PUC DOCKET NO. 38339
SOAH DOCKET NO. 473-10-5001

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR AUTHORITY TO CHANGE RATES	§ § § §	BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS

THE GULF COAST COALITION OF CITIES' EXCEPTIONS TO THE PROPOSAL FOR DECISION

THOMAS L. BROCATO
State Bar No. 03039030

CHRISTOPHER L. BREWSTER
State Bar No. 24043570

LLOYD GOSSELINK
ROCHELLE & TOWNSEND, P.C.
816 Congress Avenue, Suite 1900
Austin, Texas 78701
(512) 322-5857
Fax: (512) 472-0532

ATTORNEYS FOR THE GULF COAST COALITION OF CITIES

DECEMBER 20, 2010

838

TABLE OF CONTENTS

PUC DOCKET NO. 38339
SOAH DOCKET NO. 473-10-5001

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR AUTHORITY TO CHANGE RATES	§ § § §	BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS

THE GULF COAST COALITION OF CITIES' EXCEPTIONS TO THE PROPOSAL FOR DECISION

TO THE HONORABLE CHAIRMAN AND COMMISSIONERS:

COMES NOW, the Gulf Coast Coalition of Cities ("GCCC") and timely file these Exceptions pursuant to P.U.C. PROC. R. 22.261(d) in response to the Proposal for Decision ("PFD") issued December 2, 2010.

GCCC is a coalition of 34 cities that are located in CenterPoint Energy Houston Electric LLC's ("CenterPoint's," "Company's" or "CEHE's") service area that are directly impacted by this application.[1] They have intervened in this case due to concerns over the impact of the potential rate increase on their citizens and themselves. These concerns are particularly acute given the magnitude of the proposed request and the current economic condition in these communities.

I. INTRODUCTION [GERMANE TO PRELIMINARY ORDER ISSUE NO. 1]

CenterPoint's current rates are too high. This fact is borne out in the evidence and the Company's statements. Evidence presented by the Public Utility Commission ("PUC" or "Commission") Staff, GCCC, City of Houston and the Houston Coalition of Cities ("COH/HOC"), Texas Industrial Energy Consumers ("TIEC") and Office of Public Utility

[1] In this proceeding, GCCC is comprised of the cities of Alvin, Brazos Country, Bunker Hill Village, Clear Lake Shores, Deer Park, Dickinson, Friendswood, Fulshear, Galveston, Hilshire Village, Jersey Village, Kemah, Lake Jackson, La Marque, Manvel, Missouri City, Mont Belvieu, Morgan's Point, Nassau Bay, Piney Point Village, Rosenberg, Santa Fe, Seabrook, Simonton, South Houston, Spring Valley Village, Stratford, Sugar Land, Taylor Lake Village, Texas City, Tomball, Village of Tiki Island, Webster and Weston Lakes.

Counsel ("OPC") all support rate reductions. Each of these parties presented evidence supporting a rate decrease despite the fact that none of them addressed all of the issues in the case. Indeed, as noted in the PFD "[a]ll other parties [besides CenterPoint] proposed reductions to the overall revenue requirement ranging from approximately $59 million to $135 million...."[2] Moreover, the Company has candidly and repeatedly noted that they did not want this rate case and would not have filed one but for the PUC Staff, COH, and GCCC requiring them to do so. The Company's own testimony confirms that CenterPoint is not under-earning nor does it have under-performing assets. For example, their return on equity for the test year was an excessive 11.13%. Moreover, the Company has made it clear that they have been able to access the capital markets to fund a massive $1.5 billion dollars in transmission and distribution capital investment during some of the most challenging economic times on record.

The PFD verifies that CenterPoint overstated its request. However, it falls far short in many respects and recommends that CenterPoint receive a $26 million rate increase.[3] Respectfully, as discussed in these Exceptions, the PFD failed in many respects. For example, the PFD failed to address several issues including, no discussion or recommendation as to whether CEHE should be permitted to recover pension and Other Post-Employment Benefits ("OPEB") amounts projected beyond the test year. This is a significant issue, with the cost at stake equating to $9.070 million for the distribution function and $1.633 million for transmission. Another issue missing from the PFD is whether the Company should be permitted an unreasonably brief amortization period for its deferred pension and OPEBs amounts; GCCC has proposed throughout this case that this amortization period should be set at five years to minimize the risk of overrecovery by CEHE. A third issue missing from the PFD is whether

---

[2] PFD at 4.

[3] At page 4 of the PFD, the ALJs incorrectly state that they "recommend an overall rate decrease for CenterPoint of $84.401 million...." In truth, the PFD proposes $84 million in reductions to the Company's requested $110 million rate increase or an overall rate increase of approximately $26 million.

CEHE's Advanced Metering System ("AMS") surcharge should be reduced to reflect a $150 million stimulus grant from the Department of Energy. These and other shortcomings in the PFD should give the Commission pause when considering the outcome of this case.

In summary, the record in this proceeding demonstrates that CenterPoint's current rates are excessive and should be cut. As discussed throughout these Exceptions, the PFD stops far short of setting reasonable rates. CenterPoint's ratepayers are entitled to a rate decrease. As discussed in the testimony of GCCC witnesses Mr. Lane Kollen and Mr. Clarence Johnson and in briefs, GCCC recommends a revenue requirement of approximately $246 million less than that proposed by CenterPoint. Adoption of GCCC's recommendations will result in a rate reduction of approximately $135 million or $161 million less than recommended by the PFD. A final order that incorporates the changes to the PFD recommended in these Exceptions will stop the Company from overearning and will promote retail competition by providing rate relief to all customers.

II. JURISDICTION AND NOTICE

Not addressed.

III. PROCEDURAL HISTORY

Not addressed.

IV. EXECUTIVE SUMMARY [GERMANE TO PRELIMINARY ORDER ISSUE NO. 5]

Not addressed.

V. RATE BASE [GERMANE TO PRELIMINARY ORDER ISSUE NOS. 7 AND 9]

A. Capital Investment

1. Transmission

Not addressed.

2. Distribution

Not addressed.

B. Adjustments [Germane to Preliminary Order Issue No. 6]

1. Post-Test Year Adjustments

Not addressed.

2. AMS

Not addressed.

C. Accumulated Deferred Federal Income Tax ("ADFIT")

1. FIN 48 Liabilities [Germane to Preliminary Order Issue No. 24]

Not addressed.

2. Intervenors' Proposed Rate Base Items

Not addressed.

D. Cash Working Capital

1. State Franchise Tax

The PFD errs by relying on irrelevant Comptroller guidance in adopting CEHE's proposed negative 48.5 lead days associated with the State Franchise Tax. FoF No. 50.

The PFD incorrectly establishes a Cash Working Capital ("CWC") allowance based, in part, on an improperly performed lead/lag analysis with respect to the State Franchise Tax ("SFT"). In their PFD, the Administrative Law Judges ("ALJs") find that 48.5 negative lead days for the SFT is the proper lead/lag days for this item,[4] a conclusion which contradicts the evidence and CenterPoint's own accounting for this tax. As support for their conclusion, the PFD states simply that the ALJs were persuaded by CenterPoint's arguments and authorities.[5]

[4] PFD at 19.

[5] *Id.*

As GCCC set out in detail in its testimony and post-hearing briefs, however, the Company's arguments are without merit.

In its direct case, the Company's witnesses urged that in computing CWC associated with this item, the correct service period is the year in which the expense is paid, resulting in 48.5 negative lead days.[6] GCCC witness Lane Kollen testified that the service period for CWC purposes is the year prior to the year in which the tax is paid, a fact made evident by the way in which CenterPoint accounts for the SFT.[7] As Mr. Kollen noted, the Company accrued the SFT as a liability throughout the year prior to payment, an accounting approach which signifies that the expense was actually incurred in that prior year.[8] In view of this treatment, there is no reasonable basis for concluding that the tax expense was incurred in 2009, as the Company claims; if it had been, the Company would not have recorded that tax as liability in 2008.

The Company's own witnesses offer contradictory testimony on this issue. While Mr. Joyce insists that the proper service period for the SFT is the year in which the tax was paid, CenterPoint witness Felsenthal stated that "[t]here is a one year lag between the taxable year and the payment year for the Texas margin tax (e.g., 2008 Texas margin tax is paid in 2009, 2009 Texas margin tax is paid in 2010)."[9] Mr. Felsenthal's testimony is correct on this point. CEHE records a liability for the SFT expense in the year prior to the year in which the tax is paid, and then defers the expense as a regulatory asset until the following year when the tax is paid.[10] The regulatory asset is then amortized to expense. These facts indicate that the service period for the

---

6 Direct Testimony of Jay Joyce, CEHE Ex. 24 at JJJ-3 and JJJ-4.

7 Direct Testimony of Lane Kollen, GCCC Ex. 1 at 46.

8 *Id.*

9 Direct Testimony of Alan D. Felsenthal, CEHE Ex. 26 at 20.

10 Direct Testimony of Lane Kollen, GCCC Ex. 1 at 46.

SFT – the year during which the tax is incurred – is the year prior to the year in which the tax is paid.

