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APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES	**§ § §**	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

DIRECT TESTIMONY

OF

KARL J. NALEPA

ON BEHALF OF

CITIES SERVED BY ENTERGY TEXAS INC.

OCTOBER 26, 2022

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ATTACHMENTS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Karl J. Nalepa. I am a partner in, and President of ReSolved Energy Consulting, LLC ("REC"), an independent utility consulting company. My business address is 11044 Research Blvd., Suite A-420, Austin, Texas 78759.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am presenting testimony on behalf of the Cities Served by Entergy Texas Inc. ("Cities").

Q. PLEASE OUTLINE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have been a partner at REC since July 2011, but joined R.J. Covington Consulting, its predecessor firm, in June 2003. I lead our firm's regulated market practice, where I represent the interests of clients in utility regulatory proceedings, prepare client cost studies, and develop client regulatory filings. Before joining REC, I served for more than five years as an Assistant Director at the Railroad Commission of Texas ("RRC"). In this position, I was responsible for overseeing the economic regulation of natural gas utilities in Texas, which included supervising staff casework, advising Commissioners on regulatory issues, and serving as a Technical Rate Examiner in regulatory proceedings. Prior to joining the RRC, I worked as an independent consultant advising clients on a broad range of electric and natural gas industry issues, and before that I spent five years as a supervising consultant with Resource Management International, Inc. I also served for four years as a Fuel Analyst at the Public Utility Commission of Texas ("PUCT" or "Commission"), where I evaluated fuel issues in electric utility rate filings, participated in electric utility-related rulemaking proceedings, and participated in the review of electric utility resource plans. My professional career began with eight years in the reservoir engineering department of Transco Exploration Company, which was an affiliate of Transco Gas Pipeline Company, a major interstate pipeline company.

I hold a Master of Science degree in Petroleum Engineering from the University of Houston, and a Bachelor of Science degree in Mineral Economics from The Pennsylvania State University. I am also a certified mediator. My Statement of Qualifications is included as Attachment A.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I have testified many times before the Commission as well as the PUCT on a variety of regulatory issues. I have also provided testimony before the Louisiana Public Service Commission, Arkansas Public Service Commission, and Colorado Public Utilities Commission. I included a summary of my previously filed testimony as Attachment B. In addition, I have provided analysis and recommendations in a number of city-level regulatory proceedings that resulted in decisions without written testimony.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE AND SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose and scope of my testimony is to present recommendations regarding Entergy Texas, Inc.'s ("ETI", Entergy" or the "Company") proposal to change its base rates. I also sponsor the cost of service model supporting the Cities' case and present Cities' recommendations regarding the Company's proposed cost of service.

III. SUMMARY OF ETI'S REQUEST

Q. WHAT IS ETI REQUESTING IN ITS FILING?

A. ETI is requesting base rates designed to collect a total non-fuel retail amount of approximately $1.2 billion per year, an increase of $131.4 million, or 11.20% on average across all customer classes compared to current adjusted retail base rate and rider revenues. Including fuel, the request represents an increase of 6.95%.[1]

Q. CAN YOU DETAIL ETI'S REQUESTED INCREASE AS DESCRIBED ABOVE?

A. Yes. Table 1 shows the change in requested revenues:[2]

Table 1

	Present Revenues	Proposed Revenues	Change
Base Rates	$890,124,234	$1,219,024,749	$328,900,515
Existing Riders[3]	$85,756,987	$85,756,987	-
DCRF	$40,016,622	-	($40,016,622)
TCRF	$67,943,302	-	($67,943,302)
GCRR	$89,542,979	-	($89,542,979)
Fuel	$715,980,628	$715,980,628	-
Total	$1,889,364,752	$2,020,762,364	$131,397,612

1 Application, Attachment A.

2 Derived from Application, Attachment A and Schedule Q-7.

3 Riders AMS, EECRF, SRC, SRC-2, SCO-2, RCE-4, MTM, TCJA and FITC.

Q. DO YOU HAVE ANY ISSUES WITH THE PRESENTATION OF ETI'S REQUESTED RATE INCREASE?

A. Yes. ETI's presentation assumes the same present and proposed revenue for its existing riders. But this assumption is incorrect. Riders TCJA and FITC will terminate effective October 2022.[4]

Q. PLEASE DESCRIBE THESE RIDERS AND THEIR PURPOSE.

A. The Tax Cuts and Jobs Act ("TCJA") Rider is a mechanism to flow back to customers the estimated unprotected excess ADIT generated by the 2017 Tax Cuts and Jobs Act. The Federal Income Tax Credit ("FITC") Rider is used to credit retail customers with certain tax benefits associated with the 2017 Tax Cuts and Jobs Act.[5]

Q. HOW DO THE RIDERS IMPACT CUSTOMER RATES?

A. During the test year, the TCJA Rider provided rate credits totaling $30 million to the residential, small general service and lighting rate classes.[6] Similarly, the FITC Rider provided additional rate credits totaling $3.9 million to these same classes.[7] Because the Riders terminate this month, these rate credits go away and residential, small general service and lighting customers will see an effective $33.9 million rate increase beginning with the first billing cycle in November 2022. Although this change does not affect the proposed base rate increase, it does impact these customers' overall rates. The expiration of the TCJA and FITC Riders and resulting loss of rate credits will amplify the bill impact

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4 *See* Schedule Q-8.8, TCJA Rider and FITC Rider.

5 *Id.*

6 Schedule Q-7.

7 *Id.*

of any base rate increase approved in this case for residential, small general service and lighting customers.

IV. SUMMARY AND RECOMMENDATIONS

Q. ARE YOU SPONSORING THE CITIES' COST OF SERVICE MODEL IN THIS PROCEEDING.

A. Yes. I sponsor the Cities' cost of service model and compile adjustments to the Company's proposed revenue requirement recommended by each of the Cities' experts. Table 2 summarizes Cities' recommended adjustments:

Table 2

Adjustment	Rate Base Adjustment	Expense Adjustment	Revenue Requirement Adjustment	Sponsor
Return on Equity	-	-	($52,110,799)	O'Donnell
Depreciation Adjustment	-	($67,834,117)	($67,834,117)	D. Garrett
Accelerated Depreciation	-	(a)	(a)	M. Garrett
ST Incentive Target	-	($1,930,041)	($1,930,041)	M. Garrett
ST Incentive Funding	-	($2,210,482)	($2,120,482)	M. Garrett
LT Incentives	-	($2,516,320)	($2,516,320)	M. Garrett
ETI Payroll	-	($1,202,879)	($1,202,879)	M. Garrett
Affiliate Payroll	-	($1,394,405)	($1,394,405)	M. Garrett
Non-Qualified Retirement Plans	-	($1,329,421)	($1,329,421)	M. Garrett
Under-Recovered Pension and OPEB Amortization	-	($1,532,659)	($1,532,659)	M. Garrett
Self-Insurance Accrual	-	($4,939,235)	($4,939,235)	M. Garrett
D&O Insurance	-	($65,844)	($65,844)	M. Garrett
ROE Premium	-	(a)	(a)	M. Garrett
COVID-19 Bad Debt Amortization	-	($978,016)	($978,016)	M. Garrett
Non-AMS Meter Amortization	-	($5,568,296)	($5,568,296)	Nalepa
DIC Regulatory Asset	($8,019,571)	($2,673,190)	($3,518,401)	Nalepa
Weather Normalization	-	($1,036,599)	($1,036,599)	Nalepa
Total Cities Adjustment	($8,019,571)	($147,232,303)	($148,077,514)	

(a) See explanation in the next question and answer.

