houston Electric LLC, March 22, 2019) (Confidential).

by the activities of its parent,[306] rather than any benchmark amount that CEHE has to maintain in order to preserve its current rating.[307] As proof of this distinction, the same section of a concurrent S&P credit report for CNP—which is a riskier and financially weaker company[308] than CEHE—[redacted].[309] It would make no sense for S&P to set lower targets for a financially weaker company. It does, however, make sense for S&P to project weaker expected debt ratios for CNP.

Mr. McRae also argues that "13% [FFO to Debt] is at the bottom of the range for a company deemed to have "intermediate" financial risk"[310] and argues that targeting the low end of a credit metric range is imprudent. But what Mr. McRae does not mention is that, as shown on Mr. Gorman's Table 6, above, for a "Low Volatility" company like CEHE, a 13% FFO/Debt ratio is at the low end of an A rating, meaning that if the FFO/Debt ratio dipped below 13%, that metric would still suggest an A- rating.

Regardless, CEHE's admission that it would achieve an indicative A- rating from S&P on a stand-alone basis is critical. Not only would that rating undoubtedly allow CEHE to access the capital markets at reasonable (and perhaps even lower) rates, but CEHE would be able to do so at a ***substantially lower*** overall rate of return that, as noted above, would save ratepayers approximately ***$104.1 million per year***.[311]

(b) Mr. McRae admits that Fitch and Moody's would also provide CEHE with investment grade credit ratings.

Mr. McRae also admits that if the Commission were to adopt Mr. Gorman's 9.25% ROE and 60/40 capital structure, CEHE would merit a Baa rating from Moody's and a bbb rating from

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306 *See* Tr. (Gorman Cr.) at 578:20-579:2 ("Q: Well, basically, it says on a stand-alone basis, the FFO to debt ratio is 18 to 20 percent. Its there in black and white, isn't it? A: It says "Our stand alone case for CEHE includes adjusted FFO to debt of 18 to 20 percent." It does not identify that as the credit metric range that would be appropriate.").

307 *See* CEHE Ex. 43 (McRae Reb.) at Ex. R-RBM-4, p. 3 (S&P Global Ratings – CenterPoint Energy Houston Electric LLC, March 22, 2019) (Confidential).

308 *Cf. Id.* (CEHE's financial risk is "[redacted]) *with* TIEC Ex. 5C (CONFIDENTIAL Workpapers to the Direct Testimony of Michael Gorman) at WP 38, p. 7-8 (S&P Global Ratings – CenterPoint Energy, Inc., March 21, 2019) (Confidential) (CNP's financial risk is [redacted]).

309 TIEC Ex. 5C (CONFIDENTIAL Workpapers to the Direct Testimony of Michael Gorman) at WP 38, p. 5 (S&P Global Ratings – CenterPoint Energy, Inc., March 21, 2019) (Confidential).

310 CEHE Ex. 43 (McRae Reb.) at 23.

311 TIEC Ex. 5 (Gorman Dir.) at 37; Exhibit MPG-6.

Fitch on a stand-alone basis.[312] Mr. McRae's metrics show that CEHE's credit metrics are strong for a Baa but weak for an A rated utility with low business risk. CEHE's current Moody's rating is A3, which is at the lower end of the A rating category and just above the Baa category. That is, Mr. McRae does not specify the exact rating he would expect from each of those agencies[313]—but the general rating categories include a three-notch range from Baa1 (highest rating) to Baa3 (weakest) and bbb+ to bbb-. CEHE's stand-alone metrics should be near the top of the Baa range and near but not quite up to the A range in order to support its actual ratings from Moody's of A3 and Fitch of A-. This is explored further below. However, as a preliminary matter, even assuming the worst possible outcome within those ranges, ***Mr. McRae has admitted that Mr. Gorman's proposed ROE and capital structure would allow CEHE to continue to enjoy investment grade credit ratings from both Moody's and Fitch on a stand-alone basis.***[314] Combined with an a- stand-alone rating from S&P, these ratings would be sufficient to allow CEHE to access sufficient capital to fund its operations at a reasonable cost to ratepayers. Even at the lowest credit ratings within Mr. McRae's identified ranges, CEHE would only experience a two-notch downgrade compared to its current "group" rating of BBB+. Critically, even in Mr. McRae's ***worst case scenario***, ratepayers are still likely better off absorbing the cost of that credit downgrade than they would be if the Commission increases CEHE's equity percentage to 50%. In Mr. Gorman's direct testimony, he showed that CEHE's equity request would increase costs to ratepayers by ***$45.9 million per year***, while a one-notch downgrade in its credit rating would cost just $6.7 million per year, for a net benefit to ratepayers of $39.2 million.[315] Accordingly, CEHE's own witness has confirmed that Mr. Gorman's recommendations would allow CEHE to maintain its financial integrity on a stand-alone basis while providing service to its ratepayers at a substantial reduction in cost.

Further, it is likely that CEHE would end up with ratings from Moody's and Fitch that are at or above the high end of the ranges Mr. McRae projects. For instance, Mr. McRae's pro-forma 2019 credit metrics for CEHE are toward the middle or high end of their ranges for a Baa rating from Moody's:[316]

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[312] CEHE Ex. 43 (McRae Reb.) at 24-25.

[313] *See id.*

[314] CEHE Ex. 43 (McRae Reb.) at 24-25.

[315] TIEC Ex. 5 (Gorman Dir.) at 31.

[316] CEHE Ex. 43 (McRae Reb.) at 24.

Financial Strength Metric	Pro-forma 2019*	A	Baa	Ba
CFO pre-WC + Interest / Interest	4.21x	4.5x – 6.0x	3.0x – 4.5x	2.0x – 3.0x
CFO pre-WC / Debt	13.0%	19% - 27%	11% –19%	5% - 11%
CFO pre-WC – Dividends / Debt	12.0%	15% - 23%	7% - 15%	0% - 7%
Debt / Capitalization	54.3%	40% - 50%	50% - 59%	59% - 67%

Accordingly, based on Mr. McRae's analysis, it is likely that CEHE would receive a rating of Baa1 (equivalent to bbb+), or potentially even A3, which is in line with its current group rating.[317] In any event, it is clear that Mr. Gorman's recommendations would allow CEHE to maintain its financial integrity while significantly lowering costs to customers. The Commission should adopt those recommendations.

b. Even if CEHE received a credit downgrade under Mr. Gorman's rate of return proposal, which TIEC disputes, customers would still be better off than they would be if the Commission increased the equity percentage in CEHE's capital structure.

As discussed above, CEHE's credit rating would improve if it were insulated from the financial risks being taken by its parent company. However, it would make sense to adopt Mr. Gorman's rate of return recommendations ***even if*** they would result in a slight downgrade. This is because debt is substantially cheaper than equity. As Mr. Griffey indicated, "Debt yields are less than 5% for bonds rated Baa by Moodys, while prevailing returns on equity are between 9 and 10% in Texas."[318] Mr. Gorman demonstrated mathematically that increasing the amount of equity in CEHE's capital structure to 50% in order to avoid a one-notch credit rating downgrade is a terrible deal for ratepayers.[319] The cost of an additional 5% equity in CEHE's capital structure is $45.9 million per year, and avoiding a one-notch downgrade would only save customers $6.7 million per year in debt costs.[320] On net, that results in a ***$39.2 million increase*** in CEHE's revenue requirement, the benefits of which will flow entirely to CNP's shareholders.[321] CEHE's capital

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[317] *See* TIEC Ex. 5 (Gorman Dir.) at 40 (CEHE's current group rating from Moody's is A3).

[318] TIEC Ex. 4 (Griffey Dir.) at 7.

[319] TIEC Ex. 5 (Gorman Dir.) at 31.

[320] *Id.*

[321] *Id.*

structure request cannot be justified based on a speculative downgrade that, if it occurred, would actually benefit ratepayers.

IV. Operating and Maintenance Expenses [PO Issues 4, 5, 21, 22, 25, 26, 28, 29, 33, 35, 36, 38, 39, 54, 55]

A. Transmission and Distribution O&M Expenses [PO Issue 21]

B. Labor Expenses

1. Incentive Compensation

Consistent with its long-standing precedent,[322] the Commission should disallow all of CEHE's financially based incentive compensation expenses, which benefit shareholders rather than customers. In this case, that means at least sixty-nine percent of CEHE's short-term incentive compensation ("STI") costs and all of its long-term incentive compensation ("LTI") costs, or a total of $22.898 million, should be excluded from CEHE's rates.

Incentive compensation payments are designed to motivate CEHE's employees to achieve particular objectives.[323] Some of those objectives, like reliability and customer service targets, may benefit customers and, if CEHE can demonstrate such benefits, should be recoverable. But CEHE's parent company also sets "financially based" incentive goals that are specifically designed to align the interests of its employees with those of its shareholders.[324] While a utility may decide to have an incentive compensation program to motivate its employees to maximize shareholder value, the utility's ***customers*** should not be forced to fund it. As the Commission recently noted, "financial measures are of more immediate benefit to shareholders and financial measures are not necessary or reasonable to provide utility services."[325] Further, financially based incentives should not be allowed in rates because the entire concept of incentivizing utility employees to prioritize

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[322] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Order on Rehearing at 5 (Feb. 23, 2016) ("***It is well-established that a utility may not include in its rates the costs of incentives that are tied to financial-performance measures.***") (emphasis added).

[323] TIEC Ex. 15 (Annual Shareholders Meeting Presentation) at 22 ("We have structured our compensation program to motivate our executives to achieve individual and business performance objectives by varying their compensation in accordance with the success of our business.").

[324] *Id.* ("***The guiding principle of our compensation philosophy is that the interests of executives and shareholders should be aligned*** and that pay should be based on performance. . . . A significant portion of our named executive officers total direct compensation, which includes base salary in addition to the short-term and long-term incentive components, as applicable, is conditioned upon achieving results that are key to our long-term success and increasing shareholder value.") (emphasis added).

[325] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Order on Rehearing at FoF 194 (Mar. 19, 2018).

the interests of the company over those of its captive ratepayers is corrosive to the regulatory compact. For instance, the fastest and most effective ways to increase a utility's earnings are to overbuild infrastructure and cut maintenance programs designed to ensure reliability. However, those actions are directly contrary to the interests of customers, and in no circumstance should customers be required to fund compensation programs that incentivize utility employees to decrease the quality of electric service or increase rates for the company's benefit.

Since 2005, the Commission has only allowed the recovery of financially based incentive compensation in one instance: CEHE's last rate case, Docket No. 38339. Critically, however, in that case, the Commission disallowed the entire cost of CEHE's LTI plan,[326] and allowed recovery for financially based STI *only* because no party disputed whether that program was reasonable and necessary.[327] As such, there was no record evidence to support a disallowance.[328] Contrary to CEHE's allegations, the decision in Docket No. 38339 does not bind the Commission's hands in this proceeding, and the Commission should disallow all financially based incentive compensation: both STI and LTI.

a. Short-Term Incentive Compensation

CEHE witness Ms. Harkel-Rumford freely admitted that sixty-nine percent of CEHE's test-year STI expense was comprised of financial goals that only benefit shareholders (namely, the overall core operating income and earnings per share goals).[329] In keeping with the Commission's consistent precedent of disallowing recovery of financially based incentive compensation, the

[326] *Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates,* Docket No. 38339, Order on Rehearing at 22, FoF 82 (CenterPoint's long-term incentive-compensation plan (LTI) is not a reasonable and necessary component of CenterPoint's total compensation package." (June 23, 2011).

[327] *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Initial Post-Hearing Brief at 94 (Oct. 22, 2010) ("No party disputes the Company's STI costs."); COH Ex. 2 (Garrett Dir.) at 15.

[328] *See Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, CenterPoint's Initial Post-Hearing Brief at 94 (Oct. 22, 2010) ("No party disputes the Company's STI costs."); Docket No. 38339, Proposal for Decision at 68 (Dec. 3, 2010) ("In its initial brief, CenterPoint stated that no party disputes the Company's STI costs, but in its initial brief, TIEC contended that although some performance measures in CenterPoint's STI plan are operational, others are financial. . . . CenterPoint argues that no witness in this proceeding supports TIEC's new position. According to CenterPoint, the evidence provided by the Company proving that STI is reasonable and necessary is undisputed in the record. ***TIEC presented no evidence as to the nature of the goals it contended constituted impermissible financial goals. As a consequence, the ALJs find that TIEC's challenge to CenterPoint's inclusion of STI expenses fails and, therefore, recommend that the Commission find that CenterPoint's STI expenses are recoverable.***") (emphasis added).