CEHE and the ALJs rely on supposed new guidance from the Comptroller of Public Accounts of the State of Texas ("Comptroller") to support the claim that the service period for the Texas margin tax is the year in which the tax is paid.[11] In a portion of that guidance relied upon by both CEHE and the ALJs, the Comptroller's office states that "[a]n entity becoming subject [to the SFT] on 11/15/2009 will file a 2010 annual report due 05/17/2010 for the privilege period 11/15/2009 through 12/31/2010."[12] This guidance has no bearing on CEHE, however. It is clear that the Comptroller guidance quoted by the PFD and proffered by CEHE pertains only to ***new*** entities who first become subject to the SFT, not entities that have ongoing obligations under the SFT. On the Comptroller's website citied in the PFD, the guidance is stated in a question-and-answer format. The portion of that guidance cited by the PFD is given in answer to the question "When is a newly taxable entity's first report due?"[13]. CEHE is not a

---

[11] *See e.g.*, Rebuttal Testimony of Jay Joyce, CEHE Ex. 56 at 15-16; Direct Testimony of Jay Joyce, CEHE Ex. 24 at 21; PFD at 18.

[12] PFD at 18; Direct Testimony of Jay Joyce, CEHE Ex. 24 at 21.

[13] PFD at 18, citing http://www.window.state.tx.us/taxinfo/franchise/faq_rpt_pay.html. The full text of this portion of the Comptroller's guidance reads:

27. When is a newly taxable entity's first report due?

A taxable entity first subject to franchise tax on or after 10/04/2009 will file an annual report. They will not file an initial report.

A taxable entity becoming subject to franchise tax from 10/04/2009 through 12/31/2009 will have a 2010 annual report due on 05/17/2010. A taxable entity becoming subject to franchise tax during calendar year 2010 will have a 2011 annual report due on 05/16/2011.

The privilege period covered by the first annual report will be from the date the entity became subject to franchise tax through 12/31 of the following calendar year. For example, an entity becoming subject on 11/15/2009 will file a 2010 annual report due 05/17/2010 for the privilege period 11/15/2009 through 12/31/2010.

The first annual report will be based on the accounting period beginning on the date the entity became subject to franchise tax and ending on the last accounting period ending date used for federal income tax reporting purposes in the calendar year before the year the report is originally due.

newly taxable entity, and the PFD erred by relying upon irrelevant Comptroller guidance directed at companies with no ongoing presence in Texas.

Even assuming that the Comptroller's guidance is relevant, it would have nothing to do with the ratemaking treatment of the Company's SFT expense for CWC purposes. This guidance also is irrelevant as to how CEHE accounts for the tax. Indeed, as noted above, CEHE accrued a liability for the tax in the year before the tax was paid. This treatment is entirely inconsistent with CEHE's claim in this proceeding that the service period for the SFT is the year in which the tax was paid. If CEHE's claim was true, there would be no need to record a liability during the prior year.

The PFD merely recites the position of GCCC on this point, and does not consider how the way that CEHE actually accounts for the SFT contradicts the Company's position on how to reflect its SFT expense in its CWC calculation. The ALJs' proposed 48.5 negative lead days for the SFT should be rejected in favor of GCCC witness Mr. Kollen's proposed 317.5 lead days. Mr. Kollen calculated this figure by computing a service period of 182.5 lead days based on the midpoint of the prior year as the service period, and then adding the 135 days in 2009 until the Company paid the SFT on May 15, 2009.[14] The effect of this adjustment is a $1.677 million reduction to CEHE's proposed distribution revenue requirement and a $0.294 million reduction to its proposed transmission revenue requirement.[15]

2. Lead Days on Affiliate O&M Expense

Not addressed.

3. Remaining CWC Issues

Not addressed.

---

[14] Direct Testimony of Lane Kollen, GCCC Ex. 1 at 47-48.

[15] *Id.* at 48.

E. Materials and Supplies

Not addressed.

F. Electric Plant In Service ("EPIS") [Germane to Preliminary Order Issue No. 18]

Not addressed.

G. Electric Plant Held for Future Use ("PHFU")

The PFD errs by granting CEHE's late-made request to include in rate base as PHFU certain assets that did not qualify for inclusion in rate base a post-test year adjustment. FoF Nos. 56 and 57.

While properly denying the Company's request to add certain proposed post-test year additions to its rate base, the PFD does permit the Company to include the amounts in rate base as Plant Held for Future Use ("PHFU").[16] The ALJs found that approximately $4.3 million for two transmission substations not in service during the test year should be included in PHFU.[17] This finding is in error and should not be adopted by the Commission.

The chronology of this issue amply illustrates the error of the PFD's approach. In its direct case, the Company sought to include in rate base the post-test year amounts addressed by the PFD in this section. In its own direct case, GCCC observed that this request did not meet the 10% of requested rate base standard established by P.U.C. SUBST. R. 25.231(c)(2)(F)(II).[18] GCCC also noted that the Company had not actually requested a good cause exception to this standard, and did not even address the application of the rule in its direct case.[19] On October 1, 2010, and shortly before the beginning of the hearing on the merits, CenterPoint finally asked that good cause be found to excuse its failure to meet the Commission's rule's standards for post-

[16] PFD at 10 and 25.

[17] PFD at 25-26.

[18] Direct Testimony of Lane Kollen, GCCC Ex. 1 at 35.

[19] *Id.*

test year additions to rate base.[20] At the outset of the hearing, on October 11, 2010, the ALJs issued an oral ruling denying the Company's October 1st request for a good cause exception.

Then, in its Initial Brief, CenterPoint tried another tack – the Company requested that it be permitted to recover these amounts as PHFU.[21] As noted above, this was not the means by which CenterPoint originally tried to place these amounts into rate base - the Company wanted to include them as post-test year additions to rate base, albeit without discussing (or even citing) the relevant rule. Parties were never given the opportunity to address this latest iteration of the Company's argument on this issue in their own testimony.

The PFD appears to rest its conclusion solely on the fact that Staff did not object to adding the Rothwood and Meadow substations to PHFU in its Reply Brief.[22] No other analysis than this is given. This is an insufficient basis to permit the Company to include amounts in rate base based on a late-raised theory that the parties had limited ability to conduct discovery on, perform cross examination on, or refute in their own testimony. Denying the Company PHFU classification for these substations will work no permanent harm to the Company - if the facilities are in service during the test year of the Company's next rate case, or if they otherwise meet the standard for PHFU or post-test year additions, they can be included at that time. Alternatively, given that the assets at issue are transmission substations, CenterPoint can seek recovery through the interim transmission cost of service ("TCOS") update mechanism. In any event, permitting the Company to include these amounts as PHFU is inappropriate, not supported by the evidence, and should be reversed by the Commission.

---

[20] CenterPoint's Request for Good Cause Exception Regarding Post-Test Year Adjustments (Oct. 1, 2010).

[21] CEHE's Initial Brief at 37 (Oct. 22, 2010).

[22] PFD at 26.

H. Injuries and Damages Reserve

Not addressed.

I. Prepayments

Not addressed.

J. Regulatory Assets [Preliminary Order Issue No. Issue 10]

1. Pension Asset

In this proceeding, CEHE has proposed inclusion of an excessive level of pension and OPEBs deferral in its rate base. Pension and OPEBs encompass complex issues that touch upon both CEHE's rate base and its expense. While attempting to address the range of issues existing in this area, the ALJs failed altogether to discuss key issues raised by GCCC. GCCC witness Lane Kollen testified to three flaws in the Company's requested treatment of its OPEB deferrals: 1) Selection of the incorrect base year against which to measure the deferral, 2) proposing a post-test year amount of pension and OPEB deferral that is not known and measurable, and 3) proposing to amortize the deferred amount over an unreasonably short period. Of these issues, numbers (1) and (2) pertain to CEHE's rate base. The ALJs only addressed the first issue, the selection of the proper base year, but failed to address the second, the inclusion of post-test year amounts of pension and OPEBs.

a. Base Year: 2006 v. 2007

The PFD errs by permitting CEHE to quantify its pension and OPEB deferrals by reference to a base year of 2007. FoF No. 61.

