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**SOAH DOCKET NO. 473-19-3864**
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| **APPLICATION OF CENTERPOINT** | § | **BEFORE THE STATE OFFICE** |
| **ENERGY HOUSTON ELECTRIC,** | § | |
| **LLC FOR AUTHORITY TO CHANGE** | § | **OF** |
| **RATES** | § | |
| | § | **ADMINISTRATIVE HEARINGS** |
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# COMMISSION STAFF'S REPLY BRIEF

Respectfully Submitted,

**PUBLIC UTILITY COMMISSION OF TEXAS LEGAL DIVISION**


Margaret Uhlig Pemberton
Division Director

Stephen Mack
Managing Attorney

Rachelle Nicolette Robles
State Bar No. 24060508
Steven M. Gonzalez
State Bar No. 24109210
Rashmin J. Asher
State Bar No. 24092058
Rustin Tawater
State Bar No. 24110430
1701 N. Congress Avenue
P.O. Box 13326
Austin, Texas 78711-3326
(512) 936-7255
(512) 936-7268 (facsimile)
Rachelle.Robles@puc.texas.gov




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**COMMISSION STAFF'S REPLY BRIEF**

# I. INTRODUCTION/SUMMARY [PRELIMINARY ORDER (PO) ISSUES 1, 2, 3]

PURA § 36.006 requires that "in a proceeding involving a proposed rate change, the electric utility has the burden of proving that . . . the rate change is just and reasonable."[1] The burden of proof is on CEHE, as the applicant, to present substantial evidence in support of the prudence of each of its investments included in rate base and the reasonableness of CEHE's expenses. CEHE is requesting a prudence finding on investments made over a nine year period totaling in excess of $6 billion.[2] Staff and Intervenors were provided approximately eight to nine weeks to seek discovery on and analyze the prudence of CEHE's nine years of investment. Below, Staff responds to CEHE's initial brief regarding each of the prudence and expense adjustments identified by Staff in testimony. However, unless expressly stated in Staff's reply brief, to the extent Staff does not address CEHE's response to prudence issues raised by Intervenors, it should not be taken as Staff's agreement with CEHE's position on the merits or agreement that CEHE has met its burden of proof under PURA § 36.006.

Staff files this reply brief to specifically respond to the following arguments raised by various parties:

- Staff responds to CEHE's initial brief on rate base, rate of return, financial integrity and financial protections, expenses, revenues, cost allocation, rate design and tariff issues;

[1] Public Utility Regulatory Act, TEX. UTIL. CODE (PURA) § 36.006.
[2] Direct Testimony of Kenney Mercado, CEHE Ex. 6 at 2.

- Staff responds to Texas Coast Utilities Coalition's (TCUC) initial brief on the issues associated with depreciation expenses;

- Staff responds to Gulf Coast Coalition of Cities (GCC) initial brief on the issues associated with the excess deferred federal income taxes for amounts securitized through financing orders issued by the Commission;

- Staff responds to Texas Industrial Energy Consumer's (TIEC) Initial Brief on moderation of the ERCOT 4CP allocation;

- Staff responds to the City of Houston's (COH) initial brief on issues associated with the functionalization of certain expenses; and

- Staff responds to HEB and TCPA on issues related to the use of 4CP as opposed to NCP for cost allocation and rate design for both transmission and distribution.

## 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

Staff recommended a disallowance of $13,211,393, as CEHE failed to satisfy its burden of proof to establish that its capital investments were prudently incurred.[3]

CEHE argues that those estimates it submitted in response to Staff witness Tom Sweatman's RFI are not the estimates that should be used, and that the estimates Staff uses are "initial estimates."[4] Instead, CEHE wants Staff to use its "final estimate,"[5] resulting in CEHE underspending on the capital projects.[6]

However, substituting a subsequent estimate for the initial estimate fails to cure Staff's concern regarding the relationship between the initial estimate, the actual final cost, and the

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[3] Staff Initial Brief at 10.

[4] CEHE Initial Brief at 16.

[5] *Id.* at 17.

[6] *Id.* at 16-18.

reason for any significant deviation from the initial estimate. On rebuttal, CEHE provided additional information regarding four projects and the reasons for the cost overruns, resulting in Staff witness Mr. Sweatman's removal of those projects from his initial list of disallowances. However, CEHE failed to provide information for the remaining projects that would explain the cost overruns. Thus, the costs associated with those projects should be disallowed.

### 2. Capital Project Accounting/Capitalization Policy Changes

### 3. Land Costs

Staff seeks to disallow land costs for three distribution substation facilities because detailed descriptions were never given for these lands, as they were for every other land cost that CEHE seeks to include in plant held for future use (PHFU).[7]

CEHE focuses on whether the costs should have been placed in FERC Account 3600 or FERC Account 1050 for PHFU.[8] But CEHE failed to respond with the detailed information (acreage, specific substation name, location data) Staff required in order to review or recommend these costs as PHFU.[9] Without the required information, Staff is unable to determine the appropriateness of the land costs and whether they should be properly included as PHFU.

## B. Line Clearance Project

Staff recommends that a total of $19,376,931 should be disallowed, as this amount should have been categorized as operations and maintenance (O&M) expenses. However, CEHE improperly classified Project Number HLP/00/1055 (line clearance for 2014-17) as a capitalized project.

In its Initial Brief, Staff recommended the disallowance because the costs of clearing lines were incurred for work on *existing* transmission and distribution lines, in compliance with

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[7] Staff Initial Brief at 15.

[8] CEHE Initial Brief at 22.

[9] *Id. Also see* Staff Initial Brief at 15.

National Electrical Safety Code (NESC) clearance standards. Thus, is an O&M expense, not a capital investment.[10]

Additionally, CEHE argues that the work is capital, and not expense, because it involved "replacement of poles, conductors, and other capital assets."[11] CEHE states that "[r]eplacements of retirement units are required to be capitalized."[12] However, as Staff argued in its Initial Brief, *Accounting for Public Utilities* states, "Removal or replacement of a part of the unit, for example a downguy or brace, is considered a maintenance expense and does not affect the asset value."[13]

Capitalizing this project would unfairly enable CEHE to earn a rate of return on foreseeable, recurring O&M expenses. Thus, Staff recommends a disallowance of $19,376,931, as this amount is an O&M expense, not a capital investment to be included in rate base.

## C. Prepaid Pension Asset

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

## E. Cash Working Capital [PO Issue 15]

To the extent that the Commission adjusts CEHE's requests for operations and maintenance expense amounts, federal income tax amounts, or other tax amounts, it is appropriate to adjust accordingly the calculation and amount of cash working capital included in rate base.

## F. Other Prepayments

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

### 1. Unprotected Excess Deferred Income Tax (UEDIT)

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[10] Staff Initial Brief at 16.

[11] CEHE Initial Brief at 23.

[12] *Id.*

[13] Staff Initial Brief at 16.

### 2. Hurricane Harvey

### 3. Medicare Part D

### 4. Texas Margins Tax

CEHE should not be allowed to recover a return on and a return of a regulatory asset for the Texas margins tax (TMT) for the following reasons: (i) CEHE was never authorized to record a regulatory asset for TMT; (ii) CEHE has never requested and the Commission has never authorized the recovery of such an asset in any base rate case since the date CEHE states that it was authorized to book the asset; (iii) there is no evidence that CEHE has not recovered its TMT or gross receipts taxes on an ongoing basis through rates; (iv) and it would be inappropriate to charge customers again for expenses that CEHE's rates were previously set to recover.

In its Initial Brief, CEHE believes that it needs to recover from ratepayers amounts pertaining to a regulatory asset relating to TMT "to be kept whole for the transition from the current . . . recovery method to the requested method."[14] Staff's position is simple: CEHE should correct its accounting for the TMT and make it conform to the accounting treatment of every other electric utility in Texas, but the fact that CEHE incorrectly accounted for its TMT in the past does not mean that ratepayers should pay additional amounts in this proceeding. Also, Staff believes that a utility should record regulatory assets and liabilities on its books only when specifically authorized to do so by the Commission. In this case, the Commission never authorized CEHE to record a regulatory asset relating to TMT and CEHE may not argue that its rates were somehow historically insufficient to recover its TMT expense.

CEHE discusses at length the fact that its TMT is not paid for until the following year from when it accrued; *i.e.*, there is a one-year lag between the taxable year for the TMT and the year CEHE pays it.[15] This situation applies to all utilities (and all entities subject to TMT), but CEHE's accounting for it has been markedly different from all other utilities.[16] As noted above, Staff agrees that CEHE should correct its accounting but disagrees that the Commission ever authorized CEHE to book a regulatory asset relating to TMT.

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[14] CEHE Initial Brief at 44.

[15] *Id.*

[16] Direct Testimony of Mark Filarowicz, Staff. Ex. 4A, at 29.

CEHE argues that in Docket No. 29526[17] the Commission recognized a deferred debit for state franchise tax, but CEHE even admits that referred to the *generation* only portion of the state franchise tax: "While this reference is to the generation portion of the state franchise tax [...] ."[18] As previously explained, Staff does not believe that the final order from that case—pertaining to *generation* stranded costs—authorized CEHE to book a regulatory asset. Furthermore, as explained by Staff witness Mr. Filarowicz, in its most recent base rate proceeding in Docket No. 38339,[19] CEHE did not present any information showing that it was booking a regulatory asset relating to TMT. Finally, the final order in Docket No. 38339 did not authorize CEHE to book a regulatory asset for TMT (and it did explicitly authorize other regulatory assets for other accounting items).[20]

CEHE's initial brief asserts that just because CEHE did not request this regulatory asset in Docket No. 38339 does not mean that CEHE should not have been recording the regulatory asset. Simply put, CEHE is incorrect. Accounting principles require that a utility should not book a regulatory asset unless authorized by a regulatory body. CEHE cannot reasonably argue that it should have been recording a regulatory asset for the past fifteen years when CEHE did not seek or receive authorization for such a regulatory asset in its base rate case ten years ago. Moreover, in this case, CEHE cannot point to a final order that explicitly authorizes CEHE to book a regulatory asset relating to TMT.

CEHE's Initial Brief also asserts that it is Mr. Filarowicz's position that accounting for the TMT only became an issue when the TMT began in 2008.[21] Mr. Filarowicz never made such an assertion. Company witness Charles Pringle acknowledges that the TMT did not exist until 2008; Mr. Filarowicz agrees that a similar but different predecessor tax existed before the TMT. However, the point still remains: it would have been impossible for the Commission in 2004 to

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[17] *Application of CenterPoint Energy Houston Electric, LLC, Reliant Energy Retail Services, LLC, and Texas Genco, LP to Determine Stranded Costs and Other True-Up Balances Pursuant to PURA § 39.262*, Docket No. 29526, Order on Rehearing (Dec. 17, 2004).

[18] CEHE Initial Brief at 46.

[19] *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Order on Rehearing (June 23, 2011).

[20] *Id.*

[21] CEHE Initial Brief at 46.

order CEHE to book a regulatory asset for a tax which would not come into existence for four more years.

Finally, it is important to note that CEHE has not put on any evidence in this proceeding to show that annual amounts for TMT expense have not been recovered. The base rates set for CEHE in Docket No. 38339 included an amount for TMT expense. To say that CEHE's TMT has not been recovered is incorrect; an annual amount for TMT has been recovered through rates every year, just like every other line item for which rates were set in Docket No. 38339. Each year, CEHE recovers an amount for the TMT expense as it does for other line items, whether those items are for operations and maintenance expense or any tax item. CEHE does not dispute this. In its Initial Brief, CEHE claims that allowing for this regulatory asset would "avoid duplicative recovery."[22] Here, the Commission should prohibit CEHE from recovery anything related to this regulatory asset in order to prevent any double recovery of costs associated with the TMT that have historically been, and currently are, recovered through CEHE's rates.

The Commission should reject CEHE's request to collect money from ratepayers for a regulatory asset that was never authorized to be booked and for which there is no evidence of lack of a recovery in historic and current rates. Inclusion of a regulatory asset for TMT in CEHE's rates would lead to unjust and unreasonable rates for ratepayers.

### 5. Smart Meter Texas

### 6. REP Bad Debt

### 7. BRP Pension and Postretirement

### 8. Other Regulatory Assets and Liabilities

## H. Capitalized Incentive Compensation

CEHE does not dispute that however the Commission treats incentive compensation for expenses, the same treatment should be applied to the portion of incentive compensation that has been capitalized since the test year of CEHE's last base rate case. As is more fully detailed

[22] *Id.* at 47.

below in Section IV.B.1, Staff recommends that capitalized financially based incentive compensation be removed from rate base consistent with Commission precedent.[23]

## I. Capitalized Non-Qualified Pension Expense

# III. RATE OF RETURN [PO ISSUES 4, 5, 7, 8, 9]

A fair rate of return on invested capital for CEHE is based on an estimate of the cost of equity and an assessment of the Company-proposed cost of debt and capital structure. An appropriate return on invested capital assesses the risks faced by CEHE and provides CEHE with a reasonable opportunity to recover its reasonable capital costs, but also ensures that the rate-setting process is fair to customers.

## A. Return on Equity [PO Issue 8]

As Staff stated in its initial brief, the appropriate return on equity (ROE) for CEHE is 9.45%.[24] Staff's ROE recommendation is based on discounted cash flow (DCF) and risk-premium methodologies that are well-established at the Commission.[25] The results of these methodologies are shown in the chart below:[26]

| Methodology | Point Estimate | Range |
|---|---|---|
| Single Stage DCF Analysis | 8.38% | 6.09 – 10.95% |
| Multistage DCF Analysis | 8.31% | 7.51 – 10.22% |
| Risk premium | 9.79% | N/A |
| CAPM Analysis | 6.50% | N/A |
| **Return on Equity (ROE)** | **9.45%** (excluding CAPM) | **8.34 – 9.79%** |

[23] *Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment*, Docket No. 39896, Final Order on Rehearing at 5-6 and Findings of Fact Nos. 59-63 (Nov. 2, 2012).

[24] Staff Initial Brief at 23.

[25] Staff Initial Brief at 23-24; Direct Testimony of Jorge Ordonez, Staff Ex. 3A at 13.

[26] Staff Initial Brief at 28; Staff Ex. 3A at 28, 49 (Attachment JO-9).

Staff's ROE recommendation is similar to the ROE recommendations of the other parties in this proceeding while CEHE's ROE request of 10.4% is an outlier and should be disregarded.[27]

In the last five rate cases for investor-owned electric utility companies, the Commission has authorized an ROE between 9.50% - 9.65%.[28] In fact, as CEHE notes in its initial brief, "[t]he evidence in this proceeding establishes that the average authorized ROE for electric utilities since 2014 is 9.68%, and the Commission's most recently authorized ROE is 9.65%."[29]

Furthermore, Staff's ROE recommendation is consistent with the national average authorized ROE of 9.42% for delivery-only electric utilities in other jurisdictions as published on the S&P Global Market Intelligence RRA Regulatory Focus report for the first quarter of 2019 (1Q-2019 S&P Global Market Intelligence RRA Report).[30] This is even considering that the "delivery-only" electric utilities included in the S&P Global Market Intelligence RRA Regulatory Focus reports purchase and sell electricity and therefore have greater risk than CEHE, a wires-only utility that is not affected by the commodity risk associated with the purchase and sale of electricity.[31] In fact, the average awarded ROE for wires-only utilities was 9.18% in the first half of 2018.[32]

In its initial brief, CEHE argued that Staff's ROE witness, Jorge Ordonez, "fail[ed] to consider the impacts of the TCJA in any meaningful way in determining his ROE

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[27] TIEC Initial Brief at 9.

[28] Application of El Paso Electric Company to Change Rates, Docket No. 46831, Order, Finding of Fact No. 30 (Dec. 18, 2017); Application of Southwestern Electric Power Company for Authority to Change Rates, Docket No. 46449, Order on Rehearing, Finding of Facts No. 158 through 160 (Mar. 19, 2018); Entergy Texas, Inc.'s Statement of Intent and Application for Authority to Change Rates, Docket No. 48371, Order, Finding of Facts No. 47 through 51 (Dec. 20, 2018); Application of Southwestern Public Service Company for Authority to Change Rates, Docket No. 47527, Order, Finding of Fact 58 (Dec. 10, 2018); and Application of Texas-New Mexico Power Company to Change Rates, Docket No. 48401, Order, Finding of Fact No. 48 (Dec. 20, 2018).

[29] CEHE Initial Brief at 54.

[30] Staff Initial Brief at 28; Staff Ex. 3A at 29.

[31] Staff Initial Brief at 28; Staff Exhibit 3A at 29.