[329] Tr. (Harkel-Rumford Cr.) 1343:14 – 1344:3 (Jun. 28, 2019).

Commission should disallow recovery of at least sixty-nine percent of CenterPoint's $16.881 million request for STI compensation expense,[330] or $11.648 million for the test year.[331]

b. Long-Term Incentive Compensation

In CEHE's last rate case, the Commission disallowed the entirety of CEHE's requested LTI expense based on its finding that, "CenterPoint's [LTI] is not a reasonable and necessary component of CenterPoint's total compensation package."[332] It should make that same determination here because the record shows that CEHE's LTI package is entirely made up of financially based goals. As CEHE's parent company admitted to its shareholders, "[o]ur long-term incentive plan is designed to ***reward participants for sustained improvement in our financial performance and increases in the value of our common stock and dividends over an extended period***."[333] CEHE witness Ms. Harkel-Rumford agreed with that assessment.[334]

CEHE's witnesses admit that 70% of its LTI plan is made up of "performance shares" that are financially based goals.[335] However, they claim that the "restricted stock awards" that make up the remaining 30% of the plan are not financially based because they are guaranteed to vest over a certain amount of time.[336] But once again, that claim is belied by CNP admitting to its shareholders that, "[t]he restricted stock units are intended to retain executive officers and ***reward them for long-term stock appreciation***."[337] Additionally, as shown during cross examination with Ms. Harkel-Rumford, the value of those restricted stock awards is directly proportional to the value provided to CNP's shareholders—in this case, increases in stock price and awarded dividends—and those are factors that directly benefit shareholders, but not customers.[338]

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[330] *See* Tr. (Colvin Cr.) at 1275:1-15 (Jun. 28, 2019).

[331] Tr. (Colvin Cr.) at 17:7-9 (Jun. 28, 2019).

[332] *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Order on Rehearing at 22, FoF 82 (Jun. 23, 2011). See also, Order on Rehearing (Mar. 19, 2018).

[333] TIEC Ex. 15 (Annual Shareholders Meeting Presentation) at 34.

[334] Tr. (Harkel-Rumford Cr.) 1343:14-19 (Jun. 28, 2019).

[335] CEHE Ex. 39 (Harkel-Rumford Reb.) at 23.

[336] *Id.*

[337] TIEC Ex. 15 (Annual Shareholders Meeting Presentation) at 36 (emphasis added).

[338] Tr. (Harkel-Rumford Cr.) 1341:23 – 1344:2 (June 28, 2019).

Accordingly, because it is clear that CEHE's LTI plan is entirely made up of financially based goals, the Commission should exclude recovery of 100% of LTI compensation costs, or roughly $11.25 million of expenses for the proposed test year.[339]

2. Executive Employee Related Expenses

3. Payroll Adjustments

4. Pension and Other Postemployment Benefits (OPEB) Expense

5. Other Benefits

C. Depreciation and Amortization Expense [PO Issue 25]

D. Affiliate Expenses [PO Issue 35, 36]

1. Vectren Issues

2. Compensation for Use of Capital

3. Service Company Pension and Benefit Costs

4. Affiliate Carrying Charges

E. Injuries and Damages

F. Hurricane Harvey Restoration Costs [PO Issues 54, 55]

G. Self-Insurance Reserve [PO Issues 16, 33]

H. Vegetation Management

I. Smart Meter Texas Expense

J. Loss on Sale of Land

K. Federal Income Tax Expense [PO Issues 28, 29]

L. Taxes Other Than Income Tax [PO Issue 26]

1. Ad Valorem (Property) Taxes

2. Texas Margin Tax

3. Payroll Taxes

V. Wholesale Transmission Cost of Service [PO Issue 4, 5, 6, 37]

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[339] TIEC Ex. 3 (LaConte Dir.) at 28.

VI. Billing Determinants [PO Issue 4, 5, 45]

A. Weather Normalization

B. Energy Efficiency Program Adjustment

VII. Functionalization and Cost Allocation [PO Issues 4, 5, 43, 44, 46]

A. Functionalization

1. Texas Gross Margins Tax Expense (and associated accounts)

TIEC agrees with Staff witness Brian Murphy that CEHE's Texas Margins Tax expense should be functionalized 13.3% to the wholesale Transmission Service Function and 86.7%[340] to the retail Distribution Service function.[341] As Mr. Murphy explains, Texas Margins Tax is levied on the revenues that CEHE collects for providing wholesale transmission service and retail delivery service.[342] The tax attributable to CEHE's retail service should be allocated to customers in CEHE's retail service area, and only the tax on CEHE's wholesale transmission service should be "uplifted" or spread to all customers on the ERCOT transmission grid through TCOS.[343] CEHE's proposed functionalization is inconsistent with cost causation principles because it uplifts a large portion of the tax attributable to CEHE providing ***retail*** service to its customers into TCOS.[344] In particular, CEHE functionalized the contents of FERC Account 565—which contains ERCOT transmission payments that CEHE made to other TSPs for its retail customers' use of the ERCOT grid—to the ***wholesale*** transmission function, even though those costs were incurred in the course of CEHE providing ***retail*** service.[345] Critically, in CEHE witness Ms. Colvin's rebuttal testimony, she admitted that ***the company agrees with Commission Staff's position on the Texas Margin Tax functionalization factor***.[346] Accordingly, Staff's position is appropriate and should be adopted.

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[340] These percentages are derived using Staff-adjusted base revenues. *See* Staff Ex. 2A (Murphy Dir. (Non-Confidential)) at 32. Using CEHE's application equates to allocating 14.8% of the Texas Margins Tax to the Transmission Service Function and 85.2% to the Distribution Service Function. *Id.*

[341] *Id.* at 34, Table BTM-3.

[342] *Id.* at 25-26.

[343] *Id.* at 31.

[344] *Id.* at 30 ("The critical flaw in CEHE's approach is equating the transmission functional revenue requirement (which is a component of its ***retail*** cost of service) with its ***wholesale*** transmission revenue requirement.") (emphasis in original); Tr. 854 (Murphy Cr.) at 854:23 – 855:5.

[345] Staff Ex. 2A (Murphy Dir.) at 30-31.

[346] CEHE Ex. 35 (Colvin Reb.) at 47; Tr. (Murphy Cr.) at 858:2-23 (June 23, 2019).

City of Houston witness Ms. Pevoto contends that CEHE's original functionalization approach should be adopted because it is "consistent" with the order in CEHE's last rate case.[347] However, this issue was not contested in that docket,[348] and there is no reason that prior order would bind the Commission to continue approving an incorrect functionalization of costs in this case. Further, CEHE's proposed functionalization of the Texas Margins Tax is a clear example of why the Commission has repeatedly expressed concerns about the incentives that TSPs and certain intervenors have to inappropriately uplift costs to the ERCOT grid in order to minimize the Company's retail rates.[349] For instance, in a recent Order approving updates to the rate filing package, the Commission stated:

> The commission notes its concern, however, that a TDU, as well as certain intervening parties, may face an incentive to seek functional assignments or allocations that inappropriately shift costs onto the transmission function (TRAN), as those costs are spread to customers outside the TDU's retail service territory and are collected from customers across the ERCOT grid.[350]

The potential impacts of this inappropriate functionalization are significant. Using 2019 data on CEHE's share of the costs of the grid (acting in its role as a DSP), Mr. Murphy found that "for every dollar in common costs assigned to the transmission function . . . CEHE's retail customers will bear only 25 cents on the dollar in the form of ERCOT transmission payments."[351] In other words, this incorrect functionalization would allow CEHE's customers to receive certain aspects of their electric service at a 75% discount, while forcing all customers in ERCOT to pay for this subsidy. Accordingly, cost causation principles require the Commission to appropriately functionalize CEHE's entire cost of providing ***retail*** electric service to the Distribution Service function, as Mr. Murphy recommends.

2. Miscellaneous General Expense (account 930.2)

3. Unprotected Excess Deferred Income Tax

[347] COH Ex. 4 (Pevoto Reb.) at 10.

[348] Staff Ex. 2A (Murphy Dir.) at 32.

[349] *See* Staff Ex. 2A (Murphy Dir.) at 21 (citing several Commission discussions and decisions).

[350] *Project to Revise Rate Filing Package for Investor Owned Transmission and Distribution Utilities*, Project No. 39548, Order of Adoption at 32 (Nov. 19, 2015).

[351] Staff Ex. 2A (Murphy Dir.) at 20.

B. Class Allocation

1. Class Allocation of Transmission Costs

In general, CEHE's CCOSS is reasonable and consistent with accepted practice.[352] However, there are two areas where CEHE's proposed cost allocation fails to appropriately reflect cost causation. First, the Commission should reject CEHE's novel proposal to allocate to wholesale transmission costs among CEHE's retail classes based ***CEHE's*** four-coincident peaks (4CP), rather than the ERCOT-wide 4CP. Second, the Commission should refine CEHE's proposed allocation of municipal franchise fee (MFF) expense to reflect each class's (a) in-city kWh usage, ***and*** (b) the specific MFF rates where that usage occurs. Contrary to CEHE's claims, this approach is consistent with Commission precedent and more appropriately aligns class allocations with cost causation.

a. "CenterPoint 4CP" versus "ERCOT 4CP" Class Allocation (separately for both transmission and for distribution)

In a significant departure from Commission precedent, CEHE proposes to allocate wholesale transmission costs to its retail classes using their demand coincident with ***CEHE's 4CP***, rather than the ERCOT 4CP.[353] Nonsensically, however, CEHE is also proposing to use customer demand at the time of the ***ERCOT 4CP*** for billing purposes.[354] This fails to track any form of cost-causation and creates inappropriate cost shifting both among and within customer classes. CEHE's proposal is also inconsistent with PUC Substantive Rule 25.192, which requires wholesale transmission costs to be allocated among the DSPs using their ERCOT 4CP demand.[355] These costs should be passed on to retail customers in the same manner that they are charged to CEHE. The Commission has consistently used the ***ERCOT 4CP*** to allocate wholesale transmission costs to the retail classes in every contested case since unbundling, including CEHE's last rate case (Docket No. 38339).[356] The same method should be adopted here.

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352 TIEC Ex. 1 (Pollock Dir.) at 5.

353 CEHE Ex. 30 (Troxle Dir.) at 20.

354 Tr. (Troxle Cr.) at 1008:5-11 (Jun. 27, 2019).

355 16 TAC § 25.192.

356 Staff Ex. 7B (Murphy Dir.) at 46; TIEC Ex. 1 (Pollock Dir.) at 6.

i. CEHE incurs ERCOT wholesale transmission costs based on each customer class's demand during the ERCOT 4CP. These costs should be allocated to CEHE's retail classes on the same basis.

As a load-serving distribution service provider (DSP), CEHE incurs ERCOT wholesale transmission charges based on its customers' usage at the time of the ERCOT 4CP. These charges recover the costs of ***all transmission facilities*** within ERCOT. Ownership of the ERCOT grid is split between 49 individual Transmission Service Providers (TSPs).[357] These TSPs pool all of their wholesale transmission costs into a single "bucket" called transmission cost of service (TCOS), which is then charged back to load-serving DSPs (such as CEHE) based on their share of the ERCOT 4CP.[358] Those charges are designed to allow each TSP to collect its cost of providing wholesale transmission service, and, in the aggregate, to collect the costs associated with ***the entire ERCOT transmission system***.[359]

Under PURA § 35.004(d) and 16 TAC § 25.192, each DSP is charged for wholesale TCOS based on its customers' demand coincident with ERCOT's monthly peak in June, July, August, and September of the prior year—the ERCOT 4CP.[360] As a result, if CEHE's customers reduce their usage during the ERCOT 4CP, CEHE's allocated ERCOT transmission costs go down, whereas if the load increases coincident with the ERCOT 4CP, CEHE's allocated transmission costs increase.[361] The relationship is direct and one-for-one. As Commission Staff witness Mr. Abbott testified:

> [I]f customers are reducing their load at the time of the peak, those transmission costs are not being incurred, they are not being allocated to CenterPoint, they're not being allocated to that customers' class, and they're not being charged [to] the customer.[362]

Using the ERCOT 4CP to allocate wholesale transmission costs follows cost-causation principles.[363] As Mr. Abbott notes, "customers' load coincident with the system peak . . . is the

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[357] Staff Ex. 7B (Murphy Dir.) at 12.

[358] Tr. (Troxle Cr.) at 1005:17-24 (Jun. 27, 2019); *see also* Staff Ex. 2A (Murphy Dir.) at 13.

