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

DIRECT TESTIMONY

OF

LANE KOLLEN

ON BEHALF OF

GULF COAST COALITION OF CITIES

JUNE 19, 2024

DIRECT TESTIMONY OF
LANE KOLLEN

TABLE OF CONTENTS

ATTACHMENTS:

WORKPAPERS:

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DIRECT TESTIMONY OF
LANE KOLLEN

I. INTRODUCTION AND QUALIFICATIONS

Q. STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Lane Kollen. I am the President and a Principal of J. Kennedy and Associates, Inc., an economic consulting firm specializing in utility ratemaking and planning issues. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold several university and college degrees and several professional certifications. I am a member of numerous professional organizations. I have been actively involved in the regulated utility industry for more than 40 years, presently as a consultant to a variety of clients, including local and state government agencies and large users of utility services, and initially as an employee of a regulated utility. I have testified as an expert witness before the Public Utility Commission of Texas ("Commission"), including the two prior CenterPoint Energy Houston Electric, LLC ("Company") base rate case proceedings.[1]

[1] Additional details on my education, experience, certifications, and professional affiliations, including a list of my expert testimonies, are provided in Resume of Lane Kollen (provided as Attachment LK-1).

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am offering testimony on behalf of the Gulf Coast Coalition of Cities ("GCCC").

II. PURPOSE AND SCOPE OF TESTIMONY

Q. DESCRIBE THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING.

A. The purpose of my testimony is to 1) address and make recommendations on specific issues that affect the Company's transmission and distribution base revenue requirements in this proceeding; 2) summarize the effects of all GCCC, Houston Coalition of Cities ("HCC"), and Texas Coast Utilities Coalition ("TCUC") recommendations that affect the Company's base revenue requirements, including my recommendations and the recommendations of HCC witness Mark Garrett (operation and maintenance ("O&M") expense), HCC witness Steven Hunt (net operating loss ("NOL") accumulated deferred income taxes ("ADIT") and named storm amortization expense), HCC witness Breandan Mac Mathuna (capital structure), TCUC witness Scott Norwood (distribution capital expenditures and O&M expense), TCUC witness David Garrett (depreciation rates), and TCUC witness Randall Woolridge (return on equity); and 3) address the Company's proposed new Rider Inflation Reduction Act ("IRA") 2022 tariff to recover certain of the effects of the IRA.

Q. PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. I recommend the Commission reduce the Company's present transmission base revenues by at least $6.896 million, a reduction of $49.986 million from the original requested $43.090 million increase.[2] I recommend the Commission reduce the

[2] The Company updated its transmission base revenue increase request to an increase of $42.519 million

Company's present distribution base revenues by at least $140.352 million, a reduction of $141.353 million from the original requested $16.946 million net distribution revenue increase.[3][4]

In the following table, I provide a summary of the issues and adjustments recommended by GCCC, TCUC, and HCC witnesses, including my quantifications of the effects on the revenue requirement and requested revenue increase of certain TCUC and HCC witness recommendations. These include witness Norwood's plant and vegetation management expense recommendations, witness David Garrett's depreciation rate recommendations, witness Hunt's NOL ADIT recommendations, witness Mark Garrett's operations and maintenance expense recommendations (as to functional allocations between transmission and distribution), witness Mac Mathuna's capital structure recommendation, and witness Woolridge's return on equity recommendation.[5]

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in a May 22, 2024 Errata 2 filing and to $41.857 million in a June 14, 2024 Errata 3 filing. The overall decrease in the Company's request from these two Errata filings is $1.233 million. Due to the timing and immaterial nature of the Errata filings, my quantifications are based on the Company's original filed schedules, workpapers, and discovery responses.

[3] The Company originally requested a $237.093 million distribution base revenue increase offset by a $220.146 million DCRF revenue reduction, which results in a requested distribution net increase of $16.946 million.

[4] The Company updated its distribution base revenue increase request to an increase of $15.112 million in a May 22, 2024 Errata 2 filing and to $14.584 million in a June 14, 2024 Errata 3 filing. The overall decrease in the Company's request from these two Errata filings is $2.362 million. Due to the timing and immaterial nature of the Errata filings, my quantifications are based on the Company's original filed schedules, workpapers, and discovery responses.

[5] The calculations of the amounts shown on this summary table and cited throughout my testimony are detailed in my workpapers Revenue Requirement Adjustments Model (provided as WP LK-1). Some of the adjustments shown on the table affect the cash expenses used in the calculation of Cash Working Capital ("CWC"). I have not attempted to calculate or incorporate those effects on CWC and the revenue requirement at this time. Nevertheless, those effects should be calculated and incorporated in the number run for the Proposal for Decision ("PFD") and also in the final number run for the Commission's Final Order in this proceeding.

CenterPoint Energy Houston Electric, LLC
Revenue Requirement
Summary of Recommendations (HCC, TCUC, and GCCC)
PUCT Docket No. 56211
($ Millions)

Issue	Wholesale Transmission	Retail Distribution	Total	Sponsor	Witness
Company's Requested Change in Base Rates	43.090	237.093	280.183		
DCRF Revenues Rolled Into Base Rates		(220.146)	(220.146)		
Company's Requested Overall Change in Rates	43.090	16.946	60.036		
Rate Base Adjustments					
Adjust Plant in Service, Net of Accumulated Depreciation - Distribution Substations	(1.676)	(3.015)	(4.690)	TCUC	Norwood
Remove Land for Future Substation	(1.882)	(4.358)	(6.240)	TCUC	Norwood
Subtract Vendor-Financed Portion of Materials and Supplies Inventory	(2.126)	(1.684)	(3.809)	GCCC	Kollen
Subtract Customer Supplied Financing for Long-Term Debt Interest Payable	(2.700)	(3.762)	(6.462)	GCCC	Kollen
Reflect Adjustments Related to Municipal Franchise Fees	-	(0.862)	(0.862)	GCCC	Kollen
Exclude Prepaid Pension Asset, Net of ADFIT	(0.681)	(2.785)	(3.466)	GCCC	Kollen
Exclude Proposed Medicare Part D Regulatory Asset, Net of ADFIT	(0.141)	(0.577)	(0.718)	GCCC	Kollen
Reduce Hurricane Harvey Reg Asset Balance Due to Amortization During 2024	(0.009)	(0.674)	(0.682)	GCCC	Kollen
Remove Carrying Charges Pro Forma Addition to Hurricane Harvey Reg Asset	(0.012)	(0.934)	(0.946)	GCCC	Kollen
Remove Carrying Charges For Named Storms Laura, Nicholas and Uri	(0.024)	(1.255)	(1.279)	GCCC	Kollen
Exclude NOL ADIT from Base Revenue Requirement	(1.935)	(3.426)	(5.360)	HCC	Hunt
Reflect IIJA Expense Deferral, Net of ADFIT	0.004	0.017	0.020	GCCC	Kollen
Operating Income Adjustments					
Increase Revenues to Reflect Known and Measurable Customer Growth	-	(4.872)	(4.872)	GCCC	Kollen
Defer Expense Incurred in IIJA Grant Process, Net of Amortization	(0.044)	(0.205)	(0.249)	GCCC	Kollen
Maintain Status Quo for Amortization of Reclassified Asset EDIT	(0.510)	(0.904)	(1.414)	GCCC	Kollen
Correct Texas Margin Tax Expense to Remove Out of Period Adjustments	(0.425)	(1.874)	(2.298)	GCCC	Kollen
Correct Texas Margin Tax Expense to Remove Subsidies of Other Affiliates	(1.391)	(6.133)	(7.524)	GCCC	Kollen
Reduce Income Tax Expense for EV Tax Credits	(0.096)	(0.170)	(0.266)	GCCC	Kollen
Exclude Amortization Exp. for Proposed Medicare Part D Regulatory Asset, Grossed Up	(0.431)	(1.765)	(2.196)	GCCC	Kollen
Reduce Amortization Exp. for Hurricane Harvey Reg Asset Due to Amortization During 2024	(0.027)	(2.061)	(2.088)	GCCC	Kollen
Exclude Amortization Exp. for Hurricane Harvey Carrying Charges Pro Forma Adjustment	(0.029)	(2.259)	(2.288)	GCCC	Kollen
Exclude Amortization Exp. for Carrying Charges for Named Storms Laura, Nicholas, and Uri	(0.074)	(3.839)	(3.913)	GCCC	Kollen
Reduce Amortization Exp. to Reflect 10 Year Amortization Period for All Named Storms	(0.170)	(10.768)	(10.938)	HCC	Hunt
Reduce Direct Payroll Expense to Exclude Post-Test Year Pay Increases	(0.893)	(5.090)	(5.983)	HCC	M. Garrett
Reduce Affiliate Payroll Expense to Exclude Post-Test Year Pay Increases	(0.186)	(0.938)	(1.124)	HCC	M. Garrett
Reduce Direct Short-Term Incentive Compensation Expense	(0.787)	(2.135)	(2.923)	HCC	M. Garrett
Reduce Affiliate Short-Term Incentive Compensation Expense	(0.645)	(3.067)	(3.712)	HCC	M. Garrett
Reduce Storm Insurance Accrual	(2.403)	(3.445)	(5.848)	HCC	M. Garrett
Remove 50% of Board of Directors Expense to Share with Shareholders	(0.181)	(0.849)	(1.031)	HCC	M. Garrett
Remove 50% of D&O Insurance Expense to Share with Shareholders	(0.127)	(0.594)	(0.721)	HCC	M. Garrett
Remove 50% of Invester Relations Expense to Share with Shareholders	(0.091)	(0.424)	(0.514)	HCC	M. Garrett
Exclude Executive Severance Expense	(0.270)	(1.262)	(1.531)	HCC	M. Garrett
Exclude Edison Electric Institute Dues	(0.155)	(0.723)	(0.878)	HCC	M. Garrett
Adjust Depreciation Expense Related to Changes in Depreciation Rates	4.901	(25.789)	(20.888)	TCUC	D. Garrett
Reduce Distribution Vegetation Management Expense	-	(6.830)	(6.830)	TCUC	Norwood
Reduce Depreciation Expense for Plant In Service Adjustment - Distribution Substations	(0.455)	(0.819)	(1.274)	TCUC	Norwood
Rate of Return Adjustments					
Reflect Capital Structure of 42.5% Equity and 57.5% Debt	(10.496)	(14.427)	(24.923)	HCC	Mac Mathuna
Reflect Return on Equity of 9.5%	(23.822)	(32.744)	(56.565)	TCUC	Woolridge
Total Adjustments to Base Rates	(49.986)	(157.299)	(207.284)		
Total Recommended Change In Base Rates	(6.896)	79.794	72.898		
DCRF Revenues Rolled Into Base Rates	-	(220.146)	(220.146)		
Total Recommended Overall Change in Rates	(6.896)	(140.352)	(147.248)		

In the subsequent sections of my testimony, I address each of the issues and adjustments identified with my name on the preceding table in greater detail. I also describe my quantifications of the effects on the Company's requested base rate increase resulting from the recommendations sponsored by witnesses Mac Mathuna and Woolridge.

In addition to the revenue requirement issues shown in the preceding table, I recommend the Commission reject the Company's proposal to establish a new Rider IRA 2022 to recover a return on a potential Corporate Alternative Minimum Tax ("CAMT") asset ADIT. The CAMT is not the result of a standalone or separate tax return calculation as required by Public Utility Regulatory Act (PURA) § 36.060; rather, to the extent the Company is subject to the CAMT, it is solely because the Company is an affiliate of CenterPoint Energy, Inc. and a member of the "controlled group" included in the CenterPoint Energy, Inc. consolidated tax return. If PURA § 36.060 requires a standalone income tax calculation for ratemaking purposes and prohibits any allocation of consolidated tax savings to the Company's customers for ratemaking purposes, then the standalone income tax requirement similarly prohibits any allocation of a consolidated tax cost to the Company's customers. The Company cannot have it both ways.

If, however, the Commission allows recovery of a return on the potential asset CAMT ADIT, then I recommend it modify the proposed Rider IRA 2022 tariff language to specifically describe how the CAMT ADIT will be calculated at CenterPoint Energy, Inc. and then how it will be allocated to the Company. In that circumstance, I also recommend the Commission modify the proposed Rider IRA 2022 tariff language to include customer safeguards necessary to ensure that if CenterPoint Energy, Inc. does not have a CAMT carryforward and CAMT ADIT, then neither will the Company have a CAMT carryforward and CAMT ADIT. I note the Company has agreed to this customer safeguard in response to GCCC discovery.[6] In addition, I recommend the Commission include the return on the decrement in the NOL ADIT in each subsequent year to the extent that it is included in rate base in this proceeding.

Finally, GCCC reserves the right to modify the issues, adjustments, and quantifications on the preceding table based upon discovery, testimony, and evidence presented throughout the course of this proceeding.

III. RATE BASE ISSUES

A. Correct Working Capital to Subtract Vendor Supplied Capital for Materials & Supplies ("M&S") Inventory Purchases Reflected in Accounts Payable

1. Overview of Working Capital, Cash Working Capital, and Other Deductions Added to or Subtracted from Rate Base, Including Commission Requirements Set Forth in 16 Tex. Admin. Code § 25.231

Q. DESCRIBE THE COMMISSION'S RATEMAKING REQUIREMENTS SET FORTH IN 16 TEX. ADMIN. CODE § 25.231.

A. The Commission's substantive rule 16 Tex. Admin. Code (TAC) § 25.231 ("Rule 25.231") provides a framework for the calculation of a utility's ratemaking cost of rendering service during a historical test year, adjusted for known and measurable changes, to determine the utility's revenue requirement.[7] The cost of service includes the return on invested capital, also referred to as rate base, and allowable expenses.

[6] *See* CEHE's Response to GCCC Request for Information (RFI) 5-06(d) (provided as Attachment LK-16).

[7] 16 Tex. Admin. Code (TAC) § 25.231.

Rule 25.231 describes each component of rate base. It identifies Working Capital and Other Deductions as two separate components of rate base and Cash Working Capital ("CWC") as one of several subcomponents of Working Capital.

Working Capital addresses the balance sheet asset accounts in rate base financed by investors through equity and debt financing. The utility is allowed a return on Working Capital rate base investment at the utility's weighted average cost of capital.

CWC addresses the net investment financed either by investors through equity and debt financing or by customers through revenues they pay and avoided equity and debt financing. If the net investment is positive, then it has been financed by investors and is included in rate base where it earns a return to compensate the investors for their costs to finance the net positive investment. If the net investment is negative, then it has been financed by customers and is subtracted from rate base whereby customers earn a return to compensate them for their costs to finance the net negative investment. The net investment is calculated as the difference in the delayed receipt in cash revenues from customers to pay cash expenses compared to the delayed payment of the cash expenses.

Other Deductions addresses the balance sheet asset accounts in rate base financed by government, customers, and other cost-free sources, such as vendors. The utility is required to reduce the rate base investment for these cost-free non-investor sources of capital because they represent financing from sources other than investor equity and debt financing.

