River Bend Decommissioning Cost Escalation Rate - ETI Rate Case NRC Minimum estimate

Series Annual

Composite Energy Factors(NUREG 1307 REV 18 page 13)

Electricity	0.54
Fuel Oil	0.46

Composite Index Weights (NUREG 1307 REV 18 page 11)

Labor	0.65
Energy	0.13
Burial	0.22

Year	**Labor (1)**	% chge	**Electricity[(2)]**	% chge	**Fuel Oil [(3)]**	% chge	**Weighted Energy [(4)]**	**Burial [(5)]**	**Composite Rate**
2021	1.455		2.248		1.864				
2022	1.533	5.33%	2.436	8.35%	1.988	6.69%	7.59%	7.80%	
2023	1.603	4.55%	2.507	2.93%	1.794	-9.80%	-2.93%	7.80%	
2024	1.668	4.04%	2.575	2.72%	1.750	-2.45%	0.34%	7.80%	
2025	1.733	3.93%	2.660	3.31%	1.717	-1.86%	0.93%	7.80%	
2026	1.800	3.87%	2.748	3.32%	1.738	1.23%	2.36%	7.80%	
2027	1.869	3.84%	2.823	2.70%	1.781	2.46%	2.59%	7.80%	
2028	1.940	3.80%	2.911	3.12%	1.828	2.62%	2.89%	7.80%	
2029	2.013	3.77%	3.008	3.35%	1.881	2.92%	3.15%	7.80%	
2030	2.089	3.75%	3.094	2.84%	1.946	3.46%	3.13%	7.80%	
2031	2.167	3.72%	3.192	3.19%	2.009	3.24%	3.22%	7.80%	
2032	2.248	3.74%	3.290	3.05%	2.066	2.82%	2.94%	7.80%	
Average		4.03%		3.53%		1.03%	2.38%	7.80%	
Energy				54%		46%			
Average Factored Growth Rate (2021-32)		4.03%					2.38%	7.80%	
NRC Weights		65%					13%	22%	
Composite Escalation Rate		2.62%					0.31%	1.72%	**4.65%**

[(1)] Source : IHS US Economy 12/2021 Forecast of Employment Cost Index, Total Private Compensation

[(2)] Source: IHS US Economy 12/2021 Forecast for Producer Price Index-Electric Power

[(3)] Source: IHS US Economy 12/2021 Forecast forProducer Price Index- Crude Petroleum

[(4)] Calculated Value : Weighted Average Electricity (54%) Crude Oil (46%) For the Energy Factor

[(5)] Per Exhbit AMA-2

Calculation of Average Annual Rate in Burial Per NRC Index

Boiling Water Reactor Burial Indexes[1]

2020	12.873
1986	1.000

Calculation of Annual Growth Rate [2]

Year	Index	Growth Rate
1986	1.000	7.796%
1987	1.078	7.796%
1988	1.162	7.796%
1989	1.253	7.796%
1990	1.350	7.796%
1991	1.456	7.796%
1992	1.569	7.796%
1993	1.691	7.796%
1994	1.823	7.796%
1995	1.965	7.796%
1996	2.118	7.796%
1997	2.284	7.796%
1998	2.462	7.796%
1999	2.654	7.796%
2000	2.860	7.796%
2001	3.083	7.796%
2002	3.324	7.796%
2003	3.583	7.796%
2004	3.862	7.796%
2005	4.163	7.796%
2006	4.488	7.796%
2007	4.838	7.796%
2008	5.215	7.796%
2009	5.622	7.796%
2010	6.060	7.796%
2011	6.532	7.796%
2012	7.042	7.796%
2013	7.591	7.796%
2014	8.182	7.796%
2015	8.820	7.796%
2016	9.508	7.796%
2017	10.249	7.796%
2018	11.048	7.796%
2019	11.909	7.796%
2020	12.838	

[1] Source:Growth Rate of BWR Disposal Costs referenced in " NUREG 1307, Revision 18, Table 2-1 values of Bx
for generators located in unaffiliated states and and those located in Compact affiliated states having no disposal facility

[2] Growth rate is determined by starting at an index value of 1.000 in 1986 as described in the referenced NRC table
and applying a growth rate necessary to result in the index value in 2020