Q. DO YOU WANT TO HIGHLIGHT ANY OF THE ADJUSTMENTS IN TABLE 2?

A. Yes. I would like to highlight two adjustments: First, Cities witnesses David Garrett and Mark Garrett both address the Company's proposals regarding depreciation. David Garrett calculated the depreciation adjustment and Mark Garrett provides policy reasons for rejecting the Company's proposed recovery of the remaining plant balances for the retired Sabine Units 1, 3 and 4, Nelson 6, and Big Cajun 2 Unit 3.

Second, Cities witnesses Kevin O' Donnell and Mark Garrett both address the Company's proposed return on equity ("ROE"). Kevin O'Donnell developed the Cities' recommended ROE and Mark Garrett provides policy reasons for rejecting the Company's proposed ROE premium.

Q. WHAT DOES THE TOTAL CITIES ADJUSTMENT IN TABLE 2 REPRESENT?

A. The Total Cities Adjustment of ($148,077,514) represents the sum of the revenue requirement impacts of each of Cities' adjustments on a stand-alone basis. The combined revenue requirement impact of Cities adjustments (i.e. the impact of all the adjustments to the cost of service model together) is less than the sum of the individual adjustments because of the net effect of the adjustments. For example, the stand-alone adjustment for return on equity at the Company's rate base will be greater than the impact of return on equity on Cities' lower adjusted rate base. For this reason, the combined revenue requirement impact of Cities' adjustments, based on the cost of service model used by Cities, is ($142,308,628).

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. I recommend that:

- The Commission reject the Company's request to shorten the amortization period for its non-AMS meter regulatory asset. This adjustment reduces the Company's proposed amortization expense by $5,568,296.
- The Commission reject the Company's request to create a regulatory asset and recover certain costs it claims were denied by the Commission in Docket No. 50714. This adjustment removes ETI's proposed $8,019,571 regulatory asset from rate base and reduces the Company's proposed amortization expense by $2,673,190.
- The Company's weather normalization adjustment to Test Year sales be performed using a 10-year weather normalization period, resulting in an increase to the Company's present base-rate revenues in the amount of $1,036,599.
- The Commission adopt Cities' adjusted cost of service of $1,078 million, which represents a $141.3 million reduction from the Company's request or a decrease of $9.9 million from present base revenues.

V. <u>NON-ADVANCED METERING SYSTEM ("AMS") METERS</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL REGARDING NON-AMS METERS.

A. ETI proposes to amend the amortization period of the existing regulatory asset for the non-AMS meters authorized in Docket No. 47416.[8]

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[8] Direct Testimony of Allison P. Lofton at 18.

Q. WHAT IS THE CURRENT AMORTIZATION PERIOD FOR THE NON-AMS METERS REGULATORY ASSET?

A. In Docket No. 47416, the Commission established a regulatory asset for the balance of ETI's non-AMS meters and allowed ETI to recover the balance at the same rate as if ETI was continuing to depreciate the assets.[9] This resulted in an annual amortization of $2,333,869.[10]

Q. WHAT WOULD BE THE EFFECT OF ETI'S PROPOSAL TO AMEND THE AMORTIZATION PERIOD?

A. ETI proposes to shorten the amortization period, which increases the annual amortization by $5,568,296.[11]

Q. DID ETI PROVIDE AN EXPLANATION FOR ITS PROPOSAL?

A. No.

Q. DID THE COMMISSION PROVIDE AN OPPORTUNITY TO CHANGE THE AMORTIZATION PERIOD?

A. No. In fact, Finding of Fact 61 in the Final Order in Docket No. 47416 noted that:

> *(The regulatory asset) shall be amortized in a manner such that the amortization recognized each period (in FERC account 407) will be equal to the amount of depreciation expense that would have been recognized on the existing meters if AMS had not been implemented.* ***This amortization will continue until the balance in the account is reduced to zero. (Emphasis added)***

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[9] Docket No. 47416, Final Order, FoF 60-61 (December 14, 2017).

[10] *See* WP/Schedule P AJ014M.2.

[11] *Id.*

Q. WHAT IS YOUR RECOMMENDATION REGARDING ETI'S PROPOSAL TO CHANGE THE AMORTIZATION PERIOD OF THE REGULATORY ASSET FOR RECOVERY OF THE NON-AMS METERS?

A. I recommend the Commission reject the Company's request to shorten the amortization period for its non-AMS meter regulatory asset. The Company presented no basis for the change and the Order authorizing the regulatory asset does not provide for any change.

VI. DISTRIBUTION INVESTED CAPITAL ("DIC") REGULATORY ASSET

Q. ETI PROPOSES TO ESTABLISH A REGULATORY ASSET AND AMORTIZATION PERIOD FOR CERTAIN DIC OFFSET BY THE RETIREMENT OF THE NON-AMS METERS IN DOCKET NO. 50714. WHAT IS THE MAGNITUDE OF ETI'S PROPOSAL?

A. ETI is seeking to establish an $8,019,571 DIC regulatory asset and amortize it over three years, resulting in annual amortization expense of $2,673,190.

Q. WHAT WAS DOCKET NO. 50714?

A. Docket No. 50714 was ETI's first Distribution Cost Recovery Factor ("DCRF") application to be filed after ETI began its transition to its Advanced Metering System ("AMS") approved in Docket No. 47416. ETI sought an adjustment to its DIC related to non-AMS meters that had been retired as part of the transition to AMS. The adjustment would have resulted in higher DCRF revenues for the Company. As will be discussed further below, both the ALJ and the Commission rejected Company's proposed adjustment.

Q. PLEASE EXPLAIN THE BASIS FOR FOR THE PROPOSED DIC REGULATORY ASSET.

A. According to ETI, the proposed regulatory asset is for an amount equivalent to the annual revenue requirement associated with the DIC that was offset by the retirement and reclass of the non-AMS meters in Docket No. 50714.[12] It appears that ETI is seeking to recover certain DIC that it claims were disallowed in Docket No. 50714. In its exceptions to the Proposal for Decision ("PFD") in that docket, ETI asserted that excluding the non-AMS meter amounts in DIC will result in a disallowance of an equivalent amount of the incremental distribution invested capital until ETI's base rates are reset, amounting to $4.1 million annually that ETI will not recover.[13]

Q. DID THE COMMISSION AGREE WITH ETI?

A. No. The PFD concluded:[14]

> *The ALJ is not convinced by ETI's argument that excluding (the non-AMS meters in) FERC account 182 from the DCRF calculation results in a disallowance. ETI continues to recover amounts attributable to non-AMS meters in its current base rates and this amount will be adjusted again when ETI's base rates are reset. Although it may take longer for ETI to recover the full amount than ETI would prefer, the result is not a disallowance of the amounts.*

The Commission adopted the findings in the PFD.[15]

Q. WHAT IS YOUR RECOMMENDATION REGARDING ETI'S PROPOSAL TO ESTABLISH A REGULATORY ASSET FOR THIS DIC?

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[12] Response to Cities RFI 1-28.