Q. WHAT ARE THE COMPONENTS OF WORKING CAPITAL SET FORTH IN RULE 25.231, OTHER THAN CASH WORKING CAPITAL?

A. Rule 25.231 specifically identifies, but does not limit it to, two subcomponents of Working Capital, other than CWC. These subcomponents are:

> (i) Reasonable inventories of materials, supplies, and fuel held specifically for purposes of permitting efficient operation of the electric utility in providing normal electric utility service. This amount excludes appliance inventories and inventories found by the commission to be unreasonable, excessive, or not in the public interest.
>
> (ii) Reasonable prepayments for operating expenses. Prepayments to affiliated interests will be subject to the standards set forth in the Public Utility Regulatory § 36.058.

Q. WHAT ARE THE COMPONENTS OF OTHER DEDUCTIONS SET FORTH IN RULE 25.231?

A. Rule 25.231 specifically identifies "(C) Deduction of certain items, which include, but are not limited to, the following:"

> (i) accumulated reserve for deferred federal income taxes;
>
> (ii) unamortized investment tax credit to the extent allowed by the Internal Revenue Code;
>
> (iii) contingency and/or property insurance reserves;
>
> (iv) contributions in aid of construction;
>
> (v) customer deposits and other sources of cost-free capital.

Other sources of cost-free capital include government financing, through tax credits, grants, and tax effects of accelerated tax deductions, customer financing, and vendor financing. Rule 25.231 requires the utility to reduce the rate base investment for these cost-free non-investor sources of funding because they represent financing that was not provided by investors.

Q. WHY IS THAT IMPORTANT?

A. It is important because Rule 25.231 sets forth the calculations necessary to quantify the net investment rate base that is financed solely by investors through equity and debt financing. Rule 25.231 expressly requires reductions to the net investment rate base to exclude all non-investor financing, which is cost-free. This non-investor financing includes the cost free grants, loans, and deferred payment forms of financing provided by the federal, state, and local governments;[8] cost-free loans provided by customers;[9] and cost-free loans provided by vendors;[10] among other sources of cost-free financing.

Rule 25.231 states that the cost of service includes the return on net invested capital, which it defines as "the rate of return times invested capital." The rate of return is the weighted average cost of the equity and debt financing. When the rate of return is applied to the rate base, it scales the utility's actual capitalization to match, whether up or down, the net invested capital supplied by investors through equity and debt financing.

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[8] Recorded as deferred liabilities, credits to plant, ADIT, and taxes payable, among other accounts, all of which reduce the amounts that would have been financed by the Company's investors and reflected in increased common equity and long-term debt if the government financing did not exist.

[9] Recorded as customer deposits, long-term debt interest payable, among other accounts, all of which reduce the amounts that would have been financed by the Company's investors and reflected in increased common equity if the customer financing did not exist.

[10] Recorded as accounts payable, among other accounts, all of which reduce the amounts that would have been financed by the Company's investors and reflected in increased common equity and long-term debt if the vendor financing did not exist.

2. Unpaid Purchases of M&S Inventory Recorded in Accounts Payable are Cost Free Vendor Financing, Not Investor Financing, and Should Be Subtracted from Rate Base

Q. DESCRIBE THE COMPANY'S REQUEST TO INCLUDE M&S IN THE WORKING CAPITAL COMPONENT OF RATE BASE.

A. The Company included $398.957 million ($222.613 million transmission and $176.345 million distribution) in M&S inventory in the Working Capital component of rate base.[11] The Company calculated this amount as the 13-month test year average of the adjusted proforma M&S inventory in the test year.[12]

Q. DO THE COMPANY'S INVESTORS ACTUALLY FINANCE THE ENTIRETY OF THE M&S INVENTORY?

A. No. The Company's *vendors* finance a portion of this M&S inventory, not its investors. When the Company purchases M&S inventory, it does not pay cash or otherwise finance the purchases until after it pays the vendors in cash at a later date, typically 30 days after the purchases. When the Company purchases M&S inventory, the accounting entry is to debit M&S inventory and credit accounts payable, not cash. The M&S inventory actually financed by the Company's investors each month is the M&S inventory less the unpaid amounts recorded in accounts payable. The Company's vendors provide interest free, or zero-cost, financing until they are paid.

This is an ongoing process that repeats over and over again, where the Company purchases M&S inventory from a vendor, records the purchase in M&S inventory, records the vendor financing in accounts payable, subsequently pays the vendor, and

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[11] Application, CEHE RFP Schedules, Schedule II-B-8.

[12] *Id.*

then repeats the process for each purchase from each vendor.

Q. DOES THE VENDOR FINANCING DISPLACE OR AVOID THE NEED FOR THE COMPANY'S INVESTORS TO FINANCE A PORTION OF THE M&S INVENTORY THROUGH EQUITY OR DEBT?

A. Yes. The vendor financing is a separate source of financing; it displaces and avoids the need for the Company investors to finance the entirety of the Company's M&S inventory while the accounts payable remains outstanding and unpaid.

Q. DID THE COMPANY REFLECT THIS ZERO-COST VENDOR FINANCING IN THE OTHER DEDUCTIONS COMPONENT OF RATE BASE AS A SOURCE OF COST-FREE CAPITAL?

A. No. The failure to reflect the zero-cost vendor financing in Other Deductions as a reduction to rate base overstates rate base and the grossed-up return on rate base included in the revenue requirement. The Company's failure to reflect the zero-cost vendor financing improperly imposes an imputed or artificial cost on the Company's customers that the Company does not actually incur.

Q. DID THE COMMISSION ADDRESS THE VENDOR FINANCING ISSUE IN ANOTHER RECENT RATE CASE PROCEEDING?

A. Yes. In the most recent Oncor rate case proceeding,[13] an intervenor addressed this issue and recommended that the cost-free supplier financing be subtracted from rate base.[14]

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[13] *Application of Oncor Electric Delivery Company LLC for Authority to Change Rates*, Docket No. 53601 (May 13, 2022).

[14] *Id.*, Initial Brief of the Steering Committee of Cities Served by Oncor at 15-16 (Oct. 14, 2022) (Cities Initial Brief).

Oncor opposed this recommendation.[15] The Proposal for Decision ("PFD") adopted the intervenor's recommendation.[16] Nevertheless, the Commission reversed the PFD.[17]

The PFD includes a discussion of the cost-free supplier financing and concludes that the supplier financing is cost-free capital that must be subtracted from rate base in the following statement:[18]

> [T]he [Administrative Law Judge] ALJs determine Oncor's M&S rate base component is unreasonable and should be denied. The ALJs recommend offsetting Oncor's M&S rate base component by the portion financed by vendors at zero cost. The weight of the evidence supports Cities' contention that Oncor's vendor-financed M&S are sources of cost-free capital, which should be excluded.

The PFD includes the following Findings of Fact:

> 87. Oncor's requested inclusion of $152,038,741 of materials and supplies (M&S) inventories based on an adjusted 13-month average is unreasonable.
>
> 88. Oncor did not recognize vendor supplied financing for M&S as a cost-free source of capital.
>
> 89. It is reasonable for Oncor's M&S inventories to be offset by the portion financed by vendors at zero cost.

In response to Oncor's exceptions to the PFD, the Commission reversed the PFD in the Order, stating:[19]

> The Commission reverses the ALJs' determination that Oncor must offset its requested materials and supplies rate-base component by approximately $8.25 million to account for vendor-financed materials and supplies. The ALJs adopted Cities' argument that Oncor's vendor-financed materials and supplies must be removed from rate base because they are sources of cost-free capital. The Commission agrees sources of cost-free capital must be removed from rate

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[15] *Id.*, Reply Brief of Oncor Electric Delivery Company LLC at 29 (Oct. 28, 2022) (Oncor's Reply Brief).

[16] *Id.*, SOAH Proposal for Decision at 68 (Dec. 28, 2022) (PFD).

[17] *Id.*, Docket No. 53601, Order at 6 (Apr. 6, 2023).

[18] *Id.*, PFD at 68.

[19] *Id.*, Order at 5-6.

> base," but does not agree Oncor's materials and supplies component requires an offset to account for cost-free capital.
>
> Oncor calculated its requested materials and supplies rate-base component using the 13-month averaging method required by the Commission's rate-filing package. The Commission agrees with Oncor that its use of the 13-month average accounts for vendor financing concerns by averaging out the variable levels of costs and timing for accruals and payables. The Commission therefore determines Oncor accounted for cost-free capital in its requested materials and supplies rate-base component in compliance with Commission rules. Accordingly, the Commission reverses the ALJs on this issue and Oncor is not required to exclude approximately $8.25 million of materials and supplies from its rate base. To reflect this determination, the Commission modifies proposed finding of fact 87 and deletes proposed findings of fact 88 through 90.

Q. IS THE RATIONALE CITED BY THE COMMISSION IN THE ONCOR ORDER CORRECT AND SHOULD IT BE APPLIED TO THE COMPANY IN THIS PROCEEDING?

A. No. It is incorrect and should not be applied to the Company in this proceeding. The M&S inventory varies from month to month and the 13-month average properly addresses that variability. However, using the 13-month average factually addresses only the variability of the M&S inventories during the test year, an issue that was not contested by any party in the Oncor proceeding and which is not contested by GCCC in this proceeding. Using the 13-month average factually does not address the cost-free capital reflected in the liability accounts payable account. The inventory reflects the asset included in rate base. The related liability accounts payable reflects the cost-free supplier financing that was not financed by investors through equity and debt financing. It is an error to equivalate the variability of the asset with the source of financing for the asset.

The Oncor decision should not be applied to the Company in this proceeding. To do so, the Commission would have to find that vendor financing in the form of accounts payable does not exist, which factually is not true. It does exist and it is zero-cost. The Company is not entitled to earn a return on rate base that vendors have financed at zero cost.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission subtract the vendor financing for M&S inventory from rate base. Rule 25.231 requires that cost-free sources of capital be subtracted from rate base. Investors did not finance these costs; vendors financed these costs. The Company is not entitled to recover a cost that it did not and does not incur.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a reduction in the transmission revenue requirement of $2.126 million and a reduction in the distribution revenue requirement of $1.684 million. These reductions reflect the Company's requested grossed-up rate of return times a reduction in the transmission rate base of $25.692 million and a reduction in the distribution rate base of $20.352 million based on the 13-month average of the accounts payable related to the monthly purchases of M&S inventory for each function.[20]

B. Correct Working Capital to Subtract Customer Supplied Capital for Long-Term Debt Interest Reflected in Interest Payable

Q. DESCRIBE THE COMPANY'S MONTHLY ACCRUAL OF LONG-TERM DEBT INTEREST EXPENSE, THE INCREASE IN THE LONG-TERM DEBT INTEREST PAYABLE (ACCRUED), THE CASH PAYMENT OF THE

[20] *See* CEHE's Response to GCCC RFI 3-03 (provided as Attachment LK-2). This response provides the monthly M&S inventory purchases and other amounts by source activity. I used the purchases as a reasonable proxy for the related accounts payable, assuming net 30 terms because the Company was unable to provide the actual accounts payable for these purchases.

INTEREST EXPENSE, AND THE REDUCTION IN THE LONG-TERM DEBT INTEREST PAYABLE.

A. The long-term debt interest payable represents customer supplied financing at zero cost. That is a fact. The Company receives and records cash revenues to recover the interest expense each month. That is a fact. The Company records interest expense and the related increase in long-term debt interest payable (accrued) for each outstanding long-term debt issue each month. The payment dates vary by long-term debt issue and occur throughout the year. This cycle repeats itself for each long-term debt issue every six months. Those are facts. The Company records a reduction to the long-term debt interest payable every six months when it actually pays the cash it collected from customers for the six months of accumulated interest payable to the debt holders at the end of the six months. That is also a fact.

Q. DOES THE DELAYED PAYMENT IN CASH OF THE LONG-TERM INTEREST EXPENSE REPRESENT CUSTOMER FINANCING AT ZERO COST?

A. Yes. The long-term debt interest payable represents customer financing. The Company's customers provide the cash to pay their share of the long-term debt interest months in advance of the Company's actual payment of that cash to the debt holders. The customer financing is cost-free to the Company. It displaces investor equity and debt financing.

This delay between the receipt of cash revenues and the payment of the interest expense provides cash that is available to the Company for other purposes for approximately three months on average (half of the six-month long-term debt interest payment cycle). The availability of these cash inflows in advance of the interest expense cash payments allows the Company to avoid equity and long-term debt financing and the related financing costs during that delayed payment period.

Q. SHOULD THIS SAVINGS IN FINANCING COSTS BE REFLECTED IN THE REVENUE REQUIREMENT?

A. Yes. The long-term interest payable represents customer provided financing at zero cost to the Company. In other words, the Company's customers prepay cash for the interest expense before the Company finally pays it in cash every six months, thus displacing the need for investor financing.

The Company should not be allowed to recover a return on rate base that its investors have not financed and that does not reflect this zero-cost customer provided financing. Typically, this zero-cost financing is reflected either in CWC, which reduces the CWC due to the greater number of days lead for the delayed payment of interest expense compared to the number of days lag in receipt of cash revenues, or in working capital or other deductions by directly subtracting the long-term debt interest payable (accrued) from rate base.

Q. DID THE COMPANY REFLECT THIS ZERO COST CUSTOMER FINANCING IN THE OTHER DEDUCTIONS COMPONENT OF RATE BASE AS A SOURCE OF COST-FREE CAPITAL?

A. No. The failure to reflect the zero-cost customer financing in Other Deductions as a reduction to rate base overstates rate base and the grossed-up return on rate base included in the revenue requirement. The failure to reflect the zero-cost customer financing imposes an imputed or artificial cost on the Company's customers that the Company does not actually incur.

Q. DID THE COMMISSION ADDRESS THIS CUSTOMER FINANCING ISSUE IN ANOTHER RECENT RATE CASE PROCEEDING?

A. Yes. In the most recent Oncor rate case proceeding, Docket No. 53601, an intervenor addressed this issue and recommended that this cost-free customer financing be subtracted from rate base.[21] Oncor opposed this recommendation.[22] The PFD adopted the intervenor's recommendation.[23] Nevertheless, the Commission reversed the PFD.[24]

The PFD included a discussion of this cost-free customer financing and concluded that it is cost-free capital that must be subtracted from rate base in the following statement:[25]

> Oncor's long-term debt interest payable is customer provided financing at zero cost. It would be unreasonable for Oncor to recover a return on rate base it has not financed. Accordingly, the ALJs recommend the Commission adopt Cities' recommendation to subtract from rate base the long-term debt interest payable.