[359] Tr. (Troxle Cr.) at 1006:19-1007:4 (Jun. 27, 2019).

[360] *See* TIEC Ex. 1 (Pollock Dir.) at 28-29; Staff Ex. 7B (Murphy Dir.) at 32.

[361] See Tr. (Abbot Cr.) at 898:2 – 899:1.

[362] See Tr. (Abbot Cr.) at 898:17 – 899:1.

[363] TIEC Ex. 1 (Pollock Dir.) at 8-9; *see also* Staff Ex. 2A (Murphy Dir.) at 15 ("Summer peak loads drive the need for transmission capacity on the grid. The use of summer peak loads to assess [transmission] charges is

primary driver of transmission system costs."[364] Accordingly, these costs should be allocated to retail customer classes based on their respective ERCOT 4CP demand.

Mr. Troxle contends that using CEHE's 4CP to allocate transmission costs instead of the ERCOT system peak is appropriate because CEHE builds its portion of the ERCOT transmission system to serve its own peak load.[365] However, as explained above, TCOS represents the costs of the ***entire*** ERCOT system. Only a fraction of the transmission costs CEHE passes through to its customers in its role as a DSP is actually attributable to CEHE's own transmission assets. In fact, as a TSP, CEHE's share of TCOS is approximately 10.59%,[366] meaning that almost 90% of the transmission costs CEHE collects from its retail customers are for facilities owned by the other 48 TSPs within ERCOT. As such, even if the Commission accepts CEHE's argument that it builds its own transmission to accommodate CEHE's 4CP, it still makes no sense to allocate CEHE's overall wholesale transmission costs to customers on that basis.

ii. Using CEHE's 4CP to allocate transmission costs to retail classes while using the ERCOT 4CP as a customer's billing determinant would cause irrational cost shifting.

Peculiarly, CEHE proposes to allocate wholesale transmission costs to each customer class based on demand during the CEHE 4CP, but still intends to charge individual customers within a class based on their demand during the ***ERCOT 4CP***.[367] As a result, a customer's demand during the CEHE 4CP will cause additional costs to be allocated to that customer's class, but if the customer is not also taking power during the ERCOT 4CP then it would ***not pay*** the costs it caused its retail class to bear—other customers would. This is irrational and completely divorced from cost-causation principles.

therefore a rate design that is consistent with cost causation . . ."); Staff Ex. 7B (Abbott Cr. Reb.) at 33-34; Tr. (Abbott Cr.) at 924:10-25 ("Each class incurs those – within CenterPoint incurs those costs based on its [ERCOT] 4CP load . . . [a]nd so a [ERCOT] 4CP allocation factor for transmission cost recovery is the only one consistent with cost causation.")

[364] Staff Ex. 7B (Abbott Reb.) at 32. *See also* TIEC Ex. 1 (Pollock Dir.) at 11; TIEC Ex. 2 (Pollock Reb.) at 7-8.

[365] CEHE Ex. 30 (Troxle Dir.) at 20.

[366] Tr. (Troxle Cr.) at 1007:10-25 (Jun. 27, 2019); TIEC Ex. 34 (Commission Staff's Final Transmission Charge Matrix Docket 48928); *see also* Staff Ex. 2A (Murphy Dir.) at 13.

[367] Not all customer classes will be charged based on demand.

As demonstrated at the hearing, CEHE's proposal would result in classes being allocated transmission costs based on usage at the time of the CEHE 4CP, but then those costs will be actually be borne ***within*** a class based on each customer's usage during the ERCOT 4CP. This mismatch creates textbook cross-subsidization and cost shifting. At the hearing, Mr. Troxle was presented with a hypothetical scenario of a class that consists of two customers, Customer A and Customer B.[368] Customer A curtailed its usage during the ERCOT 4CP,[369] but was operating at full load during CEHE's 4CP. Customer B did the exact opposite, operating at full load during the ERCOT 4CP but curtailing during CEHE's 4CP. Under CEHE's allocation proposal, Customer A would cause additional transmission charges to be allocated to its retail class based on its usage during CEHE's 4CP. However, Customer A would not actually ***pay*** any of those charges because CEHE would still use Customer A's ERCOT 4CP demand for billing purposes. As a result, the charges allocated to Customer A's class would be borne by Customer B, who did operate during the ERCOT peak. In addition to the other flaws in CEHE's proposal discussed above, this result is irrational, inconsistent with cost causation principles, and should be rejected.

b. Transmission and Distribution Demand Allocation Factors (4CP vs NCP class allocation (separately for both transmission and for distribution))

In a similarly misguided proposal, HEB Witness Mr. Presses[370] and the Texas Competitive Power Advocates (TCPA), which represents competitive power generators,[371] propose to use non-coincident peak (NCP) allocation factors to allocate transmission costs.[372] This proposal should also be rejected.

First, as previously discussed, CEHE's wholesale transmission costs are driven by demand coincident with the ERCOT 4CP, and should be allocated to retail customers on the same basis—

[368] *See* Tr. (Troxle Cr.) at 1008:13-1009:19 (Jun. 27, 2019).

[369] 4CP curtailment is a common practice in ERCOT, and benefits the ERCOT transmission system. Because the transmission system is built to serve peak load, having customers voluntarily curtail usage at peak times decreases the total cost to build and maintain the system.

[370] HEB Ex. 1 (Presses Dir.) at 6.

[371] Texas Competitive Power Advocates Statement of Position at 1 (June 12, 2019).

[372] HEB Witness Mr. Presses seems to recommend that ***both*** distribution and transmission allocation factors be based on NCP. *See* HEB Ex. 2 (Presses Cross Reb.) at 17 ("H-E-B proposes that all customers that use the grid should pay their share of transmission and distribution costs and that those costs should be allocated on a Non-Coincident Peak ("NCP") basis."). For the purposes of this Initial Brief, TIEC is only addressing the ***transmission*** allocation factor.

consistent with 20 years of Commission precedent.[373] NCP allocation is based on a customer's (or a customer class's) highest single period of demand, regardless of when it occurs.[374] Mr. Abbott illustrated how 4CP rate design differs from a NCP rate design as follows:

> A customer might have an individual peak load of 1,000 kW, but only has an average load of 800 kW at the time of the four summer monthly system peaks. Under an NCP rate design, such a customer would have a billing demand of 1,000 kW, while under a 4CP rate design the customer would have a billing demand of 800 kW.[375]

In other words, a 4CP allocation "provides a price signal to the customer to reduce its load at times when the customer anticipates a system peak might be established."[376] This reduction in peak usage decreases overall costs for the transmission system because the customer's load coincident with the system peak is the "primary driver of transmission system costs."[377] In contrast, under an NCP allocation there is no similar incentive to manage demand during system peak, meaning that the cost of the transmission system will increase.

Mr. Presses and TCPA baselessly allege that load curtailment during the ERCOT 4CP "distorts price signals" in the ERCOT energy-only market.[378] Cost allocation decisions should be based on cost-causation principles and established ratemaking techniques, not an attempt to redress incidental impacts on competitive energy prices that are far beyond the scope of this case. The Commission should not attempt to prevent customers from efficiently managing their regulated utility rates through demand response based on unproven impacts to competitive power prices.[379] Nor should it. As TIEC witness Mr. Pollock states, "It is not a "distortion" of wholesale energy prices if customers use less power for any legitimate reason of their choosing."[380] As Commission Staff witness Bill Abbott indicated, "[I]t is a normal and healthy economic response for ratepayers to reduce peak load on the transmission system in response to the higher transmission costs, ***and for the complementary energy market to face some downwards price pressure due to this***

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[373] *Supra* § VII.B.1.a; *see also* TIEC Ex. 2 (Pollock Reb. at 6-9); Staff Ex. 7B (Abbott Reb.) at 32.

[374] Staff Ex. 7B (Abbott Reb.) at 9 and 30. TIEC Ex. 2 (Pollock Reb.) at 6-7.

[375] Staff Ex. 7B (Abbott Reb.) at 30.

[376] Staff Ex. 7B (Abbott Reb.) at 30.

[377] Staff Ex. 7B (Abbott Reb.) at 30.

[378] HEB Ex. 1 (Presses Dir.) at 6; Texas Competitive Power Association, Statement of Position at 1-2 (June 12, 2019).

[379] TIEC Ex. 2 (Pollock Reb.) at 8.

[380] TIEC Ex. 2 (Pollock Reb.) at 8.

rational and economically appropriate response."[381] Accordingly, the Commission should continue to provide customers with the ability to manage their transmission costs by allocating costs to customer classes on the same basis that they are charged to CEHE—demand during the ERCOT 4CP.

c. 4CP Rate Design versus NCP Rate Design (separately for both transmission and for distribution)

TIEC does not take a position on rate design for the TCRF for any classes besides the Transmission retail class, who should be billed based on their actual ERCOT 4CP demand. TIEC opposes any ***class allocation*** proposals for wholesale transmission costs that are not based on ERCOT 4CP demand, as discussed above, but does not take a position on alternative rate designs for other classes once that initial allocation has been made.

d. Moderating the Update to the 4CP Class Allocation Factor

If the Commission allocates transmission costs based on the ERCOT 4CP, as discussed above, then TIEC is not proposing any adjustments to mitigate rate impacts in this case. However, if the Commission adopts CEHE's proposal to use the CEHE 4CP to allocate transmission costs (which it should not, as discussed above), then rate moderation is warranted due to a combination of (a) the dramatic departure from longstanding Commission precedent in allocating wholesale transmission costs based on the ERCOT 4CP, and (b) the impacts of a known flaw in the Commission's TCRF rule that causes distortions between rate cases. As shown below in Mr. Pollock's Table 8, resetting class allocations based on CEHE's proposal would suddenly increase the Transmission class's allocation factor by ***22.1%***.[382]

[381] Staff Ex. 7B (Abbott Reb.) at 39-40 (emphasis added).

[382] TIEC Ex. 1 (Pollock Dir.) at 31.

Table 8 Change in 4CP Allocation Factors			
Rate Class	Current	CenterPoint Proposed	Change
Residential	47.14%	46.65%	-1.0%
Secondary ≤ 10 kVA	1.15%	0.88%	-23.5%
Secondary > 10 kVA	35.87%	34.07%	-5.0%
Primary	3.62%	3.48%	-3.9%
Transmission	12.22%	14.92%	22.1%
Sources: Schedule II-H-1.3 and CenterPoint's March 2019 TCRF Filing (Docket No. 48933).			

Given this dramatic shift in costs, if the Commission adopts CEHE's proposed allocation factors, it should moderate the impact on customer classes through a more gradual implementation.[383] To be clear, TIEC is not proposing to address normal rate impacts of differential class growth over time, which is the more common use of so-called "gradualism," but is proposing to mitigate the impact of changing course on decades of allocation precedent, combined with the impacts of correcting distortions caused by the current TCRF rule over the past ten years.

TIEC witness Jeff Pollock and Commission Staff witness Bill Abbott agree that the current design of the Commission's TCRF formula is problematic because it assigns a ***fixed*** percentage of transmission costs to each class (i.e. the class allocation factor from the utility's last rate case), but uses ***current*** billing determinants to set the TCRF charge.[384] Without regular updates, the class allocation factor does not take load growth/shrinkage into account and can lead to a "mismatch between the costs allocated to a rate class and the billing determinants used to calculate the rate for that class" which could "increase the magnitude of rate changes seen in a rate proceeding."[385] As Mr. Pollock explains:

> Irrationally, if a class is growing, its TCRF rates may continuously *decrease* since a fixed percentage of transmission costs is being spread over a growing amount of usage/customers. Conversely, if a class shrinks, it's TCRF rates would go *up*, as a fixed percentage of

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[383] TIEC Ex. 1 (Pollock Dir.) at 32-33.

[384] TIEC Ex. 1 (Pollock Dir.) at 33; Staff Ex. 7B (Abbott Reb.) at 25. See also PUC Substantive Rule § 25.193.

[385] Staff Ex. 7B (Abbott Reb.) at 24.

costs must be recovered from a smaller amount of usage/customers.[386]

CEHE's class allocation factors were last adjusted ***nine years ago*** in Docket No. 38339. During that time, CEHE has seen significant load growth in its service area, and its customer classes have not grown proportionally.[387] Because the TCRF rule updates each class's billing determinants but not class cost allocations, customers in a growing class will receive lower and lower TCRF rates until they are suddenly reset in a future rate proceeding. This fails to track cost causation, and as a result, "resetting" the allocations in a rate case causes substantial shifts in costs among the classes. As discussed in Mr. Pollock's testimony, the Commission should reopen PUC Subst. R. 25.193 to develop a long-term solution to this issue; but in the meantime, the consequences of this flawed rule's operation over the last decade should be mitigated when appropriate in utility rate proceedings.[388] This is particularly appropriate if the Commission were to also adopt an entirely new method for allocating wholesale transmission costs, as CEHE has proposed. Again, if the allocation proposed by Commission Staff and TIEC is adopted, consistent with decades of Commission precedent, then no adjustments are necessary.