[13] Docket No. 50714, ETI Exceptions to the PFD at 5.

[14] Docket No. 50714, Proposal for Decision at 13.

[15] Docket No. 50714, Final Order at 1 (October 16, 2020).

A. I recommend that the Commission reject ETI's request to create a regulatory asset to recover two years of DIC (at approximately $4 million per year) that the Company claims was disallowed by virtue of the Order in Docket No. 50714. . Both the ALJ and the Commission found that ETI's position was unfounded, thus there is no reason to create the requested regulatory asset. The effect of rejecting the regulatory asset is to remove the proposed $8,019,571 regulatory asset from rate base and remove the associated amortization expense of $2,673,190.[16]

VII. <u>WEATHER NORMALIZATION OF PRESENT BASE REVENUES</u>

Q. WHAT ARE PRESENT BASE REVENUES AND HOW ARE PRESENT BASE REVENUES USED IN A BASE RATE PROCEEDING?

A. Present base revenues represent a utility's current level of cost recovery under base rates. To ascertain if ETI's current base rates are sufficient to recover its costs, the cost of service, as measured in the cost study, is subtracted from present base revenues. If the resulting revenue differential is negative, ETI has a revenue shortfall and ETI's rates must be raised until base revenues under proposed rates are equal to the base revenue requirement, as calculated in the cost study. If the resulting revenue differential is positive, ETI has a revenue surplus and ETI's rates must be lowered until base revenues under proposed rates are equal to the base revenue requirement.

The calculation of present base revenues affects the overall revenue increase (or decrease) in this case. A one-dollar increase in present base revenues has the same effect

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[16] *See* WP/Schedule P AJ014M.2.

on the overall revenue increase (or decrease) as a one-dollar decrease in allowable expenses.

Q. HOW ARE PRESENT BASE REVENUES DETERMINED?

A. Present base revenues are calculated using test year billing units and current base rate tariff charges. A utility may also propose adjustments to actual test year billing units to make the units more representative of what the utility believes will occur in a normal operating year.

Q. HAS ETI REQUESTED ANY ADJUSTMENTS TO TEST YEAR BILLING UNITS FOR THE PURPOSE OF CALCULATING PRESENT BASE REVENUES?

A. Yes. ETI has proposed a number of adjustments, including an adjustment to normalize the billing units for the effects of weather ("weather normalization").[17]

Q. PLEASE EXPLAIN THE CONCEPTUAL BASIS FOR AN ADJUSTMENT TO TEST YEAR BILLING UNITS TO ACCOUNT FOR THE EFFECTS OF WEATHER.

A. Hot weather increases the summer cooling load on the Company's system. Cold weather increases the winter electric heating load on the system. If the summer and/or winter in a utility's service territory is hotter or cooler than usual, the utility's actual test year sales may be higher or lower than the level of sales that would have occurred under normal weather conditions. To determine if test year sales are representative of the sales that will occur under normal weather conditions, a utility performs a statistical analysis of the weather's effects on its sales. One of the variables to be considered in performing the statistical analysis is the period of time for determining normal weather conditions.

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[17] Direct Testimony of Kristin Sasser at 5.

Q. WHAT NUMBER OF YEARS HAS ETI PROPOSED TO USE IN THE WEATHER NORMALIZATION PERIOD FOR ITS STATISTICAL ANALYSIS?

A. The Company has proposed using twenty years to determine normal weather conditions. Company witness Kristen Sasser testifies, "Normal temperatures were defined as the average over the 20-year period ending December 2020."[18]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED WEATHER NORMALIZATION PERIOD?

A. No. The Company's proposed twenty-year weather normalization period conflicts with the Commission's findings on this issue in Southwestern Electric Power Company ("SWEPCO") Docket No. 40443. Texas has been undergoing a warming trend, and a 10-year weather normalization period more accurately reflects the recent warming trend. In their Commission-adopted decision in Docket No. 40443, the ALJs found:

> … a weather normalization adjustment using data from a 10-year period is consistent with Commission precedent and sound public policy and more accurately reflects the weather conditions during the test year. The Commission's recent decisions to use a 10-year period for weather normalization in rulemaking Project No. 39465, relating to the Distribution Cost Recovery Factor, and Project No. 39040, relating to the Earnings Monitoring Report, further supports the use of a 10-year period. As Mr. Abbott pointed out in his testimony, the Commission stated in adopting the Distribution Cost Recovery Factor rule that "[t]here can be weather trends, and the commission concludes that the use of ten years of data is a reasonable means of capturing such trends." Further, the Commission also addressed the weather normalization period in the recent Earnings Monitoring Report rulemaking:
>
> > For reasons stated by Cities, the commission retains the requirement to use 10-year weather data. This provides consistency between the weather-normalization of revenues in the EMR and the weather-normalization procedure required in the DCRF rule.

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18 Direct Testimony of Kristen L. Sasser at 6.

> Accordingly, the ALJs recommend that the Commission adopt Mr. Johnson's analysis supporting his alternative 10-year recommendation. The alternative recommendation appropriately adjusts SWEPCO's adjusted test year kWh amount, which is lower than it should be because it understates the normal amount of cooling degree days (or days with warm weather). The Commission should set rates based upon an increase to SWEPCO's requested test-year adjusted kWh to reflect a 10-year weather normalization period, consistent with Mr. Johnson's alternative recommendation. Mr. Johnson persuasively showed that a 30-year period does not capture the warming trend in more recent periods, such as ten years of weather.[19]

In a subsequent base-rate proceeding, Southwestern Public Service Company ("SPS") Docket No. 43695, SPS proposed, and the Commission adopted, a 10-year weather normalization period.[20] In a more recent fully litigated base-rate proceeding before the Commission, SWEPCO Docket No. 46449, SWEPCO challenged the Commission's decision, requesting the use of a 30-year period. Over SWEPCO's objection, the Commission again adopted the use of a 10-year weather normalization period. In their Commission-adopted decision, the ALJs found, "the Commission's precedent on this issue controls, and therefore, recommend that the 10-year weather normalization finding the Commission made in SWEPCO Docket No. 40443 and SPS Docket No. 43695 be made here as well."[21] The Order on Re-Hearing contained the following findings of fact:

> 271. Weather data are not randomly distributed by year. There can be weather trends, including both warming and cooling trends.
>
> 272. The use of a 30-year period for normalizing weather is not a reasonable means of capturing such trends.

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19 *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 40443, Proposal for Decision at 244 (May 20, 2013).

20 *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Direct Testimony of Janelle Marks at 8 (Dec. 8, 2014).

21 *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Proposal for Decision at 309 (Sep. 22, 2017).