[32] TIEC Initial Brief at 11.

recommendation."[33] CEHE also argues that the TCJA will put downward pressure on its credit metrics.[34] CEHE is incorrect on both of these points. The TCJA has been in effect since January 2018 and effects of the TCJA are reflected in CEHE's current credit ratings. Currently, CEHE has a credit rating of A3 from Moody's, A- from Fitch, and BBB+ from S&P.[35] Additionally, CEHE's most recent bond issuance of $700 million was rated A1 by Moody's, A+ by Fitch, and A by S&P.[36] As Mr. Ordonez explained during the hearing, the companies chosen by Mr. Ordonez for his proxy group have all been subjected to the TCJA since its passage in 2017, and therefore his analysis did consider the impacts of the TCJA.[37] Additionally, as TIEC stated in its initial brief, CEHE's parent company CenterPoint Energy, Inc., stated in a presentation to S&P that the TCJA is [redacted]"[38] CenterPoint also noted that tax reform [redacted][39]

In CEHE's initial brief, CEHE stated that Mr. Hevert's ROE recommendation of 10.4% should be chosen because his analysis is based on well-established methodologies and produces a reasonable result.[40] However, Mr. Hevert's analysis is unreliable, based on unrealistic assumptions, and should be rejected. Mr. Hevert's constant growth DCF model is based on a proxy group average growth rate of 5.79%,[41] which in Mr. Hevert's single-stage DCF model is the growth rate that is assumed to infinity, despite being well above economists' consensus projected long-term sustainable growth rate of 4.00%.[42] Not only does Mr. Hevert use an

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[33] CEHE Initial Brief at 55.

[34] *Id.* at 52.

[35] Staff Initial Brief at 31; Staff Ex. 3A at 8.

[36] Staff Initial Brief at 31; Staff Ex. 3A at 9.

[37] Staff Initial Brief at 31.

[38] TIEC Initial Brief at 38; *see also* Direct Testimony of Charles S. Griffey, TIEC Ex. 4 at 28 (June 6, 2019) (quoting CEHE Response to TCUC 1-02 in attachment SP 2018 CenterPoint Energy at 2-3. (HSPM)).

[39] *Id.*

[40] CEHE Initial Brief at 52.

[41] Direct Testimony of Robert B. Hevert, CEHE Ex. 26 at Bates 2753 (Exhibit RBH-1) (April 5, 2019).

[42] TIEC Initial Brief at 27-28.

unrealistically inflated growth rate in his constant growth DCF model, he bases his CAPM analysis on inflated market risk premiums of 10.72% and 14.10%,[43] which Mr. Hevert derives from assumed market growth of 11.63% to 14.82%.[44] In revealing contrast, the actual capital appreciation of the S&P 500 between 1926 and 2018 was between 5.8% to 7.7%.[45] This practice of using inflated growth rates and risk premiums is consistently used by Mr. Hevert and has been called into question by other Commissions as shown below:

> 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.[46]
>
> 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.[47]
>
> 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**

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[43] CEHE Ex. 26 at Bates 2771 (Exhibit RBH-4).

[44] TIEC Initial Brief at 30; *see also* Direct Testimony of Michael P. Gorman, TIEC Ex. 5 at 81.

[45] TIEC Initial Brief at 30; *see also* TIEC Ex. 5 at 81.

[46] TIEC Initial Brief at 25; TIEC Ex. 26 at 19-20, Finding of Fact 33 (emphasis added).

[47] TIEC Initial Brief at 25; TIEC Ex. 25 at 66, Finding of Fact 15 (emphasis added).

> **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 Pepco's service territory, or the riskiness of Pepco's business monopoly, justify an ROE in the range Mr. Hevert proposes.[48]
>
> 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.**[49]

Furthermore, "Mr. Hevert has only recommended an ROE lower than 10.0% in three out of 143 cases over the last five years, and during that time period, his recommended ROE [was] never [] adopted by a regulator."[50]

Overall, Staff's ROE recommendation is based on methodologies that are well-established at the Commission, in line with ROEs awarded by the Commission since 2015, and consistent with the national average ROE for delivery-only electric utilities. This is in stark contrast to CEHE's ROE recommendation of 10.4%, which is based on unreliable and unrealistic analyses and far exceeds recent ROEs approved by the Commission or the national average for delivery-only electric utilities.

## B. Cost of Debt [PO Issue 8]

Staff addressed this issue in its initial brief.

## C. Capital Structure [PO Issue 7]

Staff's recommendation of 60% long-term debt and 40% equity is the appropriate capital structure for CEHE. Staff's capital structure recommendation is based on the "constructive" and

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[48] TIEC Initial Brief 25-26; TIEC Ex. 24 at 86-87 (emphasis added).

[49] TIEC Initial Brief 26; TIEC Ex. 28 (emphasis added).

[50] TIEC Initial Brief at 24.

"credit-positive"[51] regulatory environment for electric utilities in Texas and the low business and regulatory risks faced by CEHE.

In its initial brief, CEHE argues that Mr. Ordonez's reliance on Docket No. 22344 for establishing his capital structure recommendation is misplaced.[52] However, as Mr. Ordonez discussed during the hearing, the Commission ruled in Docket No. 22344 that a 60/40 capital structure "was appropriate for transmission distribution utilities operating in Texas."[53] As Mr. Gorman explained, that capital structure was "put in place for a TDU specifically for a utility that ultimately became CenterPoint Energy Houston [CEHE]."[54] Mr. Gorman continued that this capital structure recommendation recognizes "the significantly reduced business risks of Texas TDUs because they have no commodity risks."[55]

CEHE attempts to make the argument that the Commission recognized that the capital structure recommendation of 60% long term debt/40% equity is no longer applicable because in Docket No. 38339 the Commission awarded CEHE with a 55% long term debt/45% equity capital structure.[56] CEHE states that Mr. Ordonez's "recommendation completely ignores the Commission's more recent precedent in Docket No. 38339."[57] However, Mr. Ordonez does not ignore the Commission's decision in Docket No. 38339, but rather he explains that CEHE has less business and regulatory risk than it did in 2011 when the Commission issued its order in Docket No. 38339.[58] Two mechanisms that allow CEHE to reduce or mitigate risk associated with capital expenditures are (1) the interim transmission cost of service (Interim TCOS) mechanism, and (2) the distribution cost recovery factor (DCRF) mechanism. Both mechanisms

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[51] Staff Initial Brief at 34; Staff Ex. 3A at 31; CEHE Ex. 27 at 30.

[52] CEHE Initial Brief at 65.

[53] Tr. at 665:22-23 (Ordonez Cross) (June 26, 2019).

[54] Tr. at 560:4-6 (Gorman Cross) (June 26, 2019).

[55] *Id.* at 561:12-16.

[56] CEHE Initial Brief at 65; Tr. at 665: 4-18 (Ordonez Cross) (June 26, 2019).

[57] CEHE Initial Brief at 65.

[58] Tr. at 665:4-15 (Ordonez Cross) (June 26, 2019).

were just updated or enacted prior to CEHE's base rate case in Docket No. 38339.[59] As Mr. Ordonez explained, unlike when the order in Docket No. 38339 was issued, we now know "nine years later, [] these mechanisms work very well." Mr. Ordonez also discussed that "it takes some time for utilities to start taking advantage of the[se] mechanism[s]. That's what CenterPoint and other utilities have been doing in the last few years, you know requesting update of their capital [investment]; in other words, putting into rates investment in distribution and transmission assets."[60] Therefore, currently like other TDUs operating in Texas, CEHE does not face commodity risk, and it also has less business and regulatory risk—even less than at the time of Docket No. 22344—due to the Interim TCOS and DCRF mechanisms. The Interim TCOS mechanism permits CEHE to adjust its transmission rates twice per year to account for increases in transmission investment and transmission investment related expenses, and the DCRF mechanism permits CEHE to adjust its distribution-related rates once per year to account for increases in distribution investment and distribution investment related expenses.[61] Additionally, Texas law allows CEHE to recover storm restoration costs, including related carrying charges calculated with CEHE's pretax Commission-authorized weighted-average cost of capital, thus ensuring that CEHE is kept economically whole with respect to such costs and effectively eliminating the risk of non-recovery entirely.[62] Therefore, because CEHE faces less business and regulatory risk, the fundamental rationale for the 60/40 capital structure adopted in Docket No. 22344 remains sound, and Staff's recommendation consistent therewith should be adopted.

CEHE states in its initial brief that a 50% long-term debt/50% equity capital structure properly recognizes the business risk posed by the TCJA and the increased capital expenditures of CEHE.[63] In doing so, CEHE points to a January 2018 Moody's report that placed 24 utilities on a negative outlook because of the effects of the TCJA, which went into effect in January 2018.[64] Thus, as discussed above in the Return on Equity section, the TCJA effects are properly

[59] Staff Initial Brief at 30.

[60] *Id.*; Tr. at 699:6-7, 700:20 – 701:1 (Ordonez Redirect) (June 26, 2019).

[61] Staff Initial Brief at 30; Staff Ex. 3A at 31.

[62] Staff Ex. 3A at 32, 39.

[63] CEHE Initial Brief at 67.

[64] *Id.* at 68.

accounted in the credit ratings for the proxy group chosen by Mr. Ordonez and in the high credit ratings of CEHE itself, which is four notches above a non-investment grade rating.[65] Also, as discussed above in the Return on Equity section, according to CenterPoint, the TCJA is [redacted][66] Regarding CEHE's increased capital expenditures, Mr. Ordonez notes that the utility industry is one that is capital intensive, and CEHE's increased capital expenditures are therefore accounted for through his proxy group.[67] Additionally, while CEHE may have increased capital expenditures, CEHE also has the opportunity—through regular Interim TCOS and DCRF proceedings that significantly reduce regulatory lag—to earn timely returns on its capital investment. CEHE does not need additional equity in its capital structure as a result of these increased capital expenditures, because as Mr. Mercado acknowledged, CEHE's ratio of capital expenditures to net electric plant in service has been nearly flat since its last base rate case.[68] In fact, CEHE "maintained its credit rating with an equity ratio of between 38 and 45 percent over the last three years."[69]

CEHE also points to a June 17, 2019 issuer comment from Moody's stating that Moody's foresees that CEHE's credit metrics will weaken in light of the TCJA and CEHE's capital expenditure forecast.[70] Weakening credit metrics are not the same as a credit downgrade. Furthermore, the Moody's issuer comment must be considered in light of the *Bluefield* and *Hope* standards. Under *Bluefield*, the Court stated:[71]

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

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[65] *Supra* at fn. 35 -37.

[66] *Supra* at. fn. 38.

[67] Tr. at 668: 7-12 (Ordonez Cross) (June 26, 2019).

[68] TIEC Initial Brief at 37-38.

[69] Tr. at 536: 7-11 (Dr. Woolridge Cross) (June 26, 2019).

[70] CEHE Initial Brief at 69.

[71] *Bluefield Water Works & Improvement. Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 693 (1923); Staff Ex. 3A at 10.

Under *Hope*, the Court stated:[72]

> The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital.

Therefore, under *Hope* and *Bluefield*, "investors in a utility must be given a reasonable opportunity to recover their reasonable capital costs, including a reasonable return on equity."[73] However, customers must also be considered. As Mr. Gorman explains, "there is a balance between what capital – what bond rating you are attempting to maintain [and] the rate-setting process that ensures customers are [] are fairly treated."[74]

CEHE also claims that its recommended capital structure of 50% long-term debt/50% equity is appropriate because "the average equity ratio of electric delivery-only utilities for calendar year 2018 was 49.19%."[75] However, as Mr. Ordonez explained in his direct testimony, 14 out of 16 delivery-only electric analyzed in the 2018 S&P Global Market Intelligence RRA Report purchase and sell electricity, and therefore these 14 "delivery-only" electric utilities are not a good proxy for CEHE, which is a wires-only utility that does not face this commodity risk.[76] Mr. Gorman explained during the hearing that "there are very few other utilities, very few other utilities around the country that do not have commodity risks."[77] CenterPoint Energy, Inc., the parent company of CEHE, is one of the utilities that experiences commodity risk.[78] Therefore, as discussed during the hearing, if ring-fencing protections are imposed, it would likely be a credit positive event for CEHE that would improve the credit metrics of CEHE.[79]

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[72] *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 604 (1944); Staff Ex. 3A at 10-11.

[73] Staff Ex. 3A at 11.

[74] Tr. at 624: 3-6 (Gorman Redirect) (June 26, 2019).

[75] CEHE Initial Brief at 66.

[76] Staff Initial Brief at 33; Staff Ex. 3A at 35.

[77] Tr. at 619: 1-3 (Gorman Redirect) (June 26, 2019).

[78] Tr. at 619: 5-7 (Gorman Redirect) (June 26, 2019).

[79] Tr. at 635: 16-17 (Griffey Cross) (June 26, 2019); Tr. at 639: 17-24 (Griffey Redirect) (June 26, 2019).

Overall, a 60% long-term debt/40% equity is consistent with the business and regulatory risks faced by CEHE and strikes an appropriate balance between CEHE maintaining a favorable credit rating and access to capital and the fair treatment of customers.

## D. Overall Rate of Return [PO Issue 8]

Once Staff's recommended return on equity of 9.45%, CEHE's proposed cost of debt of 4.38%, and Staff's proposed capital structure of 60% long-term debt and 40% common equity are taken into account, the rate of return is 6.41%.

## E. Financial Integrity [PO Issue 9]

CEHE's Initial brief raises the argument that the Commission's adoption of certain issues, including Staff's recommended rate of return, "would threaten the future financial integrity of CEHE."[80] Staff disputes CEHE's claims as CEHE conflates financial integrity with CEHE's desire to maintain its high credit ratings.[81] As stated above, Staff's proposed rate of return will provide CEHE access to capital on reasonable terms. Furthermore, any potential threat to CEHE's high credit ratings is due, in part, to CenterPoint's acquisition of Vectren.[82] In order to insulate CEHE from the business risks of CenterPoint and its other affiliates and actually bolster CEHE's credit ratings,[83] Staff proposes that the Commission implement the financial protections set forth in Staff's initial brief.

The Commission has the statutory authority to require CEHE to implement the financial protections recommended by Staff witness Darryl Tietjen. The financial protections are necessary to preserve the financial integrity of CEHE and ensure reliable service at just and reasonable rates. Preserving financial integrity and ensuring reliable service at just and

[80] CEHE Initial Brief at 9-10.

[81] CEHE Initial Brief at 70.

[82] Direct Testimony of Darryl Tietjen, Staff Ex. 1A at 10-12.

[83] Direct Testimony of Michael Gorman, TIEC Ex. 5 at 24-25.

reasonable rates are not only authorized by the Commission, they are core responsibilities of the Commission under PURA § 36.051.

**Commission Authorization**

The Commission has the statutory authority to take measures to protect the financial integrity of utilities and ensure reliable service at just and reasonable rates. The Texas Supreme Court has interpreted the financial integrity standard to be derived from the Commission's requirement to set rates under PURA § 36.051.[84] The financial integrity standard is met only if rates are "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[85] Protecting the financial integrity and ensuring reliable service at just and reasonable rates is a core responsibility of the Commission under Chapter 36 as the Court has held that the Commission's responsibility to preserve the financial integrity of a utility may override the normal ratemaking principles of Chapter 36 when they are in conflict. Specifically, the Court has held:

> While we agree that regulatory lag is ordinarily an element of risk for utilities, we do not accept that the legislature intended this general principle to subordinate the provisions of PURA. Rather, if the effects of regulatory lag infringe on the Commission's ability to regulate in a manner necessary to carry out the provisions of PURA, then the Commission may respond within its powers, both express and implied, under PURA to alleviate the impact of regulatory lag in order to fulfill its statutorily imposed duties. At the same time, the authority to allow the deferral of post-in-service costs is not unfettered. Rather, the Commission must not alleviate regulatory lag unless necessary to comply with the provisions of PURA[, namely preserving the financial integrity of the utility under PURA 36.051.][86]

In CEHE's current case, there is no conflict between the proposed financial protections and any statutory provisions. To the contrary, the proposed financial protections are necessary to preserve the financial integrity of the utility under PURA § 36.051, which provides:

> In *establishing an electric utility's rates*, the regulatory authority shall establish the utility's overall revenues at an amount that will permit the utility a reasonable

[84] *State v. Public Util. Comm'n*, 883 S.W.2d 190, 196-197 (Tex. 1994); see also, *State of Texas' Agencies and Institutions of Higher Education v. Public Util. Comm'n*, 450 S.W.3d 615, 645 (Tex. App.—Austin, Dec. 4, 2014) (*aff'd in part, rev'd in part on other grounds*).

[85] *Suburban Util. Corp. v. Public Util. Comm'n*, 652 S.W.2d 358, 362-63 (Tex. 1983).

[86] *State v. Public Util. Comm'n*, 883 S.W.2d 190, 196-97 (Tex. 1994).