The PFD included the following Findings of Fact:[26]

> 130. Oncor's long-term debt interest payable is customer financing at zero cost and reflects avoided equity and debt financing.
>
> 131. Oncor's request to recover a return on long-term debt interest payable is unreasonable.
>
> 132. It is reasonable to deduct from rate base the long-term debt interest payable, which equates to a $4.289 million reduction to the transmission

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[21] Docket No. 53601, Cities Initial Brief at 7-8.

[22] *Id.*, Oncor's Reply Brief at 29.

[23] *Id.*, PFD at 94.

[24] *Id.*, Order at 6.

[25] *Id.*, PFD at 94.

[26] *Id.* at 482.

revenue requirement and a reduction of $4.651 million to the distribution revenue requirement.

133. Oncor's transmission revenue requirement should be reduced by $4.289 million and the distribution revenue requirement should be reduced by $4.651 million.

In response to Oncor's exceptions to the PFD, the Commission reversed the PFD in its Order, stating:[27]

> The Commission reverses the ALJs' determination that it was appropriate to deduct long-term debt interest payable from Oncor's rate base. The ALJs were persuaded by Cities' argument that long-term debt interest payable must be removed from rate base because it is a form of zero-cost financing.
>
> The Commission determines that interest accruals on long-term debt are not a form of zero-cost financing—they are non-cash items. Under Commission rules, an investor-owned utility's non-cash items, including interest accruals on long-term debt, are addressed in the rate-base calculation through their exclusion from the lead-lag study used to set cash-working capital. Oncor complied with the Commission's rules by not considering accrued interest when determining its cash-working capital and by not requesting a return on accrued interest elsewhere in rate base. The Commission therefore determines Oncor's interest accruals are not a source of zero-cost financing and do not need to be deducted from rate base. To reflect this determination, the Commission modifies proposed finding of fact 130; deletes proposed findings of fact 131,132, and 133; and deletes proposed conclusion of law 34.

Q. IS THE RATIONALE CITED BY THE COMMISSION IN THE ONCOR ORDER CORRECT AND SHOULD IT BE APPLIED TO THE COMPANY?

A. No. It is incorrect and should not be applied to the Company in this proceeding. The Commission stated, "that interest accruals on long-term debt are not a form of zero-cost financing-they are non-cash items." That conclusion is factually incorrect. The interest accruals represent the delayed payment of interest expense in cash, similar to the delayed payment of many other expenses. It is undisputed that the Company pays

[27] *Id.*, Order at 6.

the accumulated interest in cash on a delayed basis every six months.

The fact the Company does not pay the interest expense monthly to the debtholders does not disqualify it as customer supplied financing any more than the fact the Company does not pay income tax expense monthly to the federal government does not disqualify it as customer supplied financing. The Company does not pay estimated federal taxes monthly. It pays those estimated taxes quarterly. The Commission considers the lag in payment of income tax expense a component of CWC. If, for some reason, the Commission determined that federal tax expense was properly excluded from the calculation of CWC that would not disqualify the lagged payment of this cash expense as customer financing. In that case, the income taxes payable would be the balance sheet alternative to including effect of the customer financing in the CWC component of rate base.

In the Oncor Order, the Commission states that it relied on "Commission rules" to conclude that a cash expense paid on a lagged basis is addressed by excluding this lag in the cash payments from the calculation of CWC.[28] That is factually incorrect. This lag in cash payments is NOT addressed in the calculation of CWC because Rule 25.231 simply excludes the issue from the calculation of CWC; Rule 25.231 does not establish that the cash interest payments are not cash interest payments. The exclusion from CWC simply means that this customer supplied financing must be addressed in Other Deductions or elsewhere as cost-free customer financing. The fact is the Company collects cash from customers every month for six months before it pays that accumulated interest expense in cash to debtholders. That is the very definition of

[28] *Id.*

customer financing.

The Oncor decision should not be applied to the Company in this proceeding. To do so, the Commission would have to find that customer financing in the form of long-term debt interest payable does not exist, which is factually untrue. It does exist and it is zero-cost financing. The Company is not entitled to earn a return on rate base that its investors have not financed and that its customers have financed.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission subtract the long-term debt interest payable from rate base. The long-term debt interest payable balance sheet liability is a source of customer provided financing at zero cost that provides actual savings in the real world due to avoided investor financing costs on equity and debt that has not been issued due to the availability of these customer-supplied cash funds.

The Company's approach overstates its cost of service by failing to reflect this customer financing at zero cost. In effect, the Company's approach improperly adds a financing cost to the revenue requirement that it does not incur on equity and debt financing that does not exist.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a reduction in the transmission revenue requirement of $2.700 million and a reduction in the distribution revenue requirement of $3.762 million. These reductions reflect the Company's requested grossed-up rate of return times a reduction in the transmission rate base of $32.633 million and a reduction in the distribution rate base of $45.475 million based on the 13-month average of the long term debt interest payable for each function.[29]

C. Correct Working Capital to Subtract Vendor Financing for Prepayments of Local Franchise Tax Expense; Correct CWC to Remove Non-Cash Local Franchise Tax Amortization of Prepayments Expense

Q. DESCRIBE THE COMPANY'S REQUESTS TO INCLUDE BOTH THE BALANCE SHEET PREPAYMENTS FOR LOCAL FRANCHISE TAX EXPENSE AND THE EXPENSE LEAD FOR THESE SAME PREPAYMENTS IN CASH WORKING CAPITAL.

A. The Company included $4.563 million in local franchise tax prepayments in rate base. Local franchise taxes encompass municipal franchise fees, which are payments the Company makes to use municipal rights-of-way for the placement and operation of utility equipment and infrastructure. As a factual matter, the local franchise tax expense payments are due on the first day of each month.[30] However, if the first day of a month falls on a weekend day or a holiday, then the Company prepays the following month's payment on the last business day of the prior month.[31] In these circumstances, the Company records a prepayment in its balance sheet accounts at the end of the prior month and then reverses it the following month when the payment clears.[32] This happened four times during the test year and also occurred in December 2022, so that there were five non-zero monthly prepayment amounts and eight zero monthly prepayment amounts in the 13-month average included in rate base.[33]

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[29] *See* CEHE's Response to GCCC RFI 1-08 (provided as Attachment LK-3). This response provides the monthly long-term debt interest payable by debt issuance from December 2022 through December 2023.

[30] *See* CEHE's Response to GCCC RFI 2-17(b) (provided as Attachment LK-4).

[31] *Id.*

[32] *Id.*

[33] *See* Application, CEHE RFP Schedules, Schedule II-B-10.

In addition, the Company accrues a local franchise tax liability at the end of each month.[34] It starts with the prior month ending balance, then adds the current month expense, and subtracts the current month payments to calculate the current month ending balance.[35] The 13-month average for the liability in the test year was $2.479 million.[36] However, the Company failed to subtract the 13-month average liability from rate base.[37]

Further, the Company included local franchise tax expense in its calculation of CWC included in rate base. It used the test year local franchise expense for this purpose. Company witness Timothy Lyons calculated the local franchise tax expense lead days used for this purpose.[38]

Q. IS THE LOCAL FRANCHISE TAX LIABILITY COST-FREE VENDOR FINANCING SIMILAR TO THE M&S VENDOR FINANCING?

A. Yes. The Company is required to subtract cost-free vendor financing from working capital in rate base pursuant to Rule 25.231. Similar to the M&S inventory payables, the local franchise tax liability should be subtracted from rate base.

Q. DID THE COMPANY CORRECTLY CALCULATE THE LOCAL FRANCHISE TAX EXPENSE COMPONENT OF CWC?

A. No. The Company failed to exclude the non-cash amortization of the prepayments of local franchise expense included in rate base. In contrast, the Company correctly

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[34] *See* CEHE's Supplemental Response to GCCC RFI 2-13 (provided as Attachment LK-5).

[35] *Id.*

[36] *Id.*

[37] *Id.*

[38] *See* Application, Direct Testimony of Timothy Lyons (including electronic workpapers).

subtracted the non-cash amortization of the prepayments in the "Operation and Maintenance Expense" component in the CWC calculation, so that only the cash payments for the expenses remained in the CWC calculation.[39] The non-cash amortizations of the prepayments that were removed from the Operation and Maintenance Expense component included insurance and vendor prepayments.

However, the Company failed to make a similar reduction for the non-cash amortizations of local franchise tax expense prepayments in the local franchise tax expense component of the CWC calculation. The failure to subtract the non-cash amortizations of the local franchise tax prepayments resulted in an overstated local franchise tax expense on a cash basis, the basis that is required for use in the CWC calculation, as evidenced by the Company's calculation of operation and maintenance expense on a cash basis for the CWC calculation. With the Company's proposed 61.28 net revenue lag days, this error significantly overstated the CWC included in rate base.

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. I recommend the Commission subtract the cost-free franchise tax payable liability from rate base. This is vendor financing at zero cost. I also recommend the Commission correct the Company's CWC calculation to remove the non-cash amortization of the local franchise tax prepayments from the local franchise tax expense component. The Company did so for the Operation and Maintenance expense component in the CWC calculation, thus affirming that it should be done in the same manner for all expense line items.

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[39] *See* Application, CEHE RFP Workpapers B, WP II-B-9.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a reduction in the distribution revenue requirement of $0.862 million. These reductions reflect the Company's requested grossed-up rate of return times a reduction in the distribution rate base of $10.423 million.

D. <u>Exclude Prepaid Pension Asset from Rate Base; It Is Not Recorded in the Company's Accounting Books, Was Not Financed by the Company, and Does Not Meet the Rule 25.231 Requirement for "Reasonable Prepayment of an Operating Expense"</u>

Q. DESCRIBE THE COMPANY'S REQUEST TO INCLUDE PREPAID PENSION ASSETS IN THE TRANSMISSION AND DISTRIBUTION RATE BASE AMOUNTS.

A. The Company included $8.226 million in the transmission rate base ($10.413 million for prepaid pension asset less $2.187 million for related ADIT) and $33.668 million in the distribution rate base ($42.618 million for prepaid pension asset less $8.950 million for related ADIT). The Company included these amounts in rate base as proforma adjustments to FERC account 165 *Prepayments* in an attempt to qualify them as prepayments in working capital pursuant to Rule 25.231.

Q. HAS THE COMMISSION EVER ALLOWED THE COMPANY TO INCLUDE PREPAID PENSION ASSETS IN RATE BASE, LET ALONE AS PREPAYMENTS IN FERC ACCOUNT 165?

A. No. First, the Company never sought to include a prepaid pension asset in rate base in any rate case proceeding prior to its application in Docket No. 49421.

Second, although the Company requested a prepaid pension asset in Docket No. 49421, it was denied in the PFD based on arguments in opposition made by multiple intervenors in testimony and briefing.[40] The Commission did not ultimately decide the issue because the parties in that proceeding entered into a Stipulation and Settlement Agreement ("2020 Settlement"), which was approved by the Commission in lieu of approving the PFD with modifications. The terms of the 2020 Settlement included a "black box" adjustment to the Company's requested rate increase and thus a "black box" resolution of the disputed revenue requirement issues, including the disputed prepaid pension asset rate base issue. The terms of the 2020 Settlement also included more specificity on some of the issues, such as the return on equity, capital structure, and depreciation rates. However, there was no specific term that found the requested prepaid pension asset was a "reasonable prepayment" or that expressly allowed it to be included in rate base.

Third, the Company's request in this proceeding is based solely on an amount recorded on the accounting books of CenterPoint Energy, Inc., while in the last proceeding, the Company's request was based on the sum of three factors, including the amount on the accounting books of CenterPoint Energy, Inc. and various calculations performed by the Company specifically for the rate case and not for book accounting or any other purpose. The Company's change in approach, or at least its change in description of its approach, since the last base rate case proceeding demonstrates the lack of any objective evidence in support of the Company's request, the subjectivity of its request, and the changing basis for its request.

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[40] *Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates*, Docket No. 49421, PFD at 59 (Sept. 16, 2019).

Q. IN RESPONSE TO GCCC DISCOVERY, THE COMPANY NOW CLAIMS THE COMMISSION ALLOWED A PREPAID PENSION ASSET IN RATE BASE IN DOCKET NO. 49421.[41] IS THAT CORRECT?

A. No. That claim is factually incorrect and unsupported by any actual evidence, despite the Company's litigation position in the prior rate case proceeding. Nowhere in Docket No. 49421 PFD did the ALJ allow the Company's request (to the contrary, the ALJ recommended denial of the Company's request); nowhere in the 2020 Settlement did the intervenor parties agree to the Company's request; and nowhere in the Order approving the 2020 Settlement did the Commission find that the requested prepaid pension asset was a "reasonable prepayment" or allow it to be included in rate base.

Despite those known facts, the Company now asserts that Finding of Fact 99 in the Commission's Order in Docket No. 49421 allowed the Company to include a prepaid pension asset in rate base.[42] It clearly does not. Finding of Fact 99 only addressed a deferred return on the capitalized portion of the claimed prepaid pension asset and preserved the Company's ability to seek recovery of a deferred return amount in a future rate case proceeding. Finding of Fact 99 not only did not expressly allow a prepaid pension asset in rate base, it also did not expressly authorize recovery of any deferred return the Company might seek in a future rate proceeding. In other words, the Commission did not expressly allow current recovery of a return on the expensed portion or authorize recovery of a deferred return on the capitalized portion of the prepaid pension asset.

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[41] *See* CEHE's Response to GCCC RFI 5-1(c) (provided as Attachment LK-6).

[42] *Id.*

Q. WERE THERE AND ARE THERE ANY PREPAID PENSION ASSETS ACTUALLY RECORDED ON THE COMPANY'S ACCOUNTING BOOKS AND REPORTED ON ITS FINANCIAL STATEMENTS?

A. No. There were and are no prepaid pension assets recorded on the Company's accounting books.[43] Nevertheless, the Company added allocations of a prepaid pension asset recorded on the CenterPoint Energy, Inc. accounting books to the Company's transmission rate base and the distribution rate base as if they were recorded on the Company's accounting books.[44]

Q. WHY DOES IT MATTER THAT THERE WERE AND ARE NO PREPAID PENSION ASSETS RECORDED ON THE COMPANY'S ACCOUNTING BOOKS?

A. It matters because the Company itself did not incur the costs of the prepaid assets and did not finance the cost of the prepaid assets. An essential premise of generally accepted accounting principles is that accounting entries are used to record the economic substance of transactions. If there is no accounting entry on the Company's accounting books, then there was no economic transaction. If there was no economic transaction, then the Company did not incur a cost, did not pay cash for that cost, and did not issue equity or debt to finance that cost. If there is no asset and no equity or debt issued to finance the cost of the asset, then the Company did not and does not incur the related financing costs.[45]

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[43] *See* CEHE's Response to GCCC RFI 5-9 (provided as Attachment LK-7).

[44] *Id.*

[45] *See* CEHE's Response to GCCC RFI 3-05 (provided as Attachment LK-8) wherein the Company acknowledged it was CenterPoint Energy, Inc. that financed the costs on its accounting books with debt and equity

An essential premise of ratemaking is that if the utility itself did not incur a cost, even if it is incurred by an affiliate, then the cost is not recoverable as a cost of service by the utility. In this case, the Company did not incur the cost and it is not recoverable as a cost of service.