2. Municipal Franchise Fees [PO Issue 27]

CEHE's proposed allocation of Municipal Franchise Fees (MFF) among the retail classes should be refined to reflect the differences in MFF rates and mix of inside-city kWh deliveries by customer class by city. Contrary to CEHE's assertion, as well as similar assertions from the City of Houston and OPUC,[389] this allocation is consistent with Commission precedent but more accurately reflects each customer class's contribution to CEHE's MFF expense.

In CEHE's last rate case, the Commission approved allocating MFF expense to each retail customer class based on the class's in-city kWh deliveries, but then charging all customers within the class for the MFF expense—not just in-city customers.[390] This allocation method is commonly

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386 TIEC Ex. 1 (Pollock Dir.) at 28-29.

387 *Id.* at 33.

388 *Id.* at 38-40; Staff Ex. 7B (Abbott Reb.) at 24-25; *see also* Section VI(C), *supra*, for further discussion on amending the TCRF formula.

389 COH Ex. 4 (Pevoto Cr. At 4); OPUC Ex. 7 (Nalepa Cr. Reb.) at 8-9.

390 Docket No. 38339, Order on Rehearing at 34, FoF 179 (June 23, 2011).

referred to as the "Direct" method.[391] Recovering MFF expense from all customers within the class is commonly referred to as the "Spread" method. Consistent with the "Direct" method of allocation, Mr. Pollock proposes to allocate MFF expense to each customer class based on its in-city usage.[392] However, Mr. Pollock's proposal would not change how the allocated MFF expense are collected.[393] Specifically, Mr. Pollock is not proposing to change the Spread method of collection, which charges the allocated MFF expense to all customers within the class.[394] The only difference is that Mr. Pollock applies the Direct Method separately for each city.[395] This more granular allocation weights the MFF expense allocated to each class based on the class's usage within each city and the city's individual MFF rate. While Mr. Pollock made a similar proposal in CEHE's last case and the Commission adopted CEHE's proposal instead, Mr. Pollock's approach is not at odds with the Commission's actual findings in Docket No. 38339, which state only that: "CenterPoint's allocation of municipal franchise fees to the customer classes based upon in-city kilowatt-hour (kWh) sales and collection of the fees from all customers within the customer class is reasonable and consistent with Commission precedent."[396]

No party has disputed that Mr. Pollock's allocation better reflects each class's contribution to CEHE's MFF expense. Instead, the opposition is based solely on the outcome in Docket No. 38339. When presented with a superior approach that better reflects cost-causation, the Commission should be open to refining its prior allocation methodology. Further, as discussed below, the Commission has not adopted a uniform approach for allocating MFF expense and does not have a single prevailing precedent.

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[391] TIEC Ex. 1 (Pollock Dir.) at 18-19. *See also Application of TXU Electric Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25.344, Docket No. 22350*, Order at FoF No. 156 (Oct. 4, 2001); *Application of Reliant Energy for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25.344*, Docket No. 22355, Order at FoF No. 222A (Oct. 4, 2001); *Application of AEP Texas Central Company for Authority to Change Rates,* Docket No. 28840, Final Order (Aug. 15, 2005); *Application of AEP Texas Central Company for Authority to Change Rates,* Docket No. 33309, Order on Rehearing (Mar. 4, 2008); *Application of Oncor Electric Delivery Company LLC for Authority to Change Rates*, Order on Rehearing (Nov. 30, 2009). Note: the term LGRT, or local gross receipts tax, was used synonymously with MFF.

[392] TIEC Ex. 1 (Pollock Dir.) at 17.

[393] TIEC Ex. 1 (Pollock Dir.) at 17; Tr. (Nalepa Cr.) at 487:24 – 488:2, 489:1-15.

[394] *Id.*

[395] *Id.*

[396] Docket No. 38339, Order on Rehearing at 34, FoF 179 (June 23, 2011).

a. Mr. Pollock's proposed allocation of MFF expense better reflects cost causation, and incentivizes customers to attempt to control MFF rates.

Different cities within CEHE's service territory charge vastly different MFF rates, and the proportion of kWh sales by rate class is not uniform by city.[397] For example, the City of Houston charges 0.337¢ per kWh sold within its city limits, which is higher than average, and 89.7% of kWh sales within the City of Houston are made to residential and secondary service customers.[398] In contrast, the City of Mont Belvieu charges a below-average MFF rate of 0.193¢ per kWh,[399] but those same classes represent only 4.9% of kWh sales in the City of Mont Belvieu.[400] Mr. Pollock's refinements take these differences in cost causation into account when allocating MFF costs. Reflecting both in-city sales by class ***and*** differences in the MFF rates where those sales are made not only is more consistent with cost-causation principles, it provides a stronger incentive for customers to control their MFF costs by engaging with their elected officials.[401] If usage in cities with higher MFF rates is spread equally to all customer classes, the impact of excessive MFF rates is not borne as directly by customers within that city, who have the best ability to control those costs.

In addition to capturing differences in the amount of in-city usage by class, Mr. Pollock's refinements to the "Direct" method of allocation better reflect the distinct MFF rates where each class is using electricity. He starts with exactly the same inputs as the "Direct" method: "(1) the tax level set by the city, and (2) the usage of [electricity] by customers inside the city limits."[402] However, while the standard "Direct" method would allocate MFF cost to CEHE's customers based on each class's proportion of all in-city kWh sales, Mr. Pollock takes the extra step of quantifying each class's share of each individual city's MFF charges to account for city-by-city variations in MFF charges and customer mix. To do this, Mr. Pollock quantified the MFF by class for each city and then converts that number into a percentage to allocate CEHE's test-year MFF to each delivery rate class.[403] This approach creates a weighted average rate per class, which

[397] TIEC Ex. 1 (Pollock Dir.) at 14.

[398] *Id.* at 14-15.

[399] *Id.* at 15.

[400] *Id.*

[401] *Id.* at 17.

[402] *Id.* at 17.

[403] *Id.* at 16-17.

better allocates MFF to the classes that actually incurred those costs. Mr. Pollock's Table 6 shows how his MFF allocation differs from CEHE's: [404]

Table 6 Allocation of Municipal Franchise Fees ($000)		
Delivery Rate Class	Unweighted[5]	Weighted[6]
Residential	$51,532	$53,007
Secondary ≤10 kVA	$1,885	$1,945
Secondary >10 kVA	$73,365	$75,596
Primary	$7,884	$8,198
Transmission	$17,674	$13,581
SLS Lighting	$325	$334
MLS Lighting	$116	$120
Total	$152,781	$152,871

As noted above, Mr. Pollock's analysis is an improvement to the standard "Direct" method that better matches principles of cost causation. This method is also more equitable because it allocates more MFF to customer classes that are more prevalent in cities that charge higher MFF on a per kWh basis, and, as Mr. Pollock notes, "in-city customers . . . determine the tax rate are through their elected representatives and their usage determines the amount that CenterPoint must pay to each city." [405]

b. Mr. Pollock's proposed allocation is consistent with Commission precedent.

CEHE, OPUC and the City of Houston incorrectly assert that Mr. Pollock's proposal conflicts with Commission precedent. First, as noted above, Mr. Pollock's proposal is consistent with the Commission's only finding on MFF allocation in Docket No. 38339. Consistent with that finding, Mr. Pollock allocates MFF expense based on in-city usage and then charges it to all customers. Mr. Pollock has taken the additional step of weighting the allocation based on each city's MFF rate and class usage within that particular city, but this does not contradict anything in the Commission's order in Docket No. 38339. [406] TIEC acknowledges that the Commission

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[404] *Id.* at 16.

[405] *Id.* at 17.

[406] Docket No. 38339, Order on Rehearing at 34, FoF 179 (June 23, 2011).

declined to adopt Mr. Pollock's proposal in Docket No. 38339, but disagrees that it is "inconsistent" with the Commission's actual order.

Further, the Commission has not taken a consistent approach to MFF allocation for all utilities. For example, Texas New Mexico Power's (TNMP's) Commission-approved tariff charges each city's MFF charges directly to ***only to in-city customers***—it does not spread the costs to all customers in a given class.[407] Similarly, Mr. Nalepa claimed in his testimony that the Commission rejected weighting MFF expense by class usage within each city in Entergy Texas, Inc. (ETI's) rate case in Docket No. 39896.[408] However, as demonstrated at the hearing, ETI collects all incremental MFF expense that is not in base rates through a rider charged directly to in-city customers.[409] Due to this hybrid allocation approach, the Commission's decision on how base-rate MFF expense should be allocated for ETI is not analogous to CEHE. As a result, there is no prevailing or controlling precedent, ALJs and the Commission should adopt the approach that best tracks cost-causation and aligns customers' incentive to manage the MFF rates in the cities where they use electricity. For these reasons, Mr. Pollock's approach is superior and should be adopted.

3. Transmission and Key Accounts

OPUC witness Mr. Nalepa has proposed that one-third of the expenses of CEHE's Transmission and Key Accounts Department ($678,154) be directly assigned to the Transmission class instead of being spread among all retail customer classes.[410] However, Mr. Nalepa has not submitted any workpapers or analysis to prove that a third of the Transmission and Key Accounts Department's test-year expenses are actually attributable to the transmission class.[411] Instead, Mr. Nalepa simply assumes that because the Transmission and Key Accounts department has three

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[407] *See, e.g.,* TNMP Tariff at Section 6.1 "Municipal Franchise Fees. When service falls within the incorporated limits of a municipality that assesses a franchise fee on transmission customers, such municipal franchise fees shall be added to and separately stated on the bill of each customer taking service within the incorporated limits of the municipality and shall be at the rate of $0.00175000/kWh. Transmission customers taking service outside the incorporated limits of a municipality shall not be subject to this fee.")

[408] OPUC Ex. 7 (Nalepa Cross-Reb.) at 9.

[409] TIEC Ex. 18 (Entergy Schedule FFBE); Tr. (Nalepa Cr.) 492:8-13.

[410] OPUC Ex. 5 (Nalepa Dir.) at 51.

[411] TIEC Ex. 2 (Pollock Cross-Reb.) at 1-2.

separate functions,[412] one of which deals with "the interconnection of large industrial customers and generators to the transmission system,"[413] that transmission customers account for one-third of the total Transmission and Key Accounts Department test-year expenses.[414]

This assumption is flawed for two reasons. First, even if the Transmission Accounts and Support group incurs expenses related to interconnecting transmission voltage retail customers, those expenses would already be directly paid through the required contributions in aid of construction (CIAC) for new transmission-voltage customers.[415] Therefore, Mr. Nalepa's approach would essentially charge those customers twice for the same service. Second, Mr. Nalepa's proposal is completely arbitrary in how it determines which expenses should be directly assigned to a particular class. Under Mr. Nalepa's logic, the other groups served by the Transmission Key Accounts Department—the distribution-level classes and street lighting—should also each be directly assigned one-third of the Department's expenses. However, Mr. Nalepa seems to have opportunistically singled out the transmission class for this direct assignment of costs.[416] His adjustment is baseless and should be rejected.

Finally, the Commission should not rely on CEHE witnesses' descriptions of their activities to determine appropriate cost functionalization and allocation. For instance, as noted in Mr. Pollock's cross-rebuttal testimony, CEHE witness Ms. Sugarek's description of CEHE's Power Quality Solutions department appears to have nothing to do with serving transmission-voltage customers. However, Mr. Nalepa does not propose to assign that department's $1.6 million in expenses to distribution customers. Internal department titles and descriptions may serve many purposes, and are not meant to be the basis of cost allocation among customer classes. Accordingly, the Commission should reject Mr. Nalepa's proposed direct assignment.

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[412] CEHE Ex. 10 (Sugarek Dir.) at 7-8 (testifying that the three groups within the Transmission and Key Accounts Department are: (1) Transmission Accounts and Support group, (2) Key Accounts group, and (3) Street Lighting Design group.)

[413] CEHE Ex. 10 (Sugarek Dir.) at 7-8.

[414] TIEC Ex. 2 (Pollock Cross Reb.) at 2-3.