The PFD incorrectly recommends that CEHE's pension and OPEB deferrals be calculated by reference to a 2007 base year. This issue is important because the Public Utility Regulatory Act ("PURA") permits the Company to include in rate base a deferred amount for pensions and OPEBs, with the deferral starting in a particular year. Under PURA § 36.065(b)(1), the deferral is to be measured against the annual amount of pensions and OPEBs permitted by the Commission in the utility's last rate case. In the event that the utility's last rate case was resolved in a manner such that the amount cannot be determined, the utility may use the "amount recorded....during the first year that rates from the electric utility's last general rate proceeding are in effect."[23] Because CEHE's last rate case, Docket No. 32093, was settled on a "black box" basis, there is no way to determine the annual pension and OPEB expense established in that case. Accordingly, PURA directs that the base amount be calculated as the amount of pension and OPEB expense recorded during "the first year that rates from the electric utility's last general rate proceeding were in effect. Because rates were set in Docket No. 32093 in September of 2006, the first year that rates from that proceeding were in effect was 2006.[24] This is the only natural reading of the statute, and the only interpretation which does not require the ALJs and the Commission to read into the statute words that are not there.

Nonetheless, the PFD relies upon CEHE's arguments to arrive at a base year of 2007. According to CEHE and the ALJs, the expression "the first year that rates from the electric utility's last general rate proceeding are in effect" actually means the first ***full, calendar*** year ***after*** rates from the utility's last general rate proceeding are in effect.[25] The Commission should not rewrite the statute in the manner that the PFD proposes, as the language of the provision is clear on its face.

The PFD makes much of the legislative history of PURA § 36.065(b)(1), and in a footnote even suggests that the witnesses for the parties who propose a 2006 base year (GCCC and COH/HCOC) should have examined or analyzed that history.[26] But courts in Texas will not look to legislative history, when, as here, they are faced with "a clear expression of legislative

---

[23] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 36.065(b)(1) (West 2007 and Supp. 2010) ("PURA").

[24] Direct Testimony of Lane Kollen, GCCC Ex. 1 at 37.

[25] PFD at 29-30.

[26] PFD at 29, footnote 105.

intent" in the language of the statute.[27] PURA § 36.065(b)(1) plainly states that the base year for measuring CEHE's pension and OPEBs deferral is the first year that rates from its last rate case are in effect, a year which unquestionably is 2006. Adoption of this plain-language reading of the statute by the Commission would result in a reduction to CEHE's proposed distribution revenue requirement of $7.923 million and a reduction to its proposed transmission revenue requirement of $1.427 million.[28]

b. Post-Test Year Amounts

The PFD errs by permitting post-test year, projected pension and OPEB amounts to be recovered in violation of PURA § 36.065(d)(1). FoF No. 62.

While the PFD includes a finding of fact approving the Company's proposal to include a deferral for pensions and OPEBs for 2010, the year after the test year for this case, it offers no discussion or rationale for this finding. As GCCC has made clear throughout this proceeding, PURA does not permit the inclusion of an estimated, post-test year amount in a utility's OPEB and pension deferral, and adopting a total deferral that includes such a post-test year amount is reversible error. This is all the more so given that the PFD fails to even discuss the issue.

PURA § 36.065 speaks only to adjusting a utility's rate base for pensions and OPEBs based on a historic, recorded amount. Specifically, PURA § 36.065(d)(1) requires the Commission to "review the amounts recorded to the reserve account to determine whether the amounts are reasonable expenses." The statute's use of the words "recorded" and "expenses" is critical to this issue. As Mr. Kollen testified, CEHE's proposed pension and OPEB amounts through the end of 2010 have not been recorded to the Company's reserve account.[29] And, while

---

[27] *Robinson v. Budget Rent-a-Car Systems Inc.*, 51 S.W.3d 425, 430 (Tex. App.—Houston [1st Dist.] 2001, pet. denied).

[28] Direct Testimony of Lane Kollen, GCCC Ex. 1 at 38.

[29] Direct Testimony of Lane Kollen, GCCC Ex. 1 at 38-39.

CEHE has pointed to an actuarial study for its 2010 pension and OPEB amounts, such a study can only produce an actuarial *cost* for 2010, but not an *expense.*[30]

These distinctions are critical to a proper analysis of this issue under PURA, but the PFD is silent on them. CEHE's OPEB and pension expense amount cannot be actuarially determined ahead of time. This is because pension and OPEB expense is the result of how the Company's payroll costs are actually allocated between expense amounts and capitalized amounts during 2010. As GCCC witness Kollen testified, the calculation of this expense amount is not known and cannot be known until CEHE's books are closed for the year.[31]

The Company cannot simply assert that its actuarial studies somehow produce a recorded expense for pension and OPEBs for 2010. This assertion is impossible as an accounting matter. Furthermore, without the expense being recorded, there is no way for the Commission to determine whether that expense was reasonable, as PURA § 36.065(d)(1) requires.

The PFD erred by failing to confront these serious issues and by simply granting the Company its entire proposed pension and OPEB amount, including the post-test year portion. Allowing the Company to include a deferral for pension and OPEBs after the test year squarely contradicts the statute, as described above, and is reversible error. Correction of this error results in a reduction to CEHE's requested distribution revenue requirement of $9.070 million and a reduction to its transmission revenue requirement of $1.633 million.[32] These quantifications reflect a reduction in rate base, less the related accumulated deferred federal income tax ("ADFIT"), and take into account the related amortization expense.[33]

---

30 *Id.* at 39.

31 *Id.*

32 Direct Testimony of Lane Kollen, GCCC Ex. 1 at 40.

33 *Id.*

2. Other Regulatory Assets

Not addressed.

K. Retirement Work in Progress

Not addressed.

VI. RATE OF RETURN

In order to reduce rate case expenses and avoid duplication of effort, GCCC relies upon and supports the testimony of COH/HCOC witness Mr. Butch Solomons regarding rate of return, capital structure, and cost of debt; GCCC also supports the Exceptions filed by COH/HCOC on these issues.

A. Capital Structure [Germane to Preliminary Order Issue No. 3]

Not addressed.

B. Return on Equity [Germane to Preliminary Order Issue No. 4]

1. Proxy Group

Not addressed.

2. DCF Analysis

Not addressed.

3. CAPM Analysis

Not addressed.

4. Risk Premium Analysis

Not addressed.

5. ALJs Analysis

Not addressed.

C. Cost of Debt [Germane to Preliminary Order Issue No. 4]

Not addressed.

D. Overall Rate of Return [Germane to Preliminary Order Issue No. 4]

Not addressed.

VII. COST OF SERVICE AND OPERATIONS AND MAINTENANCE [GERMANE TO PRELIMINARY ORDER ISSUE NOS. 2 AND 12]

A. Transmission and Substation Operations

Not addressed.

B. Distribution Operations [Germane to Preliminary Order Issue No. 29]

1. Post-Test Year Increase to Distribution Storm Hardening Expenses

Without discussion or analysis, the PFD errs by permitting CEHE to recover $7.15 million in post-test year storm hardening expenses that have not been incurred, and are not required by any Commission rule. FoF No. 78.

Curiously, the PFD contains a single finding authorizing the Company's proposal to recover $7.15 million in post-test year storm hardening costs, but includes no discussion or analysis of this issue. The absence of any discussion, given this finding, is particularly remarkable in view of the grave ratemaking errors posed by the Company's proposal. This issue was fully litigated by the parties, including GCCC who sponsored the testimony of Lane Kollen on this issue and fully addressed it in post-hearing briefing. As detailed below, the Company's request to recover estimated costs for supposed storm hardening falls far short of satisfying the known and measurable standard, and should be rejected.

At the heart of CEHE's proposal on this issue is its strained assertion that its requested expenditures will be required by the Commission's new storm hardening rule, P.U.C. SUBST.

R. 25.95.[34] The requested increase is wholly speculative, is not required by the new Commission rule, and is devoid of record support as a known and measurable increase. CEHE's request on this point should be denied.

As discussed in the direct testimony of GCCC witness Kollen, P.U.C. SUBST. R. 25.95 does not require that *any* expenditures take place. The rule is straightforward and requires only the filing of a storm hardening plan by May 1, 2011. By that date, CEHE must file a plan that describes the Company's current and future storm hardening plans over a five-year period beginning January 1, 2011.[35] The rule describes the minimum information that the storm hardening plan must include.[36] Notably, however, the rule does not provide for Commission approval of the plan, and is silent as to cost recovery. The rule simply requires CEHE to file a storm hardening plan. Therefore, the rule provides no support for the Company's claim that its proposed post-test year increase is somehow required by the rule.

The Company has not yet filed its storm hardening plan under the rule,[37] even though the rule would permit it to do so now. Accordingly, the Company's request is twice removed from being a known and measurable adjustment to test year expenses: not only has the Company not incurred the expenses yet, it has not even filed the plan which it claims will require it to incur those expenses in the future.

To be clear, however, the rule requires no such expenditures, does not provide for Commission approval of the plan, and does not provide for any particular cost recovery. Despite its litigation position in this proceeding, at the time of the project to consider the rule, CEHE acknowledged these features of the rule. During the hearing, Mr. Finley testified that he was

---

[34] Direct Testimony of Terry Finley, CEHE Ex. 11 at 66-67; Direct Testimony of Walter L. Fitzgerald, CEHE Ex. 28 at 11.