273. The use of 10 years of data is a reasonable means of capturing such weather trends.

274. The use of 10 years of data is more sensitive to weather patterns during the test year.

275. The weather-normalization adjustment should be applied to adjust billing units and allocation factors for a 10-year weather-normalization period, based on the class billing determinants and external allocation factors used to calculate rates using a 10-year weather normalization period.[22]

Q. HAS THE COMMISSION ADOPTED A 10-YEAR WEATHER NORMALIZATION PERIOD IN ANY OTHER PROCEEDINGS?

A. Yes. The Commission requires utilities to use a 10-year weather normalization period in their DCRF applications,[23] Energy Efficiency Cost Recovery Factor ("EECRF") applications,[24] and Earnings Monitoring Reports ("EMR").[25]

Q. WHAT DO YOU RECOMMEND?

A. Consistent with the Commission's findings in Docket Nos. 40443, 43695, and 46449, and as required in other Commission proceedings, I recommend that ETI's weather normalization be performed using a 10-year weather normalization period.

Q. IN RESPONSE TO DISCOVERY, DID ETI PROVIDE THE RESULTS OF ITS WEATHER NORMALIZATION METHODOLOGY USING A TEN-YEAR WEATHER NORMALIZATION PERIOD?

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[22] *Id.*, Order on Re-Hearing at FoFs 271-275 (Mar. 19, 2018).

[23] 16 TAC § 25.243(b)(5).

[24] 16 TAC § 25.181(e)(3)(A).

[25] Instructions for EMR Schedule X, referring to 16 TAC § 25.243(b)(5).

A. Yes. The use of a 10-year weather normalization period results in an increase in ETI's present base revenues in the amount of $1,036,599.[26] As discussed above, in the event a revenue increase is ordered in this proceeding, the adjustment has the effect of decreasing ETI's Test Year revenue shortfall; and, in the event a revenue decrease is ordered in this proceeding, the adjustment has the effect of increasing ETI's Test Year revenue surplus.

VIII. COST OF SERVICE MODEL

Q. ARE YOU SPONSORING THE CITIES' ADJUSTMENTS TO THE COST OF SERVICE MODEL?

A. I have compiled the adjustments to the cost of service model in Table 2, but I am only sponsoring the model results. Other experts retained by the Cities will sponsor their own adjustments.

Q. HOW WAS THE COST OF SERVICE MODEL DEVELOPED?

A. The starting point for the cost of service model is a reproduction of the Company's model, which was provided to the parties on July 29, 2022. It incorporates all of the components of the Company's model, and generates the same results as the Company's model prior to any adjustments by the City. Cities adjusted cost of service model is provided as Attachment D to my testimony.

Q. WHAT IS THE CITIES' PROPOSED COST OF SERVICE?

A. Using the Company's adjusted model, Cities recommend an overall cost of service of $1,077,734,342. This is $141,290,407 less than the Company's requested cost of service of $1,219,024,749.

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[26] Response to Cities RFI 6-1. $891,160,833 (Cities RFI 6-1) - $890,124,234 (Schedule Q-1) = $1,036,599.

Q. HOW DO THE CITIES' RECOMMENDED ADJUSTMENTS COMPARE TO ETI'S REQUESTED REVENUE INCREASE?

A. As discussed earlier, ETI is requesting an increase in total revenues of $131.4 million. Cities recommend that ETI's request be reduced by $141.3 million. This results in a recommended decrease of $9.9 million from present base revenues.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

KARL J. NALEPA

Mr. Nalepa is an energy economist with more than 40 years of private and public sector experience in the electric and natural gas industries. He has extensive experience analyzing utility rate filings and resource plans with particular focus on fuel and power supply requirements, quality of fuel supply management, and reasonableness of energy costs. Mr. Nalepa developed peak demand and energy forecasts for public utilities and has forecast the price of natural gas in ratemaking and resource plan evaluations. He led a management and performance review of the Texas Public Utility Commission and has conducted performance reviews and valuation studies of municipal utility systems. Mr. Nalepa previously directed the Railroad Commission of Texas' Regulatory Analysis & Policy Section, with responsibility for preparing timely natural gas industry analysis, managing ratemaking proceedings, mediating informal complaints, and overseeing consumer complaint resolution. He has prepared and defended expert testimony in both administrative and civil proceedings and has served as a technical examiner in natural gas rate proceedings.

EDUCATION

1998	Certificate of Mediation Dispute Resolution Center, Austin
1989	NARUC Regulatory Studies Program Michigan State University
1988	M.S. - Petroleum Engineering University of Houston
1980	B.S. - Mineral Economics Pennsylvania State University

PROFESSIONAL HISTORY

2011 -	ReSolved Energy Consulting Partner
2003 - 2011	RJ Covington Consulting Managing Director
1997 – 2003	Railroad Commission of Texas Asst. Director, Regulatory Analysis & Policy
1995 – 1997	Karl J. Nalepa Consulting Principal
1992 – 1995	Resource Management International, Inc. Supervising Consultant
1988 – 1992	Public Utility Commission of Texas Fuels Analyst
1980 – 1988	Transco Exploration Company Reservoir and Evaluation Engineer

AREAS OF EXPERTISE

Regulatory Analysis

Electric Power: Analyzed electric utility rate, certification, and resource forecast filings. Assessed the quality of fuel supply management, and reasonableness of fuel costs recovered from ratepayers. Projected the cost of fuel and purchased power. Estimated the impact of environmental costs on utility resource selection. Participated in regulatory rulemaking activities. Provided expert staff testimony in a number of proceedings before the Texas Public Utility Commission.

As consultant, represent interests of municipal clients intervening in large utility rate proceedings through analysis of filings and presentation of testimony before the Public Utility Commission. Also assist municipal utilities in preparing and defending requests to change rates and other regulatory matters before the Public Utility Commission.

Natural Gas: Directed the economic regulation of gas utilities in Texas for the Railroad Commission of Texas. Responsible for monitoring, analyzing and reporting on conditions and events in the natural gas industry. Managed Commission staff representing the public interest in contested rate proceedings before the Railroad Commission, and acted as technical examiner on behalf of the Commission. Mediated informal disputes between industry participants and directed handling of customer billing and service complaints. Oversaw utility compliance filings and staff rulemaking initiatives. Served as a policy advisor to the Commissioners.

As consultant, represent interests of municipal clients intervening in large utility rate proceedings through analysis of filings and presentation of testimony before the cities and Railroad Commission. Also assist small utilities in preparing and defending requests to change rates and other regulatory matters before the Railroad Commission.

Litigation Support

Retained to support litigation in natural gas contract disputes. Analyzed the results of contract negotiations and competitiveness of gas supply proposals considering gas market conditions contemporaneous with the period reviewed. Supported litigation related to alleged price discrimination related to natural gas sales for regulated customers. Provided analysis of regulatory and accounting issues related to ownership of certain natural gas distribution assets in support of litigation against a natural gas utility. Supported independent power supplier in binding arbitration regarding proper interpretation of a natural gas transportation contract. Provided expert witness testimony in administrative and civil court proceedings.

Utility System Assessment

Led a management and performance review of the Public Utility Commission. Conducted performance reviews and valuation studies of municipal utility systems. Assessed ability to compete in the marketplace, and recommended specific actions to improve the competitive position of the utilities. Provided comprehensive support in the potential sale of a municipal gas system, including preparation of a valuation study and all activities leading to negotiation of contract for sale and franchise agreements.