BILLING ALLOCATION METHODOLOGY	Basis for Selection of Billing Allocation Methodology	Example
DIRECTTX	The cost driver DIRECTTX relates to and activities caused exclusively by ETI. Therefore, costs are appropriately charged 100% to ETI, under billing method DIRECTTX.	F3PCCEPTEX - CONSUMER ED PROGRAMS TEXAS: The overall purpose of this project is to capture and manage costs associated with the Low Income Summit and low income assistance programs for ETI. The primary activities associated with this project code are summit activities and the effort of providing funds and other assistance for low income customers. Costs are driven by the activities associated with the Low Income Summit and low income assistance programs for ETI. Therefore, costs are billed under billing method DIRECTTX which bills 100% to ETI.
CUSTEGOP	Billing method CUSTEGOP pertains to all regulated customers (electric and gas), and the method allocates costs based on the proportion of customers in each jurisdiction. This billing method is appropriate when, in general, the cost of providing this service varies directly with the number of customers.	F3PCR10360 - CUSTOMER ACCOUNTING: The overall purpose of this project is to capture and manage costs associated with providing administrative, supervisory, and analytical support to the Customer Accounting Services employees in each operating company. The Primary Activities associated with this project code relate to Customer Accounting Services. ESL activities include budgeting, performing analysis of technical and financial data, reporting performance and providing managerial guidance. Costs are driven by the support provided to the Customer Accounting Services employees at each operating company, which is directly related to the number of electric and gas customers served by each operating company. Each company benefits in proportion to the number of customers it serves. Billing Method CUSTEGOP allocates these costs to the operating companies based on the proportional average number of electric and gas customers served.
PKLOADAL	The cost driver, PKLOADAL, is based upon peak load ratio, which matches the costs incurred with the benefits received. It is calculated based on the ratio of each Client Company's load to the peak load at time of all companies peak load. The calculation of Peak Load Ratio is performed using a twelve-month rolling average of the coincident peaks.	F3PCE01601-FERC Open Access Transmission: The overall purpose of this project is to capture and manage costs associated with regulatory oversight and coordination of the Entergy System Open Access Transmission Service proceeding before the Federal Energy Regulatory Commission (FERC). The primary activities associated with this project code are the preparation of filings, testimony and other documents; oversight of attorneys, regulatory consultants and internal functions (such as accounting, finance, planning) providing services for these proceedings; review of documents generated by other parties to these proceedings (such as motions, data requests, testimony and briefs); and advise and counsel senior management regarding the status, progress, and expected outcome of the proceedings. The types of costs being charged to this Project Code are labor, employee expenses, consultant fees and expenses, and other office expenses.The costs are driven by the load served by the Entergy Operating Companies. The FERC's activities affect the operations of the integrated transmission system and operations of the generation resources. Thus, ESL Billing Method PKLOADAL, which directs costs based on the ratio of each company's load at the time of peak load, is the appropriate method for this project.

BILLING ALLOCATION METHODOLOGY	Basis for Selection of Billing Allocation Methodology	Example
LBRFDPOL	Bills costs based on labor billings from ESL Federal Policy departments. Includes indirect overhead costs that should bill to the business units receiving services of the Federal Policy function. It is calculated based on total labor dollars billed to each company by ESL for the Federal Policy, Regulatory and Governmental Affairs function.	F5PCZPDEPT-SUPERVISION & SUPPORT - FED POLICY: The primary purpose of this project code is to capture certain Federal Policy Departmental overhead costs. The primary activities associated with this project code are as follows: Secretarial/clerical labor not specific to a particular project; general administrative meeting time, such as departmental staff meetings, employee evaluations and goal setting; time spent on administrative type tasks such as filling out timesheets, expense accounts, pay requests and other accounting/HR, etc. forms, other administrative time such as attending company-wide functions, attending non-project code specific, general training (such as standard software and Quality training), general departmental overhead types of expenses such as general office supplies, non-capital equipment/furniture, as well as rental, maintenance, and repair of general office furniture and equipment. The primary product/deliverable of this project code is administrative support for other projects performed and owned by Federal Policy. As the costs charged to this project code are overhead and indirect in nature, these types of expenditures are nevertheless necessary for any business unit to function and be productive. Thus, the benefits to each business unit are support for all the services provided by the Federal Policy Department. Costs are driven by the need to capture Federal Policy Departmental overhead costs. The billing method is LBRFDPOL, which bills costs based on labor billings from ESL Federal Policy departments.
CUSEOPCO	Bills all operating companies based on electric customer count as the activities will benefit the operating companies' customers. It is calculated based on a twelve-month average number of electric residential, commercial, industrial, government, and municipal customers.	F3PCTDCA01: MANAGE BUDGETS - ESL: The overall purpose of this project is to capture and manage costs associated with providing cost analysis support to Jurisdictions and Customer Service Support. The primary activities associated with this Project Code are budgeting and reporting variances. Other activities include responding to customer requests for information. Costs are driven by the number of customers in the Entergy service area, EAL, ELL, EML, ENOL and ETI. Therefore, these costs have been allocated under billing method CUSEOPCO, that bills to all operating companies based on a twelve-month average number of electric customers and reasonably reflects the cause of the cost incurred for this service.

See Native Excel file Maurice-Anderson Direct_Exhibits AMA-A through D.

DOCKET NO. 53719

APPLICATION OF ENTERGY	§	PUBLIC UTILITY COMMISSION
TEXAS, INC. FOR AUTHORITY TO	§	
CHANGE RATES	§	OF TEXAS

DIRECT TESTIMONY

OF

LORI A. GLANDER, CHP

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2022

ENTERGY TEXAS, INC.
DIRECT TESTIMONY OF LORI A. GLANDER
2022 RATE CASE

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EXHIBIT

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lori A. Glander, CHP, 148 New Milford Road East, Bridgewater, Connecticut 06752.

Q2. WHAT IS YOUR OCCUPATION?

A. I am the Sr. Manager of Decommissioning Services at TLG Services, LLC ("TLG"). On September 19, 2000, Entergy Nuclear, Inc. acquired the stock of TLG with TLG thereby becoming a wholly owned, indirect subsidiary of Entergy Corporation. As such, I am also the Sr. Manager of Decommissioning with Entergy Nuclear, Inc.

Q3. WHAT ARE YOUR RESPONSIBILITIES WITH TLG?