[35] P.U.C. SUBST. R. 25.95(d).

[36] P.U.C. SUBST. R. 25.95(e).

[37] Tr. at 212, lines 20-22 (Oct. 11, 2010).

involved in reviewing the Company's comments in that project, Project No. 37475.[38] Yet his testimony in this proceeding contradicts CEHE's position in Project No. 37475. Mr. Finley acknowledged that, in comments filed in Project No. 37475, CEHE stated that:

> "CenterPoint Energy does not object to the requirement to submit a storm hardening plan; however, if such is the requirement, there are two fundamental flaws of the proposed rule. First, there is a lack of approval process for the plan, and second, the failure to provide a mechanism for adequate and timely cost recovery of expenditures incurred to implement capital additions or perform operations and maintenance work based on the plan."[39]

Mr. Finley acknowledged that the rule ultimately adopted in Project No. 37475 did not expressly provide for approval of the plan, and did not address cost recovery.[40] GCCC witness Kollen also testified in his direct testimony that the rule provided for no Commission approval of any storm hardening activities or expenditures.[41]

In response to these points, at the hearing, Mr. Finley claimed that it was now CEHE's interpretation that the Commission's rule would in fact provide for an approval of the storm hardening plans.[42] However, the rule is not ambiguous – it makes no mention of Commission approval, nor cost recovery. In this rate case, CEHE's interpretation amounts to the fabrication of entire, new provisions that the Commission did not actually include in the rule. This supposed interpretation should be disregarded. Instead, CEHE characterized the rule properly when it was providing comments to it in Project No. 37475 – both in noting that "there is a lack of approval process for the plan," and then citing the "failure to provide a mechanism for adequate and

---

[38] Tr. at 213, line 15 – 214, line 1 (Oct. 11, 2010).

[39] Tr. at 214, line 20 – 215, line 6 (Oct. 11, 2010); *see also Rulemaking for Utility Infrastructure Storm Hardening*, Project No. 37475, Comments of CenterPoint Energy Houston Electric LLC at 4-5 (Mar. 12, 2010).

[40] Tr. at 215, line 19 – 216, line 3 (Oct. 11, 2010).

[41] Direct Testimony of Lane Kollen, GCCC Ex. 1 at 52.

[42] Tr. at 217, lines 2-7 (Oct. 11, 2010).

timely cost recovery" for the expenditures stated in the plan. The Company's sudden about-face in this proceeding should therefore be given no credence.

The record evidence in this proceeding overwhelmingly indicates that CEHE's proposed post-test year increase of $7.150 million in storm hardening costs is based on no more than an intent to expend that sum in the future. That expenditure is not required by the storm hardening rule, and in any event, CEHE has not yet even complied with the only requirement that the rule *does* establish – the filing of a five-year storm hardening plan. With the contents of the plan undetermined, and with no requirement to expend any particular sum set forth in the rule, the Company's request for storm hardening expenditures falls far short of being known and measurable. The Company's proposed test year increase in distribution costs should be denied.

C. Labor Expenses

1. Post-Test Year Payroll Adjustment/Competitive Pay Adjustment

Not addressed.

2. Incentive Compensation

Not addressed.

3. Employee Benefits

Not addressed.

4. Savings Plan Expense

Not addressed.

D. Pension and OPEB Expense [Issue 13]

The PFD errs by failing to consider whether CEHE proposed to amortize its pension and OPEB deferral over an appropriate period. FoF No. 64.

The PFD makes a finding on, but fails to discuss, an important issue in the calculation of CEHE's pension expense: the Company's proposed use of an unreasonably brief amortization period for its deferred pension and OPEB amounts. As GCCC witness Kollen noted in his direct testimony, CEHE seeks to amortize its pension assets over a period of three years, an unreasonably short period that places ratepayers at significant risk of overrecovery for this expense.[43] After addressing other pension expense issues raised by TIEC and COH/HCOC, the PFD approves the Company's proposed pension expense without any disallowance.[44] Other than the entry of a finding of fact, the PFD is silent on the amortization period underlying the expense amount, and does not discuss the issues in this area raised by GCCC.

As Mr. Kollen testified, pension and OPEB deferrals "tend to smooth themselves out" over future years as CEHE's baseline for measuring the deferral increases and as earnings on the pension trust fund assets vary.[45] A sufficient amortization period will permit time for this process to occur. Importantly, the three-year amortization period proposed by CEHE places ratepayers at significant risk for over-paying CEHE for this expense. If the Company does not file a rate case for more than three years, the expense will be fully amortized, while the Company would continue to collect the same amounts in its rates.[46] A similar dynamic exists with respect to the Company's rate base and return: the regulatory asset for pension and OPEBs will decline each year as it is amortized, but CEHE's revenues will continue at a level that assumes it is able to earn a return on the unamortized, original balance of the asset.[47]

In contrast, a longer amortization period poses no similar risk the Company. If there is a rate case before the pension and OPEB asset is fully amortized, the Company can still continue to recover the yearly amortization amount.

---

43 Direct Testimony of Lane Kollen, GCCC Ex. 1 at 57-58.

44 PFD at 73.

45 Direct Testimony of Lane Kollen, GCCC Ex. 1 at 57.

46 *Id.* at 58.

47 *Id.*

Accordingly, GCCC proposed that the ALJs and Commission adopt a five-year amortization period for this item.[48] The PFD does not consider this recommendation, but it is supported by the record, fully briefed, and properly before the Commission. The effect of this recommendation is to reduce CEHE's proposed distribution revenue requirement by $1.035 million and its proposed transmission revenue requirement by $0.186 million.[49]

E. Self-Insurance Reserve [Germane to Preliminary Order Issue Nos. 16 and 20]

The PFD errs by recommending an excessive storm reserve accrual for CEHE. FoF Nos. 89-92.

The PFD permits the Company an excessive and unreasonable storm reserve annual accrual of $4.15 million with a target reserve level of $13.28 million.[50] In reaching this figure, the PFD rests on several errors which the Commission should correct.

As GCCC witness Lane Kollen testified, the proper storm reserve annual accrual is $1.627 million for distribution and $0.676 million for transmission.[51] Mr. Kollen developed these recommendations by performing a trended loss history analysis, a method that the Commission has relied upon to calculate storm reserve accruals in the past.[52] In his analysis, Mr. Kollen removed Hurricane Rita costs of $37.8 million on the basis that these costs were atypical, and therefore should not appear in a trended lost history study.[53] The ALJs rejected this approach, stating that the abnormality of storms like Hurricane Rita are precisely the reason that they should be included in the calculation.[54] The ALJs also state that PURA does not permit the

---

48 *Id.* at 59.

49 *Id.*

50 PFD at 77.

51 Direct Testimony of Lane Kollen, GCCC Ex. 1 at 61.

52 *Id.*

53 *Id.* at 60-62.

54 PFD at 74.

securitization of storms the size of Hurricane Rita, and therefore they should be included in the storm reserve analysis.[55]

The ALJs focus on the Company's ability to recover the costs of storms the size of Hurricane Rita through either securitization or a special surcharge mechanism but fail to account for the fact that the $100 million threshold noted in the PFD is a calendar-year measure.[56] That is, the threshold that PURA requires to obtain special ratemaking treatment for restoration costs is not storm specific – if the utility experiences $100 million in damages from any number of storms during the year, it may seek special rate relief. This means that storm reserve accruals now exist against a much different statutory backdrop than prior to the legislation, and the occurrence of unusual, and large, loss events like Hurricane Rita must be given different consideration in a proper storm reserve analysis. By removing Hurricane Rita from his analysis, Mr. Kollen correctly accounts for these new circumstances. By contrast, the accrual proposed by CEHE, and recommended by the PFD, gives no consideration to the new statute whatsoever.

The ALJs also rejected Mr. Kollen's analysis in favor of the one proffered by the Company because the Company's analysis is in some way more consistent with the Commission's decision in the recent Oncor Electric Delivery Company LLC ("Oncor") rate case. The ALJs observe that in that case, the Commission did not rely solely on a trended loss history analysis (the type performed by Mr. Kollen) but instead adopted a blended trended loss and Monte Carlo analysis approach.[57] While this is true, it does nothing to support the Company's and the ALJs' proposed approach in this case, which is *solely* a Monte Carlo analysis. Indeed, in the Oncor case, the ALJs expressed discomfort with sole reliance on the type of analysis presented by Mr. Wilson (the same witness on this issue that CEHE has offered), stating that

---

55 *Id.* at 76.

56 PURA § 36.403(j).

57 PFD at 75.

they were not convinced that "actuarial analysis is any more accurate than averaging Oncor's losses for predicting future losses of a self-insured company."[58] If the PFD looks to the Oncor decision as guidance on this issue, then it is not at all clear why CEHE's Monte-Carlo-alone approach was adopted. In short, the PFD's proposed storm hardening accrual is unreasonable and permits the Company an amount in excess of its reasonable storm damage requirements, especially in view of the additional tools that PURA now grants utilities with respect to storm recovery.