Q. DID THE COMPANY INCUR A FINANCING COST FROM CENTERPOINT ENERGY, INC. THROUGH AN AFFILIATE CHARGE?

A. No. This is an important fact. The fact there is no financing cost from CenterPoint Energy, Inc. through an affiliate charge proves the Company did not and does not finance the costs on CenterPoint Energy, Inc. accounting books in that manner. If a parent company or an affiliate incurs a cost that it does not charge the utility, then, by definition, the cost incurred by an affiliate is not a cost incurred by the utility.

Q. THE COMPANY ACKNOWLEDGES THERE IS NO PREPAID PENSION ASSET RECORDED ON ITS ACCOUNTING BOOKS, BUT STILL CLAIMS THAT IT FINANCED A PORTION OF THE AMOUNT ON CENTERPOINT ENERGY, INC.'S ACCOUNTING BOOKS.[46] PLEASE RESPOND.

A. Even assuming *arguendo* that CenterPoint Energy, Inc. financed the costs, which the Company has not demonstrated, then the Company could not also have financed the same costs unless it reimbursed CenterPoint Energy, Inc. through an affiliate charge, which it denies. GCCC asked the Company in discovery to explain specifically how it financed costs recorded on CenterPoint Energy Inc.'s accounting books.[47] In its

financing, meaning, by definition, the Company did not finance CenterPoint Energy, Inc.'s costs with debt and equity financing.

[46] *See* Attachment LK-8, GCCC RFI 3-5(b); Attachment LK-6, GCCC RFI 5-1(a).

[47] *Id.*

response, the Company claims that it did so through payment of common stock dividends to CenterPoint Energy Inc.[48]

This is a nonsensical and self-serving claim unsupported by any substantive or relevant evidence. Electric utility rates in Texas are based on the cost of service, as defined by Rule 25.231, which includes a return on rate base to compensate the Company for its actual financing costs and the income taxes on the weighted equity component of the return.[49] Prepayments allowed in the rate base component of cost of service are defined as "reasonable prepayments of operating expenses."[50] However, by the Company's own admission, it has *not* made *any* prepayments of operating expenses for the prepaid pension asset recorded on the accounting books of CenterPoint Energy, Inc., let alone "reasonable" prepayments, notwithstanding its argument that common dividends somehow should be considered as a cost of service for this purpose.

Common stock dividends are not a cost of service and are not included in the rate base or allowed expense components of cost of service, as those components are defined in Rule 25.231.[51] Common stock dividends are paid to shareholders from actual earnings. Actual earnings are the result of revenues less expenses. It is the Company's practice to pay common dividends equal to half of its prior quarterly earnings. There is no direct or indirect correlation to costs that may or may not have been incurred by CenterPoint Energy, Inc., but were, in fact, not incurred by the Company. If the Company's claim that its common dividends fund CenterPoint

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[48] *Id.*

[49] *See* 16 TAC § 25.231.

[50] *Id.*

[51] *Id.*

Energy, Inc.'s financing costs is true, then using the Company's logic, it also finances indirectly any cost incurred by CenterPoint Energy, Inc., including CenterPoint Energy, Inc.'s dividends to its shareholders, which in turn are used by its shareholders to finance their retirement accounts, home purchases and renovations, business startups and expansions, college educations, weddings, financial investments, and other personal expenses, and on that basis argue that all of these costs should be included in the Company's cost of service and revenue requirement. Of course, that argument on its face is nonsensical and the result would be unreasonable.

I also note that the Company's payment of common dividends to CenterPoint Energy, Inc. actually reduces the retained earnings component of its common equity and thus, its financing costs, all else equal. This further demonstrates the fallacy of the Company's argument that common dividends somehow are a cost of service.

Q. DID CENTERPOINT ENERGY, INC. ITSELF FINANCE THE PREPAID PENSION ASSET RECORDED ON ITS ACCOUNTING BOOKS?

A. No. As described in the PFD in Docket No. 49421, the prepaid pension asset recorded on CenterPoint Energy, Inc.'s accounting books was offset with unrealized losses recorded as an increase in the Other Comprehensive Income component of CenterPoint Energy, Inc.'s common equity.[52] In other words, the unrealized losses included in the prepaid pension asset are not cash because they were unrealized and the offsetting increase to common equity was not cash because it was a deferral of the unrealized losses for accounting purposes.

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[52] Docket No. 49421, PFD at 59-63.

Q. WHAT WILL OCCUR IF THE COMPANY IS ALLOWED TO INCLUDE A HYPOTHETICAL OR IMPUTED COST THAT NEITHER IT NOR CENTERPOINT ENERGY, INC. ACTUALLY INCURS IN ITS COST OF SERVICE FOR RATEMAKING PURPOSES?

A. It will result in a rate increase in this proceeding that will allow the Company to collect actual revenues from actual customers to recover a hypothetical or imputed cost that the Company actually does not incur. The resulting revenues have no related underlying actual expense or any other actual cost incurred by the Company, so the revenue increase, after tax, will flow directly through the income statement and increase the Company's per book earnings. The per books return on equity then will exceed that authorized by the Commission, all else equal. The Company's excessive per books earnings will be included in CenterPoint Energy, Inc.'s consolidated per books earnings, which will inure solely to CenterPoint Energy, Inc.'s shareholders for a financing cost that CenterPoint Energy, Inc. itself also does not incur. This harm will repeat each and every year the Company recovers revenues for hypothetical or imputed costs that it does not incur.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reject the Company's request to include prepaid pension assets in the transmission rate base and distribution rate base. This is a cost the Company does not incur and that it is not entitled to include in its cost of service. This hypothetical or imputed cost does not qualify as a "reasonable prepayment of operating expenses," the standard set forth in Rule 25.231. If allowed, it will take from the

Company's customers for the sole purpose of giving to CenterPoint Energy, Inc.'s shareholders. That result is neither justified nor reasonable.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENATION?

A. The effects are a reduction in the transmission revenue requirement of $0.681 million and a reduction in the distribution revenue requirement of $2.785 million. These reductions reflect the Company's requested grossed-up rate of return times a reduction in the transmission rate base of $8.226 million and a reduction in the distribution rate base of $33.668 million.

E. <u>Exclude or Reduce Regulatory Assets</u>

1. Exclude Medicare Part D Regulatory Asset from Rate Base; Alternatively, Include in Rate Base, but Reduce for Additional Amortization Until Effective Date of Rate Change

Q. DESCRIBE THE COMPANY'S REQUEST TO INCLUDE A MEDICARE PART D REGULATORY ASSET IN RATE BASE.

A. The Company seeks to include Medicare Part D regulatory assets of $1.703 million (net of the related ADIT) in the transmission rate base and $6.970 million (net of the related ADIT) regulatory asset in the distribution rate base. The Medicare Part D regulatory asset (before the functional allocations to transmission and distribution) ostensibly was due to a change in the tax law that subjected to income tax the federal government's previously untaxed reimbursement of retiree prescription drug and other costs paid pursuant to the Company's OPEB benefits plan.[53] The change in the tax law was effective on January 1, 2013. The Company argues that this change in the tax law has a retroactive effect to 2004 through 2012 and included these retroactive effects in

[53] *See* Tax Relief and Health Care Act of 2006.

its request in Docket No. 49421 and in this proceeding.

Q. DID THE COMMISSION EVER AUTHORIZE A MEDICARE PART D REGULATORY ASSET?

A. No. In Docket No. 38339, the Company sought to include a regulatory asset for $9.3 million in rate base for its calculation of the grossed-up income tax effect of the change in tax law that would not be effective until January 1, 2013, some three years after the end of the 2009 test year in that proceeding, and to amortize the regulatory asset to expense over three years. In that proceeding, the Company calculated the regulatory asset based on the estimated future income tax expense on its forecast of Medicare Part D subsidies that it would receive after January 1, 2013. The Company also sought to increase income tax expense to reflect the taxability of the Medicare Part D subsidies from the government even though they would not be taxable until January 1, 2013. In that proceeding, GCCC and City of Houston/HCOC opposed the Company's requests for numerous reasons, including the fact they were premature. The Commission found the Company's requests to be premature and denied them, but allowed the Company "to monitor and accrue the difference between what its rates assume the Medicare Part B subsidy tax expense will be and what CenterPoint is required to pay as a regulatory asset to be addressed in CenterPoint's next rate case."[54] The Commission did not authorize the amount, methodology, or approve the future recovery of the Company's regulatory asset in the Company's next rate case.[55]

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[54] *Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates*, Docket No. 38339, Final Order at Finding of Fact 159A (May 12, 2011).

[55] *Id.*

In Docket No. 49421, the Company again sought to include a regulatory asset in rate base retroactive to 2004 and to amortize the regulatory asset to expense over three years. In Docket No. 49421, the Company calculated the regulatory asset in a different manner than it had in Docket No. 38991 and sought to include $33.2 million in rate base, more than tripling the amount requested in Docket No. 38991.

As in Docket No. 38991, GCCC opposed any Medicare Part D regulatory asset in rate base and the related amortization expense, but offered an alternative in which it calculated the Medicare Part D regulatory asset at $5.572 million. The PFD adopted the alternative calculation. The alternative excluded the retroactive portion requested by the Company, used the amounts from CenterPoint Energy's Inc. actuarial reports, and removed the capitalized portion of the amounts from the actuarial reports. As I noted previously in the prepaid pension asset section of my testimony, the parties entered into the 2020 Settlement, which the Commission approved. The terms included a "black box" settlement adjustment to the Company's requested rate increase and thus a "black box" resolution of the disputed revenue requirement issues, including the disputed Medicare Part D regulatory asset and amortization expense. The terms of the 2020 Settlement also included more specificity on some of the issues, such as the return on equity, capital structure, depreciation rates, and a five-year amortization period for all regulatory assets. There was no specific term in the 2020 Settlement that allowed any Medicare Part D regulatory asset in rate base or allowed the requested amortization expense in the revenue requirement.

In this present proceeding, the Company's request starts with the same $33.2 million requested in Docket No. 49421 at the end of 2018, the test year in that proceeding, adds another $2.3 million for the period 2019 through April 2020, the date when the new rates approved in Docket No. 49421 went into effect, and then subtracts $24.5 million in amortization expense since April 2020 through the end of the test year.[56]

Q. SHOULD THE COMMISSION INCLUDE A MEDICARE PART D REGULATORY ASSET IN RATE BASE OR THE RELATED AMORTIZATION EXPENSE?

A. No. This issue has become a seemingly unending saga spanning three rate cases, yet the Company serially continues to seek recovery. As I testified on behalf of GCCC in the prior two rate cases, the Company is not entitled to this so-called regulatory asset in rate base or the related amortization expense.[57] The passage of time has not changed this essential conclusion. First, the Company's request is based in large part on its claimed under-recovery of income tax expense since 2004. This is nothing more than a request for the Commission to reverse lawful orders in prior proceedings and to engage in impermissible retroactive rate recovery. This component of the Company's request should be rejected on that basis alone.

As I noted in my direct testimony in Docket No. 49421, the Commission's authorization in Docket No. 38339 to "monitor and accrue the difference between what its rates assume the Medicare Part D subsidy tax expense will be and what CenterPoint is required to pay as a regulatory asset" addressed only the period after the Medicare Part D tax changes went into effect on January 1, 2013, not the retroactive period from

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[56] *See* Application, Direct Testimony of Jennifer Story at 64 (Bates 1104) (Story Direct).

[57] *See* Docket No. 38339, Direct Testimony of Lane Kollen at 83-87 (Sept. 10, 2010) (Kollen Direct); Docket No. 49421, Direct Testimony of Lane Kollen at 27-31 (Jun. 6, 2019).

2004 through 2012.[58] The PFD in Docket No. 49421 adopted my recommendation and excluded the costs related to the retroactive period from 2004 through 2012.[59]

Second, as I noted in my direct testimony in Docket No. 49421, the Company incorrectly calculated the deferral for the years 2013 through 2018.[60] The Company failed to update its estimates in Docket No. 38339 for the actual actuarial cost amounts in the years 2013 through 2018 and failed to exclude the capitalized portion of the actuarial costs given the fact that these amounts were included in construction work in progress ("CWIP") and then plant when the CWIP was completed.[61] The PFD in Docket No. 49421 adopted my recommendations on these two issues and my calculation of the regulatory asset excluding the retroactive portion and correcting these two issues.[62] I provided this calculation, although I did not recommend that any Medicare Part D regulatory asset be included in rate base.[63]

Q. IF THE AMOUNT ADOPTED IN THE PFD IN DOCKET NO. 49421 IS USED AS THE STARTING POINT IN THIS CASE, THEN WHAT IS THE AMOUNT OF THE REGULATORY ASSET AT DECEMBER 31, 2024, ASSUMING THAT NEW RATES IN THIS PROCEEDING GO INTO EFFECT ON JANUARY 1, 2025?

A. The amount of the regulatory asset will be $0 at December 31, 2024 if the $5.572

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[58] *See* Docket No. 49421, Kollen Direct at 27-28.

[59] Docket No. 49421, PFD at 87.

[60] *See* Docket No. 49421, Kollen Direct at 29-31.

[61] *Id.*

[62] Docket No. 49421, PFD at 92.

[63] *See* Docket No. 49421, Kollen Direct at 30.

million regulatory asset adopted in the PFD in Docket No. 49421 is used as the starting point and the Company's annual amortization expense of $6.533 million is extended from the end of the test year through December 31, 2024.

The amount of the regulatory asset will be $0.278 million at December 31, 2024 if the $5.572 million regulatory asset adopted in the PFD in Docket No. 49421 is used and that amount was amortized starting in April 2020 and extended from the end of the test year through December 31, 2024.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reject the Company's request to include a Medicare Part D regulatory asset in rate base and amortize it over five years. The Company never was entitled to such a regulatory asset for the reasons that I cited in the two prior proceedings and reiterate in this proceeding. If, however, the Commission decides the Company is entitled to a regulatory asset, then I recommend it correct the Company's claimed amount in the same manner that I proposed in Docket No. 49421 and that was adopted in the PFD. Further, I recommend the Commission deem that corrected amount fully amortized on or before December 31, 2024, the date before the effective date of new rates in this proceeding.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a reduction in the transmission revenue requirement of $0.572 million and a reduction in the distribution revenue requirement of $2.341 million. These reductions reflect the Company's requested grossed-up rate of return times a reduction in the transmission rate base of $1.703 million and a reduction in the distribution rate base of $6.970 million, and a revenue equivalent reduction of $0.572 million for transmission amortization expense and a revenue equivalent reduction of $2.341 million for distribution amortization expense.