Energy Supply Analysis

Reviewed system requirements and prepared requests for proposals (RFPs) to obtain natural gas and power supplies for both utility and non-utility clients. Evaluated submittals under alternative demand and market conditions, and recommended cost-effective supply proposals. Assessed supply strategies to determine optimum mix of available resources.

Econometric Forecasting

Prepared econometric forecasts of peak demand and energy for municipal and electric cooperative utilities in support of system planning activities. Developed forecasts at the rate class and substation levels. Projected price of natural gas by individual supplier for Texas electric and natural gas utilities to support review of utility resource plans.

Reservoir Engineering

Managed certain reserves for a petroleum exploration and production company in Texas. Responsible for field surveillance of producing oil and natural gas properties, including reserve estimation, production forecasting, regulatory reporting, and performance optimization. Performed evaluations of oil and natural gas exploration prospects in Texas and Louisiana.

PROFESSIONAL MEMBERSHIPS

Society of Petroleum Engineers
International Association for Energy Economics
United States Association for Energy Economics

SELECT PUBLICATIONS, PRESENTATIONS, AND TESTIMONY

"Summary of the USAEE Central Texas Chapter's Workshop entitled 'EPA's Proposed Clean Power Plan Rules: Economic Modeling and Effects on the Electric Reliability of Texas Region,'" with Dr. Jay Zarnikau and Mr. Neil McAndrews, USAEE Dialogue, May 2015

"Public Utility Ratemaking," EBF 401: Strategic Corporate Finance, The Pennsylvania State University, September 2013

"What You Should Know About Public Utilities," EBF 401: Strategic Corporate Finance, The Pennsylvania State University, October 2011

"Natural Gas Markets and the Impact on Electricity Prices in ERCOT," Texas Coalition of Cities for Fair Utility Issues, Dallas, October 2008

"Natural Gas Regulatory Policy in Texas," Hungarian Oil and Gas Policy Business Colloquium, U.S. Trade and Development Agency, Houston, May 2003

"Railroad Commission Update," Texas Society of Certified Public Accountants, Austin, April 2003

"Gas Utility Update," Railroad Commission Regulatory Expo and Open House, October 2002

"Deregulation: A Work in Progress," Interview by Karen Stidger, *Gas Utility Manager*, October 2002

"Regulatory Overview: An Industry Perspective," Southern Gas Association's Ratemaking Process Seminar, Houston, February 2001

"Natural Gas Prices Could Get Squeezed," with Commissioner Charles R. Matthews, *Natural Gas*, December 2000

"Railroad Commission Update," Texas Society of Certified Public Accountants, Austin, April 2000

"A New Approach to Electronic Tariff Access," Association of Texas Intrastate Natural Gas Pipeline Annual Meeting, Houston, January 1999

"A Texas Natural Gas Model," United States Association for Energy Economics North American Conference, Albuquerque, 1998

"Texas Railroad Commission Aiding Gas Industry by Updated Systems, Regulations," *Natural Gas,* July 1998

"Current Trends in Texas Natural Gas Regulation," Natural Gas Producers Association, Midland, 1998

"An Overview of the American Petroleum Industry," Institute of International Education Training Program, Austin, 1993

Direct testimony in PUC Docket No. 10400 summarized in *Environmental Externality,* Energy Research Group for the Edison Electric Institute, 1992

"God's Fuel - Natural Gas Exploration, Production, Transportation and Regulation," with Danny Bivens, Public Utility Commission of Texas Staff Seminar, 1992

"A Summary of Utilities' Positions Regarding the Clean Air Act Amendments of 1990," Industrial Energy Technology Conference, Houston, 1992

"The Clean Air Act Amendments of 1990," Public Utility Commission of Texas Staff Seminar, 1992

KARL J. NALEPA
TESTIMONY FILED

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Public Utility Commission of Texas					
53601	Aug 22	Cities	Oncor Electric Delivery	Cost of Service	Revenues / Tariffs / Cost Allocation
53551	Aug 22	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
53436	May 22	TNMP Cities	Texas-New Mexico Power	DCRF	DCRF Methodology
53034	Jul 22	Xcel Municipalities	Southwestern Public Service	Fuel Reconciliation	Fuel Cost Recovery
52728	May 22	Office of Public Counsel	City of College Station	TCOS	Wholesale Transmission Rate
52487	Mar 22	Office of Public Counsel	Entergy Texas Inc.	CCN	Public Interest Review
52485	Mar 22	Office of Public Counsel	Southwestern Public Service	CCN	Public Interest Review
52195	Oct 21	City of El Paso	El Paso Electric	Cost of Service	Cost of Service Model
52194	July 21	Cities	CenterPoint Energy Houston	EECRF	EECRF Methodology
52178	July 21	Cities	Oncor Electric Delivery	EECRF	EECRF Methodology
52081	July 21	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
52067	July 21	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
51997	Aug 21	Office of Public Counsel	Entergy Texas, Inc.	System Restoration Costs	Cost Review
51802	Aug 21	Xcel Municipalities	Southwestern Public Service	Cost of Service	Cost Allocation
51415	Mar 21	CARD	SWEPCO	Cost of Service	Cost Allocation
51381	Dec 20	Entergy Cities	Entergy Texas Inc.	GCRR	GCRR Methodology
51345	Oct 20	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
51215	Mar 21	Office of Public Counsel	Entergy Texas Inc.	CCN	Public Interest Review

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
51100	Nov 20	Office of Public Counsel	Lubbock Power & Light	TCOS	Wholesale Transmission Rate
50997	Jan 21	CARD	SWEPCO	Fuel Reconciliation	Fuel Cost Recovery
50790	Jul 20	Office of Public Counsel	Entergy Texas, Inc.	Sale, Transfer, Merger	Public Interest Review
50714	May 20	Cities	Entergy Texas Inc.	DCRF	DCRF Methodology
50110	Dec 19	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
49831	Feb 20	Xcel Municipalities	Southwestern Public Service	Cost of Service	Cost Allocation
49737	Jan 20	Office of Public Counsel	SWEPCO	CCN	Public Interest Review
49594	Jul 19	Oncor Cities	Oncor Electric Delivery	EECRF	EECRF Methodology
49592	Jul 19	AEP Cities	AEP Texas Inc.	EECRF	EECRF Methodology
49586	Jul 19	TNMP Cities	Texas-New Mexico Power	EECRF	EECRF Methodology
49583	Aug 19	Gulf Coast Coalition	CenterPoint Energy Houston	EECRF	EECRF Methodology
49496	Jun 19	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
49494	Jul 19	AEP Cities	AEP Texas Inc.	Cost of Service	Plant Additions
49421	Jun 19	Office of Public Counsel	CenterPoint Energy Houston	Cost of Service	Cost of Service
49395	May 19	City of El Paso	El Paso Electric	DCRF	DCRF Methodology
49148	Apr 19	City of El Paso	El Paso Electric	TCRF	TCRF Methodology
49042	Mar 19	SWEPCO Cities	SWEPCO	TCRF	TCRF Methodology
49041	Feb 19	SWEPCO Cities	SWEPCO	DCRF	DCRF Methodology
48973	May 19	Xcel Municipalities	Southwestern Public Service	Fuel Reconciliation	Fuel / Purch Power Costs
48963	Dec 18	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
48420	Aug 18	Gulf Coast Coalition	CenterPoint Energy Houston	EECRF	EECRF Methodology