A. I am responsible for the technical and business management of the engineering consulting services in the area of decommissioning planning for nuclear generating stations.

Q4. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I completed my Bachelor of Science in Organizational Management from Manhattan College, Riverdale, New York, in 2004. I have been Certified by the American Board of Health Physics as a Health Physicist since 2006. I joined TLG in May of 2017. I was employed by Entergy Nuclear Operations, Indian Point Energy Center from 2001 through 2017 in the areas of Radiation Protection

(Health Physics) and Emergency Preparedness. I also previously worked for Orange County, New York (Government) as Radiological Officer, Nuclear Energy Services ("NES")/Scientech in Danbury, Connecticut as Decommissioning Project Manager, and Cintichem, Inc. as Decommissioning Health Physics Supervisor and Radiation Safety Officer. I have over 30 years of experience in the areas of nuclear plant decommissioning and health physics.

Q5. WHAT DECOMMISSIONING EXPERIENCE DO YOU HAVE?

A. My decommissioning experience began as a Health Physics Supervisor and Radiation Safety Officer for Cintichem, Inc., at its research reactor in Tuxedo, New York, which was decommissioned in the early 1990s. In that capacity, I supervised and managed various aspects of the Radiological Site Decommissioning and represented Cintichem for Regulatory Agency (Nuclear Regulatory Commission ("NRC")/New York State ("NYS")) inspections through final survey compliance and license termination. I supervised a staff of Health Physicists and Technicians who supported radiological characterization, decontamination, instrumentation, final survey design, final site release, and license termination for the reactor decommissioning project.

Following the Cintichem license termination, I was employed by NES/Scientech in Danbury, Connecticut as Project Manager, Radiological Decommissioning Services. There I worked as a consultant for several decommissioning projects and assisted in the preparation of Decommissioning Cost Estimates ("DCEs"). I left NES/Scientech to work for Entergy at Indian

Point Energy Center, where I worked in various Radiological and Emergency Preparedness positions of increasing responsibility.

At TLG, I have been responsible for the Technical Staff, including three managers, and am actively engaged in developing engineering and planning studies for nuclear plant decommissioning. These studies evaluate the decommissioning options available, and provide the licensees/owners of the facilities with both the technical and financial resource requirements associated with site remediation and facility disposition. I have been involved in approximately forty decommissioning studies since 2017. During this time, I was involved with the detailed decommissioning planning for Entergy (Pilgrim and Indian Point Energy Center), Duke (Crystal River), and First Energy (Davis-Besse). I have also provided written testimony for external clients related to TLG's decommissioning work products.

Q6. HAVE YOU PREPARED OR CO-AUTHORED ANY STUDIES OR REPORTS ON DECOMMISSIONING?

A. Yes. I prepared the Entergy Post Shutdown Decommissioning Activities Report (PSDAR) for Pilgrim Station, which was submitted to the NRC. I also prepared the Cintichem Final Status Survey Report for the NRC and the NYS Department of Labor.

Q7. HAS THE NRC APPROVED SITE-SPECIFIC COST ESTIMATES UTILIZING THE TLG COST ESTIMATING METHODOLOGY?

A. Yes. The NRC has reviewed TLG's cost estimating methodology. The NRC approved the decommissioning plan proposed by TLG for the Pathfinder Atomic Power Station. Funding provisions were based upon a site-specific estimate developed by TLG. TLG was also selected by the following utilities to prepare site-specific cost estimates for inclusion within the decommissioning plans submitted to the NRC for the identified nuclear units:

Long Island Lighting Company/Long Island Power Authority	Shoreham
Sacramento Municipal Utility District	Rancho Seco
Portland General Electric	Trojan
Yankee Atomic Electric Company	Rowe
Maine Yankee Atomic Power Company	Maine Yankee
Pacific Gas & Electric	Humboldt Bay-3
Southern California Edison	San Onofre-1
Consumers Energy Company	Big Rock Point
Entergy Nuclear Vermont Yankee	Vermont Yankee
Omaha Public Power District	Fort Calhoun
Duke Energy Florida	Crystal River-3
Entergy Nuclear Pilgrim Station	Pilgrim Nuclear

The NRC has also approved preliminary cost studies for nuclear units prepared by TLG, including Indian Point, Cooper, and Perry. These studies were submitted by their owners as part of the financial planning required five years prior to a scheduled cessation of operations.

Q8. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this testimony on behalf of Entergy Texas, Inc. ("ETI" or the "Company").

Q9. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am presenting the results of my calculation of the "NRC minimum" value for River Bend Station ("River Bend") that I discuss further below.

Q10. DO YOU SPONSOR ANY SCHEDULES IN ETI'S RATE FILING PACKAGE?

A. Yes. I co-sponsor Schedules H-10, M-1, and M-2.

II. NRC MINIMUM FUNDING AMOUNT

Q11. WHEN WAS THE LAST DECOMMISSIONING COST STUDY FOR RIVER BEND PERFORMED?

A. The last decommissioning cost study for River Bend was performed in 2018 by TLG.

Q12. WAS THAT STUDY SUBMITTED TO THE PUBLIC UTILITY COMMISSION OF TEXAS ("COMMISSION" or "PUCT")?