F. Affiliate Expenses [Germane to Preliminary Order Issue No. 17]

Not addressed.

G. Customer Service

Not addressed.

H. Electric Market Operations

Not addressed.

I. Energy Efficiency Expenses and Programs [Germane to Preliminary Order Issue No. 31]

Not addressed.

J. Amortization Expense [Germane to Preliminary Order Issue No. 19]

1. Hurricane Rita

The PFD errs by permitting CEHE to amortize its remaining Hurricane Rita restoration costs over three years. FoF No. 115.

The PFD unreasonably permits CEHE to amortize and recover its remaining Hurricane Rita restoration expenses over the next three years.[59] In contrast, GCCC witness Lane Kollen

[58] *Application of Oncor Electric Delivery Company LLC for Authority to Change Rates*, Docket No. 35717, Proposal for Decision at 118 (June 2, 2009).

[59] PFD at 85.

proposed that the remaining costs be amortized over five years. While both CEHE and the PFD correctly note that a seven-year amortization period was established in CEHE's last rate case, Docket No. 32093, the risk of overrecovery that the remaining three-year amortization period poses was not adequately addressed by the ALJs. The PFD states that the ALJs' decision is based on the arguments propounded by CEHE, primarily that the seven-year amortization was previously approved in Docket No. 32093.[60] The ALJs also state that there is no evidence that CEHE may not return for a rate case earlier than five years.[61]

None of these points adequately address the risk that a three-year amortization of the remaining balance of this item will result in an over-recovery. As Mr. Kollen testified, if the Commission adopts the ALJs' recommended amortization period of three years, and CEHE does not have a base rate case for five years, CEHE will continue to collect its yearly amortization amount for two years during which CEHE will over recover its deferred Hurricane Rita costs. If this scenario were to occur, for example, CEHE would over recover to the extent of $8.2 million, consisting of the $4.1 million annual amortization figure produced by a three-year amortization period times two years.[62] For this reason, GCCC urges the Commission not to adopt the recommendation of the ALJs on this point, and instead, require a five-year amortization period for the remaining Hurricane Rita restoration costs. Doing so results in a $1.640 million reduction to CEHE's proposed distribution revenue requirement.[63]

2. Hurricane Ike

The PFD errs by allowing CEHE to pass the insurance proceeds related to Hurricane Ike to ratepayers at a slower rate than it collects its remaining Hurricane Rita restoration costs. FoF No. 116.

---

[60] *Id.*

[61] *Id.*

[62] Direct Testimony of Lane Kollen, GCCC Ex. 1 at 65.

[63] *Id.* at 66.

In its original application, the Company proposed to amortize the insurance proceeds resulting from Hurricane Ike over the period of the system restoration bonds that CEHE was authorized to issue in Docket No. 36918.[64] Specifically, CEHE requested approval of a negative amortization expense of $1.475 million to amortize the $17.7 million in distribution proceeds.[65] The PFD properly rejected this proposal, but then erroneously recommended a five-year amortization period based on an apparent misunderstanding of GCCC witness Kollen's recommendation on this issue.

Mr. Kollen testified that the Company's proposal to amortize the Hurricane Ike proceeds over the life of the system restoration bonds was inappropriate in view of the Company's simultaneous proposal to amortize the remaining Hurricane Rita restoration costs over three years. As Mr. Kollen testified, the distribution portion of the proceeds should be amortized and returned to ratepayers over the same time frame as the Company's amortization of the remaining Hurricane Rita costs.[66] Thus, Mr. Kollen testified that if the Company obtained approval to amortize the Hurricane Rita costs over three years, then the Company should be required to share the proceeds related to Hurricane Ike over the same period.[67]

Mr. Kollen proposed that the Hurricane Ike insurance proceeds be amortized over five years only if the Commission ultimately adopted his recommendation to amortize the Hurricane Rita costs over five years.[68]

As noted in section J.1. above, the ALJs have recommended that CEHE's remaining Hurricane Rita costs should be amortized over three years. Simultaneously, the PFD states that

---

[64] *Application of CenterPoint Energy Houston Electric, LLC for Determination of Hurricane Restoration Costs,* Docket No. 36918.

[65] Direct Testimony of Lane Kollen, GCCC Ex. 1 at 66; *citing* CenterPoint's Rate Filing Package, CEHE Ex. 1 at Schedule II-E-1.

[66] Direct Testimony of Lane Kollen, GCCC Ex. 1 at 67.

[67] *Id.*

[68] *Id.*

the ALJs found Mr. Kollen's recommendations on the amortization of the Hurricane Ike insurance proceeds to be reasonable.[69] But given their decision on the Hurricane Rita cost amortization period, adoption of Mr. Kollen's recommendation on amortization of the Hurricane Ike proceeds would require a ***three year*** period, not five. The basis of GCCC's recommendation is that CEHE should be required to amortize its regulatory assets and liabilities using the same period, absent a compelling rationale.[70] The outcome set forth in the PFD is that CEHE may collect its remaining Hurricane Rita costs on a faster schedule than it shares its Hurricane Ike insurance proceeds with ratepayers. CEHE should not be permitted to have it both ways on these amortization issues, and the Company should be required to amortize its Hurricane Ike insurance proceeds over three years if the Commission adopts the PFD's recommendation of a three-year amortization period for the remaining Hurricane Rita costs.

K. Depreciation [Preliminary Order Issue No. 11]

In order to reduce rate case expenses and avoid duplication of effort, GCCC relies upon the recommendations of Texas Coast Utilities Coalition ("TCUC") and its witness, Mr. Pous, regarding depreciation.

1. Accumulated Depreciation Reserve

Not addressed.

2. Service Lives

Not addressed.

3. Net Salvage

Not addressed.

---

[69] PFD at 87.

[70] Direct Testimony of Lane Kollen, GCCC Ex. 1 at 67.

4. Gain on Sale of Land

Not addressed.

L. Federal Income Taxes [Germane to Preliminary Order Issue No. 23]

1. Consolidated Tax Savings Adjustment ("CTSA") [Germane to Preliminary Order Issue No. 22]

Although the PFD renders the correct determination with respect to whether to apply a CTSA to CEHE or not and whether to gross it up, it appears that the ALJs made an error in calculating the adjustment. GCCC supports the Exceptions filed by COH/HCOC on this point and requests that the Commission correct this error as described therein.

2. Medicare Part D Subsidy

The PFD errs by permitting CEHE to recover costs associated with the tax effects of Medicare Part D to recover amounts supposed shared with ratepayers that were never, in fact, share, and to do so via prohibited retroactive ratemaking. FoF Nos. 147-159.

The PFD improperly adopts two proposals by the Company with respect to the tax effect of the Medicare Part D subsidy that would unnecessarily and unreasonably inflate the Company's rates. The first is the Company's proposal to record and amortize a regulatory asset for income tax expense related to prior years with respect to the subsidy, and the second is a proposed increase to current income tax expense to reflect the elimination of the tax exemption for the Medicare Part D subsidy. In their PFD, the ALJs recommend that the Company's proposals be adopted, and state that the Company's requested approach "more closely matches the recovery of the increased tax expense with the ratepayers who received the benefit of the nontaxable Medicare Part D subsidy in prior years."[71] The conclusion is seriously flawed in a number of respects and should not be adopted by the Commission.

---

[71] PFD at 136.

As GCCC detailed in its Initial Brief and in the testimony of its witness, Lane Kollen, in 2009, CEHE recognized a regulatory asset to reflect an increase in its ADFIT.[72] According to CEHE, the increase in ADFIT was caused by recent federal health care legislation that renders the Medicare Part D subsidy taxable after January 1, 2013.[73] The Company proposed to amortize the amount over three years, a request which adds $4.870 million in annual distribution taxable income and has the effect of increasing its revenue requirement by $3.094 million.[74]

The Company's rationale for establishing this regulatory asset – the same rationale used by the ALJs to approve it – is problematic. According to CEHE, "the rationale for setting up a regulatory asset is that the tax benefit of the Medicare Part D subsidy was included in the rate calculation for the years prior to 2010, reducing income tax expense. As customers benefitted during those prior years from an anticipated income tax treatment that did not occur, future revenue requirements should be increased to recoup this amount."[75] This statement accords with the ALJs' conclusion that CEHE's proposed ratemaking treatment for this issue appropriately collects additional tax expense from ratepayers who somehow were given a benefit by the prior non-taxability of the Medicare Part D supplement.

But the premise underlying this conclusion – that ratepayers benefited from the tax-free nature of the Medicare Part D subsidy – cannot be true. CEHE's last rate case, Docket No. 32093, was settled on a black-box basis. The settlement defined only a total revenue requirement and did not specify each of the items comprising the revenue requirement. Without having the supposed tax benefit of the Medicare Part D subsidy shared with ratepayers through

---

72 GCCC's Initial Brief at 46 (Oct. 22, 2010); Direct Testimony of Lane Kollen, GCCC Ex. 1 at 83.

73 Direct Testimony of Lane Kollen, GCCC Ex. 1 at 83-84.

74 *Id.* at 84.