> opportunity to earn a reasonable return on the utility's invested capital used and useful in providing service to the public in excess of the utility's reasonable and necessary operating expenses.[87]

PURA defines a rate to "include[] . . . *a rule, practice, or contract affecting the compensation, tariff, charge, fare, toll, rental, or classification that must be approved by a regulatory authority*."[88] As is provided in more detail below, it is undisputed that the risks imposed by CenterPoint and its other subsidiaries may affect CEHE's ability to attract capital on reasonable terms.[89] Thus, it is within the Commission's jurisdiction to establish financial protections to be followed by CEHE in order to insulate the regulated utility from its unregulated parent and affiliates.

Staff witness Darryl Tietjen cites additional statutory authority for the Commission's ability to require the financial protections. Mr. Tietjen based his recommendation on PURA §§ 11.002 (Purpose and Findings) and 14.001 (Power to Regulate and Supervise).[90] PURA § 11.002 provides in subsections (a) and (b) that:

> (a) This title is enacted to protect the public interest inherent in the rates and services of public utilities. The purpose of this title is to establish a comprehensive and adequate regulatory system for public utilities to assure rates, operations, and services that are just and reasonable to the consumers and to the utilities.
>
> (b) Public utilities traditionally are by definition monopolies in the areas they serve. As a result, the normal forces of competition that regulate prices in a free enterprise society do not operate. Public agencies regulate utility rates, operations, and services as a substitute for competition.[91]

PURA § 14.001 states that:

> The commission has the general power to *regulate and supervise* the business of each public utility within its jurisdiction and to do anything specifically

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[87] PURA § 36.051 (emphasis added).

[88] PURA §§ 11.002 & 31.002 (emphasis added).

[89] Tr. at 139:25 to 140:5 (Mercado Cross); TIEC Exhibit 6, CEHE Form 10-k for the Fiscal Year Ended Dec. 31, 2017 at 7; Direct Testimony of Darryl Tietjen, Staff Exhibit 1A at 6; Rebuttal Testimony of Ellen Lapson, CEHE Exhibit 48 at 21; Direct Testimony of Charles Griffey, TIEC Exhibit 4 at 11-12.

[90] Direct Testimony of Darryl Tietjen, Staff Exhibit 1A at 3-4.

[91] PURA § 11.002.

designated or implied by this title that is necessary and convenient to the exercise of that power and jurisdiction.[92]

The plain meaning of the above statutory provisions sets out and attests to the Commission's broad authority over the rates, operations, and services of the public utilities it regulates. Accordingly, the Commission's ability to establish protective measures that help ensure a utility's financial integrity and that facilitate the utility's ability to provide reliable service at just and reasonable rates is, under any reasonable interpretation of the statutory language, a legitimate application of the Commission's general regulatory oversight function and its authority to "regulate and supervise."[93]

**Need for Ring-Fencing**

The record does not reflect a dispute as to whether there is a factual need for ring-fencing. Rather, the dispute seems to be the degree of ring-fencing needed. CEHE witness Ellen Lapson testified:

> Most retail and integrated electric utilities have an obligation to reliably operate and maintain their systems for existing customers, and expand systems to meet customer growth. All of these activities require access to funding. Thus, it is important for the utility to retain access to its own resources including its bank accounts, accounts receivable, and the ability to draw under its credit arrangements, even if its parent or a sister company is under stress. Also, most utilities must seek outside sources of capital from the debt capital market. Without adequate ring fencing, the utility's credit worthiness and access to the debt capital market could be impaired if its parent is in default or bankruptcy. Ring-fencing has been used to protect utilities from risky parents or sister companies to ensure the utility can continue to operate and serve its current and future customers.[94]

TIEC witness Charles Griffey testified:

> [I]f a utility is not ring-fenced, the financial and business risk of a utility's parent and affiliates can affect the credit rating of the utility even in the best of times. In financially challenging times, ring-fencing is essential to prevent a utility from being incorporated into a bankruptcy proceeding with its parent or affiliates. Giving the upstream parent full access to a utility's revenues during periods of financial distress can allow the utility to be "looted" to pay debtors and

[92] PURA § 14.001 (emphasis added).
[93] PURA § 14.001.
[94] Rebuttal Testimony of Ellen Lapson, CEHE Exhibit 48 at 21.

shareholders, which could prevent the utility from making investments and paying expenses necessary to provide reliable utility service. This could, in turn, compel utility regulators to take extreme and costly measures to maintain utility service, potentially at the expense of the utility's ratepayers.[95]

Ms. Lapson's and Mr. Griffey's testimony acknowledge the need for ring-fencing to protect the financial integrity of a utility and ensure access to capital on reasonable terms. Likewise, CEHE, itself, has identified the risks that CenterPoint and its other subsidiaries impose on CEHE's creditworthiness:

***We [CEHE] are an indirect, wholly-owned subsidiary of CenterPoint Energy. 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 interest.***
. . . .
***The creditworthiness and liquidity of our parent company and our affiliates could affect our creditworthiness and liquidity.***[96]

CEHE witness Kenney Mercado also acknowledged the need for and existence of some level of ring-fencing as part of the utility's responsibility.[97] In a previous rate case, CEHE also acknowledged that it is subject to—and actually has in place—certain ring-fencing measures.[98]

Because there is no dispute as to the need for financial protections for CEHE, the real dispute in this case is the degree of the financial protections needed, which is a subjective matter and within the Commission's discretion. One may not know with certainty what financial protections are needed until it is too late. CEHE implies that the Commission should address any potential increases in cost of capital due to the financial risks of CenterPoint or its other subsidiaries using the Commission's rate setting authority—after the

[95] Direct Testimony of Charles Griffey, TIEC Exhibit 4 at 13.
[96] TIEC Ex. 6 at 7 (emphasis in original).
[97] Tr. at 139:25 to 140:5 (Mercado Cross).
[98] Direct Testimony of Darryl Tietjen, Staff Ex. 1A at 9.

fact.[99] However, the after-the-fact approach advocated by CEHE is too little and too late. An after-the-fact approach would, as Mr. Griffey testifies, "compel utility regulators to take extreme and costly measures to maintain utility service, potentially at the expense of the utility's ratepayers."[100]

Because the degree of financial protection required is subjective, and subject to the Commission's discretion. Staff recommends that the Commission order the same financial protections that the Commission has ordered in the past and that have proven effective in protecting Oncor from bankruptcy.[101]

# 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

It is well established precedent that financially based incentive compensation should be excluded from rates charged to customers because financial measures are of more immediate benefit to shareholders and are not measures that are necessary and reasonable to provide

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[99] CEHE Initial Brief at 72.

[100] Direct Testimony of Charles Griffey, TIEC Exhibit 4 at 13.

[101] Staff's Initial Brief at 36-38 (listing the recommended financial protections); *see also*, Direct Testimony of Darryl Tietjen, Staff Ex. 1A at 7 & 12-16 (citing *Joint Report and Application of Oncor Electric Delivery Company LLC, Sharyland Distribution & Transmission Services, L.L.C., Sharyland Utilities, L.P., and Sempra Energy for Regulatory Approvals Under PURA §§ 14.101, 37.154, 39.262, and 39.915,* Docket No. 48929 Order (May 9, 2019); *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, Order (Mar. 8, 2018); *Joint Report and Application of Oncor Electric Delivery Company LLC, Ovation Acquisition I, LLC, Ovation Acquisition II, LLC, and Shary Holdings, LLC for Regulatory Approvals Pursuant to PURA §§ 14.101, 37.154, 39.262(l)-(m), and 39.915,* Docket No. 45188, Order (Mar. 24, 2016); *Joint Report and Application of Oncor Electric Delivery Company and Texas Energy Future Holdings Limited Partnership Pursuant to PURA § 14.101,* Docket No. 34077, Order on Rehearing (April 24, 2008)).

transmission and distribution utility services.[102] Because these expenses inure to the benefit of shareholders,[103] the expenses may be properly paid out of the increased earnings the expenses are intended to generate.

CEHE relies on recent Texas legislation that allows recovery of incentive compensation costs for "nearly all employees of a *gas* utility[.]"[104] (Emphasis added.) CEHE is *not* a gas utility. The legislature is presumed to be aware of the Commission's historical policy on financially based incentive compensation. If the Legislature intended to change the Commission's policy, it would have done so through legislation. The fact is that two bills proposed this past session would have created presumptions regarding the reasonableness of incentive compensation for electric utilities, but they never made it out of committee indicating that the legislature did not intend to modify the Commission's historical policy regarding incentive compensation for electric utilities.[105]

CEHE also argues that its full incentive compensation should be allowed in rates arguing that the Commission's historical policy regarding financially based incentive compensation is incorrect and should be changed. Staff recommends that the ALJs find that the Commission's long-standing precedent warrants excluding financially based incentives because they are unnecessary for providing electric service and because the benefits of such incentives inure more to the benefit of shareholders rather than customers.[106]

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[102] *Application of AEP Texas Central Company for Authority to Change Rates,* Docket No. 28840, Order, Findings of Fact Nos. 169 and 170 (Aug. 15, 2005).

[103] *Application of SWEPCO for Authority to Change Rates and Reconcile Fuel Costs,* Docket No. 44034, Final Order on Rehearing, Finding of Fact No. 217 (Mar. 6, 2014).

[104] CEHE Initial Brief at 91.

[105] Tr. at 1358:21-1359:5 (Reed Cross) (June 28, 2019).

[106] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449 Order on Rehearing, Finding of Fact No. 204 (Mar. 19, 2018); *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Order on Rehearing, Finding of Fact No. 137 (Feb. 23, 2016); *Application of AEP Texas Central Company for Authority to Change Rates,* Docket No. 28840, Order, Findings of Fact Nos. 169 and 170 (Aug. 15, 2005); *Application of SWEPCO for Authority to Change Rates and Reconcile Fuel Costs,* Docket No. 44034, Final Order on Rehearing (Mar. 6, 2014); *Application of ETI for Authority to Change Rates, Reconcile Fuel Costs, And Obtain Deferred Accounting Treatment*, Docket No. 39896, Final Order on Rehearing at 5-6 and Findings of Fact Nos. 59-63 (Nov. 2, 2012).

### a. Short-Term Incentive Compensation

Consistent with recent precedent, Staff calculates its recommended adjustment to short-term incentive compensation by removing all financially based incentive compensation and half of the remaining other (non-financially based) incentive compensation because its payment is based on a financial trigger.[107] Staff also relies on CEHE discovery responses and schedules to the rate filing package to determine the level of incentive compensation requested for recovery.[108]

In CEHE's initial brief, CEHE claims that Staff's proposed disallowance is not calculated on the level of incentive compensation requested in rates, "despite this evidence."[109] However, the "evidence" CEHE cites is rebuttal testimony and a table of contents to direct testimony.[110] If CEHE had made an adjustment to test year levels of incentive compensation to average four years of data, then there would have necessarily been an adjustment to the test-year data within the rate filing package. One would also expect that there would have been a workpaper providing the four years' worth of incentive compensation and the calculation averaging the data. The only direct information in the record is the information provided in Staff's workpapers that summarizes the workpapers filed with CEHE's application and CEHE's response to discovery that clearly asked for all amounts of incentive compensation, by FERC account, that CEHE included in its request for rates in this proceeding.[111]

In its initial brief, CEHE argues that the metric relating to operations and maintenance expense is operational.[112] Staff disagrees and asserts that this metric is financial in nature.[113] In general, a metric should be considered to be financial if its achievement or calculation is based

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[107] Staff Ex. 4A at 11.

[108] Staff Ex. 4A at 10 and 57-68 (Attachment MF-11).

[109] CEHE Initial Brief at 83.

[110] CEHE Initial Brief at 83, fn. 593; *see also id.* at fn. 596 (citing a page out of the table of contents to the Direct Testimony of Kristie Colvin, CEHE Ex. 12).

[111] *See* Workpapers to the Direct Testimony of Mark Filarowicz, Staff Ex. 4B; *see also* Staff Ex. 4A at 57-68 (Attachment MF-11).

[112] CEHE Initial Brief at 83.

[113] Staff Ex. 4A at 16-17.

on inputs that relate to a utility's balance sheet or income statement.[114] In this case, the metric for savings in operations and maintenance expense relates to CEHE's income statement.[115] CEHE's initial brief implies that Staff's position on the metric for savings in operations and maintenance expense is not based on Texas Commission precedent.[116] CEHE states that "[i]n making these arguments, *all four* witnesses [referring to Filarowicz, LaConte, Dively, and Garrett] refer to commissions *in other states* without adequately considering or discussing whether those decisions reflect sound policy given the facts of [this] case."[117] (Emphasis added.) In fact it even cites Mr. Filarowicz's reference to "commissions in other states."[118] When one goes and looks in Mr. Filarowicz's testimony (Staff Ex. 4A) in the spot where CEHE claims Mr. Filarowicz cited another state's commission,[119] it's not there. In fact, Mr. Filarowicz never refers to another state; he refers to Docket Nos. 46449, 43695, and 33309, cases all decided by the Public Utility Commission of Texas.[120] In the direct testimony of CEHE witness John J. Reed, he admits that "Financial goals have previously been identified as those goals that relate to 'maximizing profit and growth, increasing earnings per share, or increasing return on equity.'"[121] Here, the metric relates to profit maximization and should be considered financial.

CEHE also relies on the Commission's decision in Docket No. 38339 as the most authoritative precedent on this issue.[122] Staff has clearly shown that the precedent for electric utilities in the last decade has been to remove all financially based incentive compensation.[123]

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[114] *Id.* at 17.

[115] *Id.*

[116] CEHE Initial Brief at 83-84.

[117] *Id.*

[118] *See id.* at 84, fn. 601.

[119] CEHE Initial Brief at 84.

[120] Staff Ex. 4A at 12-14.

[121] Direct Testimony of John J. Reed, CEHE Ex. 23, at 12; Staff Ex. 4A at 17.

[122] CEHE Initial Brief at 84.

[123] Staff Ex. 4A at 13 (citing Docket No. 46449, *Application of Southwestern Electric Power Company for Authority to Change Rates*; Docket No. 43695, *Application of Southwestern Public Service Company for Authority to Change Rates*; and Docket No. 33309, *Application of AEP Texas Central Company for Authority to Change Rates*).

Overall, Staff's recommendation to remove amounts relating to financially based and non-financially based incentive compensation conforms to Commission policy and precedent. Staff disagrees with all of CEHE's arguments to abandon this policy and precedent.

### b. Long-Term Incentive Compensation

Consistent with the precedent and methodology for removing amounts of incentive compensation, Staff witness Mark Filarowicz recommends removing all long-term incentive compensation included in rates because CEHE represented that 100% of its long-term incentive compensation is financially based.[124]

CEHE misstates Staff's position regarding long-term incentive compensation.[125] Staff's concern lies in the fact that all of CEHE's long-term incentive compensation is financially based. Staff's recommendation conforms to Commission precedents and recommends that all financially-based incentive compensation be removed and that, where appropriate, half of other (non-financially based) incentive compensation be removed because it was based on a trigger. Because CEHE admitted in an RFI that all of CEHE's long-term incentive compensation is financially based,[126] CEHE should not now be permitted to change its position without Staff and Intervenors having the opportunity to address CEHE's position through direct testimony.

CEHE argues that "restricted stock units" (RSUs) are not financially based and should be allowed to be put into rates.[127] RSUs are indeed financially based in that they are tied to the value of CenterPoint stock, which CEHE admits.[128]

CEHE's request to include any portion of its long term incentive compensation in rates should be denied. The Commission disallows financially based incentive compensation from rates because such compensation benefits shareholders and executives (at the expense of

[124] Staff Ex. 4A at 13.

[125] CEHE Initial Brief at 88-89.

[126] Staff Ex. 4A at 57-62.

[127] CEHE Initial Brief at 88-90.

[128] *Id.* at 89.

ratepayers) and is not a reasonable and necessary expense in providing electric service to the public.[129]

### 2. Executive Employee Related Expenses

Staff presents its adjustment to non-qualified pension expense in sections IV.B.4 and IV.B.5 below.

### 3. Payroll Adjustments

Staff addressed this subject of the termination of employees under the "Vectren Issues" section (IV.D.1., *infra*) in its Initial Brief. But because this is a reply brief and CEHE addressed that same issue in its Initial Brief in this section, Staff provides its reply here.

CEHE argues that with regard to the Vectren acquisition, although the acquisition resulted in CEHE no longer having to pay 32 full-time employees (a gain of $1.65 million),[130] CEHE argues that it should be able to include in rates the transaction costs regarding these terminations in the way of paying these employees' severances, which according to CEHE, total $3.6 million.[131] Because these severance costs are a one-time cost and will not recur in future years, it is inappropriate to include them in the annual revenue requirement as CEHE requests. CEHE's arguments should be rejected here.

Staff's recommendation in this case removes the amounts related to the 32 full-time employees, as CEHE will no longer be incurring those costs and it prevents the recurrence of other non-recurring costs, such as severance packages.