A. Yes. That study was submitted to the Commission in Docket No. 48371 and was supported by the testimony of William A. Cloutier. Mr. Cloutier has since retired.

Q13. WHAT IS THE PLAN FOR PREPARATION OF AN UPDATED SITE-SPECIFIC RIVER BEND DECOMMISSIONING COST STUDY?

A. TLG will be preparing an updated site-specific decommissioning study for River Bend in 2023. I am advised by counsel that this new study will be performed in accordance with the five-year periodic cost re-determination set out in 16 Texas

Administrative Code ("TAC") § 25.231(b)(1)(F)(iv). I am also advised that the Company intends on filing that study with the Commission in 2023 in accordance with that same rule, and will make any appropriate request regarding River Bend decommissioning in that case as indicated by the new study.

Q14. WHAT IS YOUR UNDERSTANDING OF THE AMOUNT OF DECOMMISSIONING REVENUE FOR RIVER BEND THE COMPANY IS REQUESTING IN THIS CASE?

A. I understand that the Company is requesting a zero revenue requirement for the Texas share of River Bend decommissioning. I am advised that this is the same as the Company's request in its last rate case in Docket No. 48371.

Q15. WHY ARE YOU PROVIDING THE NRC MINIMUM VALUE FOR DECOMMISSIONING FUNDING IN THIS CASE?

A. If the available River Bend decommissioning funding does not meet the NRC minimum amount, the Company would be expected by the NRC to request adjustments in funding from its rate regulators. The funding requirement to meet the NRC minimum value has been reviewed by the Company for this case to ensure that no additional funding should be requested at this time.

Q16. PLEASE PROVIDE MORE INFORMATION ON THE REQUIREMENT TO MEET THE NRC MINIMUM VALUE.

A. The NRC's regulations require nuclear plant licensees to have a specified minimum amount of decommissioning funding available for nuclear plants licensed by the NRC. On at least a bi-annual basis, licensees, including the licensee for River Bend, must submit a report to the NRC demonstrating that the licensee's funding for decommissioning (i.e., "financial assurance") is sufficient to meet the NRC's minimum requirement. Funding for rate-regulated plants can be shown to be from a combination of funds in a trust, plus any stream of funds to be provided by ratepayers as established by cost-of-service ratemaking.[1] NRC's regulatory guidance states, "If the amount of financial assurance provided by the licensee does not equal or exceed the minimum required amount of financial assurance recalculated on December 31, then the licensee must adjust the amount of financial assurance it provides, such that it meets or exceeds the required amount."[2] Adjustments are expected to be requested by the licensee from its rate regulator: "Adjustments to the annual amount of funds being set aside may be made to coincide with rate cases considered by a licensee's public utility commission (PUC) or by the Federal Energy Regulatory Commission (FERC)."[3]

Q17. DOES THE NRC MINIMUM VALUE COVER THE ENTIRE COST OF THE NUCLEAR PLANT DECOMMISSIONING?

A. No. When the NRC established the minimum decommissioning funding requirement in 1988, it explained, "The amount listed as the prescribed amount

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[1] *See* 10 CFR § 50.75(b)-(e); NRC Regulatory Guide 1.159, Rev. 2, Section 2.1.

[2] Regulatory Guide 1.159, Rev. 2, Section 2.1.5.

[3] *Id.*

does not represent the actual cost of decommissioning for specific reactors but rather is a reference level established to assure that licensees demonstrate adequate financial responsibility that the bulk of the funds necessary for a safe decommissioning are being considered and planned for early in facility life, thus providing adequate assurance at that time that the facility would not become a risk to public health and safety when it is decommissioned."[4] The formula for computation of the NRC minimum value is not a detailed evaluation of the cost of decommissioning at any particular facility.

Further, it should be noted that there are costs included in River Bend's site-specific decommissioning cost study that are outside the scope of the NRC minimum value. In particular, the costs for site restoration and spent fuel management costs are not included within the NRC's formula amount. Accordingly, the NRC minimum funding value should be expected to substantially understate the actual cost for a complete nuclear plant decommissioning project.

Q18. HAS THE COMPANY PREVIOUSLY REQUESTED FUNDING FOR RIVER BEND'S DECOMMISSIONING TRUST BASED ON THE MINIMUM FUNDING AMOUNT REQUIRED BY THE NRC VERSUS THE SITE-SPECIFIC ESTIMATE?

A. Yes. As I noted above, NRC regulations require periodic reports on the status of decommissioning funding assurance for River Bend (as is required for all U.S.

[4] NRC Final Rule, 53 Fed. Reg. 24,018, 24,030 (June 27, 1988).

nuclear plants). Following the stock market declines of 2008 and Entergy Gulf States Louisiana, LLC's submission of its biennial decommissioning funding report in March 2009, the NRC determined that River Bend's decommissioning fund did not meet the NRC minimum funding requirement as defined in the regulations.[5] The NRC served Entergy Operations, Inc. with a request for additional information that required it to state its plan for remedying the deficiency. Entergy Operations, Inc. responded that Entergy Gulf States Louisiana and ETI would petition their rate regulators for additional funding in order to meet the NRC minimum funding requirement.[6] I understand that the Company requested funding from the Commission for the River Bend decommissioning trust in Docket No. 37744 in accordance with the NRC minimum requirements at that time, and that the Commission ordered funding to meet the requirements.