75 *Id., quoting* CEHE's Response to GCCC 06-11, included as Attachment L to Mr. Kollen's Direct Testimony.

CEHE's rates, there is no way to conclude that ratepayers "received the benefit of the nontaxable Medicare Part D subsidy in prior years," as the ALJs have concluded.

Even assuming that ratepayers *did* benefit in some way – an assumption completely belied by the evidence in this case – CEHE's and the ALJs' recommended approach would be prohibited by PURA. Section 36.111(b) clearly requires that any rates set by the regulatory authority shall be observed until changed as provided by Chapter 36 of PURA. This provision bars what is known as "retroactive ratemaking", a prohibition that prevents the Commission "from setting future rates to allow a utility to recoup past losses or to refund to consumers excess utility profits."[76] The Company's proposal, and the PFD adopting it, would do just that, and accordingly the Commission should reject it. But as noted at the outset, there is no record evidence suggesting that ratepayers somehow benefited from the Company's treatment of Medicare Part D subsidies in the years prior to 2010.

As part of the Company's proposal with respect to the tax effects of Medicare Part D, the Company requests an increase in tax expense now to reflect the taxable status of the Medicare Part D subsidy in 2013. While the PFD makes much of the accounting treatment that results from a change in future tax expense, it merely recites, without addressing, the testimony of Mr. Kollen that this issue has not given rise to any ***expense*** at all. Instead, the accounting for the regulatory asset and ADFIT that the Company describes occurred only on its balance sheet, not its income statement.[77] As Mr. Kollen testified, there has been no increase in income tax expense as a result of the change to tax status of the Medicare Part D subsidy – the resulting regulatory asset simply offsets the recognition of ADFIT.[78] The actual expense the Company incurs resulting from the taxability of the Medicare Part D subsidy will not increase until 2013.

[76] *State v. Public Utility Commission of Texas*, 883 S.W.2d 190, 199 (Tex. 1994).

[77] Direct Testimony of Lane Kollen, GCCC Ex. 1 at 85.

[78] *Id.*

With the rates resulting from this case likely going into effect in early 2011, under the PFD's approach CEHE would over-recover for this item for nearly two years awaiting 2013, the year that the subsidies become taxable. Recovery of this increased tax expense nearly two years ahead of time, as the PFD authorizes, is unreasonable and should be rejected.

M. Taxes Other than Income Taxes [Germane to Preliminary Order Issue No. 23]

1. Ad Valorem (Property) Taxes

Not addressed.

2. Texas Gross Margin Tax

The PFD errs by permitting CEHE to recover an excessive amount of the Texas gross margin tax, and essentially permitting CNP Energy, Inc. to use CEHE's rates to subsidize its other affiliates. FoF Nos. 161-165.

The PFD would permit CEHE to recover an excessive and unreasonable amount for its Texas gross margin tax. CEHE sought to recover $16.364 million in Texas margin tax, an amount that the Company computed by using the method dictated by its corporate parent, CNP Energy, Inc. ("CNP Energy"). However, the record evidence in this proceeding clearly indicates that CNP Energy chose the method of computing the tax in the manner most disadvantageous to CEHE, and most advantageous to its other affiliates. This attempt at subsidizing CNP Energy's other affiliates should be rejected, and CEHE should only be permitted to recover Texas margin tax in an amount as described below.

The Texas gross margin tax is 1% of CNP Energy's "taxable margin."[79] Taxable margin is defined by the relevant statute as the lowest of the three following amounts, on a consolidated basis:

1. Revenues less cost of goods sold;
2. Revenues less compensation;

[79] Direct Testimony of Lane Kollen, GCCC Ex. 1 at 68.

3. Revenues times 70%.[80]

In calculating its taxable margin, CNP Energy chose the first method – revenues minus cost of goods sold. As the PFD rightly notes, each of CNP Energy's affiliates then computed the amount it is to pay to CNP Energy using this method.[81]

CEHE's witness in this proceeding made clear that the reason that this was done was because CNP Energy's natural gas affiliates have a significant cost of goods sold for gas sold to their customers.[82] However, the record indicates that if CEHE's Texas margin tax were computed on a stand-alone basis using the "revenue times 70%" approach, the tax would be \$11.455 million, instead of the \$16.364 million that the Company requested.[83] In fact, CEHE's taxable margin would be the highest under the method that CNP Energy chose, because CEHE has no cost of goods sold, given that it is a transmission and distribution utility that does not actually sell electricity to its customers. The bottom line is that CNP Energy chose the Texas margin tax calculation that is the *least* advantageous to CEHE but the *most* advantageous to its gas affiliates.

The ALJs rested their decision on the fact that, for Texas margin tax calculation purposes, CEHE is not free to choose a different method than the one that CNP Energy chooses.[84] While true, this fact has no bearing on this issue. Indeed, CEHE is not able to choose a different method than its parent, because CEHE does not choose a method at all – the Texas margin tax must be calculated and paid on a consolidated basis. CNP Energy chooses the method, then computes and pays the tax; CNP Energy then requires CEHE to pay it an amount based on the

---

80 *Id.* at 68.

81 PFD at 138; Direct Testimony of Alan D. Felsenthal, CEHE Ex. 26 at 18-20.

82 Direct Testimony of Alan D. Felsenthal, CEHE Ex. 26 at 18.

83 Direct Testimony of Lane Kollen, GCCC Ex. 1 at 69.

84 PFD at 137-138.

definition of "taxable margin" that it has chosen. There is nothing in the record to suggest that anything about Texas gross margin tax law requires CNP Energy to extract a particular amount from CEHE. CEHE and the PFD frame this issue as one of tax requirements, but it is not – this is a ratemaking issue focused on the proper Texas gross margin tax that CEHE may recover through its rates. While CEHE may be bound by CNP Energy's decision for Texas margin tax purposes, as CEHE asserts, that says nothing about the proper amount of Texas margin tax to be included in the Company's rates. To prevent the subsidization of CNP Energy's other affiliates by CEHE, the PFD should be overturned on this point, and Mr. Kollen's recommended Texas margin tax of $11.455 million should be adopted.

3. Payroll Taxes

Not addressed.

N. Municipal Franchise Fees [Preliminary Order Issue No. 21]

Not addressed.

VIII. ERCOT WHOLESALE TRANSMISSION COST OF SERVICE

A. Wholesale Transmission Cost of Service Tariff Changes

Not addressed.

B. Rider UCOS Wholesale Credit

Not addressed.

IX. COST ALLOCATION AND RATE DESIGN

A. Cost Allocation [Germane to Preliminary Order Issue Nos. 14 and 25]

1. Capacity Allocation (Minimum System)

Not addressed.

2. Class Cost of Service

a. Gradualism

Without any mention of GCCC's position, the ALJs conclude that gradualism should not be applied in this case.[85] GCCC takes exception to this recommendation. In this case, a revenue allocation should be avoided that results in some classes receiving total revenue decreases while other classes are assigned total revenue increases. This should be the case in both a system revenue increase or decrease. Beyond that, the circumstances of a system increase or decrease require different approaches to applying gradualism. Under the PFD, residential customers would see a 6.25% increase while the overall system increase is less than 1%. Applying gradualism as recommended by GCCC would reduce the residential increase to approximately 4%. Specifically, GCCC proposes that in the event the Commission grants an overall revenue increase, no class should receive a revenue decrease. Alternatively, in the event of an overall decrease, gradualism should be applied to overall system revenue reductions, such that all customer classes receive the benefit of the rate decrease.

As set out in GCCC witness Mr. Johnson's testimony, there are several factors that support the application of gradualism for the residential class that are not apparent in the class cost of service study.[86] For example, load diversity at the local distribution level is not taken into account in the class cost of service study. If diversified demands (class non-coincident peaks) ("NCP") had been used to allocate demand-related distribution plant, the residential class would be responsible for less cost responsibility than reflected in the class cost of service study.[87] The Company's cost allocation study uses four coincident peak ("4CP") as the measure of demand.

---

[85] *Id.* at 147.

[86] Direct Testimony of Clarence Johnson, GCCC Ex. 2 at 36-37.

[87] *Id.*

Mr. Johnson testified that the unadjusted CP/NCP coincidence factors[88] suggest that the residential class would be allocated less costs by a NCP allocation than 4CP. CenterPoint is the only electric utility in Texas which relies upon CP demand rather than NCP demand, to allocate distribution plant. Distribution plant is sized to serve localized loads. For that reason, class demands are usually favored over system demands for distribution demand allocation. The omission of local demand diversity consideration suggests that the residential class has been over-allocated costs.