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[129] *See* Docket No. 46449, *Application of Southwestern Electric Power Company for Authority to Change Rates*; Docket No. 43695, *Application of Southwestern Public Service Company for Authority to Change Rates*; and Docket No. 33309, *Application of AEP Texas Central Company for Authority to Change Rates.*

[130] Staff Ex. 4A at 25-26.

[131] CEHE Initial Brief at 96.

### 4. Pension and Other Postemployment Benefits (OPEB) Expense

Staff addressed the subject of capitalized non-qualified pension expenses under Staff's additional section II.I. in its Initial Brief. But because this is a reply brief and CEHE addressed that same issue in its Initial Brief in this section, Staff provides its reply here.

Staff witness Filarowicz's recommendation to remove capitalized amounts for non-qualified pension conforms to Commission precedent. The Commission has previously found that non-qualified pension expenses "are not reasonable or necessary to provide utility service to the public, are not in the public interest, and should not be included in [...] cost of service."[132]

CEHE's only statement on this in its initial brief is: "Mr. Filarowicz relies on a Commission decision for another utility[.]"[133] CEHE fails to provide any reasoning as to why the Commission's policy decisions and precedent that apply to every other electric utility in the State of Texas should not apply to CEHE.

CEHE's request to recover non-qualified pension expense from customers should be denied. The Commission has repeatedly found that non-qualified pension expense should not be allowed in rates and that utilities should not be allowed to earn a return on any capitalized amounts of this properly disallowed expense.[134]

### 5. Other Benefits

Staff addressed this subject of non-qualified pension expenses under the "Pension and Other Postemployment Benefits (OPEB) Expense" section (IV.B.4., *supra*) in its Initial Brief. CEHE specifically addresses non-qualified pension expense in section IV.B.5 relating to Other Benefits and in section IV.B.4 asserts that "no party challenged the Company's reliance on the 2019 actuarial studies to determine its requested pension and OPEB expense."[135] Because Staff

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[132] Staff Ex. 4A at 19-20.

[133] CEHE Initial Brief at 98.

[134] Staff Ex. 4A at 19-21 (citing Docket No. 46449, *Application of Southwestern Electric Power Company for Authority to Change Rates*, Order on Rehearing, Findings of Facts Nos. 129, 204 (Mar. 19, 2018), as well as Docket No. 40443, *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Order on Rehearing, Finding of Fact No. 227 (Mar. 6, 2014)).

[135] CEHE Initial Brief at 97.

challenges CEHE's request for pension expense regarding non-qualified (supplemental) pension expense, Staff's reply appears in this section.

Non-qualified (supplemental) pension expense is payment for an employer-sponsored retirement plan aimed at the unique retirement needs for key executive employees who earn wages far in excess of average wages.

Staff witness Filarowicz's recommendation to remove capitalized amounts for non-qualified pension is based on Commission precedent. The Commission has previously found that non-qualified pension expenses "are not reasonable or necessary to provide utility service to the public, are not in the public interest, and should not be included in [...] cost of service."[136]

CEHE's main statement in reply to this recommendation is that "Mr. Filarowicz relies on a Commission decision for another utility[.]"[137] CEHE here, as in other places, misunderstands the notion of precedent—the idea that a standard set in one case will apply to similar cases in the future. CEHE ends by making a vague and inaccurate assertion that if "shareholders should bear the BRP costs whereas customers would bear the costs for regular pension expense, [it would] conflict with the overall standard that reasonable and necessary costs must be recovered through rates."[138] Here, CEHE misses the fact that the Commission has routinely found that non-qualified pension expense for highly compensated executives is not a reasonable or necessary expense for a TDU in providing electric service to the public. Once again, CEHE presents an extraordinary request and believes that Commission precedent and policy that applies to every other electric utility should not apply to CEHE.

## C. Depreciation and Amortization Expense [PO Issue 25]

***Depreciation***

Staff witness Mr. Reginald Tuvilla reviewed CEHE witness Mr. Dane Watson's SPR and actuarial analysis and results and also performed his own SPR and actuarial analyses, using his own Excel-based models, on individual transmission, distribution, and general plant accounts to

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[136] *Id.* at 19-20 (citing Docket No. 46449, Order on Rehearing, Finding of Fact No. 204 (Mar. 19, 2018) and Docket No. 40443, Order on Rehearing, Finding of Fact No. 227 (Mar. 6, 2014)).

[137] CEHE Initial Brief at 98.

[138] *Id.*

analyze the reasonableness of CEHE's proposed life parameters.[139] Based on this comprehensive review and independent analysis, Staff is not recommending any adjustments to the Company's proposed life parameters or net salvage rates.[140]

In its Initial Post-Hearing Brief, Texas Coast Utilities Coalition (TCUC) asserts that Mr. Watson relied on "unreliable data, erroneous assumptions and flawed analysis" when conducting his Depreciation study.[141] However, TCUC fails to mention that the data, assumptions and analysis that Mr. Watson employed are not only industry standard[142] but are also consistent with Commission precedent.[143]

Staff recommends approval of CEHE's proposed depreciation rates.[144]

***Amortization***

In its Initial Brief, CEHE did not address Staff's position regarding amortization expense under this section. Staff proposed a five-year amortization for regulatory assets and liabilities (as opposed to CEHE's requested three-year period), in order to minimize the likelihood of over-recovery of these amounts. The Commission should adopt Staff's recommendation. Alternatively, Staff does not oppose—from an accounting perspective—recovery for certain regulatory assets and liabilities through a separate rider to prevent over-recovery of these amounts.

## D. Affiliate Expenses [PO Issue 35, 36]

### 1. Vectren Issues

Staff presents its adjustment relating to 32 employees whose positions were terminated as a result of the Vectren acquisition in section IV.B.3 above.

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[139] Direct Testimony of Reginald Tuvilla, Staff Ex. 9 at 3.

[140] *Id.* at 12.

[141] TCUC's Initial Post-Hearing Brief at 39.

[142] Tr. at 329:7-21 (Watson Cross) (Jun. 25, 2019).

[143] Tr. at 847:14-25 (Tuvilla Redirect) (Jun. 26, 2019).

[144] Direct Testimony of Reginald Tuvilla, Staff Ex. 9 at 3.

### 2. Compensation for Use of Capital

Staff presents its adjustment relating to carrying charges on shared assets in section IV.D.4 below.

### 3. Service Company Pension and Benefit Costs

### 4. Affiliate Carrying Charges

Staff's recommendation of an adjustment of ($4,942,320) to remove the equity portion of carrying charges associated with affiliate or shared assets follows Commission precedent on the topic—Docket Nos. 43695 and 46449—wherein the Commission disallowed such carrying charges on affiliate assets, finding that such "carrying costs are unnecessary and unreasonable."[145] In Docket No. 43695, the Proposal for Decision further elaborated, "The cost of a profit to an affiliate is an unnecessary and unreasonable expense to Texas ratepayers and is inconsistent with case law."[146]

CEHE argues, in its Initial Brief, that "[Mr. Filarowicz] admits that he has not fully followed the Commission's determination in those cases."[147] This critique is misleading. Mr. Filarowicz clearly explained that "[i]n Docket Nos. 43695 and 46449 ... the Commission disallowed such carrying charges on affiliate assets[.]"[148] In his Direct Testimony, Mr. Filarowicz stated, "I didn't include any such amounts because [CEHE] failed to provide such information on the record."[149] However, in those cases, the utilities provided information about the expenses they paid for carrying charges on shared assets that could be netted against the equity portion of the company's revenues for carrying charges on shared assets. In this

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145 Docket No. 43695, *Application of Southwestern Public Service Company for Authority to Change Rates*, Order on Rehearing, Finding of Fact No. 137 (Feb. 23, 2016); Docket No. 46449, *Application of Southwestern Electric Power Company for Authority to Change Rates*, Order on Rehearing, Finding of Fact No. 212 (Mar. 19, 2018).

146 Docket No. 43695, *Application of Southwestern Public Service Company for Authority to Change Rates*, Proposal for Decision at 157 (Oct. 12, 2015).

147 CEHE Initial Brief at 105-106.

148 Staff Ex. 4A at 27.

149 *Id.*

proceeding, Mr. Filarowicz invited CEHE to provide this information, and CEHE failed to do so. Mr. Filarowicz's testimony clearly explains how he followed Commission precedent despite the lack of information provided on the record by CEHE in this proceeding.

CEHE also argues that the Commission's precedent should not be followed because CEHE "was not a party to those cases and it is not clear whether the decisions in those cases were based on the facts of those particular cases or were intended to have broader effect."[150] However, CEHE bears the burden of proof in this case, and CEHE has not provided any legitimate reason why the Commission's policy decisions and multiple precedents should not apply to CEHE.

## E. Injuries and Damages

Staff witness Mark Filarowicz proposes an adjustment of ($2,293,936) to CEHE's request of $20.528 million (rounded) for injuries and damages. Mr. Filarowicz recommends this adjustment because CEHE's requested annual amount for injuries and damages (that of the test year) is inconsistent with CEHE's previous years' amounts for injuries and damages.[151]

Staff proposed an adjustment to include in rates an amount for injuries and damages equal to an average over a five-year period including and ending with the test year.[152] There are Commission precedents to use averages for the amount of injuries and damages included in rates. Some recent Commission precedents use an average over a three-year period.[153] Staff witness Filarowicz explained how, if he had used a three-year average instead of a five-year average, it would have led to a greater recommended reduction.[154]

In further support of its proposed reduction, Staff noted that the projected numbers for 2019 that were given by CEHE in response to Staff RFI, when extrapolated for 12 months, are

[150] CEHE Initial Brief at 106.

[151] Staff Ex. 4A, at 21.

[152] *Id.* at 21-25.

[153] *Id.* at 23, 24 (citing Docket No. 40443, *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Order on Rehearing, Findings of Fact Nos. 240-242 (Mar. 6, 2014), and Docket No. 46449, *Application of Southwestern Electric Power Company for Authority to Change Rates*, Order on Rehearing, Finding of Fact No. 217 (Mar. 19, 2018)).

[154] Staff Ex. 4A, at 24, 25.

significantly lower than what CEHE is requesting. CEHE, in its Initial Brief, responds that "reviewing costs for only a three- or four-month period is not reflective or indicative of the costs for an entire year."[155] But CEHE does not give a good reason why extrapolation based on a third of a year[156] is not reliable. CEHE merely says, in its Initial Brief, that "[d]ue to the timing throughout the year when injuries and damages costs are incurred, it is more reasonable to consider a full twelve-month period to analyze these costs."[157] CEHE's reasoning regarding the fluctuation of injury and damage expense over time is more supportive of Mr. Filarowicz's recommendation to use a five year average than it is for CEHE's request to use the injury and damage expenses incurred in the test year. Moreover, CEHE is inconsistent in applying this logic, as CEHE supports extrapolation of annual numbers based on monthly amounts when it benefits CEHE regarding vegetation management expense. Finally, Staff's recommended adjustment in this case is merely corroborated by the partial-year data; in this case, Staff proposes adjusting to an average over a five-year period including the test-year. Staff's methodology is a good representation of CEHE's historical costs and is a reasonable representation of its costs going forward.[158]

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

This issue was addressed in Staff's initial brief.

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

## H. Vegetation Management

Staff recommends $31.64 million for CEHE's vegetation management allowance, a downward adjustment of $4.62 million to CEHE's requested of $35.02 million for costs CEHE incurred in 2018. To arrive at this amount, Staff took the average of three years' worth of

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155 CEHE Initial Brief at 107.

156 Staff Ex. 4A at 23; CEHE's Response and Updated Response to PUC RFI 9-06 (May 28 and 31, 2019) at Bates 71-74 (Attachment MF-13) of Staff Ex. 4A.

157 CEHE Initial Brief at 107.

158 *See id.* at 111.

vegetation management expenses, in order to normalize the effects of factors that might skew the test year amounts.[159]

CEHE's costs for tree-trimming incurred in the test year[160] should not alone be used as the reference point for what dollar amount to allow CEHE to put in its rate base going forward.[161] The test year was an anomaly. Because of Hurricane Harvey in 2017, CEHE had not performed its typical tree trimming schedule, resulting in heightened tree trimming activities during the test year.

CEHE argues that Staff is incorrect to use a multi-year average to arrive at its recommended amount, and that Staff should simply use the same number from the test year.[162] However, where it may be established that the test year expenses are not representative of the costs apt to prevail into the future, it is appropriate to normalize the test year for known and measurable changes.

CEHE argues that Staff witness Blake Ianni uses an outdated multi-year average to come up with his number.[163] Although, Mr. Ianni used 2016-18 actual expense, which is more representative of the expected costs as it is not limited to one specific year that included abnormal costs.

CEHE also argues that Mr. Ianni's methodology of taking 2016-18 averages should not be taken into account, because it is not "[]representative of CEHE's ongoing vegetation management expenditures, especially in light of the disruption caused to these activities by Hurricane Harvey in 2017."[164] CEHE's argument is backwards. Staff's method of normalizing the timing of the non-hurricane expenditures is to take an average of three years so that the period relied upon is not skewed by either the reduction of vegetation management expense due to the incurrence of the hurricane or the excess of vegetation management expense because of

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[159] Staff Ex. 6 at 11.

[160] January 1, 2018 to December 31, 2018.

[161] Staff Initial Brief at 50.

[162] CEHE Initial Brief at 109-11.

[163] *Id.* at 110.

[164] *Id.*

the need to perform additional vegetation management. The fact that CEHE experienced a hurricane in the year before the test year and had to delay vegetation management expenses and incur them in the test year is not expected to be a regular occurrence.

## I. Smart Meter Texas Expense

## J. Loss on Sale of Land

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

To the extent that the Commission adjusts CEHE's request for return on rate base or component cost of debt, it is appropriate to adjust accordingly the calculation and amount of federal income tax included in revenue requirement.

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

### 1. Ad Valorem (Property) Taxes

To the extent that the Commission adjusts CEHE's plant in service based on other adjustments, it is appropriate to adjust accordingly the calculation and amount of *ad valorem* tax expense included in revenue requirement.

### 2. Texas Margins Tax

To the extent that the Commission adjusts CEHE's total revenue requirement based on other adjustments, it is appropriate to adjust accordingly the calculation and amount of Texas margins tax expense included in revenue requirement.

### 3. Payroll Taxes

To the extent that the Commission adjusts CEHE's requests for payroll and compensation amounts, it is appropriate to adjust accordingly the calculation and amount of payroll tax expense included in revenue requirement.

## M. Adjustment to Wholesale Transmission Changes in Retail Cost of Service (not in agreed outline)

Staff addressed this issue in its initial brief.

## V. WHOLESALE TRANSMISSION COST OF SERVICE [PO ISSUE 4, 5, 6, 37]

Staff's Initial Brief establishes the appropriate wholesale transmission cost of service of $336,923,105, which results from the flow-through effects of Staff's adjustments to CEHE's overall requested revenues and the functionalization of costs.[165] The Staff-adjusted wholesale transmission cost of service represents a decrease of $58,873,468 to CEHE's requested wholesale transmission cost of service.[166]

However, in its Initial Brief, CEHE states:

> The Company's proposed wholesale TCOS is calculated to be $394 million, which results in a transmission service rate of $5.684962 per kW per month. This calculation is uncontested and should be approved by the Commission.[167]

While Staff does not dispute CEHE's *calculation methodology*, this must be distinguished from the *amount* recommended by Staff as the appropriate wholesale transmission cost of service for CEHE, because it fails to account for the two ways in which Staff challenged CEHE's requested wholesale transmission cost of service.

First, in the cost study to determine CEHE's overall costs, Staff performed a number of adjustments to CEHE's requested overall revenues, which are necessary to remove amounts that should not be included in CEHE's overall revenues as set by the Commission. Second, Staff adjusted the functionalization of costs among its wholesale and retail rate jurisdictions. CEHE accepted two of the three functionalization adjustments (Texas Gross Margins Tax Expense[168]

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[165] Staff Initial at 54.

[166] *Id.*

[167] CEHE's Initial Brief at 116.

[168] *Id.* at 122.

and Miscellaneous Expenses in account 930.2[169]) and partially accepted Staff's third functionalization adjustment (Unprotected Excess Deferred Income Taxes).[170]

Both of these categories of challenges change CEHE's calculation of wholesale transmission cost of service, which is the numerator in the determination of CEHE's wholesale transmission access rate. Although CEHE agreed to Staff's functionalization adjustments, CEHE did not flow through the effects of that acceptance to re-calculate its wholesale transmission cost of service consistent with Staff's functionalization.

Staff's recommended cost-of-service and functionalization adjustments to CEHE's wholesale transmission cost of service amounts to $336,923,105;[171] and, its corresponding wholesale transmission access rate should be set to $4.8569719 per kilowatt of ERCOT Average 4CP demand,[172] which is calculated using the same ERCOT billing units in the denominator as were used by CEHE in its methodology.