Q19. DID YOU PROVIDE THE COMPANY WITH THE NRC MINIMUM FUNDING AMOUNT USED AS THE BASIS FOR THE RIVER BEND DECOMMISSIONING REVENUE REQUIREMENT?

A. Yes. I provided that figure to Company witness Richard E. Lain. The figure I calculated and provided was $670.7 million for 100% of the plant, which

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5 *See* letter of Alan Wang, Project Manager of NRC, to Vice President, Operations, Entergy Operations, Inc., dated June 18, 2009, NRC ADAMS Accession Number ML091540293.

6 *See* "River Bend Station Unit 1 (70% Regulated Share) Plan for Decommissioning Funding Adjustment Amended as of November 12, 2009," NRC ADAMS Accession Number ML093200212, November 12, 2009.

corresponds to a value of $469.5 million for the 70% regulated portion of River Bend.[7]

Q20. HOW DID YOU CALCULATE THE NRC MINIMUM FUNDING AMOUNT?

A. I used the formula specified in NRC regulations at 10 CFR § 50.75(c). The formula is described in NRC guidance as follows:[8]

$$\text{Estimated cost (Year X)} = [1986\ \$\ \text{cost}]\ [A^*L_x + B^*E_x + C^*B_x]$$

where A, B, and C are coefficients representing the percent or portion of the total 1986 dollar costs attributable to labor (0.65), energy (0.13), and burial (0.22), respectively, and sum to 1.0. The factors L_x, E_x, and B_x are defined by:

L_x = labor cost escalation factor, January of 1986 to the latest month of Year X for which data are available,

E_x = energy cost escalation factor, January of 1986 to the latest month of Year X for which data are available, and,

B_x = LLW burial/disposition cost escalation factor, January of 1986 to the latest month of Year X for which data are available.

For the labor escalator (L_X), I escalated the 1986 base value using the December 2021 Bureau of Labor Statistics ("BLS") escalator for Private Industry Workers, South. For the energy escalator (E_X) for a Boiling Water Reactor ("BWR") plant, the NRC requires a mix of power pricing and fuel oil pricing to be used. I escalated 1986 base values for these commodities by the December 2021 BLS escalators for Industrial Electric Power and Light Fuel Oils, respectively. For the burial cost escalator (B_X), I used the escalator for BWRs

[7] I understand that the 70 percent share of River Bend serves ETI and Entergy Louisiana, LLC ("ELL"). I also understand that the 30 percent share was acquired by Entergy as part of the bankruptcy of Cajun Electric Power Cooperative, and that it has been sold on a life-of-plant basis to Entergy New Orleans, Inc. and ELL, and that the decommissioning obligation for that share is separately funded.

[8] NRC NUREG-1307, Rev. 18 at 5. NUREG-1307 describes the required calculation of the NRC minimum value in detail.

specified by the NRC in NUREG-1307 Rev. 18. Combining these values, I computed an NRC minimum value of $670.7 million as shown in Exhibit LAG-1.

Q21. HAS RIVER BEND RECEIVED A LICENSE RENEWAL FROM THE NRC?

A. Yes. The licensee filed a license renewal application with the NRC in May 2017 seeking a 20-year extension to the River Bend operating license. The renewal was approved in December of 2018 and the license was extended for 20 years, now expiring on August 29, 2045.[9]

Q22. HAVE YOU PROVIDED ANY ADDITIONAL INFORMATION RELATED TO THE 2021 RIVER BEND NRC MINIMUM CALCULATION?

A. Yes. I prepared a cash-flow based on the 2018 TLG River Bend DCE, escalated to 2021 dollars using TLG's standard process. This cash-flow information was then used by Mr. Lain to apportion the NRC Minimum into annual increments in a cash-flow format.

TLG's escalation process is as follows: The escalation indices are established for each of five cost categories: (1) Labor, (2) Equipment and Materials, (3) Energy, (4) Radioactive Waste Disposal, and (5) Other. The escalation indices for Labor, Equipment and Materials, Energy, and Other are provided by IHS-Markit (an S&P Global Company). Because IHS-Markit does not provide historical or projected costs for disposal of radioactive waste, TLG

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9 *See* "Record of Decision U.S. Nuclear Regulatory Commission Docket No. 50-458 License Renewal Application for the River Bend Station, Unit 1," NRC ADAMS Accession Number ML18284A374, December 20, 2018.

has developed a low level radioactive waste Disposal/Recycling index, which is applied to this category in our escalation analysis. This index is a combination of historical information through 2020 from NRC NUREG-1307 for disposal site rates and projections using the Consumer Price Index, Services information provided by IHS-Markit.

III. CONCLUSION

Q23. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

AFFIDAVIT OF LORI A. GLANDER

THE STATE OF TEXAS)
)
COUNTY OF HARRIS)

This day, Lori A. Glander, the affiant, appeared in person before me, a notary public, who knows the affiant to be the person whose signature appears below. The affiant stated under oath:

My name is Lori A. Glander. I am of legal age and a resident of the State of New York. The foregoing testimony and exhibits offered by me are true and correct, and the opinions stated therein are, to the best of my knowledge and belief, accurate, true, and correct.

Lori A Glander

Lori A. Glander

SUBSCRIBED AND SWORN TO BEFORE ME, notary public, on this the 8th day of June 2022.