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
48404	Jul 18	Cities	Texas-New Mexico Power	EECRF	EECRF Methodology
48371	Aug 18	Cities	Entergy Texas Inc.	Cost of Service	Cost of Service
48231	May 18	Cities	Oncor Electric Delivery	DCRF	DCRF Methodology
48226	May 18	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
48222	Apr 18	Cities	AEP Texas Inc.	DCRF	DCRF Methodology
47900	Dec 17	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
47527	Apr 18	Xcel Municipalities	Southwestern Public Service	Cost of Service	Cost of Service
7461	Dec 17	Office of Public Counsel	SWEPCO	CCN	Public Interest Review
47236	Jul 17	Cities	AEP Texas	EECRF	EECRF Methodology
47235	Jul 17	Cities	Oncor Electric Delivery	EECRF	EECRF Methodology
47217	Jul 17	Cities	Texas-New Mexico Power	EECRF	EECRF Methodology
47032	May 17	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
46936	Oct 17	Xcel Municipalities	Southwestern Public Service	CCN	Public Interest Review
46449	Apr 17	Cities	SWEPCO	Cost of Service	Cost of Service
46348	Sep 16	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
46238	Jan 17	Office of Public Counsel	Oncor Electric Delivery	STM	Public Interest Review
46076	Dec 16	Cities	Entergy Texas Inc.	Fuel Reconciliation	Fuel Cost
46050	Aug 16	Cities	AEP Texas	STM	Public Interest Review
46014	Jul 16	Gulf Coast Coalition	CenterPoint Energy Houston	EECRF	EECRF Methodology
45788	May 16	Cities	AEP-TNC	DCRF	DCRF Methodology
45787	May 16	Cities	AEP-TCC	DCRF	DCRF Methodology

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
45747	May 16	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
45712	Apr 16	Cities	SWEPCO	DCRF	DCRF Methodology
45691	Jun 16	Cities	SWEPCO	TCRF	TCRF Methodology
45414	Feb 17	Office of Public Counsel	Sharyland	Cost of Service	Cost of Service
45248	May 16	City of Fritch	City of Fritch	Cost of Service (water)	Cost of Service
45084	Nov 15	Cities	Entergy Texas Inc.	TCRF	TCRF Methodology
45083	Oct 15	Cities	Entergy Texas Inc.	DCRF	DCRF Methodology
45071	Aug 15	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
44941	Dec 15	City of El Paso	El Paso Electric	Cost of Service	CEP Adjustments
44677	Jul 15	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
44572	May 15	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
44060	May 15	City of Frisco	Brazos Electric Coop	CCN	Transmission Cost Recovery
43695	May 15	Pioneer Natural Resources	Southwestern Public Service	Cost of Service	Cost Allocation
43111	Oct 14	Cities	Entergy Texas Inc.	DCRF	DCRF Methodology
42770	Aug 14	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
42485	Jul 14	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
42449	Jul 14	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
42448	Jul 14	Cities	SWEPCO	TCRF	Transmission Cost Recovery Factor
42370	Dec 14	Cities	SWEPCO	Rate Case Expenses	Rate Case Expenses
41791	Jan 14	Cities	Entergy Texas Inc.	Cost of Service	Cost of Service/Fuel
41539	Jul 13	Cities	AEP Texas North	EECRF	EECRF Methodology

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
41538	Jul 13	Cities	AEP Texas Central	EECRF	EECRF Methodology
41444	Jul 13	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
41223	Apr 13	Cities	Entergy Texas Inc.	ITC Transfer	Public Interest Review
40627	Nov 12	Austin Energy	Austin Energy	Cost of Service	General Fund Transfers
40443	Dec 12	Office of Public Counsel	SWEPCO	Cost of Service	Cost of Service/Fuel
40346	Jul 12	Cities	Entergy Texas Inc.	Join MISO	Public Interest Review
39896	Mar 12	Cities	Entergy Texas Inc.	Cost of Service/ Fuel Reconciliation	Cost of Service/ Nat Gas/ Purch Power
39366	Jul 11	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
38951	Feb 12	Cities	Entergy Texas Inc.	CGS Tariff	CGS Costs
38815	Sep 10	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
38480	Nov 10	Cities	Texas-New Mexico Power	Cost of Service	Cost of Service/Rate Design
37744	Jun 10	Cities	Entergy Texas Inc.	Cost of Service/ Fuel Reconciliation	Cost of Service/ Nat Gas/ Purch Power/ Gen
37580	Dec 09	Cities	Entergy Texas Inc.	Fuel Refund	Fuel Refund Methodology
36956	Jul 09	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
36392	Nov 08	Texas Municipal Power	Texas Municipal Power	Interim TCOS	Wholesale Transmission Rate
35717	Nov 08	Cities Steering Committee	Oncor Electric Delivery	Cost of Service	Cost of Service/Rate Design
34800	Apr 08	Cities	Entergy Gulf States	Fuel Reconciliation	Natural Gas/Coal/Nuclear
16705	May 97	North Star Steel	Entergy Gulf States	Fuel Reconciliation	Natural Gas/Fuel Oil
10694	Jan 92	PUC Staff	Midwest Electric Coop	Revenue Requirements	Depreciation/ Quality of Service
10473	Sep 91	PUC Staff	HL&P	Notice of Intent	Environmental Costs

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
10400	Aug 91	PUC Staff	TU Electric	Notice of Intent	Environmental Costs
10092	Mar 91	PUC Staff	HL&P	Fuel Reconciliation	Natural Gas/Fuel Oil
10035	Jun 91	PUC Staff	West Texas Utilities	Fuel Reconciliation Fuel Factor	Natural Gas Natural Gas/Fuel Oil/Coal
9850	Feb 91	PUC Staff	HL&P	Revenue Req. Fuel Factor	Natural Gas/Fuel Oil/ETSI Natural Gas/Coal/Lignite
9561	Aug 90	PUC Staff	Central Power & Light	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas Natural Gas/Fuel Oil Natural Gas
9427	Jul 90	PUC Staff	LCRA	Fuel Factor	Natural Gas
9165	Feb 90	PUC Staff	El Paso Electric	Revenue Requirements Fuel Factor	Natural Gas/Fuel Oil Natural Gas
8900	Jan 90	PUC Staff	SWEPCO	Fuel Reconciliation Fuel Factor	Natural Gas Natural Gas
8702	Sep 89 Jul 89	PUC Staff	Gulf States Utilities	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas/Fuel Oil Natural Gas/Fuel Oil Natural Gas/Fuel Oil
8646	May 89 Jun 89	PUC Staff	Central Power & Light	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas Natural Gas/Fuel Oil Natural Gas
8588	Aug 89	PUC Staff	El Paso Electric	Fuel Reconciliation	Natural Gas