## VI. BILLING DETERMINANTS [PO ISSUE 4, 5, 45]

### A. Weather Normalization

CEHE and Staff differ in their weather adjustments to test year sales both in the normalization period selected and the weather adjustment modeling. As acknowledged by Dr. McMenamin during the hearing, there is not only one direct method for determining weather adjustments to test year sales.[173] Rather, in making weather adjustments to test year sales, one must make a series of decisions including the weather normalization period, whether to use monthly or daily data in the weather normalization modeling, which and how many years of data to use in weather normalization modeling, and which variables should be included in performing weather normalization modeling.[174] While weather adjustments to test year sales can be made

[169] *Id.*

[170] *Id.* at 123.

[171] Staff Ex. 2A at 39.

[172] *Id.*, at 40.

[173] Tr. at 357: 6-8 (McMenamin Cross) (June 25, 2019).

[174] Tr. at 357: 6 – 362:6 (McMenamin Cross) (June 25, 2019).

through a variety of modeling techniques, the weather normalization adjustment to test year sales made by Staff's witness Ms. Maloy should be adopted because it is based on Commission precedent and clear mathematical principals.

**A 10-Year Weather Normalization Period is Based on Clear Commission Precedent**

In its initial brief, CEHE advocates for a 20-year weather normalization period stating that a 20-year period reflects recent trends in the industry as the dominant time period for determining normal weather.[175] However, as Staff discusses in its initial brief, the 10-year weather normalization period is based on Commission precedent.[176] In rate-making proceedings in 2014, 2015, and 2016, the Commission ruled that a 10-year weather normalization period is a reasonable means of capturing weather trends.[177] Additionally, the Commission requires a 10-year weather normalization period in Distribution Cost Recovery Factor applications.[178] CEHE argues that the Commission's rejection of a 30-year period and shift to a 10-year weather normalization period was consistent with trends in the industry in 2013 and that based on industry studies the trend in 2017 and 2018 shows a shift to a 20-year weather normalization period.[179] However, as both CEHE and Staff notes these industry studies were performed by Dr. McMenamin and his group themselves.[180] Furthermore, these studies were not included as an attachment to Dr. McMenamin's direct or rebuttal testimony.[181]

**Matching the Time Period of Data for Weather Normalization Modeling to the Weather Normalization Period Chosen is Consistent with Commission Practice and Mathematical Principles**

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[175] CEHE Initial Brief at 118.

[176] Staff Initial Brief at 55.

[177] Staff Initial Brief at 55; Direct Testimony of Alicia Maloy, Staff Ex. 5A at 19-20.

[178] Staff Initial Brief at 55; Staff Ex. 5A at 20.

[179] CEHE Initial Brief at 118.

[180] *Id.*; Staff Initial Brief at 55; Tr. at 366: 16-24 (McMenamin Cross) (June 25, 2019).

[181] Tr. at 357: 5-6 (McMenamin Cross) (June 25, 2019).

CEHE also argues that Dr. McMenamin's modeling should be adopted because four years of daily AMS data provides richer modeling than 10-years of monthly data.[182] In its weather normalization modeling, CEHE uses four years (2015-2018) of daily AMS data, which includes the test year of 2018. Staff uses 10-years (2008-2017), which matches its weather normalization period and excludes the test year of 2018.[183] In choosing to use monthly data, Ms. Maloy follows Commission practice. The rate filing package requires that utilities provide "data for the Test Year on a monthly basis by weather station."[184] Additionally, as Staff explained in its initial brief, if the weather normalization time period does not match the time period used for the weather regression models, then there is a mismatch of time periods used in the equation used to calculate the impact of weather on energy sales.[185] Specifically, if CEHE's four year time period data for weather regression models is used the coefficients determined from the weather regression models are based on a four year time period whereas the normalized heating and cooling degree days are determined from their 20 year normalized time period.[186]

**Excluding Test Year Data in Weather Normalization Modeling is Consistent with Commission Practice and Does Not Create Bias in the Weather Analysis**

In its initial brief, CEHE claims that it is better practice to use test year (2018) data in weather normalization modeling because it helps determine how customers in the test year reacted to changes in weather.[187] As discussed above, it is important to match the normalization time period to the time period for the data used in modeling.[188] Furthermore, as Ms. Maloy explained during the hearing, using the test year in weather regression modeling creates a bias

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[182] CEHE Initial Brief at 119.

[183] Staff Initial Brief at 56; Staff Ex. 5A at 21; CEHE Ex. 29 at 9.

[184] Staff Initial Brief at 59.

[185] Staff Initial Brief at 56-57.

[186] *Id.*

[187] CEHE Initial Brief at 119.

[188] *Supra* fn. 185.

towards the test year and the purpose in performing weather normalization is "to remove the impacts of weather from the test year."[189]

**Excluding Variables Below the 95% Confidence Level Creates Strong Models**

CEHE argues for the inclusion of variables below the 95% confidence level in the weather normalization models because Ms. Maloy has previously testified that "inclusion of variables below the 95% confidence level may still be valid to include in regression models if the variable makes theoretical sense."[190] Ms. Maloy also explains that within CEHE's residential model there are 18 variables included that are below the 95% confidence level and that the confidences levels for these variables range from 1% to 94%.[191] When a variable is not significant above a 95% confidence level, the impact of that variable may not be meaningful to the equation.[192] Correspondingly, if all the variables included in the model are significant above a 95% confidence level, the impacts of all the variables are meaningful to the equation and the coefficient for that variable provides an accurate prediction in the model. Ms. Maloy provides an example in her testimony stating "[f]or example, a coefficient for a HDD [Heating Degree Day] variable with a T-statistic above 1.96 means that there is 95% confidence that the coefficient is an accurate prediction of the correlation between the HDD variable and electricity sales."[193]

**Dr. McMenamin's Rebuttal Models**

Dr. McMenamin's rebuttal testimony should be disregarded because in his rebuttal testimony Dr. McMenamin creates a new model to compare to Ms. Maloy's regression models in order to claim that Ms. Maloy's models are incorrect.[194] His comparison model, termed the rebuttal model, changes the variables and constants used and instead of using 10 years of

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[189] Staff Initial Brief at 57; Tr. at 887: 13-18 (Redirect Maloy) (June 26, 2019).

[190] CEHE Initial Brief at 119.

[191] Staff Initial Brief at 58; Staff Ex. 5A at 23-24.

[192] Staff Ex. 3A at 15.

[193] *Id.*

[194] Staff Initial Brief at 58-59.

monthly data for modeling, Dr. McMenamin uses 4 years of daily data in his modeling.[195] Therefore, his comparison is simply a manipulation of mathematical modeling in order to achieve his desired result. As discussed, the rebuttal model he creates serves no purpose; he does not recommend the results from his rebuttal model for his weather normalization adjustment.[196]

Overall, Staff's 10-year weather normalization period should be adopted as well as Staff's weather normalization modeling results performed by Ms. Maloy. The normalization period and modeling results recommended by Staff follow Commission precedent and follow clear mathematical principles.

## B. Energy Efficiency Program Adjustment

CEHE recommends an Energy Efficiency Program (EEP) adjustment that would increase rates for certain rate classes by an estimated amount of kWh savings due to energy efficiency measures installed during the test year under CEHE's energy efficiency programs.[197] CEHE claims that the EEP adjustment is a known and measurable adjustment, that it is similar to the standard customer adjustment, that it is required under PURA and Commission rules, and that the adjustment is different from the Company's previous lost revenue adjustment mechanism (LRAM) proposals that have been repeatedly rejected by the Commission in the past.[198]

CEHE's proposed EEP adjustment should be rejected, as it does not meet the "known and measurable" standard required under the Commission's rules, is not similar to the standard customer adjustment, is not required under PURA and the Commission rules, and as it is substantively identical to the Company's similar LRAM requests rejected by the Commission in previous proceedings.[199]

### i. The EEP Adjustment is not Known and Measurable

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[195] *Id.*

[196] *Id.* at 59.

[197] Staff Initial Brief at 60; Direct Testimony of William Abbott, Staff Ex. 7 at 6.

[198] CEHE Initial Brief at 120.

[199] Staff Ex 7. at 15 – 16.

CEHE claims that the EEP adjustment is known because it is based on programs that were put in place during the test year, and measurable because the energy usage impacts on test year billing determinants are calculated using the Commission's own deemed savings standards in the Technical Reference Manual (TRM), which is used in other proceedings to set rates pursuant to 16 TAC § 25.181(q).[200] That the energy efficiency programs were implemented during the test year is not the focus of the dispute here; it is the inaccuracy and unreliability of the energy efficiency savings estimates that fails to meet the known and measurable standard. As discussed by Staff witness William Abbott, the TRM clearly indicates that the energy efficiency savings values included therein are estimates, not known and measurable values.[201] Additionally, the Commission's own alternative ratemaking report to the Legislature pointed out that energy efficiency savings values have "dubious reliability," that calculating them "is problematic and controversial," and that relying on them to increase rates creates "significant risk of over-estimating efficiency gains, thus over-compensating utilities and over-charging customers."[202] CEHE's only response to the unreliability of the energy efficiency savings values is to note that they are used to calculate Energy Efficiency Cost Recovery Factor rates under 25.181.[203] CEHE fails to note that the Company's proposed use of energy efficiency savings to adjust billing determinants in this proceeding is entirely different from how those savings are used to establish EECRF rates under the Commission rules. CEHE witness Troxle admits that there is no requirement that energy efficiency savings be used to adjust billing determinants in calculating EECRF rates,[204] and that instead, the energy efficiency savings are used to determine whether a utility has met its energy efficiency goal and to calculate the energy efficiency bonus recoverable under the EECRF.[205] Mr. Troxle also acknowledges that EECRF rates are trued-up for any past over- or under-recoveries, thus making the precision of EECRF billing determinants a relatively

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[200] CEHE Initial Brief at 120-121.

[201] Staff Ex. 2A at 9-10.

[202] *Id.* at 11-12.

[203] CEHE Initial Brief at 120.

[204] Staff Ex. 19.

[205] Staff Ex. 20 and 21.

less significant issue compared to the billing determinants used to set base rates in this proceeding.[206] Staff does not take issue with the reasonableness and appropriateness of using energy efficiency savings estimates to comply with the energy efficiency goals under PURA § 39.905 and the requirements of 16 TAC § 25.181,[207] rather Staff takes issue with CEHE's claim that these estimates are sufficiently known and measurable to meet the standard required under 16 TAC § 25.234 for CEHE to meet its burden of proof with regard to this billing unit adjustment to increase base rates.

#### ii. The EEP Adjustment is Substantially Different Than the Customer Adjustment

CEHE's initial brief makes no attempt to address Staff witness Mr. Abbott's testimony that the proposed EEP adjustment is substantially different that the standard customer adjustment to billing determinants. As Mr. Abbott noted, the number of a utility's customers at the end of a test year is clearly a known and measurable quantity,[208] unlike the imprecise energy efficiency savings estimates. Furthermore, Mr. Abbott notes that the appropriateness of a customer adjustment is attested to by its inclusion in the Commission-approved rate filing package (RFP) for TDUs.[209] While not determinative, the fact that an EEP adjustment is not included in the RFP despite almost two decades of energy efficiency programs indicates the extraordinary nature of CEHE's request.[210]

#### iii. The EEP Adjustment is not Required Under PURA and the Commission Rules

CEHE's assertion that the EEP adjustment is required under PURA and the Commission Rules is unsupported by any reference that does not beg the question as to whether the adjustment meets the "known and measurable" standard. Energy efficiency goals have been

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[206] Staff Ex. 22.

[207] Staff Ex. 2A at 13.

[208] *Id.* at 13-14.

[209] *Id.* at 14.

[210] *Id.*

mandated by Commission rule since at least the year 2000.[211] Despite almost two decades of energy efficiency programs, CEHE has not identified any rate proceeding in which an EEP adjustment was approved by the Commission. CEHE's contention that an EEP adjustment is required under PURA and the Commission rules, yet has never been implemented in almost twenty years of energy efficiency programs, simply defies logic. Notably, Mr. Abbott's testimony demonstrates that CEHE's claims that an increase to rates was necessary under PURA to account for energy efficiency savings have been previously considered, and rejected, by the Commission.[212]

### iv. The EEP Adjustment is Substantively Identical to the Rejected LRAM

CEHE attempts to distinguish the EEP adjustment from previous LRAM proposals rejected by the Commission by reference to Mr. Troxle's claims that an LRAM is "usually" a forward-looking mechanism based on changes after the test year.[213] In contrast to Mr. Troxle's testimony regarding hypothetical LRAM mechanisms, CEHE's actual past LRAM proposals were based on *past* energy efficiency savings. Mr. Abbott's testimony points out that CEHE's 2010 LRAM proposal in Docket No. 38213 was, in CEHE's own words, to recover lost revenue due to verified and reported 2009 energy efficiency savings.[214] Similarly, CEHE's 2011 LRAM proposal in Docket No. 39363 requested lost revenues due to verified and reported 2010 energy efficiency savings.[215] In both of those dockets, the Commission excluded LRAM as an issue to be addressed, as the relevant statute did not allow for an LRAM.[216] These decisions resulted in the exclusion of LRAM as issue to be addressed in CEHE's last base rate case, Docket No. 38339.[217] CEHE's proposed EEP adjustment in this 2019 proceeding is based on EE savings

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211 *Energy Efficiency Programs*, Project No. 21074 (Mar. 21, 2000).

212 Staff Ex. 7 at 15.

213 CEHE Initial Brief at 121.

214 Staff Ex. 7 at 18.

215 *Id.*

216 *Id.*

217 *Id.* at 16.

from the 2018 test year, and therefore is not substantially different from the actual LRAM proposals previously rejected by the Commission. The record indicates no attempt by CEHE to distinguish its current EEP proposal from the *actual* LRAM proposals that the Commission considered and rejected.

CEHE's proposal results in higher rates than in the absence of the adjustment.[218] Because CEHE's proposal is based on estimated amounts instead of known amounts and the Commission has previously declined to include similar requests in CEHE's last base rate case and EECRF's, CEHE's energy efficiency program adjustment proposal should be rejected.

# VII. FUNCTIONALIZATION AND COST ALLOCATION [PO ISSUES 4, 5, 43, 44, 46]

## A. Functionalization

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

Staff's Initial Brief recommended rejection of the functionalization of Texas Gross Margins Tax expense that was presented by CEHE in its direct case, and adoption of Staff's functionalization approach.[219] CEHE's functionalization was inconsistent with cost causation, due to the fact that it would collect costs associated with serving CEHE's retail customers from wholesale transmission service customers across the ERCOT grid.[220] In its rebuttal testimony, CEHE agreed with Staff's recommended functionalization.[221]

However, in its initial brief COH/HCC, states that it supports the recommendation of the Company.[222] COH/HCC is incorrect. The Company accepts Staff's position on this issue.[223] COH/HCC states that its position is consistent with the Commission's Order in Docket No.

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218 Staff Ex. 18.

219 Staff Ex. 2A at 28 and Table BTM-2 at 32.

220 *Id.* at 28 – 29.

221 Rebuttal Testimony of Kristie Colvin, CEHE Ex. 35 at 47.

222 COH/HCC Initial Brief at 31.

223 CEHE Ex. 35 at 47: Q. DOES THE COMPANY AGREE WITH THE STAFF'S POSITION FOR THE TEXAS MARGIN TAX FUNCTIONALIZATION FACTOR? A. Yes.

38339. However, the functionalization of Texas Gross Margins Tax expense was not contested in Docket No. 38339.[224] COH/HCC states that Staff is the only party that takes issue with the precedent from Docket No. 38339.[225] However, in addition to the Company's acceptance of Staff's position, Texas Industrial Energy Consumers (TIEC) also supports Staff's position.[226] In fact, it is COH/HCC who is alone in supporting the functionalization methodology that was uncontested in Docket No. 38339.

The basis for COH/HCC's position is that it believes Staff has counted Account 565 (transmission of electricity by others) twice in its analysis.[227] COH/HCC states that the basis for its belief is that "$942.6 million in costs suggested by him is equal to the sum of the $395.8 million and $546.7 million wholesale costs presented by the Company."[228] But, in the testimony COH/HCC cites to, Mr. Murphy clarifies that the $942.6 million does not represent the sum of the $395.8 million and the $546.7 million amounts, stating:

> Q. Okay. So the 942.6 number includes 395.8?
> A. 395.8 is a smaller number than 942.6, but the 395.8 in the wholesale column here is not part of the 942.6 that's in the retail column shown under – under my part of the correct approach they are different revenue amounts.
>
> ...
>
> Q. Okay. I think maybe we've, again, misunderstood each other. Does the 942.6 at the very least encompass the number 395.8?
> A. No, it does not.