2. Reduce Hurricane Harvey Regulatory Asset to Reflect Additional Amortization through December 31, 2024

Q. DESCRIBE THE COMPANY'S REQUEST TO RECOVER THE REMAINING UNAMORTIZED HURRICANE HARVEY REGULATORY ASSET.

A. The Company included $8.247 million as an unamortized Hurricane Harvey regulatory asset in rate base, net of the related ADIT, at the end of the test year in rate base and amortization of the regulatory asset over five years. This amount excludes the Company's request to include deferred carrying costs on this regulatory asset, which I separately address in the next section of my testimony.

Q. IS IT APPROPRIATE TO USE THE AMOUNT OF THE UNAMORTIZED HURRICANE HARVEY REGULATORY ASSET AT THE END OF THE TEST YEAR?

A. No. It should be revised to reflect the additional amortization expense until new rates resulting from this proceeding become effective. This is a known and measurable adjustment to the regulatory asset, and it affects the amortization expense included in the revenue requirement, also a known and measurable adjustment. The revision is necessary because the Company continues to collect and customers continue to pay the amortization expense reflected in present rates. If a regulatory asset is fully amortized prior to the date when new rates become effective, then there should be no amortization expense included in the revenue requirement. It also is necessary to remove the regulatory asset from rate base as an attendant known and measurable effect.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission revise the unamortized Hurricane Harvey regulatory asset and the related amortization expense to reflect the amount at December 31, 2024, which will be a zero balance. These are both known and measurable adjustments and will ensure the Company does not over-recover this deferred cost.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a reduction in the transmission revenue requirement of $0.035 million and a reduction in the distribution revenue requirement of $2.735 million. These reductions reflect the Company's requested grossed-up rate of return times a reduction in the transmission rate base of $0.105 million and a reduction in the distribution rate base of $8.142 million, and a reduction of $0.027 million in transmission amortization expense and a reduction of $2.061 million in distribution amortization expense.

3. Exclude Unauthorized Deferred Carrying Costs on Hurricane Harvey Regulatory Asset

Q. DESCRIBE THE COMPANY'S REQUESTS TO RECOVER DEFERRED CARRYING COSTS ON THE HURRICANE HARVEY REGULATORY ASSET.

A. There actually are two requests, both of which reflect proforma adjustments to rate base and amortization expense for the requested deferred carrying costs, one of which is for the deferred carrying costs through December 31, 2018, the end of the test year in Docket No. 49421, and the second of which is for the deferred carrying costs from January 1, 2019 through April 22, 2020, the date before new rates went into effect due to the Commission Order in Docket No. 49421.

The first request is for a $2.292 million proforma adjustment to include deferred carrying costs in rate base calculated from the dates the Hurricane Harvey costs were incurred in 2017 and 2018 through December 31, 2018 less the accumulated amortization through the end of the test year in this proceeding, assuming that the amortization began on April 23, 2020, the date when new rates went into effect due to the Commission Order in Docket No. 49421.[64] The first request also includes $0.458 million in amortization expense to reflect a five-year amortization of the deferred carrying costs. The deferred carrying costs for the first request in this proceeding were based on the Company's errata request to include carrying costs in Docket No. 49421.[65]

The second request is for a $9.148 million proforma adjustment to include deferred carrying costs in rate base calculated from the day after the end of the Company's test year in Docket No. 49421 through April 22, 2020, the day before the new rates from the prior case went into effect, less the accumulated amortization from April 23, 2020 through the end of the test year in this proceeding, assuming that the amortization began on April 23, 2020.[66] The second request also includes $1.830 million in amortization expense to reflect a five-year amortization of the deferred carrying costs.[67]

Q. HAS THE COMMISSION EVER AUTHORIZED THE COMPANY TO DEFER CARRYING COSTS ON THE HURRICANE HARVEY REGULATORY ASSET?

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[64] *See* Application, CEHE RFP Workpapers B, WP II-B-12.3.

[65] The Company's application in Docket No. 49421 did not include a request for deferred carrying costs.

[66] *See* Application, CEHE RFP Workpapers B, WP II-B-12.3.

[67] *Id.*

A. No. The Company claims the Commission approved deferred carrying costs on the Hurricane Harvey regulatory asset in Docket No. 49421, citing specifically Finding of Fact 98 and Ordering Paragraph 21 in the Final Order in that docket.[68] However, that claim is not factually correct. Finding of Fact 98 does not address deferred carrying costs on the Hurricane Harvey regulatory asset; it only addresses a five-year amortization period for the "regulatory assets and liabilities maintained on its books and records and at issue in this proceeding." Similarly, Ordering Paragraph 21 does not address deferred carrying costs on the Hurricane Harvey regulatory asset; it only addresses a five-year amortization period for the "regulatory assets and liabilities maintained on its books and records and at issue in this proceeding over five years."

In addition, the PFD in Docket No. 49421 recommended denial of the Company's request for deferred carrying costs, concluding that the securitization statute does not apply to the Hurricane Harvey regulatory asset because it was not securitized.[69]

Further, the Company never recorded deferred carrying costs to the Hurricane Harvey regulatory asset on its accounting books.[70] If the Company actually had understood the Commission to authorize deferred carrying costs on the Hurricane Harvey regulatory asset in Docket No. 49421, then it would have recorded the deferred carrying costs to the regulatory asset for accounting purposes, but it did not. The fact

[68] Application, Direct Testimony of Kristie Colvin at 51 (Bates 813), n.37 (Colvin Direct).

[69] Docket No. 49421, PFD at 76, wherein it states: "The ALJs agree with GCCC witness Kollen that the specific statutory authority relied on by CenterPoint is inapplicable in this case. Securitized bonds have not been issued for these funds and the amounts incurred are below the statutory threshold."

[70] The Company added the requested deferred carrying costs as proforma adjustments, meaning they were not recorded for accounting purposes.

the Company did not do so undermines the validity of Company witness Colvin's arguments in this proceeding as to her claims regarding both the alleged Commission authorization and the claimed statutory authorization that I subsequently address in more detail.

Q. COMPANY WITNESS COLVIN REFERS TO A SECURITIZATION FINANCING STATUTE IN SUPPORT OF THE COMPANY'S REQUEST TO RETROACTIVELY DEFER CARRYING COSTS.[71] PLEASE RESPOND TO THIS CLAIM.

A. Although neither witness Colvin nor I are attorneys and are not able to offer legal opinions, witness Colvin acknowledges that the statute she relies on is related specifically to securitization financing.[72] Witness Colvin then asserts the language of a statute related specifically to securitization financing "confirms that it is appropriate for the Company to be requesting recovery of carrying costs for storm restoration cost in this rate case." I absolutely disagree. It neither "confirms" nor authorizes the Commission to act unreasonably and impermissibly to retroactively allow the Company to create and then recover deferred carrying costs on the Hurricane Harvey deferred costs. In addition, the PFD in Docket No. 49421 found that the securitization statute did not apply to the Hurricane Harvey costs.[73]

Further, as evidenced by the fact the Company never actually recorded the

[71] Application, Colvin Direct at 52-53 (Bates 814-15).

[72] *Id.* at 52.

[73] Docket No. 49421, PFD at 76. "The ALJs agree with GCCC witness Kollen that the specific statutory authority relied on by CenterPoint is inapplicable in this case. Securitized bonds have not been issued for these funds and the amounts incurred are below the statutory threshold."

deferred carrying costs, the Company itself obviously did not believe the securitization financing statute authorized it to record deferred carrying costs on its accounting books.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reject both of the requested increases to the Hurricane Harvey regulatory asset for deferred carrying costs. Deferred carrying costs were not authorized in Docket No. 49421, despite the Company's request in that proceeding, and should not be authorized in this proceeding. If the Company's requests are adopted, then it will open the door for a rush of potential requests by the Company and other utilities for retroactive deferral of carrying costs on any other deferred cost or capitalized cost. If, however, the Commission is inclined to allow the retroactive deferral of carrying costs on this regulatory asset, then the accumulated amortization should be revised through December 31, 2024, not stopped at December 31, 2023.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a reduction in the transmission revenue requirement of \$0.041 million and a reduction in the distribution revenue requirement of \$3.193 million. These reductions reflect the Company's requested grossed-up rate of return times a reduction in the transmission rate base of \$0.145 million and a reduction in the distribution rate base of \$11.295 million, and a reduction of \$0.029 million in transmission amortization expense and a reduction of \$2.259 million in distribution amortization expense.

4. Exclude Unauthorized Deferred Carrying Costs on Hurricane Nicholas, Winter Storm Uri, and Hurricane Laura Regulatory Assets

Q. DESCRIBE THE COMPANY'S REQUESTS TO RECOVER DEFERRED CARRYING COSTS ON THE HURRICANE NICHOLAS, WINTER STORM URI, AND HURRICANE LAURA REGULATORY ASSETS.

A. The Company requests deferred carrying costs from the dates these storm costs were incurred through December 31, 2023 in rate base and amortization expense, assuming a five-year amortization period.[74] The Company cites the same reasons for its requests for these deferred carrying costs as it provides for its requests for the deferred carrying costs on the Hurricane Harvey regulatory asset.[75]

More specifically, the Company requests \$7.202 million for deferred carrying costs on the Hurricane Nicholas regulatory asset in rate base and \$1.440 million in amortization expense to amortize the deferred carrying costs over a five-year amortization period.[76] The Company requests \$3.117 million for deferred carrying costs on the Winter Storm Uri regulatory asset in rate base and \$0.623 million in amortization expense to amortize the deferred carrying costs over a five-year amortization period.[77] The Company requests \$9.246 million for deferred carrying costs on the Hurricane Laura regulatory asset in rate base and \$1.849 million in

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[74] *See* Application, Colvin Direct at 56-57 (Bates 818-19); CEHE's Response to the Office of Public Utility Counsel (OPUC) First RFI Question No. 01-06 (May 8, 2024) (CEHE's Response to OPUC's First RFI). Witness Colvin incorrectly describes the deferred carrying costs calculation through December 31, 2024; however, OPUC 01-06 shows the calculation extending through December 31, 2023.

[75] Application, Colvin Direct at 57 (Bates 819).

[76] CEHE's Response to OPUC's First RFI Question No. 01-06(b) – Confidential. Pursuant to an agreement with the Company's counsel, the following confidential portions of the Company's response to OPUC 01-06 have been de-designated as confidential: The "Summary" tab of the "Hurricane Nicholas Confidential" Excel sheet; the "Summary" tab of the "Winter Storm Uri Confidential" Excel sheet; and the "Laura Carrying Costs Calculation" tab of "Hurricane Laura Confidential" Excel sheet.

[77] CEHE's Response to OPUC's First RFI Question No. 01-06(c) – Confidential.

amortization expense to amortize the deferred carrying costs over a five-year amortization period.[78]

Q. DO YOU OPPOSE RETROACTIVE AUTHORIZATION TO DEFER CARRYING COSTS ON THESE REGULATORY ASSETS FOR THE SAME REASONS YOU OPPOSE SUCH AUTHORIZATION ON THE HURRICANE HARVEY REGULATORY ASSET?

A. Yes. In addition to those reasons, the Company could have securitized these costs in order to reduce the financing costs since the storm costs were incurred, but chose not to do so. Further, the Company could have sought an accounting order from the Commission for authorization to defer carrying costs, but chose not to do so. Finally, the Company has absolutely no claim that the Commission Order in Docket No. 49421 authorized deferred carrying costs on storms that had not occurred and for which costs had not been incurred prior to the end of the test year in Docket No. 49421.

Q. WHAT IS YOUR RECOMMENDATION?

A I recommend the Commission deny the Company's requests to retroactively authorize deferred carrying costs on these regulatory assets.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a reduction in the transmission revenue requirement of $0.098 million and a reduction in the distribution revenue requirement of $5.094 million. These reductions reflect the Company's requested grossed-up rate of return times a reduction in the transmission rate base of $0.292 million and a reduction in the distribution rate

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[78] CEHE's Response to OPUC's First RFI Question No. 01-06(d) – Confidential.

base of $15.165 million, and a reduction of $0.074 million in transmission amortization expense and a reduction of $3.839 million in distribution amortization expense.

IV. OPERATING INCOME ISSUES

A. Increase Revenues for Known and Measurable Growth in Customers through March 31, 2024

Q. DID THE COMPANY REFLECT A KNOWN AND MEASURABLE ADJUSTMENT TO ANNUALIZE REVENUES FOR CUSTOMER GROWTH AFTER THE END OF THE TEST YEAR, BUT BEFORE RATES FROM THIS PROCEEDING WILL BE IN EFFECT?

A. No. The Company annualized revenues for customer growth only through the end of the test year. The Company experienced additional significant growth in revenues due to growth in the number of residential and general service small customers during the three months following the test year, but failed to include a proforma adjustment to annualize standard service base revenues for this known and measurable change.

Q. DESCRIBE THE GROWTH IN CUSTOMERS FROM DECEMBER 30, 2023 THROUGH MARCH 31, 2024.

A. The Company experienced additional growth of 15,616 customers in the residential class and 939 customers in the secondary voltage small class during the three months following the test year. The Company ended the test year with 2,455,399 customers in the residential class, but had 2,470,925 customers by March 31, 2024 in that class.[79]

[79] CEHE's Response to GCCC RFI 4-02 (provided as Attachment LK-9).

The Company ended the test year with 155,776 customers in the secondary voltage small class, but had 156,715 customers by March 31, 2024 in that class.[80]

Q. ARE THE ADDITIONAL REVENUES FROM THE ACTUAL GROWTH IN CUSTOMERS IN THE THREE MONTHS FOLLOWING THE TEST YEAR A KNOWN AND MEASURABLE CHANGE?

A. Yes. The additional revenues from the growth in customers is known with certainty because they are based on the actual revenues at present tariff rates due to the actual growth in customers.

Q. HAVE YOU QUANTIFIED THE ADDITIONAL REVENUES THE COMPANY WILL ACHIEVE DUE TO THE ACTUAL GROWTH IN CUSTOMERS DURING THE SIX MONTHS FOLLOWING THE TEST YEAR?

A. Yes. The Company will achieve an additional $4.725 million in annualized base revenues from the residential class and an additional $0.147 million in annualized base revenues from the secondary voltage small class due to the actual growth in customers after the end of the test year through March 31, 2024. These revenues are in addition to the additional annualized base revenues from the Company's known and measurable adjustment to annualize revenues due to the customer growth in the test year.[81]

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[80] *Id.*

[81] GCCC requested the Company provide the calculations of the increase in annualized revenues due to the actual growth in customers after the end of the test year through March 31, 2024 in GCCC 4-01. The Company refused to provide the calculations; however, it provided the customer counts through March 31, 2024. I used the customer counts at March 31, 2024 and calculated the proforma increase in base revenues using the Company's adjusted base revenues per customer that were included as part of the Company's proforma increase in base revenues through the end of the test year.

Q. WHY SHOULD THE COMMISSION ANNUALIZE THE REVENUES DUE TO THE ACTUAL GROWTH IN CUSTOMERS IN THE THREE MONTHS AFTER THE TEST YEAR?