NOTARY PUBLIC STATE OF TEXAS
CATHERINE SPENCE
Notary ID #4231566
My Commission Expires
May 28, 2024

Notary Public, State of Texas

My Commission expires:
5/28/2024

Plant name: **River Bend Station (Regulated 70%)**

	Month	Day	Year
Year of Biennial:	12	31	2021
Termination of Operation:	8	29	2045

	MWth	1986$	ECI	Base Lx		Lx	Px	Fx		Ex		Bx-Vendor
BWR	3091	$131,315,000	145.6	1.98	0.65	2.88	2.203	3.939	0.13	3.00	0.22	12.637

NRC Minimum: $670,725,835

Licensee:	% Owned:	Amount of NRC Minimum/Site Specific:
Entergy	70.00%	$469,508,084

Escalation Formula (10CFR50.75(c)(2))= 0.65Lx + 0.13Ex + 0.22Bx

Lx= Labor (south)

Source: Bureau of Labor Statistics,www.bls.gov, Databases & Tables tab, Series Report
Series Report ID: CIU2010000000220i

		FYE 2021
BLS (Base June 1989=100) =		
BLS 2005 Factor Base(Base 2005=100) =		1.98
Multiply Year End ECI (Dec 2005=100) =		145.6
Divide by 100 =		100
	Lx (South) =	**2.883**

Ex=Energy

Source: Bureau of Labor Statistics,www.bls.gov , Databases & Tables tab, Series Report
Series Report ID: wpu0543 (industrial electric power), wpu0573 (light fuel oils) @3/2022

		FYE 2021
Px (Industrial Electric Power)=	Dec (P)	251.614
Divide by January 1986 Value =		114.2
	Px =	**2.203**
Fx (Light Fuel Oil)=	Dec (P)	322.997
Divide by January 1986 Value =		82
	Fx =	**3.939**
BWR Ex = [0.54Px + 0.46Fx] =	Ex (BWR) = 0.54Px + 0.46Fx	**3.002**

Bx=Burial

Source: Nureg-1307 Revision 18 , Table 2.1 for 2020

		FYE 2021
BWR Bx :	**Waste Vendors =**	12.837

Escalation Factors = 0.65(Lx)+0.13(Ex)+0.22(Bx)=	
BWR Vendor	**5.088**

This workpaper contains voluminous information that is being provided electronically.

DOCKET NO. 53719

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

ELIZABETH S. HUNTER

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2022

ENTERGY TEXAS, INC.
DIRECT TESTIMONY OF ELIZABETH S. HUNTER
2022 RATE CASE

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EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, EMPLOYER AND OCCUPATION.

A. My name is Elizabeth S. Hunter. My business address is 639 Loyola Avenue, New Orleans, Louisiana 70113. I am employed by Entergy Services, LLC ("ESL") as Director, Investments and Cash Management.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Entergy Texas, Inc. ("ETI" or the "Company").

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. In 2003, I graduated cum laude from Millsaps College with a Bachelor of Business Administration degree in Economics and Business Administration. I completed a Master of Business Administration degree with a Finance Concentration at Loyola University New Orleans in 2008.

I began working in the ESL Finance Department in 2003 as a financial analyst in the Finance Operations Center. In 2005, I joined the Entergy Treasury department on the Cash Management team, where I focused on cash forecasting and Money Pool investing. From 2007 to 2011, I supported both Cash Management and the Investments team within the Treasury Department. When I first joined the Investments team in the Treasury Department, my focus was on 401(k), pension and Voluntary Employee Beneficiary Association trusts. In 2011, I took on the Investments role full time, and in 2013, expanded that role to include supporting the investments of the Nuclear Decommissioning Trusts (collectively referred to herein as the "Funds"), associated with nuclear power plants owned and operated by various of Entergy Corporation's regulated Operating Companies and unregulated affiliates.

In 2019, I became the manager of the Investments team. In 2021, I was promoted to the position of Director, Investments and Cash Management and assumed the additional responsibility for the oversight of Treasury's Cash Manager and Cash Management team.

Q4. DO YOU USE DEFINED TERMS IN YOUR TESTIMONY?

A. Yes. The term "ETI Fund" is used when specifically referring to ETI's retail jurisdictional portion of the River Bend Nuclear Station ("River Bend") nuclear decommissioning trust fund. "River Bend Fund" refers to the River Bend nuclear decommissioning trust fund as a whole, which includes Entergy Louisiana, L.L.C.'s ("ELL") retail jurisdiction and Federal Energy Regulatory Commission ("FERC") jurisdictional assets in addition to the ETI Fund.

Q5. PLEASE DISCUSS THE PURPOSE OF YOUR TESTIMONY AND HOW IT RELATES TO OTHER WITNESSES.

A. The purpose of my testimony is to present and discuss various financial assumptions supporting the River Bend decommissioning revenue requirement shown on Rate Filing Package ("RFP") Schedule M-2. The financial assumptions addressed in my testimony include the: (1) April 30, 2022 ETI Fund liquidation values; (2) weighted average after-tax earning rates; and (3) ETI Fund administrative fees. The ETI Fund liquidation value as of April 30, 2022 is known and measurable. The assumptions referred to above are necessary to calculate the River Bend decommissioning revenue requirement.