[415] *Id.* at 3-4; *see also* TIEC Ex. 1 (Pollock Dir.) at 37.

[416] TIEC Ex. 2 (Pollock Cross Reb.) at 4-5.

4. Allocation of Hurricane Harvey Restoration Costs [PO Issue 56]

VIII. Revenue Distribution and Rate Design [PO Issues 4, 5, 43, 49, 50]

A. Residential Customer Charge

B. Customer Charge on Per Meter Basis vs. Per Customer Basis

C. Transmission Service Rate

1. The Commission should require CEHE to recover all of its wholesale transmission costs through the TCRF to prevent over-recovery.

The Commission should reject CEHE's proposal to set its Transmission Cost Recovery Factor (TCRF) charge to zero and recover all wholesale transmission costs through base rates.[417] Instead, to prevent over-recovery, CEHE should be required to remove all wholesale transmission costs from base rates and recover them exclusively through the TCRF. Commission Staff has consistently recommend this approach in prior cases since the current TCRF rule was adopted,[418] and it is consistent with the Commission's stated intent to prevent over-recovery of wholesale transmission costs.[419] The Commission has previously approved recovering wholesale transmission costs exclusively through the TCRF for Oncor,[420] TNMP,[421] and Sharyland,[422] and AEP is proposing this same approach in its pending rate case.[423] Based on both sound ratemaking principles and Commission precedent, CEHE should be required to remove all wholesale transmission costs from base rates and recover them solely through the TCRF.

In 2010, the Commission amended the current TCRF rule to reflect that DSPs like CEHE "essentially serve as billing and collection agents for passed-through TCRF costs" and cannot

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[417] TIEC Ex. 1 (Pollock Dir.) at 27.

[418] *Id.* at 26.

[419] Project No. 37909, *Rulemaking Proceeding to Amend PUC Subst. R. 25.193, Relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF)*, Order at 7 (Oct. 5, 2010) ("The commission's adoption of the modified proposal allows DSPs to recover, but not over-recover, the additional transmission costs flowed through by TSPs").

[420] *Application of Oncor Electric Delivery Company LLC for Authority to Change Rates,* Docket No. 38929 at 8-9, FoF 39 (Aug. 26, 2011); *see also* Tr. (Abbott Cross) 916:24 – 917:4 (June 26, 2019).

[421] *Application of Texas-New Mexico Power Company for Authority to Change Rates,* Docket No. 38480 at 5, FoF 16 (Jan. 27, 2011); *see also* Tr. (Abbott Cross) 916:24 – 917:4 (June 26, 2019).

[422] *Application of Sharyland Utilities L.P. to Establish Retail Delivery Rates, Approve Tariff for Retail Delivery Service and Adjust Wholesale Transmission Rates,* Docket No. 41474 at 6, FoF 35 (Jan 23, 2014); *see also* Tr. (Abbott Cross) 916:24 – 917:4 (June 26, 2019).

[423] *See Application of AEP Texas, Inc. for Authority to Change Rates*, Docket No. 49494, Petition and Statement of Intent to Change Rates, at 3 (May 1, 2019); *see also id.*, *Direct Testimony of Jennifer L. Jackson* at 20-21, 41.

directly control those costs.[424] In light of this, the Commission adopted a TCRF formula that provides for exact cost recovery of a DSP's actual wholesale transmission costs—no more and no less.[425] Specifically, if a DSP over- or under-recovers its actual wholesale transmission costs through the TCRF during a six-month period, the difference is "trued-up" and customers are issued a refund or surcharge in the DSP's next TCRF filing.[426] In contrast, if wholesale transmission costs are recovered through a DSP's base rates and the DSP over-recovers its actual costs as a result of load growth (increased customer usage), that over-recovery ***is not*** refunded to customers.

As a result, in every rate case filed since the current TCRF rule was adopted, DSPs have removed all wholesale transmission costs from their base rates and recovered them exclusively through the TCRF. Commission Staff has consistently recommended this approach, and it has been consistently adopted. In Docket No. 38480, TNMP similarly proposed to "zero out" its TCRF and recover all of its wholesale transmission charges through the TSC.[427] Staff witness Mr. Lain recommended that TNMP instead recover all of those costs through the TCRF,[428] which was ultimately adopted through a Commission-approved settlement.[429] Mr. Lain explained that his recommendation was based on two clarifications from the Commission on the recovery of transmission costs in adopting the new TCRF rule:

> First, the Commission highlighted the distinction between a DSP's TCRF costs and costs recovered through base rates. The Commission advised that DSPs essentially serve as billing and collection agents for passed-through TCRF costs and, under the Commission's current rules, have no ability to avoid such costs or address and manage the regulatory lag that exists with respect to these costs. Second, ***the Commission underscored that for transmission costs it was concerned about over-recovery***."[430]

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[424] *Rulemaking Proceeding to Amend PUC Subst. Rule § 25.193, Relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF),* Project No. 37909, Order (Oct. 5, 2010).

[425] Project No. 37909, Order at 30 ("the modified proposal as reflected in the adopted rule appropriately allows a DSP to recover-but not over-recover-the passed-through transmission costs that the DSP is charged by TSPs.")

[426] *See* PUC Subst. R. 25.193; *see also* Tr. (Abbott Cr.) at 915:12 – 916:12.

[427] TIEC Ex. 32 (D. 38480 Direct Testimony of Richard Lain Excerpt) at 29.

[428] *Id.*

[429] Docket 38480, Order at 5, FoF 16 (Jan. 27, 2011).

[430] TIEC Ex. 32 (D. 38480 Direct Testimony of Richard Lain Excerpt) at 29-30 (emphasis added).

Mr. Lain testified that if TNMP recovered its transmission costs through the TSC, *i.e.* through base rates, TNMP could over-recover its transmission costs if it experienced load growth.[431] In contrast, he concluded that "if all transmission costs were recovered through the TCRF and additional transmission costs were collected through Rider TCRF . . . the likelihood of an over-recovery of costs is remote."[432]

Similarly, in Sharyland's last rate case, Staff witness Mr. Abbott recommended that Sharyland be required to recover all of its TCOS through the TCRF.[433] As he explained,

> [I]n two recent ERCOT TDU rate cases, the Commission approved the recovery of all of the utility's WTS charges through the TCRF rider, leaving no such costs in a utility's base rates ("full rider recovery"). Such "full rider recovery" helps to reduce the likelihood of over-recovery of WTS charges by the DSP. Inappropriate over-recovery is more likely to occur if a portion of the costs are recovered in base rates and another portion recovered in the TCRF rider. . . . I recommend "full rider recovery" regardless of the methodology approved for base revenue distribution, and have calculated Staff's proposed TCRF rates accordingly.[434]

CEHE's proposal would allow it to over-recover wholesale transmission costs by retaining excess revenues from load growth in base rates—revenue that would be credited back to customers if CEHE recovered its wholesale transmission costs through the TRCF.[435] As Staff witness Bill Abbott confirmed, unlike the TSC charge in base rates, the TCRF "true-up feature" ensures that if CEHE "recovers more or less than they were meant to recover over a given period, it gets trued-up through either a refund or a surcharge" in the next period.[436] The TSC in base rates contain no such true up, and because the TCRF formula does not account for growth in those revenues,[437]

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[431] *Id.* at 30 ("If TNMP experiences load growth, the billing determinants used to set transmission rates collected through base rates would not increase until a subsequent rate proceeding, after the ones currently used to set rates had been approved. Thus, TNMP would over-recover the difference between the higher billing determinants from increased load growth, and the lower billing determinants in base rates, multiplied by the base transmission rates.").

[432] *Id.*

[433] TIEC Ex. 31 (D. 41474 Direct Testimony of William B. Abbott Excerpt) at 20.

[434] *Id.*

[435] TIEC Ex. 1 (Pollock Dir.) at 26.

[436] Tr. (Abbott Cr.) at 915:12-19 (June 26, 2019); *see also* Tr. (Abbott Cross) 915:12 – 916:14 (June 26, 2019).

[437] TIEC Ex. 1 (Pollock Dir.) at 25-26, Exhibit JP-8.

CEHE effectively gets to keep them.[438] Mr. Pollock determine that CEHE incurred $898.7 million in wholesale transmission costs in the test year, but CEHE actually recovered $950.6 million through the combination of the TSC and TCRF, meaning that ***CEHE over-recovered $51.9 million*** during the test year.[439] If CEHE removed all costs from base rates and collected them instead through the TCRF, this over-recovery would be prevented in the future.

Despite Staff's prior position and the consistent treatment for other ERCOT utilities, Staff witness Mr. Abbott suggests that CEHE should be allowed to recover wholesale transmission costs in base rates to mitigate the effects of the allocation flaws in the current TCRF rule. As noted previously, the current TCRF rule causes rate distortions over time because class allocations are held constant, but class billing determinants are updated. This means a growing class will receive a lower and lower TCRF rate between rate cases, as a fixed percentage of costs is spread over a growing number of billing determinants.[440] A growing class will then be exposed to a sudden, potentially dramatic increase in transmission rates when the class allocations are later updated. TIEC agrees that this is a serious problem, as addressed in Mr. Pollock's testimony. However, the correct way to address this problem is by reopening the TCRF rule to update class allocations more regularly—not by intentionally allowing CEHE to over-recover its wholesale transmission costs to keep TCRF rates artificially high. As Mr. Abbott acknowledged at the hearing, allowing CEHE to recover wholesale transmission costs through base rates mitigates the impact of the flawed TCRF rule "by allowing the Company to overrecover its wholesale transmission charges rather than reallocating it among the customer classes."[441]

Intentionally allowing CEHE to over-recover its transmission costs harms ***all customer classes***, benefitting only CEHE, and does not fix the underlying TCRF allocation flaws. As a result, CEHE should be required to remove all wholesale transmission costs from base rates and recover them exclusively through the TCRF, consistent with other utilities in ERCOT.

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438 Tr. (Abbott Cr.) at 916:2-13.

439 TIEC Ex. 1 (Pollock Dir.) at 27.

440 *Id.* at 28-29.

441 Tr. at 922:21-923:3 ("Q: But it [mitigates the mismatch] by allowing the Company to over-recover its wholesale transmission charges rather than reallocating it among the customer classes. Is that correct? A. Yes.").

D. Transmission Service Facility Extensions

The Commission should require CEHE to amend its proposed tariff language related to facilities extensions for transmission voltage customers to ensure that these customers are treated equitably.

Generally, CEHE requires transmission voltage customers to own and operate their own substations,[442] as well as to fund the cost of building any facilities necessary to interconnect those substations via payments called contributions in aid of construction (CIAC).[443] These CIAC, which are often very substantial payments, represent CEHE's ***estimated*** construction costs to interconnect the new customer.[444] At any time after receiving the CIAC, CEHE may revise the estimated amount, and the customer must pay the revised estimate.[445] Also, the customer must pay the CIAC in full prior to beginning construction, and does not have any opportunity to determine the reasonableness of the original cost estimate and/or any subsequent revisions before the construction commences.[446] Given that CEHE is a monopoly service provider, TIEC believes that CEHE's tariff should include explicit provisions addressing the costs that will be required from customers seeking transmission voltage service from CEHE. Those are discussed below.

1. CEHE's tariff should explicitly require CEHE to true up its actual construction costs against the customer's CIAC after the interconnection is complete.

To better ensure that customers only pay for the ***actual*** construction costs of the extension, CEHE's tariff should require it to provide a refund/credit to customers if the actual construction costs are less than the customer's CIAC.[447] In CEHE witness Ms. Sugarek's rebuttal testimony, she explained that after construction is complete on a transmission facilities extension, it is CEHE's general policy to true up its actual construction costs against any CIAC within 30 days, with the customer either receiving a refund or surcharge, as the situation demands.[448] However, she acknowledged that CEHE's draft tariff, which is presented in Mr. Troxle's Exhibit MAT-9,

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[442] CEHE Ex. 33 (Sugarek Reb.) at 23.

[443] *Id.* at Ex. R-JPS-19; CEHE Ex. 30 (Troxle Dir.) at Ex. MAT-9 (CEHE's Annotated Tariff) at 269.

[444] TIEC Ex. 1 (Pollock Dir.) at 37; CEHE Ex. 30 (Troxle Dir.) at Ex. MAT-9 (CEHE's Annotated Tariff) at 270.

[445] TIEC Ex. 1 (Pollock Dir.) at 37–38.

[446] *Id.* at 38.