A. The actual growth in customers and the additional revenues are known and measurable changes that reduce the Company's distribution revenue deficiency and requested increase.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission adopt a known and measurable adjustment to increase present revenues to reflect actual customer growth through March 31, 2024. This adjustment is necessary to account for actual changes occurring after the test-year period to make the test-year data as representative as possible. The increase in revenues is known and it is measurable. The adjustment is necessary to reflect the present revenues, which are subtracted from the revenue requirement to calculate the base rate increase. If the present revenues do not reflect the actual growth in customers through March 31, 2024, then they will be understated, which, in turn, means that the rate increase will be overstated.

Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION?

A. The effect of this known and measurable adjustment is to reduce the requested distribution revenue increase by $4.872 million.

B. <u>Defer Expenses Incurred in Infrastructure Investment and Jobs Act ("IIJA") Grant Process</u>

Q. DESCRIBE THE EXPENSES INCURRED BY THE COMPANY IN THE IIJA GRANT PROCESS.

A. The Company incurred $0.311 million in the IIJA in the test year, which it expensed.[82]

Q. ARE THESE EXPENSES RECURRING?

A. No. They are unique to the Company's attempt to obtain grant funding.

Q. SHOULD THE EXPENSES BE RECOVERED FROM CUSTOMERS?

A. Yes. The only question is whether they should be included in the revenue requirement as recurring or should be deferred and amortized. In the first instance, the Company will over-recover if it does not incur the same level of expense year after year until base rates are reset in the next rate case proceeding. In the second instance, the Company will fully recover its costs, no more and no less.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission direct the Company to defer these costs, include the costs in rate base net of the related ADIT, and amortize the deferred costs over five years. I also recommend the Commission authorize the Company to defer any additional costs incurred in the IIJA grant process after the end of the test year for recovery in a future rate case proceeding.

Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION?

A. The effect is a reduction of $0.040 million in the transmission revenue requirement and $0.188 million in the distribution revenue requirement and requested increase. These

[82] CEHE's Response to GCCC RFI 02-06 (provided as Attachment LK-10).

reductions consist of a reduction in the Company's test year expense of $0.311 million, offset by an increase of $0.245 million in rate base multiplied by the Company's requested cost of capital with the weighted equity return grossed up for income taxes and an increase of $0.062 million for the amortization expense over a five-year amortization period.

C. Maintain Status Quo for Amortization of Asset Excess Deferred Income Taxes ("EDIT") Reclassified from Protected to Unprotected

Q. DESCRIBE THE COMPANY'S REQUEST TO SHORTEN THE AMORTIZATION PERIOD FOR AN ASSET EDIT RECLASSIFIED FROM PROTECTED TO UNPROTECTED.

A. After the last rate case proceeding, the Company concluded that an asset EDIT it had included as protected in that proceeding was incorrectly classified and should have been included as unprotected.[83] The Company since has reclassified the asset EDIT related to cost of removal and mixed service costs from protected to unprotected and requests authorization to amortize these asset EDIT amounts over five years instead of the asset service lives, the present amortization period for the asset EDIT amounts.[84]

Q. IS THIS A REASONABLE PROPOSAL?

A. No. There is no compelling reason for the Commission to accelerate the recovery of these asset EDIT amounts instead of maintaining the status quo. The asset EDIT amounts are related to plant, and the status quo is to recover the asset EDIT over the service lives of the underlying assets. The utility includes the asset EDIT as an addition

[83] *See* Application, Story Direct Testimony at 33-34 (Bates 1073-74).

[84] *Id.*

to rate base, so it earns a return on the asset EDIT and is not harmed by the status quo recovery period.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission deny the Company's request. The status quo provides the Company full recovery of the asset EDIT over the service lives of the underlying assets and includes a return on the unamortized balance.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a $0.510 million reduction in the transmission revenue requirement and requested increase and a $0.904 million reduction in the distribution revenue requirement and requested increase. These are the revenue equivalent effects of simply removing the Company's proposed increases to income tax expense to shorten the recovery period to five years compared to the service lives of the underlying assets under the status quo.

D. <u>Correct Company's Texas Margin Tax Expense to Remove Out of Period Adjustments</u>

Q. DESCRIBE THE COMPANY'S REQUEST FOR TEXAS MARGIN TAX EXPENSE.

A. The Company requests $27.506 million for Texas margin tax expense. This amount consists of $25.070 million for the test year plus another $2.436 million in accounting entries recorded in the test year but related to "corrections" in the 2021 and 2022 expenses.[85]

[85] CEHE's Response to GCCC RFI 5-10 (provided as Attachment LK-11).

Q. IS THE $27.506 MILLION REQUEST FOR TEXAS MARGIN TAX EXPENSE CONSISTENT WITH PRIOR YEAR REQUESTS?

A. No. The Company acknowledged in response to GCCC discovery that "[t]he payment amount should have been $25,207,050 consistent with the Texas margin tax return calculation" and that "[t]he $25,207,050 is the calculated amount from the Texas margin tax return for CEHE consistent with prior years."[86]

Q. SHOULD THE CORRECTIONS IN THE 2021 AND 2022 TEXAS MARGIN TAX EXPENSE RECORDED FOR ACCOUNTING PURPOSES IN THE TEST YEAR BE INCLUDED IN THE REVENUE REQUIREMENT?

A. No. The corrections are prior period adjustments, meaning the accounting entries were recorded in the test year, but related to prior year expenses. The corrections for the prior years are unrelated to the test year and should be excluded from the revenue requirement.

Q. DESPITE ITS ACKNOWLEDGEMENT THAT THE REQUEST FOR THE $27.506 MILLION INCLUDES CORRECTIONS FOR PRIOR YEARS, DOES THE COMPANY AGREE THAT THE CORRECTIONS FOR PRIOR YEARS SHOULD BE EXCLUDED FROM THE REVENUE REQUIREMENT?

A. No. In response to GCCC discovery, the Company claims, "[s]imilar to the Company's Texas Margin Tax in Docket No. 49421, the test year Texas Margin Tax includes the current period provision and any return to accrual adjustments." The term "return to accrual adjustments" refers to corrections for prior years.[87]

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[86] CEHE's Response to GCCC RFI 5-11(a) and (b) (provided as Attachment LK-12).

[87] Attachment LK-11, GCCC RFI 5-10(b).

Q. DID THE COMMISSION RULE ON THE COMPANY'S REQUESTED EXPENSE IN DOCKET NO. 49421?

A. No. The 2020 Settlement reflected a "black box" settlement of the revenue requirement and the base rate increase. Even assuming *arguendo* that the Company's filing included such prior period corrections, the Commission did not rule in that proceeding on the amount of expense included in the test year and whether prior period adjustments should be included or excluded in that expense. The 2020 Settlement did, however, include the following statement with respect to the Texas margin tax expense: "The signatories agree that CenterPoint Houston shall be permitted, for purposes of future DCRF, TCOS, and general rate case proceedings, to reflect Texas margin tax expense based on the current Texas margin tax rate applicable in the period that rates are recovered."[88] The methodology described does not authorize recovery of prior period corrections, nor should it have.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission exclude the corrections related to prior years from the Texas margin tax expense reflected in the revenue requirement.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a $0.425 million reduction in the transmission revenue requirement and requested increase and a $1.874 million reduction in the distribution revenue requirement and requested increase.

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[88] Docket No. 53601, Stipulation and Settlement Agreement at 8 (Jan. 23, 2020).

E. <u>Correct Company's Allocation of CenterPoint Energy, Inc. Texas Margin Tax Expense to Remove Subsidies of Other Affiliates</u>

Q. DESCRIBE THE COMPANY'S CALCULATION OF THE $25.207 MILLION TEXAS MARGIN TAX EXPENSE RECORDED IN THE TEST YEAR FOR THE TEST YEAR.

A. The Company is allocated a portion of the consolidated CenterPoint Energy's Inc. Texas margin tax expense. The Company is included in the consolidated CenterPoint Energy, Inc. Texas margin tax return. CenterPoint Energy, Inc. made an election on the consolidated Texas margin tax return that resulted in reducing the consolidated tax expense, then allocated the consolidated tax expense so that it resulted in an excessive allocation of the expense to the Company and a subsidy of the expense allocated to the other CenterPoint Energy, Inc. affiliates.

The Texas margin tax is calculated as the gross revenues for the taxpayer less its cost of goods sold times a 0.75% tax rate. The taxpayer, in this case, CenterPoint Energy, Inc., may elect to use its "actual" cost of goods sold or a "30% of gross revenues" cost of goods sold for this purpose, which then is applied on a consolidated basis for its applicable affiliates. For electric utilities, the actual cost of goods sold is the utility's fuel and purchased power expense. For natural gas utilities, the actual cost of goods sold is the utility's purchased gas expense.

On its consolidated Texas margin tax return, CenterPoint Energy, Inc. elected to use the "actual" cost of goods sold because it resulted in a lower consolidated Texas margin tax expense than if it used the "30% of gross revenues" cost of goods sold for this purpose. CenterPoint Energy, Inc. then allocated the consolidated Texas margin tax to its affiliates, including the Company, based on the assumption that the "actual" cost of goods sold methodology was used to determine the taxable income for each of the affiliates. This allocation methodology resulted in a "0%" cost of goods sold for the Company because it has no "actual" cost of goods sold.

Q. DOES THE CENTERPOINT ENERGY, INC. ELECTION AND THE RESULTING ALLOCATION RESULT IN A SUBSIDY FROM THE COMPANY TO THE OTHER CENTERPOINT ENERGY, INC. AFFILIATES?

A. Yes. The net benefit from CenterPoint Energy, Inc.'s election on its consolidated Texas margin tax return provides incremental benefits to other CenterPoint Energy, Inc. affiliates, but directly harms the Company by providing the entirety of those benefits, the benefits using the "30% cost of goods sold" *and* the incremental benefits for the "actual cost of goods sold" in excess of the "30% cost of goods sold," to the other affiliates. The harm imposed on the Company from this election and the related allocation forced it to pay for and thus, subsidize, the entirety of the cost of goods sold benefits allocated to the other affiliates. This is inequitable and imposes a cost on the Company that it did not cause in order to achieve benefits for the other affiliates greater than they each would have received if CenterPoint Energy, Inc. had elected the "30% cost of goods sold" methodology.

In other words, if CenterPoint Energy, Inc. had elected the "30% cost of goods sold" methodology and then allocated the consolidated Texas margin tax using that same methodology, then its affiliates, including the Company, would achieve the 30% reduction in Texas margin tax expense. Instead, CenterPoint Energy, Inc's election to use the "actual" cost of goods sold methodology incrementally increased the consolidated cost of goods sold deduction compared to the "30% cost of goods sold" methodology, but the allocation to the Company and the other affiliates then shifted the entirety of the cost of goods sold benefit from the Company to the other affiliates, thereby transferring the benefits of the base "30%" cost of goods sold to the other affiliates and leaving the Company with nothing, a "0%" cost of goods sold deduction.

Q. IS THAT OUTCOME REASONABLE OR EQUITABLE?

A. No. It takes from the Company in order to subsidize the other affiliates. That, by definition, is unreasonable and inequitable. The problem is not with the CenterPoint Energy, Inc. election, but rather the allocation of the effects of the election among the Company and the other affiliates.

Q. DESCRIBE THE STATUTE APPLICABLE TO THE RECOVERY OF AFFILIATE TRANSACTION EXPENSES.

A. PURA § 36.058 provides the requirements for the recovery of affiliate transaction expenses as follows.

> Sec. 36.058. CONSIDERATION OF PAYMENT TO AFFILIATE.
>
> (a) Except as provided by Subsection (b), the regulatory authority may not allow as capital cost or as expense a payment to an affiliate for:
>
> (1) the cost of a service, property, right, or other item; or
>
> (2) interest expense.
>
> (b) The regulatory authority may allow a payment described by Subsection (a) only to the extent that the regulatory authority finds the payment is reasonable and necessary for each item or class of items as determined by the commission.
>
> (c) A finding under Subsection (b) must include:
>
> (1) a specific finding of the reasonableness and necessity of each item or class of items allowed; and
>
> (2) a finding that the price to the electric utility is not higher than the prices charged by the supplying affiliate for the same item or class of items to:
>
> (A) its other affiliates or divisions; or

(B) a nonaffiliated person within the same market area or having the same market conditions.

(d) In making a finding regarding an affiliate transaction, the regulatory authority shall:

(1) determine the extent to which the conditions and circumstances of that transaction are reasonably comparable relative to quantity, terms, date of contract, and place of delivery; and

(2) allow for appropriate differences based on that determination.

(e) This section does not require a finding to be made before payments made by an electric utility to an affiliate are included in the utility's charges to consumers if there is a mechanism for making the charges subject to refund pending the making of the finding.

(f) If the regulatory authority finds that an affiliate expense for the test period is unreasonable, the regulatory authority shall:

(1) determine the reasonable level of the expense; and

(2) include that expense in determining the electric utility's cost of service.

Q. IS THE AFFILIATE CHARGE FOR THE ALLOCATION OF THE CONSOLIDATED TEXAS MARGIN TAX EXPENSE REASONABLE?

A. No. It is unreasonable and inequitable. The CenterPoint Energy, Inc. election imposes a cost on the Company in order to allocate the entirety of the "actual cost of goods sold" savings, not only the incremental savings compared to the "30% cost of goods sold," to the other affiliates. This is the classic definition of a subsidy from one affiliate to other affiliates.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission find that the allocation of the consolidated CenterPoint, Inc. Texas margin tax expense to the Company is unreasonable and excessive in that it results in a subsidy by the Company to other CenterPoint Energy, Inc. affiliates.

I recommend the Commission adopt a two-step allocation methodology to calculate a reasonable allocation of the consolidated Texas margin tax expense to the Company. This allocation methodology will eliminate the subsidy from the Company to the other CenterPoint Energy, Inc. affiliates, while preserving the benefits of the CenterPoint Energy, Inc. election to use the benefits of the "actual cost of goods sold" methodology in excess of the "30% cost of goods sold" methodology for the other affiliates.

The two-step allocation methodology first would calculate the Texas margin tax expense using the "30% cost of goods sold" methodology and allocate the result to all CenterPoint Energy, Inc. affiliates, including the Company, and then calculate and allocate the residual for the "actual costs of goods sold" methodology to the other CenterPoint Energy, Inc. affiliates.

The result of this allocation methodology would be the same as if the Company's Texas margin tax expense was calculated on a standalone basis and without the cost imposed on the Company through an unreasonable allocation of the consolidated CenterPoint Energy, Inc. Texas margin tax expense.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a $1.391 million reduction in the transmission revenue requirement and requested increase and a $6.133 million reduction in the distribution revenue requirement and requested increase.

Q. DOES THE COMPANY CONSIDER THE TEXAS MARGIN TAX TO BE AN INCOME TAX EXPENSE PURSUANT TO GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP") AND PURA § 36.060?