Lori Glander presents the Nuclear Regulatory Commission ("NRC") minimum funding amount for River Bend. Alyssa Maurice-Anderson presents the Company's proposed decommissioning cost escalation rate and explains the basis for ETI's proposal to include the current NRC minimum funding level for the River Bend plant as the decommissioning cost to be included in Texas retail rates. Mr. Lain uses the information provided by me, Ms. Glander, and Ms. Maurice-Anderson to calculate the revenue requirement for the decommissioning costs.

Q6. DOES YOUR DISCUSSION REGARDING FINANCIAL ASSUMPTIONS USED TO CALCULATE RIVER BEND DECOMMISSIONING REVENUE REQUIREMENT INCLUDE INFORMATION RELATED TO THE 30% PORTION OF RIVER BEND FORMERLY OWNED BY CAJUN ELECTRIC POWER COOPERATIVE?

A. No, it does not. When the 30% share of River Bend, formerly owned by Cajun Electric Power Cooperative ("Cajun"), was transferred by Cajun to Entergy Gulf States, Inc. (now ELL) pursuant to a 1996 order of a U.S. Bankruptcy Court, its fully pre-funded decommissioning fund (the "30% Fund") was also transferred.[1] The 30% Fund is governed by an entirely separate trust agreement, and there is no commingling of investments between that 30% Fund and the 70% share pertaining to the rest of River Bend. Hereafter, all my testimony, exhibits, and workpapers related to decommissioning refers only to the 70% portion that was originally owned by ELL.

Q7. WHAT DECOMMISSIONING RFP SCHEDULES ARE YOU SPONSORING OR CO-SPONSORING?

A. I am co-sponsoring decommissioning RFP Schedules M-1 and M-2.

II. DECOMMISSIONING FUNDING ASSUMPTIONS

Q8. PLEASE SUMMARIZE THE PURPOSE OF DECOMMISSIONING FUNDING FOR NUCLEAR GENERATING FACILITIES.

A. The primary objective of decommissioning funding is to accumulate a sum of money necessary to provide reasonable assurance that sufficient funds will be available for the safe dismantlement, decontamination, and disposal of a nuclear generating facility at the end of its useful life in a way that protects the health and safety of the public. Alternatively, as described by Ms. Glander, if the available decommissioning funding does not meet the NRC minimum amount, the Company would be expected to request adjustments in funding from its rate regulator. It is my understanding that nuclear plant decommissioning expense is a

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[1] All of River Bend is currently owned and operated by ELL.

legitimate cost of service component recoverable in rate proceedings, per Public Utility Commission of Texas ("PUC") Substantive Rule § 25.231(b)(1)(F)(i).[2] Therefore, it is appropriate to charge both current and future customers who receive power from a nuclear facility a portion of the costs ultimately required to pay for decommissioning.

Q9. HOW DO THE FUNDING ASSUMPTIONS FACTOR INTO THE DEVELOPMENT OF THE RIVER BEND DECOMMISSIONING REVENUE REQUIREMENT INCLUDED IN RFP SCHEDULE M-2?

A. For purposes of this rate case, the first step in determining the appropriate annual River Bend decommissioning revenue requirement, or expense, is determining the NRC minimum value. This value is discussed in detail in Ms. Glander's direct testimony.

Next, the NRC minimum value is escalated by applying an escalation factor to determine a "future" dollar cost estimate that becomes the target amount to be funded. Ms. Maurice-Anderson provides the recommended escalation rate.

Once the future dollar amount is determined, the revenue requirement is calculated. The revenue requirement calculation considers the estimated ETI Fund value at the start of the funding period (i.e., the April 30, 2022 liquidation value), the assumed after-tax rates of return on the ETI Fund, the assumed trustee and investment management fees (net of taxes) and related expenses, and the recommended funding method. Mr. Lain presents the revenue requirement

[2] 16 Tex. Admin. Code ("TAC") § 25.231(b)(1)(F)(i).

calculation.

A. <u>April 30, 2022 Liquidation Value</u>

Q10. WHAT IS A TRUST FUND LIQUIDATION VALUE, AND WHY IS THAT VALUE USED IN DECOMMISSIONING FUNDING CALCULATIONS?

A. A trust fund liquidation value is the market value of a fund reduced by any accrued but not yet paid income taxes and accrued but not yet paid fees net of income taxes. More specifically, to arrive at the April 30, 2022 liquidation value, the market value of the ETI Fund at April 30, 2022 is adjusted to account for the tax effect on accumulated unrealized gains or losses at the time, and accumulated investment manager and trustee fees net of taxes. The method of determining the earnings rates used to project earnings for future years is discussed later in my testimony. The liquidation value is used in decommissioning funding calculations because that is the estimated value that would be available to use to decommission a nuclear plant.

Q11. WHAT IS THE PROJECTED ETI FUND LIQUIDATION VALUE AS OF APRIL 30, 2022?

A. The estimated ETI Fund liquidation value at April 30, 2022 is approximately \$273.9 million, the full amount of which is tax qualified. The non-tax qualified fund was liquidated and closed in 2012; therefore, its liquidation value at April 30, 2022 is zero. The calculations supporting the tax qualified liquidation values are shown on Exhibit ESH-1. The Company's liquidation value calculation is based on the same methodology used in ETI's last rate case, Docket No. 48371.