[447] *Id.*

[448] CEHE Ex. 33 (Sugarek Reb.) at 24.

does not include language that ***requires*** CEHE to abide by those general practices.[449] Instead, there is a placeholder in the form Facilities Extension Agreement for Transmission Voltage Facilities that leaves room for negotiated payment language.[450] On cross-examination, Ms. Sugarek indicated that CEHE would not be opposed to including language in its tariff that would obligate CEHE to true up its actual construction costs against the customer's CIAC after every transmission voltage facilities extension.

2. CEHE's tariff should explicitly require CEHE to exclude "System Improvement Costs" from the CIAC it charges to customers seeking interconnection.

The Commission should also require CEHE to formalize its practice of excluding "System Improvement Costs" from transmission voltage customers' CIAC amounts. As Ms. Sugarek explained, CEHE's CIAC amounts generally exclude "System Improvement Costs," which are the portion (if any) of the facility being constructed that CEHE believes the Commission will allow it to put into rates.[451] This practice is reasonable and equitable because it prevents CEHE from recovering the same costs twice. Again, this practice is not required by CEHE's tariff, and the Commission should require CEHE to add language formalizing its stated practice.

3. CEHE's tariff should require CEHE to refund a portion of a transmission customer's CIAC if the facilities constructed with that CIAC are later used to serve other customers.

In many cases, interconnection facilities that are initially funded by and constructed to serve a single transmission-voltage customer are later used to serve additional customers. While there is generally nothing wrong with CEHE efficiently using available facilities to provide electrical service to new customers, this situation is inequitable to the original customer who fully funded the facilities, and can create a "first mover" penalty in growing industrial areas. This issue is not addressed in CEHE's tariff or its form facilities extension agreement.

At least one other Texas utility has adopted line extension policies that deal with this situation. Entergy Texas, Inc.'s (ETI's) tariff specifically contemplates a situation where a customer funds a transmission extension and that extension is then used to serve additional large commercial or industrial customers within a four-year period. In that situation, the customer that

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[449] Tr. (Sugarek Cr.) at 1230:4 – 1231:10 (June 27, 2019); CEHE Ex. 30 (Troxle Dir.) at Ex. Mat-9, p. 273.

[450] Tr. (Sugarek Cr.) at 1228:7–24 (June 27, 2019).

[451] Tr. (Sugarek Cr.) at 1235:4-13. (June 27, 2019).

funded the interconnection is "entitled to receive a prorated refund of the [payment] for the common facilities..."[452] In practice, the new customers requesting interconnection through the facility are required to make an up-front payment representing a portion of the original cost of the facilities, and that amount is then refunded to the customer that provided the initial project funding as a partial offset to its CIAC.[453]

TIEC believes that the Commission should require CEHE to adopt similar language in its tariff because no customer should have to subsidize facilities that are used to serve others.

4. TIEC has drafted revised tariff language to accomplish the objectives described above.

Based on Ms. Sugarek's Exhibit R-JPS-19, which is the actual negotiated language from a transmission voltage facilities extension agreement,[454] TIEC has drafted a revised version of CEHE's form Facilities Extension Agreement for Transmission Voltage Facilities that would accomplish the three objectives described above.

Additionally, in CEHE's tariff in Section 6.1.2.2, subsection 2.1 under "costs" TIEC proposes deleting the word "nonrefundable" so that the sentence reads "In those exception cases, Retail Customer must execute an appropriate agreement in the form set out in Section 6.3 of this Tariff and pay a CIAC to Company prior to commencement of any Construction Services..."[455] This change will prevent any confusion with respect to whether a later true-up is allowed.

TIEC is open to discussing further revisions of CEHE's draft tariff language with CEHE as this proceeding progresses, with the hope of arriving at mutually agreeable language.

E. Street Lighting Service

F. Other Rate Design Issues

IX. Riders [PO Issues 4, 5, 43, 51, 52]

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[452] TIEC Ex. 1 (Pollock Dir.) at 38 (citing Entergy Texas, Inc., Section IV Rules and Regulations, Sheet No. 18B, Extension Policy (Eff. Date Oct. 17, 2018).

[453] TIEC Ex. 1 (Pollock Dir.) at 38–39.

[454] Tr. (Sugarek Cr.) at 1228: 21-24 (June 27, 2019).

[455] CEHE Ex. 30 (Troxle Dir.) at Ex. Mat-9 (Annotated Tariff), p. 271. Ms. Sugarek agreed on cross examination that CEHE's form extension agreement and its extension policies should be uniform, and indicated that in principle, CEHE was not opposed to clarifying that in some circumstances (like a post-construction true-up) CIAC amounts can be refunded. Tr. (Sugarek Cr.) at 1231: 4-10 (June 27, 2019).

A. Rider UEDIT [PO Issue 51]

As discussed previously, ratepayers make payments in anticipate of a utility's future tax liability, created an Accumulated Deferred Federal income Tax (ADFIT) balance. This occurs primarily because utilities generally depreciate their assets on different schedules for income tax and ratemaking purposes, which allows them to collect a large portion of their prospective federal income taxes in rates before those taxes actually become due. Utilities' ADFIT balances essentially function as a long-term, interest free loan from ratepayers.[456]

When the TCJA lowered the federal corporate income tax rate from 35% to 21%, it created an excess deferred income tax (EDIT) balance for CEHE and other utilities, since customers had previously funded anticipated tax liabilities at the 35% rate that would now never be owed.[457] As of January 1, 2018, the Commission ordered CEHE (among other utilities) to record its EDIT as a regulatory liability in anticipation of promptly returning it to ratepayers.[458] The TCJA deems certain EDIT related to the depreciation of poles and wires assets to be "protected EDIT," and requires that those amounts be returned to ratepayers over the remaining life of the associated assets using a method called the "average rate assumption method" (ARAM).[459] The remaining portion of CEHE's ADIT is referred to as "unprotected EDIT," and can be refunded to customers over any period deemed reasonable by the Commission.[460]

CEHE's proposed Rider UEDIT would refund its entire unprotected EDIT balance, as well as the first year of protected EDIT, over the next three years.[461] However, as discussed below, customers should not have to wait three more years to recover EDIT funds to which CEHE no longer has any legitimate claim. Rather than allowing CEHE to refund those amounts over three years, the Commission should require it to return its entire UEDIT balance over the next two years, and the first year of protected EDIT (which has already been amortized using ARAM) over a single year.

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[456] TIEC Ex. 3 (LaConte Dir.) at 4.

[457] *Id.*

[458] *Id.* at 3; *Proceeding to Investigate and Address the Effects of Tax Cuts And Jobs Act of 2017 on the Rates of Texas Investor-Owned Utility Companies*, Project No. 47945, Order Related to Changes in Federal Income Tax Rates at 2–3 (Jan. 25, 2018).

[459] TIEC Ex. 3 (LaConte Dir.) at 6.

[460] *Id.* at 7.

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

1. Unprotected EDIT should be returned to customers over the next two years.

As discussed in Ms. LaConte's testimony, it would also be inequitable for CEHE to spread the return of its unprotected EDIT over the course of the next three years, which would mean that CEHE would still be refunding UEDIT amounts ***five years*** after the passage of the TCJA. CEHE witness Ms. Colvin asserted that a three-year amortization period is equitable to both CEHE and its customers, but provided no reasoning for her claim.[462] Many other utilities have refunded their unprotected EDIT balances to their retail customers over a much shorter time period.[463] For example, Entergy Arkansas, Inc. refunded $466 million of unprotected EDIT over a period ranging from 7 to 21 months.[464] Similarly, Gulf Power Company refunded $69 million of unprotected EDIT during 2018.[465]

Returning unprotected EDIT amounts over a shorter period is also consistent with the intent behind the TCJA. One of the primary objectives of the TCJA was to put money back into customers' pockets and encourage new investment.[466] Because the majority of CEHE's EDIT is protected, customers will have to wait decades until they receive the last of the EDIT that ***they funded in the first place***.[467] And the longer it takes for CEHE to return its EDIT balance, the less likely that CEHE will be returning that money to the customers who paid it initially.[468] With each passing year, CEHE will acquire new customers who will receive credit for EDIT amounts they had no part in funding, and some of CEHE's customers will leave, and never fully recover amounts they paid CEHE to cover tax payments that, now, will never occur. Therefore, from an equity standpoint, it makes sense to at least require CEHE to refund the entirety of the unprotected EDIT balance as quickly as possible.[469] The Commission should find that a two-year amortization period is appropriate.

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[462] CEHE Ex. 35 (Colvin Reb.) at 62.

[463] TIEC Ex. 3 (LaConte Dir.) at 8.

[464] *Id.*; *see also In the Matter of the Application of Entergy Arkansas, Inc. for a Proposed Tariff Revision Regarding the Request for Approval of a Tax Adjustment Rider to Provide Tax Benefits to its Retail Customers,* Docket No. 10-014-TF, Order No. 2 at 3 (Mar 27, 2018).

[465] TIEC Ex. 3 (LaConte Dir.) at 8–9; *see also In re: Consideration of the Stipulation and Settlement Agreement between Gulf Power Company, the Office of Public Counsel, Florida Industrial Power Users Group, and Southern Alliance for Clean Energy regarding the Tax Cuts and Jobs Act of 2017*, Docket No. 20180039-EI, Final Order Approving Joint Motion to Approve Stipulation and Settlement Agreement at 2 (Apr. 12, 2018).

[466] *Id.*

[467] *Id.*

[468] *Id.*

[469] *Id.*

2. The $18.7 million in protected EDIT that has already been amortized under ARAM should be returned to customers over one year.

CEHE is also holding $18.7 million in EDIT that has already been amortized from its protected EDIT balance under the ARAM method.[470] CEHE's proposal to return this amount to ratepayers over the next three years under its proposed Rider UEDIT is inequitable because those amounts are already due to ratepayers. As Ms. Colvin admitted on cross-examination, the protected EDIT amount that is amortized next year will all be returned to the ratepayers over the course of a single year.[471] There is no reason to treat the first year of protected EDIT differently, and especially not in a way that unduly benefits CEHE at its customers' further expense. CEHE made no attempt to justify its disparate treatment of the first year of protected EDIT in its rebuttal testimony. Accordingly, the Commission should order CEHE to return the $18.7 million in protected EDIT that has already been amortized to customers over one year, which is consistent with the requirements of the ARAM method.

B. Merger Savings Rider

C. Other Riders

X. Baselines for Cost-Recovery Factors [PO Issue 4, 5, 43, 53]

A. Transmission Cost of Service

B. Transmission Cost Recovery Factor

XI. Other Issues [including but not limited to PO Issues 13, 14, 20, 30, 31, 32, 40, 41, 42, 47, 48, 57, 58, 59]

A. Contested Issues

B. Uncontested Issues

XII. Conclusion

The Commission should reject CEHE's unreasonable and unjustified rate request. Rather than increasing CEHE's equity level and ROE, which is unnecessary and would solely benefit CEHE's parent company, the Commission should implement reasonable ring fencing conditions to financially separate CEHE from its parent, and adopt TIEC witness Mr. Gorman's recommended 40% equity ratio and a 9.25% ROE. As described above, these changes would save

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[470] *Id.* at 7.

[471] *Id.* at 1273:13–1274:4 (June 28, 2019).

ratepayers ***$104.1 million per year*** while ensuring that CEHE retains access to capital at reasonable rates.[472]

In addition to establishing a more reasonable ROE and capital structure and adopting appropriate ring-fencing, the Commission should:

- Continue to allocate wholesale transmission costs to CEHE's retail classes using the ERCOT 4CP, in line with decades of Commission precedent.[473]
- Prevent CEHE from over-recovering its wholesale transmission costs by requiring it to remove those costs from its base rates and recover them exclusively through the TCRF,[474] as has been done for Oncor,[475] TNMP,[476] and Sharyland,[477] and as AEP is proposing in its pending rate case.[478]
- Refine CEHE's proposed allocation of municipal franchise fee (MFF) expense to reflect each class's (a) in-city kWh deliveries, and (b) the specific MFF rates where that delivery occurs.[479]
- Require CEHE to revise its proposed tariff to (1) ensure that CEHE will true up the cost of constructing transmission voltage facilities extensions against the contributions in aid of construction (CIAC) provided by customers and (2) ensure that transmission voltage customers will receive a credit if the facilities for which they paid a CIAC are later used to serve other customers.[480]
- Require CEHE to functionalize its Texas Margins Tax expense as suggested by Commission Staff witness Brian Murphy in order to ensure that CEHE does not uplift costs associated with serving its retail customers to TCOS.[481]
- Require CEHE to return to ratepayers all excess deferred income taxes (EDIT) related to its securitized transition and system restoration bonds (as recommended by GCCC witness

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[472] TIEC Ex. 5 (Gorman Dir.) at 37 and Ex. MPG-6.