A. Yes, the Company confirmed this in response to discovery.[89] PURA § 36.060(a) states:

> If an expense is allowed to be included in utility rates or an investment is included in the utility rate base, the related income tax benefit must be included in the computation of income tax expense to reduce the rates. If an expense is not allowed to be included in utility rates or an investment is not included in the utility rate base, the related income tax benefit may not be included in the computation of income tax expense to reduce the rates. The income tax expense shall be computed using the statutory income tax rates.

Q. WHY IS THAT RELEVANT?

A. It is relevant because the present version of PURA § 36.060 now requires a standalone calculation of the utility's income tax expense "based solely on those items that are contained within the Company's cost of service," except for the income tax expense itself, which is the result of the rate base and allowed expenses included in cost of service.[90] In contrast to the present version, the prior version of PURA § 36.060 required that tax savings resulting from the utility's parent company's consolidated tax return be reflected in the income tax expense for ratemaking purposes.[91]

It is relevant because the standalone calculation of income tax expense cannot include the effects of elections made by the utility's parent company, whether beneficial or adverse to the utility, or the effects of the revenues, expenses, and

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[89] *See* CEHE's Response to GCCC RFI 2-21(b) (provided as Attachment LK-13).

[90] Application, Story Direct at 50 (Bates 1090).

[91] The present version of PURA § 36.060 was enacted on September 1, 2013.

investment costs of other affiliates, whether resulting in consolidated tax savings or increased costs to the utility.

A standalone calculation means a standalone calculation based on all benefits as well as harms resulting from the calculation of the utility's income tax expense on a standalone basis. For example, the Company calculates taxable income or losses on a standalone basis and if there is a standalone taxable loss, it records an asset net operating loss ("NOL") accumulated deferred income tax ("ADIT") for the NOL carryforward and seeks to include it in rate base, as it has in this application, even if the parent company is able to utilize that loss on the consolidated tax return and there is no asset NOL ADIT on a consolidated basis.

Q. COMPANY WITNESS STORY ASSERTS THAT THE COMPANY CALCULATED THE TEXAS MARGIN TAX ON A STANDALONE BASIS.[92] IS THAT ASSERTION CORRECT?

A. No. The Company started not with the revenues, expenses, and investment costs of the Company itself on a standalone basis, but rather started with the consolidated CenterPoint Energy, Inc. Texas margin tax return to determine the election between the "actual" cost of goods sold methodology and the "30%" cost of goods sold methodology. CenterPoint Energy, Inc., not the Company, elected the "actual" cost of goods sold methodology on a consolidated return basis and then imposed an unreasonable allocation of the resulting consolidated Texas margin tax expense onto the Company compared to the expense the Company would have incurred if either CenterPoint Energy, Inc. on a consolidated basis or the Company on a standalone basis

[92] Application, Story Direct at 50 (Bates 1090).

had elected the "30%" cost of goods sold methodology. The Company on a standalone basis never would have elected the "actual" cost of goods sold methodology and foregone the "30%" costs of goods sold methodology in order to *increase* its Texas margin tax expense. The Company reasonably and prudently would have acted to *minimize* its Texas margin tax expense.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission calculate the Texas margin tax expense on a standalone basis to comply with the requirements of PURA § 36.060. The Company's expense was not calculated on a standalone basis; it is an allocation of the consolidated CenterPoint Energy, Inc. Texas margin tax expense and the result of an election that its parent company made on its consolidated Texas margin tax return, an election the Company would not have made and would not make on a standalone basis.

Q. IS YOUR RECOMMENDATION TO CALCULATE THE COMPANY'S INCOME TAX EXPENSE ON A STANDALONE BASIS CONSISTENT WITH YOUR RECOMMENDATION TO REVISE THE ALLOCATION OF THE CONSOLIDATED TEXAS MARGIN TAX EXPENSE FROM CENTERPOINT ENERGY, INC. TO THE COMPANY?

A. Yes. The Commission must comply with the requirements of both PURA § 36.058, the affiliate transaction statute, and PURA § 36.060, the consolidated tax savings statute for ratemaking purposes. My recommendations, separately and together, will allow the Commission to do so.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a $1.391 million reduction in the transmission revenue requirement and requested increase and a $6.133 million reduction in the distribution revenue requirement and requested increase. These are the same effects as for my recommendation to deny the Company's unreasonable allocation of the consolidated CenterPoint Energy, Inc. Texas margin tax to the Company and instead adopt the reasonable allocation that I recommend.

F. Reduce Income Tax Expense for Electric Vehicle ("EV") Tax Credits

Q. DESCRIBE THE EV AND ELECTRIC VEHICLE CHARGING STATION TAX CREDITS PURSUANT TO THE IRA THE COMPANY EARNED IN THE TEST YEAR.

A. The Company earned EV tax credits of $0.180 million for EV purchases during the test year.[93] The Company earned EV charging station tax credits of $0.030 million for purchases during the test year.[94]

Q. DID THE COMPANY REFLECT THE REVENUE EQUIVALENT OF THESE TAX CREDITS AS REDUCTIONS TO THE REVENUE REQUIREMENTS AND THE REQUESTED INCREASES?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reduce the revenue requirements and the requested increases by the revenue equivalents of these credits. The credits were earned in the

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[93] CEHE's Response to GCCC RFI 2-1 (provided as Attachment LK-14).

[94] *Id.*

test year.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a $0.096 million reduction in the transmission revenue requirement and requested increase and a $0.170 million reduction in the distribution revenue requirement and requested increase.

V. <u>COST OF CAPITAL QUANTIFICATIONS</u>

A. <u>Quantification of HCC Witness Mac Mathuna's Recommended Capital Structure</u>

Q. HAVE YOU QUANTIFIED THE EFFECT ON THE COMPANY'S REVENUE REQUIREMENT OF THE 42.5% EQUITY AND 57.5% LONG-TERM DEBT CAPITAL STRUCTURE RECOMMENDATION SPONSORED BY HCC WITNESS MAC MATHUNA?

A. Yes. The effect is a reduction of $10.496 million in the Company's claimed transmission base revenue requirement and requested rate increase and a reduction of $14.427 million in the Company's claimed distribution base revenue requirement and requested rate increase. These effects are calculated in a sequential manner and are incremental to all prior rate base and cost of capital adjustments that I have addressed and quantified.

B. <u>Quantification of TCUC Witness Woolridge's Recommended Return on Equity</u>

Q. HAVE YOU QUANTIFIED THE EFFECT ON THE COMPANY'S REVENUE REQUIREMENT OF THE 9.50% RETURN ON EQUITY RECOMMENDATION SPONSORED BY TCUC WITNESS WOOLRIDGE?

A. Yes. The effect is a reduction of $23.822 million in the Company's claimed transmission base revenue requirement and requested rate increase, and a reduction of $32.744 million in the Company's claimed distribution base revenue requirement and requested rate increase. The effects of this recommendation are incremental to the effects of the capital structure adjustment that I previously quantified.

Q. HAVE YOU QUANTIFIED THE EFFECT OF EACH 0.10% RETURN ON COMMON EQUITY?

A. Yes. The effect of each 0.10% return on common equity is $2.647 million on the transmission base revenue requirement and $3.638 million on the distribution base revenue requirement.

Q. PROVIDE A COMPARISON OF THE COST OF CAPITAL COMPONENTS AS FILED BY THE COMPANY TO THE CAPITAL STRUCTURE RECOMMENDATION OF HCC WITNESS MAC MATHUNA AND THE RETURN ON EQUITY RECOMMENDATION OF TCUC WITNESS WOOLRIDGE.

A. I provide a comparison in the following table of the capital structure, costs of each component, weighted average cost of capital, and grossed-up weighted average cost of capital proposed by the Company in its filing to the capital structure and cost of capital recommended by witnesses Mac Mathuna and Woolridge after all cost of capital adjustments.

CenterPoint Energy Houston Electric, LLC
Cost of Capital
PUCT Docket No. 56211

CEHE Cost of Capital Per Filing

	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed-Up Weighted Avg Cost
Long Term Debt	55.10%	4.29%	2.36%	2.36%
Common Equity	44.90%	10.40%	4.67%	5.91%
Total Capital	100.00%		7.03%	8.27%

CEHE Cost of Capital Recommended by TCUC and HCC

	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed-Up Weighted Avg Cost
Long Term Debt	57.50%	4.29%	2.46%	2.46%
Common Equity	42.50%	9.50%	4.04%	5.11%
Total Capital	100.00%		6.50%	7.58%

VI. CORPORATE ALTERNATIVE MINIMUM TAX AND PROPOSED RIDER IRA 2022

Q. DESCRIBE THE CORPORATE ALTERNATIVE MINIMUM TAX.

A. The IRA established a new CAMT. As I previously noted, it also modified and established various tax credits, including tax credits for electric vehicles and infrastructure, as well as tax credits for renewable natural gas and renewable electric generating facilities.

The CAMT is imposed on "applicable corporations" with adjusted financial statement income ("AFSI") above $1 billion. The applicable corporation is subject to

CAMT if its AFSI (tentative minimum tax) for the tax year times the 15% CAMT tax rate is greater than its regular income tax liability for the tax year.

AFSI is calculated based on the applicable corporation's per books net income or loss as reported on its applicable financial statements adjusted for various provisions set forth in the IRA. AFSI is adjusted to remove the federal income tax expense reported on the taxpayer's applicable financial statement. AFSI is also adjusted to add back book depreciation expense and to subtract tax depreciation deductions. AFSI is also adjusted to subtract alternative NOL carryforwards for CAMT purposes that are utilized in the tax year, although these alternative NOL carryforward amounts are unlikely to be the same amounts as the NOL carryforwards utilized for regular tax purposes in the tax year.

The CAMT then is compared to the "regular tax," meaning the current income tax expense based on the federal income tax return without consideration of the CAMT. To the extent the CAMT is greater than the regular tax, then the Company will record an asset CAMT ADIT, which may be carried forward to use in subsequent years to reduce the regular tax if the regular tax is greater than the CAMT in any year. To the extent the CAMT is less than the regular tax, and there is no CAMT carryforward from a prior tax year, then the Company simply records the regular tax. To the extent the CAMT is less than the regular tax, and there is a CAMT carryforward from a prior year, then the Company records a reduction to the regular tax in an amount up to the excess of the regular tax over the CAMT in the tax year and an equivalent reduction in the asset CAMT ADIT.

Q. WOULD THE COMPANY BE SUBJECT TO THE CAMT IF IT WERE A STANDALONE SEPARATE LEGAL ENTITY AND NOT A CENTERPOINT ENERGY, INC. AFFILIATE AND MEMBER OF THE AFFILIATE CONTROLLED GROUP INCLUDED IN THE CENTERPOINT ENERGY, INC. CONSOLIDATED FEDERAL TAX RETURNS?

A. No. The Company would not be subject to the CAMT if it were a standalone separate legal entity. The primary reason the Company is subject to the CAMT is the fact that it is a member of a "controlled group" and its income and deductions are included in the CenterPoint Energy, Inc. consolidated tax return for both the consolidated regular tax and the consolidated CAMT.[95] On a standalone separate return basis, the Company's AFSI for the last three years did not exceed the $1 billion applicable threshold; thus, by definition, it would not be an "applicable corporation," except for the fact that it was a member of the controlled group reflected in the consolidated federal income tax return.

Q. WHY IS THAT IMPORTANT?

A. It is important because the threshold for the CAMT is based on the consolidated AFSI of the controlled group, comprised of the affiliates who join in filing a consolidated federal tax return. The regular tax, and the CAMT are calculated on a consolidated tax return basis, even though some of the members of the controlled group may have

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[95] CEHE's Response to GCCC RFI 2-09 (provided as Attachment LK-15), wherein witness Story states: "The Company is an applicable corporation because it is the member of a controlled group that exceed $1 billion average AFSI for the three proceeding taxable years. For this purpose, an applicable corporation (i.e., member of a controlled group) is an entity under a single employer as defined by I.R.C. §52(a) or (b) that meets the parameters of the AFSI test. The entity need not itself meet the AFSI test buy only be a part of the single employer that does. The Company's AFSI for purposes of the AFSI test is that of the single employer and not the Company's own AFSI."

regular tax greater than the CAMT and some of the members of the controlled group may have CAMT greater than the regular tax and these positions may change from tax year to tax year. It is the fact the Company is a member of the controlled group and included in the consolidated CenterPoint Energy, Inc. federal tax return that this cost is imposed on the Company for any reason.

Regardless of any aspect of federal tax law applicable to single employers and members of a controlled group that files a consolidated federal tax return, PURA § 36.060 independently requires that income tax expense be calculated on a "stand-alone" basis for ratemaking purposes, meaning that no consolidated or affiliate income tax savings or income tax costs are allowed to be reflected in the utility's cost of service for ratemaking purposes. As I noted previously, the Company would not be an applicable corporation with respect to the CAMT on a standalone basis. There are no "expenses" or "investments" otherwise included in cost of service and rate base that cause a CAMT for the Company on a standalone basis. Further, the CAMT itself cannot cause income tax expense because it is itself, by definition, an income tax expense.

Q. IS THERE YET ANOTHER ISSUE WITH RESPECT TO THE CAMT ALLOCATION FROM CENTERPOINT ENERGY, INC. TO THE COMPANY?

A. Yes. In response to GCCC discovery, the Company stated that if the consolidated CAMT for CenterPoint Energy, Inc. is $0, then there will be no CAMT recorded for the Company or any of the other CenterPoint Energy, Inc. affiliates.[96] Nowhere is that customer protection set forth in the Company's testimony or proposed Rider IRA 2022

[96] Attachment LK-16, GCCC RFI 5-06.

tariff language. Nor has the Company addressed the circumstance where the CAMT for CenterPoint Energy, Inc. is less than the sum of the CAMTs recorded by the Company and the other CenterPoint Energy, Inc. affiliates.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reject any attempt to include CAMT ADIT in rate base whether in the base revenue requirement or through a rider as proposed by the Company. The applicability of the CAMT to the Company is solely the result of the fact that CenterPoint Energy, Inc.'s AFSI exceeds the $1 billion threshold and the fact the Company is a member of the controlled group and an affiliate included in the consolidated CenterPoint Energy, Inc. tax return. As I noted with respect to the Texas margin tax, the Company is ineligible to recover any consolidated tax cost for the same reasons that it is ineligible to share in consolidated tax savings for ratemaking purposes pursuant to PURA § 36.060.

Q. DESCRIBE THE COMPANY'S PROPOSAL TO RECOVER A RETURN ON THE CAMT ADIT IMPOSED ON THE COMPANY FROM CENTERPOINT ENERGY, INC. DUE TO THE FILING OF A CONSOLIDATED FEDERAL RETURN.