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224 Staff Ex. 2A at 32: Q. The Company states that its approach "is also consistent with the functionalization factor that was approved in Docket No. 38339." How do you respond? A. The issue was not contested in Docket No. 38339.

225 COH/HCC Initial Brief at 31.

226 TIEC Initial Brief at 4: 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.

227 COH/HCC Initial Brief at 31.

228 *Id.* at 32.

COH/HCC's confusion arises from an idiosyncrasy in how the Company presented its cost study in this case. As Staff witness Murphy explained in his direct testimony:

> The wholesale revenue requirement is overlaid within the retail cost of service's transmission function, and Account 565 is used in that function as a plug to ensure that the transmission functional "revenue requirement" ties to the Company's total wholesale transmission expenses, which are costs associated with serving CEHE's retail customers that the Company incurs in its role as a DSP.[229]

The confusion disappears when the Company's requested revenues in this proceeding are reviewed. The Company's originally requested *wholesale* transmission revenue requirement is $395,796,573.[230] In developing his functionalization of Texas Gross Margins Tax expense, Staff witness Murphy placed the full amount of the Company's wholesale transmission revenue requirement in the wholesale column where it belongs.[231] The Company's originally requested *retail* delivery revenue requirement is $2,282,203,678.[232] Included within the retail delivery revenue requirement is the total amount of wholesale transmission charges (ERCOT transmission payments) incurred by CEHE acting in its role as a DSP, in the amount of $942,402,945.[233] Staff witness Murphy testified:

> ... the Company's total wholesale transmission charges are the responsibility of CEHE acting in its role as DSP; are included in the cost of service for each retail class; and, are shown under each retail class's rate schedule as "transmission system charges."[234]

The full amount of $942,402,945 is a component of the Company's originally requested retail revenue requirement and belongs in the "retail" column in the development of the functionalization of Texas Gross Margins Tax expense. The full amount of $395,796,573

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229 Staff Ex. 2A at footnote 3.

230 CEHE Ex. 1 at 12, column (b).

231 Staff Ex. 2A at 30.

232 CEHE Ex. 1 at 12.

233 CEHE Ex. 1, at Schedule III-A TCOS Calculation. *See* electronic copy of the RFP, workpaper "Schedule H-I-J and CA.XLS," worksheet "II-A TCOS Calculation," at Microsoft Excel row 25.

234 Staff Ex. 2A at 17.

represents the Company's originally requested wholesale revenue requirement and belongs in the "wholesale" column. In this proceeding, the Company's retail rates will be set to fully recover the wholesale transmission charges that the Company incurs as a DSP; and, the Company's wholesale transmission rates will be set to fully recover the wholesale transmission costs that the Company incurs as a TSP. Those rates will generate revenues subject to Texas Gross Margins Tax. Staff witness Murphy testified:

> Q. How does CEHE collect wholesale transmission revenues and retail delivery revenues?
>
> A. In this proceeding, CEHE's wholesale transmission rates and retail delivery rates will be set by the Commission. After the rates are set, CEHE will collect revenues based on its sales (billing units) multiplied by its rates. Wholesale revenues will be wholesale transmission rates multiplied by ERCOT billing units. Retail delivery revenues will be retail delivery rates multiplied by retail billing units. Texas Margins Tax will be levied on CEHE's revenues collected from each rate jurisdiction—wholesale and retail.[235]

The $395.8 million amount and the $942.4 million amount referenced by COH/HCC are not overlapping revenue amounts that are somehow being double-counted. The $395.8 is the full amount of the Company's originally requested wholesale transmission revenue requirement. The $942.4 million is the full amount of the wholesale transmission charges (ERCOT transmission payments) assigned to CEHE as a DSP and the full amount is included in the Company's originally requested retail delivery revenue requirement, to be collected in full under the Company's retail rates under the "transmission system charge" component of base rates, as stated in the above block quotes from Mr. Murphy's testimony. Upon reviewing Mr. Murphy's testimony, the Company accepted Staff's position in rebuttal.

### 2. Miscellaneous General Expense (account 930.2)

CEHE requests $146.2 million in FERC Account 930.2.[236] Staff supports CEHE's approach of directly assigning 3.6% of the expenses in FERC Account 930.2 to customer

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[235] Staff Ex. 2A at 26.

[236] *Id.* at 34.

service, but recommends a more granular approach to the functionalization of the balance of the requested amount, which better reflects cost causation.[237]

In its rebuttal testimony, CEHE agreed with Staff's recommendation.[238] No other party addressed this particular issue in its initial briefs.

### 3. Unprotected Excess Deferred Income Tax

UEDIT represents a portion of excess ratepayer-funded tax payments that CEHE must refund to customers. Staff's Initial Brief recommended rejection of CEHE's proposed assignment of UEDIT that remains to be returned to customers solely to retail distribution rates, as collection of the excess tax payments occurred from both wholesale and retail customers, and therefore should be credited back to both wholesale and retail customers.[239]

CEHE states that its proposed allocation of the refund solely to retail customers is reasonable, and defers to the Commission regarding allocating a portion of the fund to wholesale transmission customers.[240]

COH argues that Staff's allocation method is arbitrary,[241] and that Staff did not provide a reason to use the functionalization as in Docket Nos. 48065 and 48226, a proceeding to set CEHE's wholesale transmission rates and DCRF proceeding, respectively. However, Staff witness Mr. Murphy, in justifying the allocations, stated that, in Docket Nos. 48065 and 48226, CEHE functionalized 24.5% of UEDIT to wholesale transmission and 75.5% to retail distribution.[242] Here, however, CEHE allocated 100% retail distribution without any explanation as to why it sought to change the functionalization established in the previous dockets, or why it is appropriate to take excess tax payments made by wholesale customers and refund those

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[237] *Id.* at 35.

[238] CEHE Ex. 35 at 48.

[239] *Id.* at 69.

[240] CEHE Initial Brief at 123.

[241] COH Initial Brief at 33.

[242] Staff Ex. 2A at 69.

wholesale overpayments to retail customers. Neither CEHE nor COH contests the fact that a portion of the UEDIT was originally collected from wholesale customers.

Thus, Staff recommends adoption of its functionalization of Rider UEDIT, as it is consistent with the functionalization in CEHE's previous dockets concerning the same funds, and it would be inequitable to refund the wholesale share of UEDIT credits to retail customers.

## B. Class Allocation

### 1. Class Allocation of Transmission Costs

As in its Initial Brief,[243] and based on the adjustments contained in Staff's testimony, Staff recommends adoption of Staff's class cost of service, as demonstrated by the table below.[244] These amounts are all flow through impacts of Staff's recommended adjustments.

**Class Cost of Service (thousands of dollars)**

| Class | CEHE[245] | Staff[246] |
|---|---|---|
| Residential | 1,217,815 | 1,164,020 |
| Secondary Small | 30,607 | 28,898 |
| Secondary Large | 739,867 | 710,523 |
| Primary | 70,090 | 66,283 |
| Transmission | 162,434 | 146,540 |
| Lighting - SLS | 58,265 | 51,458 |
| Lighting - MLS | 3,127 | 2,687 |
| TOTAL | 2,282,205 | 2,170,409 |

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

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243 Staff Initial Brief at 68-69.

244 Staff Ex. 2A, Table BTM-10 at 48.

245 CEHE Ex. 30 at 2.

246 *See* Staff Ex. 2C.

Staff recommended adherence to longstanding and unbroken Commission precedent in the class allocation of wholesale transmission charges, or ERCOT transmission payments, by continuing the practice of allocating the charges in proportion to class demand coincident with ERCOT 4CP at source.[247] Correspondingly, Staff recommended rejection of CEHE's proposal to use the CEHE 4CP to allocate the costs.[248] In addition to adhering to precedent, Staff's proposal directly aligns CEHE's retail cost recovery of transmission expenses with the customer classes causing those transmission expenses to be incurred, consistent with the Commission's rules.[249] TIEC's witness, Jeffry Pollock, also recommended Staff's proposed allocation.[250]

There are two types of transmission costs at issue in this proceeding. First, there are the costs CEHE incurs while acting in its role as a transmission service provider (TSP) to build out its transmission system as a portion of the overall ERCOT transmission grid.[251] Those costs are included in CEHE's wholesale transmission cost of service (TCOS)[252] and divided by the ERCOT 4CP to calculate CEHE's wholesale transmission rate, which will be assessed to all wholesale transmission customers (the DSPs) in ERCOT based on their ERCOT 4CP loads.[253] Second, there are the wholesale transmission charges (or ERCOT transmission payments) that are incurred by CEHE while acting in its role as a distribution service provider (DSP).[254] These costs are included in CEHE's retail cost of service, and included in CEHE's retail delivery rates. Through CEHE, in its role as a DSP, CEHE's retail customers receive transmission services from the entire ERCOT transmission grid and must pay all of the ERCOT TSPs for the use of the grid.[255]

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247 Staff Ex. 2A at 47.

248 Staff Initial Brief at 69; Staff Ex. 2A at 43 – 44.

249 16 TAC § 25.192 and 16 TAC § 25.234.

250 Direct Testimony of Jeffry Pollock, TIEC Ex. 1 at 13-14.

251 Staff Ex. 2A at 12.

252 *Id.*, at 10.

253 *Id.*, at 15.

254 *Id.*, at 16.

255 *Id.*, at 17.

The most important principle in cost allocation is cost causation.[256] Cost causation is an inquiry into the nature of the costs to ascertain how the costs should be allocated.[257] Since there are two types of transmission costs in this case, there are two separate inquiries into the nature of the costs and two different answers as to what causes the costs. The fatal flaw in CEHE's proposed methodology for the allocation of wholesale transmission charges among retail rate classes is that CEHE has confused what causes CEHE to incur wholesale transmission costs as a TSP with what causes CEHE to incur wholesale transmission charges as a DSP, a part of its retail cost of service.[258]

CEHE states:

> The basic premise behind the use and application of [the Coincident Peak Demand] allocator is that utilities build infrastructure to meet peak system demand. Therefore, a class's demand directly influences investment and supporting operations, justifying the Coincident Peak Demand method as the basis for cost allocation.[259]

In other words, because CEHE claims that it incurs transmission costs as a TSP based on class demands coincident with its own system, those same demands should be used to allocate wholesale transmission charges (assessed to the CEHE as a DSP) among the CEHE's retail classes.

However, CEHE while acting in its role as a DSP does not incur wholesale transmission charges based on customer demands coincident with CEHE's own system's peak demands. Consistent with 16 TAC § 25.192(b)(1), as a DSP, CEHE incurs wholesale transmission charges[260] based on class demands coincident with the peak demands on the entire ERCOT transmission grid.[261] In the case of wholesale transmission charges, there is no ambiguity about

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[256] *Id.*, at 18.

[257] *Id.*

[258] *Id.* at 17.

[259] CEHE Initial Brief at 124.

[260] Staff Ex. 2A at footnote 19: 16 TAC § 25.192(b)(1): ... The monthly transmission service charge to be paid by each DSP is the product of each TSP's monthly rate as specified in its tariff and the DSP's previous year's average of the 4CP demand that is coincident with the ERCOT 4CP.

[261] *Id.*, at 44: Q. What causes CEHE's DSP Avg 4CP? A. Class load imposed on CEHE's system at the time of the ERCOT peak load, measured at source. Put differently, DSP Avg 4CP load is an aggregation of class

what causes the costs to be incurred. PURA § 35.004(d) and 16 TAC § 25.192(b)(1) require that wholesale transmission charges be assessed based on demand coincident with the peak demands of the entire ERCOT transmission grid, which are not the same as CEHE's system peak demands.[262] No party disputes this fact.

Transmission costs CEHE incurs as a TSP and transmission charges CEHE incurs as a DSP differ in several ways. As a TSP, CEHE's wholesale transmission costs will be assessed to all wholesale customers (DSPs) on the ERCOT grid.[263] CEHE's Staff-adjusted wholesale transmission cost of service is $336,923,105.[264] Based on the 2018 ERCOT 4CP load data approved in the most recent wholesale transmission matrix,[265] approximately 75% of CEHE's wholesale transmission rate revenues will be collected from other DSPs, and about 25% of CEHE's wholesale transmission rate revenues will be collected from itself (in its role as a DSP),[266] or about $83,230,776.[267]

As a DSP, CEHE also pays about 25% of the wholesale transmission charges imposed by all other 48 TSPs on the ERCOT transmission grid. Of CEHE's total incurred wholesale transmission charges (as adjusted by Staff) in the amount of $927,700,584,[268] only $83,230,776, or approximately 9%, represents recovery of the costs included in CEHE's wholesale transmission service rate. The other 91% of the wholesale transmission charges to CEHE represents recovery of the charges from the other 48 TSPs in ERCOT. Nonetheless, under CEHE's proposal, the entire amount of wholesale transmission charges to CEHE as a DSP would

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load coincident with ERCOT 4-CP load. Class load coincident with ERCOT 4-CP causes CEHE to incur ERCOT transmission payments.

[262] *Id.*: "Class loads at the time of the peak of CEHE's distribution system are not the same as loads coincident with ERCOT 4CP."

[263] *Id.*, at 15.

[264] *Id.*, at 39.

[265] TIEC Ex. 34.

[266] Staff Ex. 2A at 16.

[267] 0.25 x $336,923,105 = $84,230,776.

[268] Staff Ex. 2A at 41: "CEHE's ERCOT transmission payments consistent with Staff's recommended wholesale TCOS amounts to $927,700,584, which represents a downward adjustment of $14,702,361 as compared to CEHE's requested ERCOT transmission payments in the amount of $942,402,945."

be allocated among classes on the basis of the peak demands on CEHE's own system—which is only one of the 49 TSPs in ERCOT.

If CEHE is concerned that the demands that cause it to incur transmission costs as a TSP do not correspond with the ERCOT 4CP demands that are used to recover the CEHE's wholesale transmission costs from wholesale customers, the appropriate venue to hear those arguments would be in a rulemaking to change the Commission's transmission pricing rule, 16 TAC § 25.192.[269] The transmission pricing rule[270] is not open for revision, and a base-rate proceeding for a single TDU is not the appropriate venue in which to implement a sweeping change to transmission pricing in ERCOT, which would affect all 49 TSPs and more than one hundred DSPs across the State.[271]

When it comes to wholesale transmission charges, cost causation is crystal clear. At the hearing on the merits, Staff witness William Abbott testified:

> Substantive Rule 25.192 mandates how cost causation occurs in this situation. It says wholesale transmission charges are charged to distribution service providers based upon their 4CP -- their ERCOT 4CP load. So this is the most clear-cut case of cost causation I think there is. The rules say how those costs are incurred.[272]

CEHE's proposal is inferior to Staff's and TIEC's because it is unequivocally at odds with what causes CEHE to incur wholesale transmission charges as a DSP. CEHE's proposal would cause wholesale transmission charges to be assessed to customers on a different basis than what causes the costs to be incurred by CEHE. This would create a "free rider" situation, where customers that cause costs to be incurred do not pay those costs in their rates. CEHE's proposal to use its own system peak demands to allocate the costs among classes is inconsistent with cost causation and precedent, and should be rejected.

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[269] Tr. at 930 (Abbott Cross) (Jun. 26, 2019): "In this case, we're not -- this is not a rulemaking to revise [16 TAC § 25.192]. So I'm taking [25.192] as a given. And [25.192] says CenterPoint's wholesale transmission expenses, which is the costs we're talking about allocating and designing rates around here, under that rule, those costs are caused by CenterPoint's ERCOT 4CP. So to establish an allocation factor for transmission costs or rate design for transmission costs that is different from one based upon the ERCOT 4CP load would be inconsistent with how those costs are caused under [25.192]."

[270] 16 TAC § 25.192.

[271] Staff Ex. 2A at 14.

[272] Tr. at 924:3-9.

In addition to using incorrect demand measurements, CEHE's approach also measures the demands at the wrong place in the system. CEHE uses "at meter" demands to allocate the costs,[273] but wholesale transmission charges are not assessed based on at-meter demands, they are assessed based on the demand imposed by CEHE on the ERCOT transmission system, which occurs at the source, not at the meter. Each year, ERCOT posts the demands of all DSPs at the time of the ERCOT system peak demands. Those ERCOT 4CP demands are used to assess wholesale transmission charges. The demands are measured "at source,"[274] which is where the DSP connects to the ERCOT transmission grid,[275] not "at meter," which is where the retail customer connects to the DSP's own system.[276]

The use of "at meter" information distorts the class allocation because it fails to account for the line losses that occur to distribute power to different customer classes. Power is lost as it is distributed through the system to customers' points of delivery. Generally speaking, losses increase at lower voltages. Customers who take service "upstream" at higher voltage, such as retail transmission customers, do not cause as much line losses as customers who take service "downstream" at lower voltage, such as residential customers. For this reason, the use of "at meter" demand information, which does not account for line losses, is inferior to the use of "at source" information which accounts for the relative line losses of the classes, resulting in an alignment of the class's at-source demand with the at-source demand measured by ERCOT and used to assess wholesale transmission charges to CEHE as a DSP.