Assuming that the Commission orders a reduction to total system revenues, GCCC proposes to balance the results of Mr. Johnson's class cost of service study with the desirability of providing revenue reduction benefits for all customer classes. The class cost of service is a moving target for setting rates. Class relationships change in the future as the Company's cost structure and demands constantly change. Therefore, the class cost relationships should not be treated with fixed point accuracy. As stated previously, all classes should receive a revenue reduction in this case. In order to recognize that some degree of cost variations above and below unity relative rates of return exist, GCCC recommends assigning 85% of the system average percent revenue reduction to classes with a current relative rate of return below unity.[89] The remaining classes with a relative rate of return above unity would receive the remaining revenue decrease.

If a system revenue increase is ordered by the Commission, classes for which a total revenue decrease is indicated, based upon the class cost of service study, should be assigned a zero change in revenues.[90] At a minimum, this permits the class revenue increases resulting

---

[88] CenterPoint Rate Filing Package, CEHE Ex. 1 at Schedule II-H-1.3(c), *see* "coincidence factor system/class" lines.

[89] Direct Testimony of Clarence Johnson, GCCC Ex. 2 at 38.

[90] *Id.* at 39.

from the cost of service study to be moderated, facilitating the traditional factors of gradualism and customer acceptance. However, this approach also brings class revenues in closer alignment with costs by assigning no revenue increase to classes with relative rates of return above unity.[91]

b. Transformer Classification

Not addressed.

c. Business Development Expenses (Account 908)

The PFD proposes to allocate business development expense on class revenue requirement based upon the assumption that "economic development costs benefit all customer classes."[92] The PFD's assumption is incorrect and should be rejected. In contrast, this expense should be directly assigned based upon the classes that contain customers which received economic development services.

Economic development services are provided to "expanding or relocating businesses" and consist of "site selection assistance, market research, regional assistance, and industry due diligence."[93] The economic development unit also provides "market, intelligence," "project analysis," and advisory services to local economic development organizations seeking to attract new businesses. During 2009, the Company's economic development department received commitments from 49,845 KVa of business load.[94] Sixty percent of the attracted load was commercial, and the remaining 40% industrial. As such, it is reasonable to assign 60% (commercial) of economic development costs to the secondary and primary classes and 40%

---

[91] *Id.*

[92] PFD at 149.

[93] www.centerpointenergy.com/services/electricity/business/economicdevelopment.

[94] *See* Direct Testimony of Clarence Johnson, GCCC Ex. 2 at Attachment H (Response to GCCC 08-13).

(industrial) to the primary and transmission classes. The commercial and industrial portions of economic development are allocated among the specified classes on the basis of revenues.[95]

d. Records & Collection Expense (Account 903)

The PFD adopts CEHE's proposal to allocate Account 903-Region Operations Expense based upon number of customers, despite the fact, that the Company presented virtually no justification for its request. Indeed, the Company's entire response in its brief was that GCCC's recommended allocation is "based on faulty assumptions and do not track cost causation."[96] In contrast, because the principal function of the region operations customer records and collection is revenue-related, GCCC recommends using a customer allocator weighted by class revenues. In support of their recommendation, the ALJs simply state, like the Company, that GCCC's recommendation is "based on a faulty assumption."[97] The only other explanation provided by the ALJs is that they believe allocating records and collections expense by revenue is "inconsistent with the principle that cost allocation should follow cost causation."[98] Like the Company, however, they fail to identify what the faulty assumption in GCCC's proposal is or why it violates the principle.

Customer records and collection expense include region operations and customer service operations. More specifically, the region expense is comprised of field service representatives, service area managers, operations, revenue protection, and administration. GCCC's recommendation focuses on the region operations, which is principally concerned with residential, secondary commercial, and primary service classes.

---

[95] The resulting allocation of economic development costs is shown on Schedule CJ-2 to the Direct Testimony of Clarence Johnson, GCCC Ex. 2.

[96] CEHE's Initial Brief at 179 (Oct. 22, 2010).

[97] PFD at 150.

[98] *Id.*

Admittedly, the workload of the region operations customer records and collection may be driven by the number of customers. However, the time and attention applied to transactions should be related to the revenue associated with each transaction. For example, revenue protection investigations, which pertain to fraud and electricity diversion, are likely to require more resources if higher revenue accounts, with more sophisticated commercial customers, are involved. Other types of transactions include billing disputes and retail electric provider ("REP") communications. Accordingly, it is appropriate to use a customer allocator weighted by class revenues to allocate Account 903-Region Operations Expense.

e. Customer Installation Expense (Account 587)

GCCC takes exception to the PFD's proposal to allocate customer installation expense (excluding transmission and lighting) on the basis of customers. In contrast, these Account 587 expenses should be allocated on the basis of poles, lines and services investment.

Customer installation expense is comprised of dispatch operations, revenue protection, and service center operations. The facilities related to customer installation activities consist of poles, lines and services. The Account 587 sheet in the cost allocation model includes the "poles, lines, services" allocator, but the Company did not use the "poles, lines, services" allocator. It is not clear whether this reflects an error by the Company or a decision to reconsider its use of this allocation factor. The PFD assumes that the costs incurred for this account are for dispatch operations, revenue protection, and service center operations rather than for poles, lines and services.[99] Regardless, allocating Account 587 on the basis of poles, lines and service investment is appropriate and should be adopted.

[99] PFD at 151.

f. Uncollectible Expense

Consistent with longstanding PUC precedent, the Company appropriately proposes to allocate uncollectible expense on a revenue basis. Although it is not clear, the PFD appears to recommend continuation of this approach and simply urges the Commission require CenterPoint to track uncollectible cost date on a class basis in the future.[100]

Regardless of whether the Company has data that would allow uncollectible expense to be directly assigned among customer classes, PUC Staff witness Lain's and TIEC witness Pollock's recommendation should, nevertheless, be rejected. First, the PUC has a longstanding precedent for allocating uncollectible costs on a revenue basis. Second, uncollectible expense is more appropriately viewed as a social cost. Third, uncollectible expenses for transmission distribution utilities ("TDUs") in areas subject to customer choice are caused by REPs rather than end-use customers.

The Commission's use of a revenue allocation for uncollectibles is one of the most consistent allocation practices approved or ordered by the Commission over the past 20 years. Ironically, the PUC Staff was the principal advocate of this practice during most of that period including since TDU rates were unbundled in 2002.

In support of his argument, Mr. Lain claims that class "direct assignment" of uncollectibles is consistent with cost causation. However, the Commission has previously rejected that conclusion. Specifically in Docket No. 16705, Entergy Gulf States Utilities, Inc. ("EGS") proposed a direct assignment of uncollectibles. The order in Docket No. 16705 rejected

[100] *Id.* at 152.

direct assignment, in favor of a revenue allocation and concluded that uncollectibles are a social cost that must be absorbed on an equitable basis by all classes.[101]

Even if CenterPoint prepares a direct assignment study as recommended by the ALJs, that methodology is not justified on a cost causal basis. The direct assignment method assigns uncollectible costs to the remaining collectible accounts, none of which are the "cause" of the uncollectible expense. Given the lack of an appropriate causal basis for assigning the cost, a general indirect allocation such as revenues is reasonable.

The argument for direct assignment of TDU uncollectibles to customer classes is further weakened by the existence of customer choice in CenterPoint's service area. Specifically, the uncollectible expense at issue is not associated with defaults by end-use customers. Instead, the TDU's uncollectible expense arises from defaults by REPs. REPs (not the TDU) bear the cost of end user customer uncollectible accounts. The TDU's uncollectible costs arise because particular REPs encounter problems meeting their credit requirements, enter bankruptcy, or can no longer provide generation service to end users. The uncollectible cost is caused by the REP and may result from defects in the REP's business strategy or flaws in the Electric Reliability Council of Texas ("ERCOT") market. Just as expenses such as unaccounted for energy are spread across the market by ERCOT, this is a market-related expense which cannot be causally assigned to customer classes on a rational basis. For example, commercial customers of well-established, stable REPs, like Reliant or TXU Energy, should not be held accountable for defaults by REPs that bet on the spot energy market and happen to sign up commercial customers.

---

[101] *Application of Entergy Gulf States, Inc. for Approval of its Transition to Competition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors and to Recovery a Surcharge for Underrecovered Fuel Costs*, Docket No. 16705 Second Order on Rehearing at FoF 231 (Oct. 14, 1998).

Based upon the foregoing, GCCC recommends that the Commission adopt the Company's proposal to allocate uncollectible expense on a revenue basis and not require CenterPoint track uncollectible cost data on a class basis.