[473] *See* Section VII.B.1.

[474] *See* Section VIII.C.

[475] *Application of Oncor Electric Delivery Company LLC for Authority to Change Rates,* Docket No. 38929 at 8-9, FoF 39 (Aug. 26, 2011); *see also* Tr. (Abbott Cross) 916:24 – 917:4 (June 26, 2019).

[476] *Application of Texas-New Mexico Power Company for Authority to Change Rates,* Docket No. 38480 at 5, FoF 16 (Jan. 27, 2011); *see also* Tr. (Abbott Cross) 916:24 – 917:4 (June 26, 2019).

[477] *Application of Sharyland Utilities L.P. to Establish Retail Delivery Rates, Approve Tariff for Retail Delivery Service and Adjust Wholesale Transmission Rates,* Docket No. 41474 at 6, FoF 35 (Jan 23, 2014); *see also* Tr. (Abbott Cross) 916:24 – 917:4 (June 26, 2019).

[478] *See Application of AEP Texas, Inc. for Authority to Change Rates*, Docket No. 49494, Petition and Statement of Intent to Change Rates, at 3 (May 1, 2019); *see also id., Direct Testimony of Jennifer L. Jackson* at 20-21, 41.

[479] *See* Section VII.B.2.

[480] *See* Section VIII.D.

[481] *See* Section VII.A.1.

Lane Kollen) or, in the alternative, open a separate proceeding to address the treatment of those amounts (as recommended by Commission Staff witness Darryl Tietjen).[482]

- Disallow all of CEHE's incentive compensation expenses related to financially-based goals, which amounts to 69% of CEHE's short-term incentive compensation costs and 100% of its long-term incentive compensation costs.[483]
- Require CEHE to return its entire unprotected excess deferred income tax (UEDIT) balance to customers through Rider UEDIT over the course of two years, and the $18.7 million of protected EDIT that CEHE proposes to return through that rider over the course of one year.[484]
- Reject OPUC witness Nalepa's baseless proposal to directly assign one-third of the expenses of CEHE's Transmission and Key Accounts Department ($678,154) to the transmission class.[485]

For these reasons, the Commission should reject CEHE's requested rate increase, and set its rates consistent with TIEC's recommendations, as discussed above.

Respectfully submitted,

THOMPSON & KNIGHT LLP

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ATTORNEYS FOR TEXAS INDUSTRIAL ENERGY CONSUMERS

[482] *See* Section II.D.

[483] *See* Section IV.B.1.

[484] *See* Section IX.A.

[485] *See* Section VII.B.3

CERTIFICATE OF SERVICE

I, Diane Tran, Attorney for TIEC, hereby certify that a copy of the foregoing document was served on all parties of record in this proceeding on this 9th day of July, 2019 by hand-delivery, facsimile, electronic mail and/or First Class, U.S. Mail, Postage Prepaid.

Diane Tran w/permission

Diane Tran

ATTACHMENT A

6.3.1.2 FACILITIES EXTENSION AGREEMENT FOR TRANSMISSION VOLTAGE FACILITIES (RETAIL CUSTOMER-OWNED SUBSTATION)

This Transmission Facility Extension Agreement (this "**Agreement**") is between CenterPoint Energy Houston Electric, LLC ("**Company**") and [INSERT COUNTERPARTY'S NAME] ("**Customer**") and is dated as of [INSERT DATE]. Company and Customer may be referred to herein individually as a "**Party**" or collectively as the "**Parties**".

Company is a public utility that owns and operates facilities for the transmission and distribution of electricity and offers electricity delivery services to retail customers at 60,000 volts or higher ("**Transmission Service**") from its high-voltage transmission system (the "**Transmission System**") pursuant to its Tariff for Retail Delivery Service (as amended from time to time, the "**Tariff**") approved by the Public Utility Commission of Texas (the "**PUCT**").

Customer (i) requires Transmission Service to operate its commercial plant located at [INSERT CUSTOMER'S PLANT LOCATION] (the "**Customer Plant**"), (ii) is willing to install, own and maintain an electric substation (the "**Customer Substation**") for the purpose of receiving Transmission Service to serve the Customer Plant, and (iii) desires that Company provide Construction Services to modify, upgrade and extend the Transmission System as needed to enable the provision of such Transmission Service.

Company is willing to provide such Construction Services in accordance with the terms and conditions set forth below.

Therefore, Company and Customer agree as follows:

1. Defined Terms. All capitalized terms used but not defined in this Agreement have the respective meanings given to them in the Tariff.

2. Customer Representations. Customer represents and warrants to Company that (i) the Customer Plant is expected to consume approximately [INSERT DEMAND] megawatts of electricity (the "**Demand Level**") and (ii) the Customer Plant and Customer Substation will be ready to receive Transmission Service on [INSERT DATE] or such other date as the Parties may subsequently agree (the "**Requested Service Date**").

3. Customer Substation.

(a) Substation Construction. Customer shall design and construct the Customer Substation in strict accordance with the Tariff and with Company's "Specification for Customer-Owned 138 kV Substation Design" and "Specification for Remote Telemetry of a Customer Owned Facility" (together, as may be amended from time to time, the "**Specifications**"). Customer hereby acknowledges that it has received a copy of the Specifications in effect as of the date hereof. Company may amend the Specifications at any time after the date of this Agreement consistent with Good Utility Practice, and Customer agrees that any such amended Specifications will become effective hereunder upon Customer's receipt of notice thereof from Company pursuant to Section 11 hereof.

(b) Substation Operation. At all times during its operation and maintenance of the Customer Substation, Customer agrees to be strictly bound by the Tariff, including the Power Factor requirements, and the Company's "Transmission & Substation Outage and Clearance Coordination Procedures" (as may be amended from time to time, the "**Procedures**"). Customer hereby acknowledges that it has received a copy of the Procedures in effect as of the date hereof. Company may amend the Procedures at any time after the date of this Agreement consistent with Good Utility Practice, and Customer agrees that any such amended Procedures will become effective hereunder upon Customer's receipt of notice thereof from Company pursuant to Section 11 hereof. If, at any time following the completion of the Project (as defined below), Customer fails or is unable, in the sole determination of Company, to operate and maintain the Customer Substation in conformance with the Tariff, the Specifications, or the Procedures, and, in Company's sole discretion, such failure or inability jeopardizes the reliability of the Transmission System or violates any North American Electric Reliability Corporation ("**NERC**") standards, (i) Company may immediately and without recourse disconnect the Customer Substation from the Transmission System and take such other actions that Company deems necessary in accordance with Good Utility Practice to maintain the reliability of the Transmission System, and (ii) Customer shall reimburse Company for the cost of such actions taken by Company.

4. Construction Services Obligation. Subject to the Tariff and any applicable PUCT rules (as amended from time to time), Company shall use Good Utility Practice to provide Construction Services sufficient to connect the Transmission System to the Customer Substation and enable the commencement of Transmission Service to the Customer Substation at the Demand Level by the Requested Service Date (the "**Project**"). Notwithstanding anything to the contrary herein, Company's obligation to commence or complete the Project is contingent upon the validity of each of the following assumptions (collectively, the "**Construction Services Conditions**"):

(a) The Project is approved by the PUCT or is otherwise in accord with the rules and requirements of the PUCT and the Electric Reliability Council of Texas ("**ERCOT**") applicable to transmission construction projects.

(b) Company receives correct and timely payment for all amounts charged to Customer in accordance with this Agreement, including receipt of payment for any Initial CIAC Estimate and Additional Amounts (as defined below) invoiced by Company.

(c) Customer's design and construction of the Customer Substation is in accordance with the applicable requirements of the Tariff, Specifications and Procedures.

(d) Customer has granted Access Rights (as hereinafter defined) to Customer's land and the Customer Substation at no cost to Company and in the form acceptable to Company. If third party Access Rights are required, Customer has acquired and provided to Company, at Customer's sole cost and expense, any and all such Access Rights at least forty-five (45) days prior to the commencement of the Construction Services.

(e) To the extent outages are necessitated by the Construction Services, such outages have received timely prior approval from ERCOT.

5. Payment for Construction Services. Customer shall pay Company for the provision of the Construction Services by Company in accordance with the terms in this Section 5.

(a) Customer shall pay Company the Actual Facilities Extension Cost as a contribution in aid of construction. As of the date of this Agreement, the Actual Facilities Extension Cost is estimated to be $ (the "**Initial CIAC Estimate**"). The term "**Actual Facilities Extension Cost**" means the Actual Cost less the System Improvement Cost. The term "**Actual Cost**" means the sum of (i) all costs actually incurred for the design, modification, upgrade, procurement, construction, installation, removal, project management and commissioning of any Transmission System facilities and equipment provided by Company for the Project, including all such costs attributable to any Customer Scope Changes, plus (ii) any overhead costs, general and administrative fees, plus (iii) any applicable tax gross up respecting the foregoing, plus (iv) in the event this Agreement is terminated prior to completion of the Project, any costs that Company incurs from third parties as a consequence of the cancellation of any purchases or rentals of necessary equipment, materials or work to construct the Project that Company does not reasonably expect to recover through its Tariff. The term "**System Improvement Cost**" means the portion, if any, of the Actual Cost that, in Company's sole judgment in accordance with Good Utility Practice, would be deemed by the PUCT to be necessary and reasonable costs for the overall Transmission System and recoverable by Company through the Transmission Service rates approved for Company by the PUCT.

(b) Company will invoice Customer for the Initial CIAC Estimate following Customer's execution and delivery of this Agreement to Company, and Customer shall pay the Initial CIAC Estimate to Company in accordance with the terms therein.

(i) Customer acknowledges and agrees that Company may increase the Initial CIAC Estimate pursuant to Good Utility Practice at any time after the date of this Agreement as new information becomes known or if changes by Company or Customer are made to the scope or design of the Project, including Customer Scope Changes accepted by Company. Company will issue an invoice to Customer for the amount of such increase (the "**Additional Amount**"), and Customer shall pay the Additional Amount to Company in accordance with the terms therein.

~~(i)~~(ii) After completion of the Project or termination of this Agreement pursuant to Section 10 hereof, whichever occurs first, (the "**Completion Date**"), the difference between (i) the Actual Facilities Extension Cost as of the Completion Date and (ii) the sum of the Initial CIAC Estimate paid by Customer plus any Additional Amounts paid by Customer (that sum, the "**Project Payments**"), shall be paid to (x) Customer if the Actual Facilities Extension Cost is less than the Project Payments, or (y) Company if the Actual Facilities Extension Cost is greater than the Project Payments. Company shall issue a refund or invoice for that difference, as the case may be, within 30 days after the Completion Date, and Customer shall pay any such invoice in accordance with the terms therein.

(c) If at any time within four years following the Completion Date, the Company uses any of the facilities paid for by the Customer to serve other loads, the Company shall refund an amount of the Project Payments (grossed up for income taxes at the rate used in calculating the Project Payments) that reflects the Customer's share of the total loads to be served from the facilities.

(d) [INSERT NEGOTIATED LANGUAGE REGARDING PAYMENT OF CIAC IN LUMP SUM OR USE OF PAYMENT PLAN]

6. Audit Rights. Customer may, at its expense and during normal business hours, audit the books and records of Company to verify the Actual Costs incurred by Company on the Project. Such audit rights shall expire one (1) year after the Completion Date. However, in the event that the provisions of Section 5(c) become applicable, Customer may conduct an additional audit to verify the appropriateness of any refund of prior Project Payments.

7. Ownership and Responsibilities. Company shall at all times own and maintain the Transmission System in accordance with Good Utility Practice, the Tariff and the PUCT's rules. Except for Transmission System equipment inside the Customer Substation that is installed and owned by Company, Customer shall own and maintain the Customer Substation in accordance with Section 3 of this Agreement. Customer acknowledges and agrees that Company has no obligations with respect to the maintenance of the Customer-owned equipment inside the Customer Substation or

the connections between the Customer Substation and the Customer Plant. Company will be solely responsible for ensuring compliance with the NERC Critical Infrastructure Protection ("CIP") standards, including the physical access requirements, for equipment owned by Company inside the Customer Substation. Customer will be solely responsible for ensuring compliance with the NERC CIP standards, including the physical access requirements, for equipment owned by Customer inside the Customer Substation.