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Railroad Commission of Texas					
9896	Sep 22	City of El Paso	Texas Gas Service	Cost of Service	Consolidation / Cost of Service
07061	Sep 21	Texas Cities Alliance	Multiple	Gas Cost Securitization	Prudence Determination
05509	Dec 20	LDC, LLC	LDC, LLC	Cost of Service	Cost of Service/Rate Design
10928	Mar 20	TGS Cities	Texas Gas Service	Cost of Service	Cost of Service/Rate Design
10920	Feb 20	East Texas Cities Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10900	Nov 19	Cities Steering Committee	Atmos Energy Triangle	Cost of Service	Cost of Service
10899	Sep 19	NatGas, Inc.	NatGas, Inc.	Cost of Service	Cost of Service/Rate Design
10737	Jun 18	T&L Gas Co.	T&L Gas Co.	Cost of Service	Cost of Service/Rate Design
10622	Apr 17	LDC, LLC	LDC, LLC	Cost of Service	Cost of Service/Rate Design
10617	Mar 17	Onalaska Water & Gas	Onalaska Water & Gas	Cost of Service	Cost of Service/Rate Design
10580	Mar 17	Cities Steering Committee	Atmos Pipeline Texas	Cost of Service	Cost of Service/Rate Design
10567	Feb 17	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10506	Jun 16	City of El Paso	Texas Gas Service	Cost of Service	Cost of Service/Energy Efficiency
10498	Feb 16	NatGas, Inc.	NatGas, Inc.	Cost of Service	Cost of Service/Rate Design
10359	Jul 14	Cities Steering Committee	Atmos Energy Mid Tex	Cost of Service	Cost of Service/Rate Design
10295	Oct 13	Cities Steering Committee	Atmos Pipeline Texas	Revenue Rider	Rider Renewal
10242	Jan 13	Onalaska Water & Gas	Onalaska Water & Gas	Cost of Service	Cost of Service/Rate Design
10196	Jul 12	Bluebonnet Natural Gas	Bluebonnet Natural Gas	Cost of Service	Cost of Service/Rate Design
10190	Jan 13	City of Magnolia, Texas	Hughes Natural Gas	Cost of Service	Cost of Service/Rate Design
10174	Aug 12	Cities Steering Committee	Atmos Energy West Texas	Cost of Service	Cost of Service/Rate Design

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
10170	Aug 12	Cities Steering Committee	Atmos Energy Mid Tex	Cost of Service	Cost of Service/Rate Design
10106	Oct 11	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10083	Aug 11	City of Magnolia, Texas	Hughes Natural Gas	Cost of Service	Cost of Service/Rate Design
10038	Feb 11	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10021	Oct 10	AgriTex Gas, Inc.	AgriTex Gas, Inc.	Cost of Service	Cost of Service/Rate Design
10000	Dec 10	Cities Steering Committee	Atmos Pipeline Texas	Cost of Service	Cost of Service/Rate Design
9902	Oct 09	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
9810	Jul 08	Bluebonnet Natural Gas	Bluebonnet Natural Gas	Cost of Service	Cost of Service/Rate Design
9797	Apr 08	Universal Natural Gas	Universal Natural Gas	Cost of Service	Cost of Service/Rate Design
9732	Jul 08	Cities Steering Committee	Atmos Energy Corp.	Gas Cost Review	Natural Gas Costs
9670	Oct 06	Cities Steering Committee	Atmos Energy Corp.	Cost of Service	Affiliate Transactions/ O&M Expenses/GRIP
9667	Nov 06	Oneok Westex Transmission	Oneok Westex Transmission	Abandonment	Abandonment
9598	Sep 05	Cities Steering Committee	Atmos Energy Corp.	GRIP Appeal	GRIP Calculation
9530	Apr 05	Cities Steering Committee	Atmos Energy Corp.	Gas Cost Review	Natural Gas Costs
9400	Dec 03	Cities Steering Committee	TXU Gas Company	Cost of Service	Affiliate Transactions/ O&M Expenses/Capital Costs

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Louisiana Public Service Commission					
U-36254	Jul 22	PSC Staff	Dixie Electric Membership Corporation	Formula Rate Plan	Emergency Rate Relief
U-35359	Feb 20 Nov 20	PSC Staff	Dixie Electric Membership Corporation	Cost of Service	Cost of Service / FRP Renewal / AMS Certification Stipulation
U-34344/ U-34717	Apr 18	PSC Staff	Dixie Electric Member Corporation	Formula Rate Plan	Stipulation
U-34344	Jan 18	PSC Staff	Dixie Electric Member Corporation	Formula Rate Plan	Adjusted Revenues
U-33633	Nov 15	PSC Staff Entergy Gulf States Louisiana	Entergy Louisiana, LLC/	Resource Certification	Prudence
U-33033	Jul 14	PSC Staff Entergy Gulf States Louisiana	Entergy Louisiana, LLC/	Resource Certification	Revenue Requirement
U-31971	Nov 11	PSC Staff Entergy Gulf States Louisiana	Entergy Louisiana, LLC/	Resource Certification	Certification/Cost Recovery
Before the Colorado Public Utilities Commission					
18A-0791E	Mar 19	Pueblo County	Black Hills Colorado Electric	Economic Development Rate	Tariff Issues
Before the Arkansas Public Service Commission					
O7-105-U	Mar 08	Arkansas Customers & pipelines serving CenterPoint	CenterPoint Energy, Inc.	Gas Cost Complaint	Prudence / Cost Recovery

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc.	Prepared By: Josh Paternostro
to the First Set of Data Requests	Sponsoring Witness: Allison P. Lofton
of Requesting Party: CITIES	Beginning Sequence No. LC97
	Ending Sequence No. LC98

Question No.: CITIES 1-28 Part No.: Addendum:

Question:

Regulatory Assets and Liabilities: For each regulatory asset and liability, provide an explanation of the item, the reason for including it in rate base, and any related statutes, orders, legal precedent, or other available documentary support for including the item in rate base.

Response:

Regulatory Assets

1823TA (Reg Asst ETI Pre-2008 Storm) - Reflects the pre-2008 storm costs that were reclassed from the storm reserve account 228.1 deficit balance and authorized for inclusion in rate base to be amortized over twenty years pursuant to the Commission's Final Orders in Docket Nos. 39896 and 41791.

1823TN (ETI NQ Pension Over/Under) - This account is used to track the over/under of non-qualified pension expense for Entergy Texas, Inc. ("ETI"). The Company proposes to include this account in rate base in accordance with Texas PURA § 36.065(b), which authorizes a utility to establish one or more reserve accounts (i.e., regulatory assets) to capture any difference between the amount of pension and other post-employment benefits ("OPEB") expenses included in base rates and the amount actually incurred by the utility.

1823TP (ETI Qualified Pension Over/Under) - This account is used to track the over/under of qualified pension expense for ETI The Company proposes to include this account in rate base in accordance with Texas PURA § 36.065(b), which authorizes a utility to establish one or more reserve accounts (i.e., regulatory assets) to capture any difference between the amount of pension and OPEB expenses included in base rates and the amount actually incurred by the utility.

1823CB (Reg asset Covid 19 bad debt) - This regulatory asset captures expenses resulting from the effects of Covid-19, specifically bad debt expense. The Company proposes to include this account in rate base pursuant to the Order in Project No. 50664, accounting order related to accrual of Regulatory Assets issued by the Commission.