3. 4CP Transmission Cost Allocation

a. Coincident Peak Demand Allocation

Not addressed.

b. Proposed Weather Adjustment

In the Company's class cost of service study, transmission costs are allocated to the retail customer classes using the ERCOT 4CP allocation factors. Similar to the adjustment applied to the 4CP demand allocation factors for distribution costs, CEHE applied a weather adjustment to the transmission allocation factors. In contrast, the PFD recommends removal of the weather adjustment from the transmission allocation factors.[102] The effect of removing the weather adjustment is to increase the transmission costs allocated to the most weather-sensitive classes (Residential and Secondary >10kva).[103] The inconsistent application of weather adjustment as proposed by TIEC witness Mr. Pollock and PUC Staff witness Mr. Lain, and adopted by the PFD, results in residential customers being allocated more costs than is appropriate. The only reasonable outcome is to either: adjust both the class ERCOT 4CP demand and the class transmission billing units for weather; or make no weather adjustment to either the demand allocator or the class transmission billing units. However, if the PFD is adopted, the weather adjustments should be removed from the billing determinants used to develop retail transmission rates.

---

[102] PFD at 155.

[103] Cross Rebuttal Testimony of Clarence Johnson, GCCC Ex. 4 at 4.

In his rebuttal testimony, GCCC witness Johnson testified as to the problems associated with Mr. Pollock's and Mr. Lain's proposal. First, he indicated that they forwarded no convincing arguments that the retail transmission allocation cannot be adjusted for weather normalization.[104] Furthermore, if the weather adjustment is removed from the 4CP allocation factors, consistency requires that the weather normalization adjustment should also be removed from retail class billing determinants.[105] Mr. Lain's transmission allocation increased the costs for weather sensitive classes by including abnormal weather effects, while simultaneously ignoring the same abnormal weather effects on the billing determinants used to fix class transmission rates.[106] The ultimate impact of Mr. Lain's asymmetric treatment of demand allocations and billing units is to unfairly inflate the rates of residential and secondary customer classes.

In the PFD, the ALJs cite the PUC Staff's concern that CEHE's transmission allocation "would be mixing unadjusted 4CP to determine ERCOT transmission revenues that DSPs...are required to pay to TSPs with CenterPoint's adjusted 4CP used to allocate costs and set rates for CenterPoint's retail customers"[107] Yet, ironically, the PFD is unconcerned with mixing unadjusted transmission allocations with adjusted kilowatt hour billing units that determine the actual retail rate for residential customers. By far, the most significant adjustment to both the 4CP allocation factors and the kilowatt hour billing units in this case is related to weather normalization. The ALJs' "solution" is worse than the problem, because mixing unadjusted allocation factors with weather adjusted billing units *guarantees* that the residential class will overpay for transmission costs. As demonstrated by the illustration at Schedule CJ-Rebuttal-1,

[104] *Id.* at 5.

[105] *Id.*

[106] *Id.*

[107] PFD at 154.

failing to match the weather adjustments for both allocation and billing determinants creates a permanent subsidy of the non-weather sensitive class by the weather-sensitive class (residential).[108] Considering PUC Staff witness Lain's desire to eliminate cross-subsidies among customer classes, it is ironic that the PFD's proposal to mix actual 4CP demands with weather adjusted billing determinants will force the residential class to subsidize other classes.

The PFD also cities the Commission's treatment of this issue in Docket Nos. 28840 and 35717 as support for their recommendation. However, neither of these cases specifically pertain to the application of weather normalization adjustments to the transmission 4CP allocation.

The finding of fact in Docket No. 28840 only states that the utility "unnecessarily adjusted the 4CP allocator."[109] More importantly, the "unnecessary" adjustment apparently had nothing to do with weather normalizing the 4CP allocation factors. The issue in that case arose because the utility mixed different allocation methods for IDR and non-IDR customer classes, such that the factors are "no longer on a 4CP basis."[110] Moreover, CEHE witness Troxle was the PUC Staff witness who addressed the transmission allocation in Docket No. 28840, and he testified in this case, "I participated in that Docket and know the issue addressed in the order was not weather adjusting and year-end customer adjusting of the 4CP."[111] Interpreting this finding as precedent for the ALJs' position on weather normalization is a leap in logic. In addition, the cited Oncor language clearly pertains to whether the 4CP allocation factor should be replaced by the Average & Excess methodology. Thus the Oncor decision pertains to replacement of the 4CP allocation methodology, and does not specifically address weather normalization.

---

[108] Cross Rebuttal Testimony of Clarence Johnson, GCCC Ex. 4 at Schedule CJ-Rebuttal-1.

[109] *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840, Final Order at 46, FoF 243 (Aug. 15, 2005).

[110] Docket No. 28840, Proposal for Decision at 151-152 (July 2, 2004).

[111] Rebuttal Testimony of Matthew A. Troxle, CEHE Ex. 61 at 30.

By failing to match the treatment of transmission allocation factors and the billing units, the PFD inflates the recommended transmission rates for the residential and secondary classes. If the class demands are increased to include hotter weather, the billing determinants should also be increased to reflect the same weather. If the allocation demands and billing determinants are treated consistently, then the additional cost allocated to weather sensitive classes is offset (in part, at least) by spreading the additional cost over more billing units. If weather normalization were to be removed from the kilowatt hours used to set residential and small secondary transmission rates, current revenues for those classes would increase by $5.377 million, thereby reducing the required revenue increase for those two classes by that amount.[112]

As noted above, the only reasonable outcome is to either: adjust both the class ERCOT 4CP demand and the class transmission billing units for weather; or make no weather adjustment to either the demand allocator or the class transmission billing units. Moreover, the PFD's argument that normalizing adjustments are not allowable for the retail transmission demand allocation is incorrect. As such, the ALJs' proposal to remove the weather adjustment from the transmission allocation factors should be rejected.

c. Proposed Customer Adjustment

Not addressed.

d. Proposed Hourly Interval Adjustment

Not addressed.

4. Municipal Franchise Fees

Not addressed.

[112] CenterPoint's Rate Filing Package, CEHE Ex. 1 at Schedule II-H-4.1.

B. Rate Design [Germane to Preliminary Order Issue Nos. 26 and 32]

1. Alternative Customer Charge [Germane to Preliminary Order Issue No. 8]

Not addressed.

2. Demand Ratchets

Not addressed.

3. Street Lighting

The PFD incorrectly adopts the Company's proposal to extend the period for replacing burned out bulbs and repairs of outages for street lighting repair from 48 to 72 hours because "72 hours is consistent with current industry practice."[113] Regardless of the practice of other utilities, the fact remains that the Company provided no justification for this change. As such, GCCC takes exception to the proposed change.

As noted in Mr. Johnson's testimony, denial is reasonable, because: (a) the Company has not met its burden to justify the change; (b) reducing the Company's target for street lighting reliability adversely affects public safety and reduces customers' sense of security on public streets; and (c) reducing the reliability of street lighting service is particularly inappropriate when the Company is proposing significant increases in the cost of street lighting service.[114]

C. Billing Determinants

1. Weather Normalization [Germane to Preliminary Order Issue No. 15]

The PFD's proposal to adopt CEHE's weather adjustment should be rejected. Specifically, the use of 30 years of weather data to define normal weather is too lengthy and understates the temperatures which would have been expected during the 2009 test year.[115]

---

[113] PFD at 164.

[114] Direct Testimony of Clarence Johnson, GCCC Ex. 2 at 51.

[115] *Id.* at 8.

CEHE's methodology, adopted by the ALJs, is based upon comparing the deviations between the test year weather and the average weather conditions that existed over the previous 30 years. If weather over the 30-year period is not representative of more recent weather trends, the normalization adjustment will produce inaccurate results.

The PFD sets out three arguments in support of its recommendation.[116] None of these arguments are persuasive. First, the ALJs point out that reliance on a rolling 30-year interval for establishing normal weather is consistent with prior Commission precedent involving CenterPoint. Although Commission precedent is useful for ratemaking policies and principles, issues which are based on empirical facts must be determined based on the specific evidence in the rate case. This applies to the determination of an appropriate time period used to define normal weather. Significantly, CEHE does not rely exclusively on a 30-year definition of normal weather. In fact, the Company stated that it uses both a 30-year and 10-year definition of normal weather.[117] For example, CenterPoint has used a 10-year definition of weather in earning reports to investors.[118]

The second justification set out in the PFD is that "weather impacts usage in ways beyond just temperature."[119] According to the PFD, recent hurricanes affect a 10-year period more than 30 years. This argument fails for several reasons. First, it ignores the fact that other hurricanes have occurred in the 20-year period prior to 1999. Second, if anything, this argument suggests that customer consumption has been understated in the past. This hardly justifies using a 30-year normal weather definition which would further understate consumption in CEHE's

---

[116] PFD at 166.

[117] Direct Testimony of Clarence Johnson, GCCC Ex. 2 at Attachment D (*Year-End 2009 Electric Utility Earnings Reports Pursuant to SUBST. R. 25.73(b)*, Docket No. 37993, Company Response to GCCC (Informal) Request No. 2-09).

[118] *Id.*

[119] PFD at 166.