CEHE's proposal to measure demands at meter should also be rejected. The demands should be measured at source, consistent with Staff's and TIEC's positions.

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[273] CEHE Initial Brief at 123.

[274] Staff Ex. 2A at 44: Q. What causes CEHE's DSP Avg 4CP? A. Class load imposed on CEHE's system at the time of the ERCOT peak load, measured at source.

[275] *Id.*, at 11: "Power is transmitted throughout the grid from the source (a market generator) to points of interconnection with the grid's wholesale customers (distribution utilities throughout the grid)."

[276] *Id.*, at 15: "The Company receives power from the ERCOT transmission grid, distributes the power through its distribution system, and delivers the power to its end-use retail delivery customers."

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

Staff recommended usage of the ERCOT 4CP class allocation factor for transmission cost allocation.[277] An ERCOT 4CP allocation is appropriate for these transmission costs because it is consistent with cost causation, the Commission's rules, and longstanding precedent, as explained above.

Staff, in recommending usage of ERCOT 4CP, rejects HEB's and TCPA's proposal to use the NCP allocation factor for transmission costs. However, Staff is not opposed to using the class NCP allocation factor for distribution costs.[278] Using the class NCP cost allocation factor for demand-related distribution costs is reasonable, and is consistent with standard Commission practice.[279] A class NCP allocation is appropriate for distribution costs because most elements of the distribution system must be sized to handle localized loads that may peak at times different than the system peak.[280]

HEB and TCPA argue for the application of the NCP allocation factor for transmission costs, rather than the 4CP allocation factor, as supported by CEHE, Staff, and TIEC.[281] HEB argues that using NCP "more fairly allocates costs among customer classes and better aligns with the market principles of ERCOT's energy only market."[282] It also posits that "a reduction in ERCOT 4CP demand does not result in a system-wide reduction of the ERCOT TCOS that will be apportioned amongst the TSPs."[283] The crux of HEB's and TCPA's TCOS arguments is their claims that customers that reduce their 4CP load cause costs to be shifted between ratepayers,

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277 Staff Initial Brief at 71; Staff Ex. 7B at 9 - 10.

278 Staff Ex. 7B at 9.

279 *Id.* at 31.

280 *See* Final Order, Docket No. 43695, Findings of Fact 278, 279, 281, 282, and 359.

281 HEB Initial Brief at 36.

282 *Id.*

283 *Id.*

and does not cause costs to be avoided.[284] HEB and TCPA fundamentally misunderstand both Staff's position as well as how transmission cost recovery works in ERCOT, as discussed futher below. Furthermore, HEB's and TCPA's proposed solution, an NCP allocation and rate design, conflicts with the very remedy that the Commission considered to address potential 4CP "gaming" concerns.

The Commission has never approved usage of an NCP allocation factor for transmission costs.[285] Moreover, HEB's and TCPA's request largely rely on reports published by the ERCOT Independent Marketing Monitor (IMM) and William Hogan and Susan Pope (Hogan-Pope Report),[286] reports that primarily concern wholesale electricity market issues, the majority of which are unrelated to regulated utility rate design.[287] The Commission has acknowledged that adopting the Hogan-Pope Report recommendations with regard to transmission cost recovery would require a change to law.[288] As Staff witness Mr. Abbott described, the reports' narrow focus on wholesale energy market impacts fail to consider the broader public interest,[289] they conflict with established ratemaking criteria,[290] and it would be inappropriate to rely upon the reports when it comes to regulated ratemaking. Contrary to HEB's and TCPA's "gaming" claims, customer load reductions around the ERCOT 4CP represent a normal and healthy economic response.[291]

In advocating their positions, it becomes clear that HEB and TCPA misunderstand both Staff's arguments supporting a 4CP allocation factor, as well as the details regarding transmission cost recovery in ERCOT. Perhaps due to imprecise use of terminology among

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[284] HEB Initial Brief at 39; TCPA Initial at 3.

[285] Staff Ex. 2A at 43.

[286] Staff Ex. 7B at 29.

[287] *Id.* at 36.

[288] *Id.* at 36-37.

[289] *Id.* at 37-38.

[290] *Id.* at 41-42.

[291] *Id.* at 40-41.

stakeholder discussion at ERCOT, several parties mischaracterize the details of wholesale transmission cost recovery within the ERCOT region.[292]

**Staff's Position**

Under 16 TAC § 25.234, rates must be based on cost. Additionally, pursuant to 16 TAC § 25.192(b)(1), pertaining to transmission service rates, wholesale transmission rates are based on the ERCOT 4CP load, because it is what causes CEHE to incur those costs.

The retail transmission rates are a resulting pass through of the wholesale transmission service charges that CEHE pays as a distribution service provider for wholesale transmission service.[293]

Thus, cost causation principles, as required by 16 TAC § 25.234, require that CEHE's transmission costs, incurred based on ERCOT 4CP load,[294] should, in turn, be allocated based on ERCOT 4CP load. In order to be consistent, transmission costs should be allocated, and the retail customers should be charged, based on their ERCOT 4CP load. For transmission costs, an ERCOT 4CP class allocation and rate design are unambiguously the most consistent with cost causation under the Commission's substantive rules.

**HEB and TCPA Misunderstand Staff's Argument**

HEB claims that Staff's reasoning is "circular" and "conclusory".[295] TCPA erroneously claims that Mr. Abbott testified that "PURA § 35.004(d) and 16 TAC § 192.(b)(1) mandate use of the 4CP method for transmission cost allocation to retail customers".[296] These claims are based on misreadings or misunderstandings of Staff's position as well as of wholesale transmission cost recovery in ERCOT. Throughout their briefs, these parties conflate *wholesale*

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[292] CEHE Initial Brief at 123-125; HEB Initial at 36; and TCPA Initial at 1-7.

[293] Tr. at 1006:6-11 (Troxle Cross).

[294] 16 TAC § 25.192(b)(1).

[295] HEB Initial Brief at 39.

[296] TCPA Initial Brief at 4.

transmission issues with *retail* transmission cost recovery. HEB and TCPA also repeatedly conflate wholesale and retail cost recovery issues and raise arguments against the 4CP rate design for wholesale transmission rates required under 16 TAC § 25.192, while attempting to apply those arguments against the allocation and rate design associated with CEHE's pass-through of those wholesale transmission charges to retail customers at issue in this proceeding.

Unlike HEB and TCPA, Staff takes 16 TAC § 25.192(b)(1) as a given, as no party has requested a good cause exception to the ERCOT 4CP rate design for wholesale transmission rates that is mandated under that rule, and as 48 of the 49 TSPs that charge wholesale transmission rates in ERCOT are not parties to this proceeding. HEB's and TCPA's arguments against 16 TAC § 25.192(b)(1) in this proceeding are therefore misplaced. With this understanding, Staff's position as to the transmission cost allocation and rate design issues *in this proceeding* can be summarized in the following manner:

1. PURA § 35.004(d) mandates a coincident peak rate design for TSP's wholesale transmission rates in ERCOT.
2. 16 TAC § 25.192(b)(1) more specifically requires that the coincident peak rate design for TSP's wholesale transmission rates is one based on the ERCOT 4CP.
3. Therefore, it is unambiguous that it is CEHE's customers' ERCOT 4CP loads that cause CEHE to incur wholesale transmission charges as a DSP.
4. CEHE's transmission costs (ERCOT transmission payments) are a "pass-through" to retail customers of the wholesale transmission charges that CEHE incurs as a DSP.
5. Title 16 TAC § 25.234 requires that rates be based on cost (cost causation). Title 16 TAC § 25.192(b)(1) establishes that customer's ERCOT 4CP is what causes CEHE's ERCOT transmission payments.
6. Therefore, cost causation (as required by 16 TAC § 25.234) dictates that CEHE's transmission costs, which are incurred based on ERCOT 4CP load (as required by 16 TAC § 25.192), should be allocated to classes based on ERCOT 4CP load, and that it is appropriate to charge individual customers based on their ERCOT 4CP load.

There is no circularity in Staff's arguments, as Staff simply rejects HEB and TCPA's arguments against the wholesale transmission rate design established under 16 TAC § 25.192(b)(1) as irrelevant to this proceeding. An ERCOT 4CP allocation and rate design for transmission costs are unambiguously the most consistent with cost causation under the rules.

**HEB, TCPA, and CEHE Misunderstand Wholesale Rate Recovery in ERCOT**

HEB, TCPA, and CEHE witness Mr. Troxle are fundamentally incorrect in their understanding or characterization of wholesale transmission cost of service cost recovery in ERCOT. Wholesale transmission rate recovery works just as most rate recovery works in Texas – a rate is calculated based on cost of service (the transmission cost of service, or TCOS, here), and, once that rate is established, customers (DSPs here) are charged based on the rate (the TSP's wholesale transmission rate), multiplied by their billing units (the DSP's ERCOT 4CP load). This cost recovery approach of using TCOS to calculate a *rate* which is charged based on load is established under PURA § 35.004(d) and 16 TAC § 25.192(b)(1), which states that a TSP's wholesale transmission rate shall be calculated as its TCOS divided by the ERCOT 4CP, converted to a monthly rate, and charged to DSPs as the "product of each TSP's monthly rate" and the DSP's ERCOT 4CP load. This approach contrasts to the characterization by Mr. Troxle,[297] which is relied upon by HEB[298] and TCPA[299] in support of their "cost shifting" arguments.

In the 2019 final transmission matrix approved in Docket No. 48928,[300] there are 49 different TSPs with separately approved wholesale transmission service (WTS) rates based on each TSP's own transmission cost of service (TCOS) calculated pursuant to 16 TAC § 25.192. Each of these TSP WTS rates is applied to each of the approximately DSPs. HEB and Mr. Troxle are incorrect that the transmission cost of service for each TSP is incorporated into the

[297] Tr. at 1005-1010.

[298] HEB Initial Brief at 37.

[299] TCPA Initial Brief at 3.

[300] TIEC Ex. 34.

"ERCOT TCOS"; there is no "ERCOT TCOS", only transmission cost of service values established for each TSP in the TSP's individual WTS rate proceeding. As clearly stated under 16 TAC § 25.192(b)(1), the TCOS of each TSP is divided by the ERCOT 4CP to establish that TSP's WTS rate on a per-4CP kw basis:

> (b) **Charges for transmission service delivered within ERCOT**. DSPs, excluding storage entities, shall incur transmission service charges pursuant to the tariffs of the TSP.
>
> (1) A TSP's transmission rate shall be calculated as its commission-approved transmission cost of service divided by the average of ERCOT coincident peak demand for the months of June, July, August and September (4CP), excluding the portion of coincident peak demand attributable to wholesale storage load.

Moreover, there is no aggregation of TCOS values into a single "ERCOT TCOS".

HEB also misunderstands how DSPs such as CEHE are charged for wholesale transmission service. As 16 TAC § 25.192(b)(1) states, a DSP pays to each TSP an amount equal to the TSP's WTS rate multiplied by the DSP's ERCOT 4CP load:

> The monthly transmission service charge to be paid by each DSP is the product of each TSP's monthly rate as specified in its tariff and the DSP's previous year's average of the 4CP demand that is coincident with the ERCOT 4CP.

Furthermore, HEB incorrectly states that the TCOS values are aggregated and then apportioned among DSPs.[301] There is no such aggregation or apportionment. Rather, each TSP charges a rate, and the amount of money recovered is a function of the TSP's rate and the DSP's ERCOT 4CP load. HEB and CEHE witness Mr. Troxle's claim that the total wholesale transmission payments, what HEB refers to as the "ERCOT TCOS", is "essentially fixed" and that "the total amount must be collected" is incorrect.[302] Under PURA § 36.051, PURA § 35.004(d), and 16 TAC § 25.192(b)(1), the Commission-approved WTS rate for each TSP is *calculated* based on a TCOS value sufficient to allow the TSP to recover its costs and earn a reasonable return, however once that WTS rate is established, the actual amount of rate revenue (wholesale transmission charges) that a TSP receives may increase above that TSP's actual TCOS or decrease below the actual TCOS, based on the actual changes to the ERCOT 4CP load

[301] HEB Initial Brief at 39.

[302] HEB Initial Brief at 37.

– the total amount of ERCOT TSP wholesale transmission charges is *not* "essentially fixed."[303] Absent a change in WTS rates approved by the Commission, the amount of total ERCOT wholesale transmission charges is a function of the ERCOT 4CP load. HEB's claim that "a reduction in ERCOT 4CP demand does not result in a system-wide reduction of the total ERCOT TCOS that will be apportioned among TSPs"[304] is inconsistent with the plain language of PURA § 35.004(d) and 16 TAC § 25.192(b), and is patently incorrect – all else equal, if the ERCOT 4CP demand falls by 10%, then each TSP will collect 10% less in wholesale transmission charges. Similarly, if CEHE's ERCOT 4CP load falls by 50%, all else equal, the WTS charges to CEHE as a DSP fall by 50%, and the WTS charges for the remaining DSPs are *unchanged.* Contrary to Mr. Troxle's characterizations, adopted by HEB and TCPA, there is no "fixed" total amount of wholesale transmission payments that is reallocated among DSPs in the event that a reduction in ERCOT 4CP demand occurs.[305] Also contrary to Mr. Troxle's suggestion that there is a fixed total ERCOT TCOS that is apportioned among DSPs, the TSP's are in aggregate charging and collecting more than the total approved ERCOT TSP TCOS amounts from the DSPs, because the DSPs' ERCOT 4CP loads have grown since some of the WTS rates were established.[306] There is no fixed amount that is reallocated, as HEB suggests. Contrary to HEB's assertion that costs are shifted if a customer reduces their 4CP load, based on the WTS rates shown in the matrix,[307] and all else equal, if one of CEHE's customers reduce their ERCOT 4CP load by 100 kW, then the amount of wholesale transmission costs that CEHE would be

[303] Indeed, a TSP's rate recovery may increase so far above the TSP's TCOS that the Commission orders that the TSP submit an application for a rate change due to over-earnings. See, for a recent example, the October 16, 2018 order in DN 48158.

[304] HEB Initial Brief at 37.

[306] This can be seen by referencing Attachment A to the wholesale transmission "matrix" approved in DN 48928 (TIEC Ex. 34) – the approved TCOS value for each TSP is included in the third column, and the total for all ERCOT TSPs, (presumably the "ERCOT TCOS" referred to by HEB) $3,640,213,045 can be seen at the bottom of that column; similarly, the fifth column shows the approved WTS rates for each TSP, with the total "postage stamp" rate of $54.567752 per ERCOT 4CP kW shown at the bottom; finally, the ERCOT 4CP load for each DSP is seen in the last column, showing a total ERCOT 4CP load of 69,368,963.5 kW. At the time of this matrix order, the total transmission charges can be determined by multiplying the aggregate postage stamp rate by the aggregate ERCOT 4CP load, producing total wholesale transmission charges in the amount of $54.567752 * 69,368,963.5 = $3,785,308,370. As the Commission-approved wholesale transmission matrix shows, the total aggregate TCOS amounts approved amount to $3,640,213,045 (noted in TCPA's initial brief at 3), while the total rate recovery at this time was $3,785,308,370. Clearly the "ERCOT TCOS" or "total TCOS" is different from the actual total ERCOT wholesale transmission charges.

[307] TIEC Ex. 34

subject to would fall by ($54.567752 * 100) $5,456.78, and no other DSP would be allocated those charges – TSPs would simply collect less in wholesale transmission charges.

HEB's and TCPA's understanding, and Mr. Troxle's characterization that wholesale transmission charges are "essentially fixed" and are reallocated or "reapportioned" among DSPs in response to customer reductions in load, is incorrect, and their arguments should be rejected. It is unambiguous that, under PURA § 35.004(d) and 16 TAC § 25.192(b)(1), CEHE customers that reduce their ERCOT 4CP load cause wholesale transmission cost reductions for CEHE as a DSP, and those costs are not shifted onto other DSPs – there is no "free-riding" or "gaming" of the system, as HEB, TCPA, and Mr. Troxle suggest.