Question No.: CITIES 1-28

1822AM (Unrecovered plant - meters) - This account was established to record and include in rate base the unrecovered plant balance for the non-AMS meters pursuant to the Commission's Order in Docket No. 47416, ETI's AMS CCN filing. In Docket No. 47416, there was agreement that the balance in this account should be included in rate base in all future base-rate cases (or equivalent rate-setting decisions).

Proposed regulatory asset - See WP/P AJ 14M. The Company proposes to establish a regulatory asset for an amount equivalent to the annual revenue requirement associated with the Distribution Invested Capital that was offset by the retirement and reclass of the non-AMS meters in ETI's DCRF application, Docket No. 50714.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc.
to the Sixth Set of Data Requests
of Requesting Party: CITIES

Prepared By: Gareth Hutchinson
Sponsoring Witness: Crystal K. Elbe
Beginning Sequence No. LC2698
Ending Sequence No. LC2698

Question No.: CITIES 6-1 Part No.: Addendum:

Question:

Refer to the Direct Testimony of Kristin Sasser at 12. Please provide test year energy and revenues by class adjusted using 10-year average temperatures.

Response:

Please see the attachment (TP-53719-00CIT006-X001).

ENTERGY TEXAS, INC.
REVENUE SUMMARY
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2021

RESPONSE TO CITIES 6.1

		Present				Proposed				Base Plus Rider Change		
Line No.	Rate Class	Present Base Rate Revenue	Present Rider Revenue (1)	Present Fuel Revenue (2)	Total Present Revenue	Proposed Base Rate Revenue (4)	Proposed Rider Revenue (4)(5)	Proposed Fuel Revenue (2)	Total Proposed Revenue	Change To Base Plus Rider Revenue	Percent Change (excl Fuel)	Percent Change (excl Fuel)
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Residential Service	$ 470,127,100	$ 143,089,196	$ 238,875,472	$ 852,091,768	$ 654,215,068	$ 41,981,605	$ 238,875,472	$ 935,072,145	$ 82,980,377	13.53%	9.74%
2	Small General Service	$ 36,621,813	$ 10,762,228	$ 18,749,370	$ 66,133,411	$ 46,404,711	$ 4,256,149	$ 18,749,370	$ 69,410,230	$ 3,276,819	6.92%	4.95%
3	General Service	$ 160,965,435	$ 65,101,388	$ 120,922,943	$ 346,989,766	$ 218,625,700	$ 26,547,667	$ 120,922,943	$ 366,096,310	$ 19,106,544	8.45%	5.51%
4	Large General Service	$ 48,669,519	$ 19,241,481	$ 49,122,483	$ 117,033,483	$ 64,746,367	$ 7,441,581	$ 49,122,483	$ 121,310,431	$ 4,276,948	6.30%	3.65%
5	Large Industrial Power Service (3)	$ 162,333,099	$ 41,412,522	$ 285,689,757	$ 489,435,378	$ 219,111,949	$ 3,545,874	$ 285,689,757	$ 508,347,580	$ 18,912,202	9.28%	3.86%
7	Lighting Service	$ 12,443,867	$ 3,911,872	$ 3,459,637	$ 19,815,376	$ 16,113,201	$ 2,104,528	$ 3,459,637	$ 21,677,366	$ 1,861,990	11.38%	9.40%
8	Total Retail	$ 891,160,833	$ 283,518,687	$ 716,819,662	$ 1,891,499,182	$ 1,219,216,996	$ 85,877,404	$ 716,819,662	$ 2,021,914,062	$ 130,414,880	11.10%	6.89%

Proposed Base Rate Revenue	$ 1,219,216,996	
Proposed Rider Revenue (Exc.) Fuel	$ 85,877,404	
Total Exc. Fuel	$ 1,305,094,400	
Base Revenue Requirement Change	$1,219,022,261	6.895%
	$ 85,877,404	
	$ 1,304,899,665	
SMS impact on RR	$0	
Total Increase	$ 1,304,899,665	
Difference is rounding in rate design.	$ 194,735	
Present Base Rate Revenue	$ 891,160,833	
Present Rider Revenue (Exc.) Fuel	$ 283,518,687	
Total Exc. Fuel	$ 1,174,679,520	

Sponsored by Rudolph P. Griffin

Attachment C

Difference	$	130,414,880
% Diff.		11.10%
Proposed Revenue Inc. Fuel	$	2,021,914,062
Present Revenue Inc. Fuel	$	1,891,499,182
Total Exc. Fuel	$	130,414,880
% Diff.		6.89%

Attachment C

Sponsored by Rudolph P. Griffin

ENTERGY TEXAS, INC.
TEST YEAR ENERGY SALES BY RATE CLASS
FOR TWELVE MONTHS ENDING DECEMBER 31, 2021

RESPONSE TO CITIES 6.1

Line No.	Rate Class	Test Year Adjusted
(a)	(b)	(j)
1	Residential Service	6,275,296,876
2	Small General Service	492,548,420
3	General Service	3,181,848,697
4	Large General Service	1,300,400,521
5	Large Industrial Power Service	7,964,873,163
6	Lighting Service	90,885,214
7	Total Retail	19,305,852,892

Sponsored by Rudolph P. Griffin

Attachment C

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the First Set of Data Requests of Requesting Party: Office of Public Utility Counsel	Prepared By: Gregory S. Wilson Sponsoring Witness: Gregory S. Wilson Beginning Sequence No. LC3 Ending Sequence No. LC4

Question No.: OPUC 1-3 Part No.: Addendum:

Question:

Please refer to the Direct Testimony of Mr. Gregory S. Wilson, Exhibit GSW-3.

a. Please provide the calculation of how the costs related to Hurricanes Rita, Gustav, Ike, Laura, Delta and Harvey were removed from the costs from each of these years of historical data.

b. Please confirm or deny that the annual costs shown on this exhibit are already net of the costs for each of these hurricanes.

Response:

a. See the table below for the calculation.

Storm	Date	Original Expense	Expense Removed	Net Remaining	Notes
Rita	9/24/2005	175,621,244	173,608,533	2,012,711	The expenses for Hurricane Rita were removed from the analysis during 2007. At the time of the next analysis, there were additional payments for Rita that were not securitized. These were charged to the Insurance Reserve.
Gustav	9/2/2008	14,908,545	14,908,545	-	
Ike	9/11/2008	340,775,285	340,775,285	-	
Harvey	8/24/2017	21,925,686	20,527,124	1,398,562	All the expenses for Hurricane Harvey were removed from the analysis during 2018. At the time of this analysis, there were additional payments for Harvey that had not been

Question No.: OPUC 1-3

Storm	Date	Original Expense	Expense Removed	Net Remaining	Notes
					included in the regulatory asset filing or securitized. These were charged to the Insurance Reserve.
Laura	8/25/2020	53,139,554	37,355,161	15,784,393	
Delta	10/9/2020	9,222,277	7,158,175	2,064,102	

b. Confirmed, to the extent that the losses were not otherwise recovered.

ATTACHMENT D

TO THE DIRECT TESTIMONY OF KARL J. NALEPA

WILL BE PROVIDED ELECTRONICALLY