8. Access Rights. Customer hereby grants Company, at no cost to Company, access rights to Customer's property as reasonable and necessary to install, test and maintain the Transmission System facilities to serve the Customer Substation, and in and to the Customer Substation to install and maintain Transmission System equipment at and within the Customer Substation. If requested by Company, such access rights shall also be granted to Company in the form of a separate written easement or other right-of-way conveyance form acceptable to Company. To the extent any portion of the Construction Services will take place on or require the use of private property owned by a third party, Customer and Company will cooperate in good faith to obtain the property rights from such third party reasonably necessary for Company to perform such Construction Services and to install, own and maintain the Transmission System facilities and equipment needed for the Project on such property. All such access and property rights are herein referred to collectively as "**Access Rights**." Customer shall pay for all reasonably necessary Access Rights.

9. Incorporation of Tariff. The Tariff is incorporated into this Agreement, including without limitation Sections 5.2.1 (limitation of liability), 5.2.4 (force majeure), and 5.2.6 (disclaimer of warranties) thereof. In the event of any conflict between the terms of this Agreement and the terms of the Tariff, the terms of the Tariff shall prevail.

10. Termination. This Agreement will remain in effect until all obligations hereunder are performed or otherwise discharged, except (a) Customer may terminate this Agreement at any time by giving notice thereof to Company, and (b) Company may terminate this Agreement immediately by giving notice thereof to Customer if Customer fails to perform any obligation hereunder by the due date for such performance. The payment obligations in this Agreement shall survive this Agreement's termination until performed.

11. Notice. Any notice to be given by a Party upon another Party in connection with this Agreement must be in writing and shall be sent to such other Party at its delivery address for notice set forth below by (i) regular U.S. mail, private delivery service or recognized overnight courier, or (ii) facsimile or email transmission of a portable document format (PDF).

Delivery address
for notice to Customer:

XXXXXX
Attention: XXXXXXX
XXXXXXXXXX
XXXXXXXXXX
Telephone No: XXXXXXXXXXX
FAX No.: XXXXXXXXXXX
Email: XXXXXXX@XXX

Delivery address
for notice to Company:

CenterPoint Energy Houston Electric
Attention: XXXXXXX
XXXXXXXXX
Houston, TX XXXXX
Telephone No.: XXXXXXXXX
FAX No.: XXXXX

ATTACHMENT A

6.3.1.2 FACILITIES EXTENSION AGREEMENT FOR TRANSMISSION VOLTAGE FACILITIES (RETAIL CUSTOMER-OWNED SUBSTATION)

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Customer (i) requires Transmission Service to operate its commercial plant located at [INSERT CUSTOMER'S PLANT LOCATION] (the "**Customer Plant**"), (ii) is willing to install, own and maintain an electric substation (the "**Customer Substation**") for the purpose of receiving Transmission Service to serve the Customer Plant, and (iii) desires that Company provide Construction Services to modify, upgrade and extend the Transmission System as needed to enable the provision of such Transmission Service.

Company is willing to provide such Construction Services in accordance with the terms and conditions set forth below.

Therefore, Company and Customer agree as follows:

1. Defined Terms. All capitalized terms used but not defined in this Agreement have the respective meanings given to them in the Tariff.

2. Customer Representations. Customer represents and warrants to Company that (i) the Customer Plant is expected to consume approximately [INSERT DEMAND] megawatts of electricity (the "**Demand Level**") and (ii) the Customer Plant and Customer Substation will be ready to receive Transmission Service on [INSERT DATE] or such other date as the Parties may subsequently agree (the "**Requested Service Date**").

3. Customer Substation.

(a) Substation Construction. Customer shall design and construct the Customer Substation in strict accordance with the Tariff and with Company's "Specification for Customer-Owned 138 kV Substation Design" and "Specification for Remote Telemetry of a Customer Owned Facility" (together, as may be amended from time to time, the "**Specifications**"). Customer hereby acknowledges that it has received a copy of the Specifications in effect as of the date hereof. Company may amend the Specifications at any time after the date of this Agreement consistent with Good Utility Practice, and Customer agrees that any such amended Specifications will become effective hereunder upon Customer's receipt of notice thereof from Company pursuant to Section 11 hereof.

(b) Substation Operation. At all times during its operation and maintenance of the Customer Substation, Customer agrees to be strictly bound by the Tariff, including the Power Factor requirements, and the Company's "Transmission & Substation Outage and Clearance Coordination Procedures" (as may be amended from time to time, the "**Procedures**"). Customer hereby acknowledges that it has received a copy of the Procedures in effect as of the date hereof. Company may amend the Procedures at any time after the date of this Agreement consistent with Good Utility Practice, and Customer agrees that any such amended Procedures will become effective hereunder upon Customer's receipt of notice thereof from Company pursuant to Section 11 hereof. If, at any time following the completion of the Project (as defined below), Customer fails or is unable, in the sole determination of Company, to operate and maintain the Customer Substation in conformance with the Tariff, the Specifications, or the Procedures, and, in Company's sole discretion, such failure or inability jeopardizes the reliability of the Transmission System or violates any North American Electric Reliability Corporation ("**NERC**") standards, (i) Company may immediately and without recourse disconnect the Customer Substation from the Transmission System and take such other actions that Company deems necessary in accordance with Good Utility Practice to maintain the reliability of the Transmission System, and (ii) Customer shall reimburse Company for the cost of such actions taken by Company.

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(a) The Project is approved by the PUCT or is otherwise in accord with the rules and requirements of the PUCT and the Electric Reliability Council of Texas ("**ERCOT**") applicable to transmission construction projects.

(b) Company receives correct and timely payment for all amounts charged to Customer in accordance with this Agreement, including receipt of payment for any Initial CIAC Estimate and Additional Amounts (as defined below) invoiced by Company.

(c) Customer's design and construction of the Customer Substation is in accordance with the applicable requirements of the Tariff, Specifications and Procedures.

(d) Customer has granted Access Rights (as hereinafter defined) to Customer's land and the Customer Substation at no cost to Company and in the form acceptable to Company. If third party Access Rights are required, Customer has acquired and provided to Company, at Customer's sole cost and expense, any and all such Access Rights at least forty-five (45) days prior to the commencement of the Construction Services.

(e) To the extent outages are necessitated by the Construction Services, such outages have received timely prior approval from ERCOT.

5. Payment for Construction Services. Customer shall pay Company for the provision of the Construction Services by Company in accordance with the terms in this Section 5.

(a) Customer shall pay Company the Actual Facilities Extension Cost as a contribution in aid of construction. As of the date of this Agreement, the Actual Facilities Extension Cost is estimated to be $ (the "**Initial CIAC Estimate**"). The term "**Actual Facilities Extension Cost**" means the Actual Cost less the System Improvement Cost. The term "**Actual Cost**" means the sum of (i) all costs actually incurred for the design, modification, upgrade, procurement, construction, installation, removal, project management and commissioning of any Transmission System facilities and equipment provided by Company for the Project, including all such costs attributable to any Customer Scope Changes, plus (ii) any overhead costs, general and administrative fees, plus (iii) any applicable tax gross up respecting the foregoing, plus (iv) in the event this Agreement is terminated prior to completion of the Project, any costs that Company incurs from third parties as a consequence of the cancellation of any purchases or rentals of necessary equipment, materials or work to construct the Project that Company does not reasonably expect to recover through its Tariff. The term "**System Improvement Cost**" means the portion, if any, of the Actual Cost that, in Company's sole judgment in accordance with Good Utility Practice, would be deemed by the PUCT to be necessary and reasonable costs for the overall Transmission System and recoverable by Company through the Transmission Service rates approved for Company by the PUCT.

(b) Company will invoice Customer for the Initial CIAC Estimate following Customer's execution and delivery of this Agreement to Company, and Customer shall pay the Initial CIAC Estimate to Company in accordance with the terms therein.

(i) Customer acknowledges and agrees that Company may increase the Initial CIAC Estimate pursuant to Good Utility Practice at any time after the date of this Agreement as new information becomes known or if changes by Company or Customer are made to the scope or design of the Project, including Customer Scope Changes accepted by Company. Company will issue an invoice to Customer for the amount of such increase (the "**Additional Amount**"), and Customer shall pay the Additional Amount to Company in accordance with the terms therein.

~~(i)~~(ii) After completion of the Project or termination of this Agreement pursuant to Section 10 hereof, whichever occurs first, (the "**Completion Date**"), the difference between (i) the Actual Facilities Extension Cost as of the Completion Date and (ii) the sum of the Initial CIAC Estimate paid by Customer plus any Additional Amounts paid by Customer (that sum, the "**Project Payments**"), shall be paid to (x) Customer if the Actual Facilities Extension Cost is less than the Project Payments, or (y) Company if the Actual Facilities Extension Cost is greater than the Project Payments. Company shall issue a refund or invoice for that difference, as the case may be, within 30 days after the Completion Date, and Customer shall pay any such invoice in accordance with the terms therein.

(c) If at any time within four years following the Completion Date, the Company uses any of the facilities paid for by the Customer to serve other loads, the Company shall refund an amount of the Project Payments (grossed up for income taxes at the rate used in calculating the Project Payments) that reflects the Customer's share of the total loads to be served from the facilities.

(d) [INSERT NEGOTIATED LANGUAGE REGARDING PAYMENT OF CIAC IN LUMP SUM OR USE OF PAYMENT PLAN]

6. Audit Rights. Customer may, at its expense and during normal business hours, audit the books and records of Company to verify the Actual Costs incurred by Company on the Project. Such audit rights shall expire one (1) year after the Completion Date. However, in the event that the provisions of Section 5(c) become applicable, Customer may conduct an additional audit to verify the appropriateness of any refund of prior Project Payments.

7. Ownership and Responsibilities. Company shall at all times own and maintain the Transmission System in accordance with Good Utility Practice, the Tariff and the PUCT's rules. Except for Transmission System equipment inside the Customer Substation that is installed and owned by Company, Customer shall own and maintain the Customer Substation in accordance with Section 3 of this Agreement. Customer acknowledges and agrees that Company has no obligations with respect to the maintenance of the Customer-owned equipment inside the Customer Substation or

the connections between the Customer Substation and the Customer Plant. Company will be solely responsible for ensuring compliance with the NERC Critical Infrastructure Protection ("CIP") standards, including the physical access requirements, for equipment owned by Company inside the Customer Substation. Customer will be solely responsible for ensuring compliance with the NERC CIP standards, including the physical access requirements, for equipment owned by Customer inside the Customer Substation.

8. Access Rights. Customer hereby grants Company, at no cost to Company, access rights to Customer's property as reasonable and necessary to install, test and maintain the Transmission System facilities to serve the Customer Substation, and in and to the Customer Substation to install and maintain Transmission System equipment at and within the Customer Substation. If requested by Company, such access rights shall also be granted to Company in the form of a separate written easement or other right-of-way conveyance form acceptable to Company. To the extent any portion of the Construction Services will take place on or require the use of private property owned by a third party, Customer and Company will cooperate in good faith to obtain the property rights from such third party reasonably necessary for Company to perform such Construction Services and to install, own and maintain the Transmission System facilities and equipment needed for the Project on such property. All such access and property rights are herein referred to collectively as "**Access Rights**." Customer shall pay for all reasonably necessary Access Rights.

9. Incorporation of Tariff. The Tariff is incorporated into this Agreement, including without limitation Sections 5.2.1 (limitation of liability), 5.2.4 (force majeure), and 5.2.6 (disclaimer of warranties) thereof. In the event of any conflict between the terms of this Agreement and the terms of the Tariff, the terms of the Tariff shall prevail.

10. Termination. This Agreement will remain in effect until all obligations hereunder are performed or otherwise discharged, except (a) Customer may terminate this Agreement at any time by giving notice thereof to Company, and (b) Company may terminate this Agreement immediately by giving notice thereof to Customer if Customer fails to perform any obligation hereunder by the due date for such performance. The payment obligations in this Agreement shall survive this Agreement's termination until performed.

11. Notice. Any notice to be given by a Party upon another Party in connection with this Agreement must be in writing and shall be sent to such other Party at its delivery address for notice set forth below by (i) regular U.S. mail, private delivery service or recognized overnight courier, or (ii) facsimile or email transmission of a portable document format (PDF).

Delivery address for notice to Customer:	XXXXXX Attention: XXXXXXX XXXXXXXXXX XXXXXXXXXX Telephone No: XXXXXXXXXXX FAX No.: XXXXXXXXXXX Email: XXXXXXX@XXX
Delivery address for notice to Company:	CenterPoint Energy Houston Electric Attention: XXXXXXX XXXXXXXXX Houston, TX XXXXX Telephone No.: XXXXXXXXX FAX No.: XXXXX