**An NCP Allocation of Transmission Costs is Inconsistent With the Commission's Solution to "Gaming" Concerns as well as the ERCOT Planning Process**

HEB erroneously claims that the Commission's Order No. 40 in Docket No. 22344 concludes that 4CP rate design "would lead to cost shifting and intraclass subsidies".[308] The Commission did not agree with those concerns. In that docket, the commission noted that "Parties opposing the use of a 4CP-billing determinant cited cost shifting and intraclass subsidies as the primary concerns" but the Commission did not state its agreement with those arguments. HEB and TCPA also ignore the Commission's stated solution to the potential for "gaming" the 4CP. DN 22344 Order 40 clearly indicates the Commission's stated preference for addressing "gaming" concerns: "In the event that "gaming" of the 4CP methodology becomes a problem, the advisability of broadening the relevant peak period may be examined at that time. The distribution facilities/delivery charge for IDR metered customers shall be billed on the NCP billing determinant." HEB and TCPA's proposal to use an NCP allocation and rate design to address 4CP "gaming" concerns is inconsistent with the Commission's stated solution of broadening the peak period if 4CP "gaming" became an issue.

TCPA's initial brief includes more than a page of discussion regarding the ERCOT transmission planning process with no citations to the record, claiming that transmission planning is based on a TSP's system peak, and not the ERCOT 4CP. While not agreeing with TCPA's uncited assertions, even if it were the case that ERCOT transmission planning for a TSP

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[308] HEB Initial Brief at 38.

were based on the TSP's system peak, an NCP class allocation factor or rate design would remain inappropriate for transmission costs. In this case, it would be customer's load *coincident* with a TSP's system peak which drove the transmission costs, not the customer's NCP load. A cost-based class allocation of transmission costs based on each TSP's system peak would potentially require 49 different class allocation factors to implement (one for each TSP). When one considers that the ERCOT system 4CP represents the peak load on the aggregate of all the TSP's systems, TCPA's assertion regarding the ERCOT transmission planning process for individual TSPs actually supports the use of the ERCOT 4CP load for allocation and rate design of transmission costs, as the ERCOT 4CP load represents the aggregate peak load of all the TSPs combined.

Thus, Staff's and CEHE's recommendation to use the 4CP class allocation factor for transmission costs should be approved. HEB's and TCPA's proposal to use the NCP class allocation factor for transmission costs should be rejected, as it goes against Commission precedent and fails to abide by cost causation principles.

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

Staff recommended approval of CEHE's proposed 4CP transmission service charge rate design for IDR metered customers and rejection of HEB's and TCPA's proposal to use an NCP rate design with respect to transmission charges.[309] As discussed thoroughly above, it is load at the time of the ERCOT 4CP that causes CEHE to incur wholesale transmission charges. Customers that reduce their load at the time of the ERCOT 4CP therefore cause CEHE to incur a lesser amount of wholesale transmission charges. It is appropriate that these customers face an ERCOT 4CP rate design that properly reflects cost causation.

Staff's response to HEB and TCPA on this particular issue are the same as elucidated above, since HEB and TCPA conflate the issues and make the same arguments with regard to the ERCOT 4CP rate design as they do with regard to the ERCOT 4CP class allocation of transmission costs.

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[309] Staff Initial Brief at 72.

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

Staff, in its Initial Brief, agreed with CEHE's proposal to set class revenue requirements at cost, and disagreed with TIEC's recommendation to moderate the update to the 4CP class allocation factor, as such moderation fails to comply with the 16 TAC § 25.234 requirement that rates be based on cost, as well as Commission precedent.[310] Additionally, doing otherwise results in cross-subsidization into the TDU rates, which harms competition.[311] Title 16 TAC § 25.234 requires setting rates at cost, and this requirement is to be observed unless doing so would result in rate shock. However, rate shock is not a concern here; thus, gradualism is not appropriate.[312]

Staff and TIEC agree that the ERCOT 4CP should be used, as opposed to CEHE's suggestion that the CEHE 4CP would be appropriate.[313] In its Initial Brief, TIEC clarifies that it is only proposing adjustments to mitigate rate impacts in the event that the Commission does not allocate transmission costs using the ERCOT 4CP, and instead adopts CEHE's suggestion of using the CEHE 4CP.[314]

However, even if the Commission adopts CEHE's position to depart from precedent and use the CEHE system 4CP to allocate transmission costs, rather than Staff's and TIEC's recommendation regarding which 4CP to use, Staff still recommends adoption of CEHE's proposal to set class revenue requirements and rates at cost, since the increase in rates to the Transmission Services class would not rise to the level of rate shock that would justify rate moderation. Under CEHE's unadjusted proposal, the Transmission Service class would only face a 13.42% increase in rates,[315] falling to 11.8% when factoring in the Rider UEDIT credit,

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[310] Staff Initial Brief at 73; Staff Ex. 7B at 24.

[311] *Id.* at 73.

[312] Staff Ex. 2A at 55; Staff 7B at 16-26.

[313] Staff Initial Brief at 69; TIEC Initial at 58.

[314] TIEC Initial Brief at 63.

[315] Staff Ex. 7B at 18; *also see* Application, Rate Filing Package at Schedule II-I.

not the 22.1% suggested by TIEC.[316] Additionally, when evaluated on a total-bill basis, as required under Commission precedent, the bill impacts are even lower.[317]

TIEC distinguishes its proposal from gradualism in that it proposes to "mitigate the impact on changing course of decades of allocation precedent, combined with the impacts of correcting distortions caused by the current TCRF rule over the past ten years."[318] However, TIEC concedes the point that an appropriate venue to resolve a part of its concern regarding the TCRF rule would be to reopen the rule.[319]

Since rate shock is not a concern in this proceeding, adjustments made to mitigate potential impacts on customers, regardless of which 4CP the Commission allows CEHE to use, is unnecessary.

### 2. Municipal Franchise Fees [PO Issue 27]

### 3. Transmission and Key Accounts

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

## VIII. REVENUE DISTRIBUTION AND RATE DESIGN [PO ISSUES 4, 5, 43, 49, 50]

On an overall basis, Staff finds that the CEHE's revenues must be decreased by $11,120,997, calculated as follows:

**Staff's Recommended Overall Change in Revenues[320]**

| | Present Base Revenues-$s | Base Revenue Requirement-$s | Change-$ | Change-% |
|---|---|---|---|---|
| Wholesale transmission | 388,968,021 | 336,923,105 | -$52,044,916 | -13.4 |
| Retail Delivery | 2,129,484,979 | 2,170,408,898 | +$40,923,919 | +1.9 |

316 *Id.* at 18; *also see* Staff Initial at 74-75.

317 Staff Ex. 7B at 23.

318 TIEC Initial at 64.

319 *Id.* at 65.

320 Staff Ex. 2A at 51-52.

| | | | | |
|---|---|---|---|---|
| TOTAL | 2,518,453,000 | 2,507,332,003 | -$11,120,997 | -0.5 |

Additionally, Staff supports CEHE's proposal to set revenues at cost.[321] As discussed above, Staff recommends a finding that gradualism (or rate moderation) is not necessary in this proceeding because at all levels of retail revenues proposed by parties no revenue increase to any one customer class would be particularly harsh or excessive or promote rate shock.[322]

## A. Residential Customer Charge

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

## C. Transmission Service Rate

## D. Transmission Service Facility Extensions

## E. Street Lighting Service

Staff recommended rejection of CEHE's proposal to amend its Lighting Services tariff, which requires installation and usage of LED lights for the 160 municipalities in its service territory, as the proposed language fails to provide its affected customers a meaningful choice in type of lighting service CEHE would provide.[323]

CEHE mischaracterized Staff's position by stating that Staff witness Mr. Murphy challenged CEHE's proposal to shift to LED as the standard lighting offer.[324] Staff expressed concern regarding CEHE's proposal to eliminate the customer's ability to choose a non-LED

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[321] *Id.* at 55.

[322] *Id.* at 55.

[323] *Id.* at 67.

[324] CEHE's Initial Brief at 134.

alternative over LED, not the shift to LED as the standard.[325] As stated in its Initial Brief, Staff's concern lies in the customer's ability to choose between LED and a non-LED alternative, not which type of lighting will the standard for new installations.[326] The proposed language does not give customers a meaningful choice.

Additionally, CEHE stated:

> Furthermore, CEHE plans to convert non-LED lamps to their LED-equivalent at no cost to the customer during the normal course of maintenance when individual lamps burn out and, for new installations, the cost of installing the LED-equivalent standard offering is the same as the non-LED equivalent, resulting in no additional upfront cost to the customer.[327]

But Staff's concern is not about the cost to the customer based on the rates CEHE has requested in this proceeding, but rather the customer impacts of the LED conversion once the conversion costs are included in rates.[328] CEHE has stated that its LED conversion costs are being capitalized and deferred for future rate recovery, and that CEHE may request recovery of the LED conversion costs in a future DCRF proceeding.[329] This means that the LED rates that CEHE has requested in this proceeding do not fully reflect the costs of LED lighting services. Consequently, CEHE's proposal is misleading, because CEHE has not been transparent about the true customer impacts of the proposal, when the deferred conversion costs are reflected in rates. Staff re-iterates that CEHE has not made any effort to quantify the deferred LED conversion costs and show what the customer impacts will be when the conversion costs are charged to

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[325] *See* Staff Ex. 2A at 67: Q. Do you have any concerns about the program from a regulatory standpoint? A. Yes. I am concerned that by eliminating customer choice the proposal puts the Commission in the position of supplanting each municipality's jurisdiction over what type of lighting is appropriate for its community given its preferences and budget constraints.

[326] Staff Initial Brief at 79.

[327] CEHE Initial Brief at 134-135.

[328] Staff Initial Brief at 79.

[329] Staff Ex. 38: Q. Please refer to the RT of Sugarek at 20, Under the Company's proposal, who will bear the installation costs for LED lighting installations, when, and under what cost recovery mechanisms? A. The Company investors bear the installation costs and LED lighting customers pay back the investors. Therefore, the Company may request recovery of the capital (including a reasonable return) and the reasonable and necessary expenses associated with the conversion through Commission approved rate recovery mechanisms, most likely

customers in a future DCRF proceeding. When asked to provide customer impact analyses, CEHE points Staff to a generic schedule comparing current individual lighting rates to CEHE's requested lighting rates, which does not show the customer impacts of transitioning customers from a non-LED installation to an LED equivalent.[330] As stated above, LED conversion costs are being deferred, and the generic rate comparison schedule CEHE cites to does not reflect the LED conversion costs. At the same time, CEHE has presented evidence in this case that the capital expenditures of LED are 1.5 to 3.0 times as high as equivalent non-LED fixtures.[331] CEHE has also stated that under the LED conversion the monthly fixture charge paid to CEHE will likely increase substantially.[332] Staff is also concerned that in a DCRF proceeding CEHE may seek treatments that would shift LED conversion costs onto lighting customers who do not receive LED lighting services, and also onto other customer classes who do not receive any lighting services.

CEHE argues that the lifecycle costs of LED are lower than the lifecycle costs of high-pressure sodium fixtures, the current standard.[333] However, CEHE's calculation of the lifecycle costs of LED does not include the operations and maintenance expenses the CEHE incurs to maintain LED installations. In her rebuttal testimony, CEHE witness Ms. Sugarek lists the operations and maintenance expenses.[334] CEHE's lifecycle cost analysis also fails to account for

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either a distribution capital recover factor application under 16 TAC § 25.243 or some other Commission rate proceeding.

[330] CEHE Ex. 45: "Q. PLEASE DESCRIBE MR MURPHY'S CONCERN THAT THE MAGNITUDE OF THE IMPACT OF ESTABLISHING LED LIGHTS AS THE STANDARD OFFERING IS UNCLEAR IN THE COMPANY'S PROPOSED RATES. A. Mr. Murphy's states the rate impacts of the proposal on lighting customers is unclear because the Company did not perform an analysis comparing a non-LED installation with an equivalent LED lighting installation. Q. DO YOU AGREE WITH MR. MURPHY'S CONCERN? A. No. This analysis was provided in the workpapers supporting the RFP." In footnote 24, Company witness Troxle cites to Errata 1 WP-Streetlight Rate Design tabs Tariff Comp, SLS Rate Design, and Schedules A thru E, which is a generic comparison of current to proposed lighting rates, with no identification of non-LED and LED equivalents, and no quantification of customer impacts when LED conversion costs hit rates.

[331] Staff Ex. 2C, Workpaper "PUC03-09 LED Conversion Summary Presentation.PDF" at 35: "LED fixtures average 1 ½ to 3 times the cost of standard HPS [high pressure sodium] fixtures."

[332] *Id.*

[333] CEHE's initial brief at footnote 966.

[334] CEHE Ex. 33 at 18: "Once the LED light is installed, however, there are various O&M costs, including, but not limited to: fuse replacement, maintaining the post, conduit replacement, and clamp/connector replacement, over its used and useful life to maintain their standard performance."

the relative risks of the different alternatives. High pressure sodium is a proven technology with a known useful life and bulb replacement cycle. In contrast, CEHE's lifecycle cost projections for LED—an emerging technology[335]—are subject to considerable uncertainties, including the unknown useful life of an LED installation,[336] a critical input in the lifecycle cost calculations.

Staff does not oppose CEHE's proposal to make LED lighting the standard type for new installations.[337] In its Initial Brief, Staff clarified that it accepts CEHE's proposal to make LED the standard lighting type for new installations, subject to acceptance by CEHE of Staff's amendments to CEHE's proposal to address Staff's concerns regarding the lack of choice for CEHE's lighting customers.[338] Additionally, Staff reserved the right to seek ratemaking treatments designed to insulate customers who do not receive LED lighting services from LED conversion costs in future rate proceedings.[339]

Thus, Staff recommends rejection of CEHE's proposed amendments to its Lighting Services tariff to eliminate customer choice.

## F. Other Rate Design Issues

### 1. Retail Class Rate Design

With the exception of Staff's non-opposition to HEB's proposal for an NCP rate design for the distribution service charge applicable to retail transmission customers, Staff accepts the Company's proposed rate design and recommends adoption of Staff's recommended retail rates in Staff witness Mr. Murphy's Direct Testimony, Attachment BTM-7.

# IX. RIDERS [PO ISSUES 4, 5, 43, 51, 52]

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[335] CEHE Ex. 30, Exhibit MAT-8 at 38: "LED street lights are an emerging technology with no established industry standard."

[336] Staff Ex. 2A at 66: "In CEHE's analysis, the standard deviation of 5 years around its estimated useful life of 15 years represents one-third of the estimate, which means that the estimated useful life of an LED installation is uncertain."

[337] Staff Initial Brief at 80.

[338] *Id.*

[339] *Id.*

## A. Rider UEDIT [PO Issue 51]

The initial brief of Gulf Coast Coalition of Cities requests that the Commission require CEHE to refund to customers the excess accumulated deferred income taxes associated with CEHE's stranded generation costs and system restoration charges that have been securitized.[340] The questions at issue are potentially whether the excess accumulated deferred income taxes (EDIT) is customer contributed or not, whether the issues surrounding the balances of excess EDIT associated with the securitizations are subject to further litigation given the nature of securitization funding, determining the amount of the securitization-related excess EDIT that would be payable to customers while also taking into account the related reductions in the amounts of offsetting credits to customers, and whether the remaining EDIT balances should be refunded to customers given the nature of securitization funding.[341]

If the Commission determines that the refund to ratepayers of securitization-related excess EDIT balances is appropriate, the record in this case does not contain a sufficient and thorough amount of information and evidence for the Commission to make an appropriately informed decision on the quantification of the refund.[342] Accordingly, if the Commission believes that this issue warrants additional review and possible action, Staff recommends that the Commission require CEHE to file, by a Commission-determined date, a separate proceeding to specifically address the appropriate treatment of EDIT amounts related to CEHE's four securitized bond issuances still outstanding. CEHE's filing should include information responsive to the points Mr. Tietjen discussed in his testimony, and any other information that CEHE—and the Commission—believe may be relevant and necessary for the Commission to consider.

GCCC states that severing this issue to another case is not warranted because this is a base rate case and CEHE bears the burden of proof on any information needed.[343] However, GCCC's initial brief misses the point as the issues arise out of securitization cases for which the Commission has issued financing orders outside of the context of base rates.[344] As such, these issues are not base rate issues.

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[340] GCCC Initial Brief at 34-39.
[341] Direct Testimony of Darryl Tietjen, Staff Ex, 1A at 24-26.
[342] Direct Testimony of Darryl Tietjen, Staff Ex, 1A at 24-25.
[343] GCCC Initial Brief at 38.
[344] Direct Testimony of Darryl Tietjen, Staff Ex, 1A at 17-22.

### 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

#### 1. Wholesale Transmission Rates

Staff addressed this issue in its initial brief.

### B. Uncontested Issues

## XII. CONCLUSION

For the foregoing reasons, Staff respectfully requests that the ALJs issue a proposal for decision consistent with Staff's recommendations on financial protections, revenue requirements, cost allocation, revenue distribution, and rate design.

**SOAH DOCKET NO. 473-19-3864**
**PUC DOCKET NO. 49421**

## CERTIFICATE OF SERVICE

I certify that a copy of this document will be served on all parties of record on June 9, 2019 in accordance with. 16 TAC § 22.74

Rachelle N. Robles