A. The Company proposes a new Rider IRA 2022 and proposes that the return on any potential asset CAMT ADIT in future years be recovered pursuant to this new tariff.[97] The Company also proposes "that beginning with the year following the test year, the return on the CAMT carryforward, using the Company's proposed weighted average

[97] Application, Story Direct at 16-17 (Bates 1056-57).

cost of capital in this base rate case, would be deferred into a regulatory asset which would accumulate carrying costs until recovered through the Rider IRA."[98] Alternatively, the Company seeks authorization to include any CAMT ADIT in its future TCOS and DCRF filings.[99]

The Company had no asset CAMT ADIT at the end of the test year and did not include a CAMT ADIT in the rate base for the base revenue requirement, but it "expects" to have CAMT ADIT in 2024.[100]

Company witness Durland sponsors the proposed new Rider IRA 2022 tariff and provides the proposed tariff language. Witness Durland also addresses the allocation between the transmission and distribution functions. However, neither witness Durland nor any other Company witness describes the proposed tariff language, addresses how the revenue requirement will be calculated, or explains how the rates will be implemented. More specifically, witness Durland does not address how the consolidated CenterPoint Energy, Inc. CAMT will be calculated, how the consolidated CAMT will be allocated to the Company, the timing of the CAMT ADIT calculation and the timing of the recovery of the return on the CAMT ADIT, the sources of data, or any other calculations or procedural aspects, such as estimates followed by true-ups to actuals or when those calculations will be performed, if at all, or any customer safeguards the Company has agreed to in response to discovery. Nor does witness Durland or any other Company witness address the Company's proposal to initially defer a return on the CAMT in the year following the test year and recover it

[98] Application, Colvin Direct at 106 (Bates 868).

[99] Application, Story Direct at 19-20 (Bates 1059-60).

[100] *Id.* at 17 (Bates 1057).

either through the proposed Rider IRA or in some other manner. Nor does witness Durland or any other Company witness address the Company's alternative proposal to recover a return on a CAMT ADIT through the TCOS and DCRF and the modifications to those tariffs necessary to implement such a proposal.

Q. ARE THERE OTHER PROBLEMS WITH THE COMPANY'S REQUEST TO INCLUDE CAMT IN THE PROPOSED RIDER IRA 2022?

A. Yes. There are numerous other ratemaking problems with the Company's request to include a return on the CAMT ADIT in the proposed Rider IRA 2022. First, and most importantly, the proposed tariff language fails to even generally, let alone in sufficient detail, define the costs that will be recovered through the rider. The entire description of the costs that will be recovered in the proposed tariff language is: "This rider is the result of the Inflation Reduction Act of 2022 ("IRA") to recover changes in the Company's tax obligation." That proposed tariff language fails even to describe the Company's request for a return on the CAMT ADIT as detailed by witness Story. That is unacceptable on its face and should disqualify the proposed Rider IRA 2022.

Second, the proposed tariff Rider IRA or, alternatively, modifications to the TCOS and DCRF tariffs, would create some undefined ratemaking mechanism to recover some effect of the CAMT, however that effect may be defined and/or calculated in future Rider IRA, TCOS, and DCRF filings, ostensibly based on the difference between the regular income tax expense and CAMT in future years, also undefined, that would be untethered to the historic test year in this proceeding or any other defined test year in some Rider IRA 2022 proceeding. Neither the regular tax nor the CAMT in a future tax year will be tied to the test year in this proceeding. Those tax calculations will be a function of the per books revenues and expenses in the future tax years.

Third, the Company's proposal is single issue ratemaking because it cherry picks a potential increase in costs due to the CAMT but fails to include other increases or reductions in cost of service. The Company's proposal fails even to incorporate any other non-IRA or IRA tax effects, such as the potential declines in the asset NOL ADIT after the end of the test year, if, in fact, the Commission allows an NOL ADIT in rate base.[101]

Fourth, the CAMT is a function of the Company's actual CAMT and regular income tax calculations in future years, which in turn reflect all GAAP income (revenues) and deductions (expenses) in the tax year, which are not calculated on a ratemaking basis or even on a "normalized" income tax expense basis (current income tax expense plus deferred income tax expense), but only on a tax return, or current income tax expense basis. In other words, it is a cash income tax calculation. Even worse, all income and deductions are reflected on a per books basis, not on a proforma ratemaking basis. Still worse, it includes disallowed costs, abnormal and nonrecurring costs, and accelerated tax depreciation, none of which are reflected in the ratemaking process or are reflected on a normalized basis.

Fifth, the regular tax is reduced by the effects of any NOL carryforward, while the CAMT is potentially reduced by the effects of an alternative CAMT NOL carryforward, meaning that even if an NOL carryforward is utilized and the NOL ADIT

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[101] I note that HCC witness Hunt recommends that no NOL ADIT be included in rate base, and alternatively, recommends that the NOL ADIT be limited to the minimum necessary to avoid a potential "normalization violation" as quantified by the Company.

is reduced or eliminated, it may be replaced in part or whole in the CAMT ADIT. This is not simply an academic observation. Rather, it could result in both the NOL ADIT included in base revenues and the same ADIT repackaged as CAMT ADIT and included in the proposed IRA 2022 in some manner, albeit unknown based on the Company's flawed request.

Q. IS THERE ANY REQUIREMENT UNDER FEDERAL TAX LAW THAT THE CAMT ADIT BE INCLUDED IN RATE BASE OR THE RETURN ON THE CAMT ADIT BE INCLUDED IN THE REVENUE REQUIREMENT FOR UTILITY RATEMAKING PURPOSES, SIMILAR TO THE NORMALIZATION REQUIREMENTS FOR ACCELERATED TAX DEPRECIATION IN EXCESS OF STRAIGHT-LINE TAX DEPRECIATION SET FORTH IN SECTION 168 OF THE INTERNAL REVENUE CODE?

A. No. There is no such requirement set forth in the Internal Revenue Code or the related Treasury Regulations. Whether or not a return on the CAMT ADIT is included in the utility's cost of service for ratemaking purposes is a matter of state law and regulatory discretion, subject to informed judgment by the Commission.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reject the Company's flawed proposal to include some undefined amount and in some undefined manner a return on a CAMT ADIT in a poorly drafted proposed Rider IRA 2022 or in some undefined manner in the TCOS and DCRF tariffs.

Q. IF THE COMMISSION IS INCLINED TO AUTHORIZE A NEW RIDER IRA 2022 TO ALLOW THE COMPANY TO RECOVER A RETURN ON THE

CAMT ADIT, HOW SHOULD IT MODIFY THE COMPANY'S PROPOSED TARIFF?

A. The Company's proposed Rider IRA 2022 should be modified to include language as to the purpose of the tariff, the applicability of the tariff, the calculation of the revenue requirement, including a calculation template, the sources of the data used for the calculation of the revenue requirement, and the procedural aspects of the tariff, including the potential use of estimates and the requirement to true-up estimates to the actual CenterPoint Energy, Inc. consolidated tax returns and amounts allocated to the Company based on the CAMT calculated on a ratemaking basis, including customer safeguards.

In addition, in the event the Commission allows the Company to include an NOL ADIT in rate base for purposes of the base revenue requirement, despite the opposition by GCCC and HCC, then the return on the decrement in the NOL ADIT also should be reflected in the calculation of the revenue requirement.

Further, the calculation should include the revenue equivalent of all tax credits pursuant to the IRA. These tax credits include electric vehicle tax credits and charging station tax credits.[102] The Company agrees that these tax credits should be reflected in the proposed Rider IRA 2022.[103]

Q. HAVE YOU DEVELOPED A MODIFIED RIDER IRA 2022 TARIFF THAT INCORPORATES THESE MODIFICATIONS?

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[102] Attachment LK-14.

[103] *Id.*

A. Yes,[104] although I continue to oppose the recovery of the return on a CAMT ADIT in any form, I have drafted a modified version of the proposed Rider IRA 2022 tariff, including a calculation template. The template includes a return on a CAMT ADIT, subtracts the return on the decrement in the NOL ADIT at the end of the current year compared to the amount included in rate base in the base revenue requirement, if any, and subtracts the revenue equivalent of additional tax credits earned pursuant to the IRA.

VII. RATE CASE EXPENSES

Q. IS THE COST INCURRED BY GCCC TO RETAIN YOUR FIRM A REASONABLE RATE CASE EXPENSE IN THIS PROCEEDING?

A. Yes. The cost incurred by GCCC for my firm is a necessary and reasonable expense incurred in order to represent and protect the interests of GCCC in the outcome of this proceeding. GCCC retained my firm to address revenue requirement and other rate issues, as well as to address rate case expenses incurred by my firm as a reasonable rate case expense. The revenue requirement and other rate issues that my firm addressed in our analyses and my testimony directly affect the outcomes of this proceeding, including the base revenue change, expense deferrals and future rate increases to recover the deferrals, and the rate tariffs used to bill customers for service.

Q. WHAT ARE THE HOURLY RATES CHARGED BY YOUR FIRM FOR THE CONSULTANTS WHO WORKED ON THIS CASE?

A. My hourly billing rate is $325 in this proceeding. Randy Futral's hourly rate is $315.

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[104] I have developed a modified Rider IRA 2022 tariff (provided as Attachment LK-17).

Jessica Inman's hourly rate is $140. These rates are equal to or less than the rates that my firm charges other clients for similar work pursuant to contracts entered into contemporaneously. I have reviewed invoices and billing rates charged by other consulting firms for consultants with similar education, skill competencies, and experience in numerous base rate proceedings. The billing rates charged by my firm generally are within and at the lower end of the range of hourly rates charged by these other experts.

Q. DOES YOUR FIRM ALSO CHARGE FOR OUT-OF-POCKET EXPENSES, SUCH AS TRAVEL, LODGING AND MEALS RELATED TO PROJECTS SUCH AS THIS BASE RATE CASE?

A. Yes. My firm charges for such expenses at actual cost, without any markups or overhead adders. Such expenses are necessary and reasonable in conjunction with expert consulting services incurred in a base rate proceeding, including physical appearance at the hearing. These expenses include reproduction services, courier services, airfare, lodging, and meals while in Austin for the hearing, among others. To date, my firm has incurred and charged only minimal out-of-pocket expenses in this proceeding. If the case goes to hearing, then my firm will incur additional out-of-pocket expenses for travel to Austin, if applicable. The additional travel expenses will include airfare, which will be limited to the economy fare unless economy seating is not available during a reasonable travel time window; lodging, which will be limited to reasonably priced hotels; and meals, which will be limited to no more than $25 for dinner and lesser amounts for other meals. These expenses will not include luxury items or expenses that are personal in nature.

Q. DOES YOUR FIRM BILL SEPARATELY FOR OVERHEAD EXPENSES?

A. No.

Q. HOW MUCH HAS YOUR FIRM BILLED THUS FAR AND DO YOU EXPECT THAT IT WILL CONTINUE TO BILL THROUGH THE COMPLETION OF THIS PROCEEDING?

A. Through May 31, 2024, my firm has billed $49,541.80, consisting of $49,507.50 for consulting services and $34.30 for out-of-pocket expense reimbursement. Supporting documentation for GCCC's total rate case expenses incurred through May 31, 2024, is included with my testimony as Attachments LK-18, LK-19, and LK-20. My firm will bill additional amounts for services and expenses incurred after May 31, 2024 to complete our analyses and my prefiled testimony; review the direct testimony of other parties; respond to discovery; review the Company's rebuttal testimony; develop discovery on the Company's rebuttal testimony and review the responses; assist GCCC counsel in pre-hearing activities, including hearing preparation; prepare for and appear at the hearing for cross-examination; assist GCCC counsel in post-hearing activities; and assist GCCC counsel in settlement negotiations and analyses, if any.

Q. ARE THE COSTS OF YOUR SERVICES IN THIS PROCEEDING REASONABLE?

A. Yes. The amount billed to date and the total estimated cost for our services are reasonable based on the scope and complexity of the issues in this case and the issues that I address and/or quantify in my testimony. These costs are reasonable for the specialized consulting services that we have provided and continue to provide to GCCC.

Q. HAVE ANY OF THE CONSULTANTS WITH YOUR FIRM BILLED MORE THAN 12 HOURS IN A SINGLE DAY IN THIS PROCEEDING?

A. No.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, at this time. However, I reserve the right to amend and/or supplement my testimony as may be required.

RESUME OF LANE KOLLEN, PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

Chartered Global Management Accountant (CGMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Society of Depreciation Professionals

Mr. Kollen has more than forty years of utility industry experience in the financial, rate, tax, and planning areas. He specializes in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Mr. Kollen has expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, PRESIDENT

EXPERIENCE

1986 to Present: **J. Kennedy and Associates, Inc.:** Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986: **Energy Management Associates:** Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: **The Toledo Edison Company:** Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
CF&I Steel, L.P.
Climax Molybdenum Company
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
City of Austin
Georgia Public Service Commission Staff
Florida Office of Public Counsel
Indiana Office of Utility Consumer Counsel
Kentucky Office of Attorney General
Louisiana Public Service Commission
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York City
New York State Energy Office
South Carolina Office of Regulatory Staff
Texas Office of Public Utility Counsel
Utah Office of Consumer Services

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation

Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
As of June 2024

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.
2/88	10064	KY	Kentucky Industrial Utility	Louisville Gas &	Revenue requirements, O&M expense, capital

**Expert Testimony Appearances
of
Lane Kollen
As of June 2024**

Date	Case	Jurisdict.	Party	Utility	Subject
			Customers	Electric Co.	structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.

**Expert Testimony Appearances
of
Lane Kollen
As of June 2024**

Date	Case	Jurisdict.	Party	Utility	Subject
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.

**Expert Testimony Appearances
of
Lane Kollen
As of June 2024**

Date	Case	Jurisdict.	Party	Utility	Subject
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8469	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.

Expert Testimony Appearances
of
Lane Kollen
As of June 2024

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
4/94	U-20647 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.

Expert Testimony Appearances
of
Lane Kollen
As of June 2024

Date	Case	Jurisdict.	Party	Utility	Subject
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.

Expert Testimony Appearances
of
Lane Kollen
As of June 2024

Date	Case	Jurisdict.	Party	Utility	Subject
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.

**Expert Testimony Appearances
of
Lane Kollen
As of June 2024**

Date	Case	Jurisdict.	Party	Utility	Subject
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	U-22491 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735 Rebuttal	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.

Expert Testimony Appearances
of
Lane Kollen
As of June 2024

Date	Case	Jurisdict.	Party	Utility	Subject
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	CT	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
7/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.

Expert Testimony Appearances
of
Lane Kollen
As of June 2024

Date	Case	Jurisdict.	Party	Utility	Subject
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.

Expert Testimony Appearances
of
Lane Kollen
As of June 2024

Date	Case	Jurisdict.	Party	Utility	Subject
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.

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As of June 2024**

Date	Case	Jurisdict.	Party	Utility	Subject
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.

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Date	Case	Jurisdict.	Party	Utility	Subject
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.