Q12. PLEASE EXPLAIN HOW THE LIQUIDATION VALUE SHOWN ON EXHIBIT ESH-1 WAS DETERMINED.

A. The calculation includes both actual and projected data. The starting point for the calculation is the April 30, 2022 market values as reported by the Funds' Trustee, The Bank of New York Mellon. The April 30, 2022 market value for the ETI Fund was approximately $299.7 million. This market value reflects all contributions made through April 30, 2022, as well as all income, expense, and realized and unrealized gains and losses. The April 30, 2022 market values were then reduced by approximately $25.8 million to account for the tax effect on accumulated unrealized gains or losses, and accrued investment manager and trustee fees net of taxes, at April 30, 2022. This value is the beginning balance for determining the River Bend decommissioning revenue requirement as shown on RFP Schedule M-2 and Mr. Lain's Exhibit REL-3 (HSPM).

B. After-Tax Rates of Return

Q13. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section of my testimony discusses the methodology used by the Company to develop the assumed after-tax rates of return shown on Exhibit ESH-4 (HSPM) and RFP Schedule M-1.

Q14. BEFORE EXPLAINING THE DEVELOPMENT OF THE PROJECTED/ ASSUMED RATES OF RETURN, PLEASE EXPLAIN THE INVESTMENT STRATEGY AND ASSET ALLOCATION THE COMPANY APPLIES TO THE RIVER BEND FUND, INCLUDING THE INVESTMENT GOALS.

A. The main investment goal of the Company related to the River Bend Fund is earning a reasonable return over the long term and preservation of principal. The asset allocation of the River Bend Fund is consistent with an Asset and Liability Study conducted in 2019 by Callan LLC ("Callan"). Callan is a nationally recognized investment consulting firm with significant expertise in advising utilities with nuclear generation on managing decommissioning funds.

The 2019 Callan Asset and Liability Study for the River Bend Fund reaffirmed information that Callan provided in their 2008 and 2013 Asset and Liability Studies, including the target equity allocation. The highly sensitive 2019 Callan Asset and Liability Study is attached as Exhibit ESH-5 (HSPM).

Investment research shows that the use of equities provides the opportunity to earn superior long-term after-tax returns as compared to fixed income investments. However, higher returning asset classes are associated with an increased risk level. An asset allocation in the River Bend Fund that assumes a reasonable equity allocation is important to achieve a reasonable return over the long term. Fixed income investments are used to balance (or diversify) the return-seeking portion of the portfolio invested in equities, since the performance of fixed income investments has proven over long periods of time historically to be inversely correlated with the performance of equities. The balance of equities and fixed income investments produces prudent, diversified exposure to markets for capital appreciation. This strategy, over the long term, will provide the Company an opportunity to achieve reasonable after-tax returns while reducing the overall investment risk of the portfolio, which supports the goal of principal preservation. Such a strategy should lower annual customer revenue requirements, while continuing to provide reasonable expectations that sufficient funds will be available to meet the NRC minimum funding requirement.

The current asset allocation targets are 60% equities and 40% fixed income securities, consistent with the target portfolio weighting for other Entergy Operating Company-affiliated regulated decommissioning trust fund investments. This is consistent with the recommendations in the 2019 Asset and Liability Study mentioned previously.

The Company's strategy related to rebalancing the River Bend Fund to maintain the target asset allocation is, to the extent possible, to avoid selling securities for the sole purpose of rebalancing the asset allocation of the River Bend Fund. Instead, new contributions to, if applicable, or payment of taxes and fees from the River Bend Fund are used to rebalance the asset allocation where possible. If allocating new contributions to fixed income still leaves the equity allocation higher than desired, rebalancing will be performed.

Q15. DOES THE 20% INCOME TAX RATE APPLICABLE TO THE QUALIFIED ETI FUND AFFECT THE COMPANY'S CALCULATION OF PROJECTED AFTER-TAX RETURNS USED IN THE RIVER BEND DECOMMISSIONING REVENUE REQUIREMENT MODEL?

A. Yes. The application of any non-zero tax rate means that tax-free municipal bonds could be more attractive than taxable bonds depending on market conditions. Therefore, municipal bonds are an asset class considered in the calculation of the projected after-tax returns. The returns of municipal bonds compared to taxable bonds have fluctuated over the years, sometimes proving to have higher after-tax returns than taxable bonds and sometimes lower. Therefore, allowing fixed income investment managers the flexibility to invest in both municipal bonds and taxable bonds is the policy decision that best serves the ETI Fund. The asset allocation during the decommissioning period includes an allocation to municipal bonds to illustrate that the manager would have the flexibility to invest in various types of fixed income securities as may make sense based on the current market returns, investment time horizon, and tax rates.

In general, historical after-tax returns of taxable securities at a 20% tax rate have been higher than returns on municipal bonds. As a result, the ETI Fund currently has a 0% target for municipal bonds. But as I mentioned, the trust allows fixed income investment managers the flexibility to include municipal bonds when they are favored by current market conditions, so the actual allocation to municipal bonds may be higher than the target of 0%. This practice is supported by the 2019 Asset and Liability Study. Market conditions were favorable to certain municipal bonds on April 30, 2022, so there was an allocation to municipal bonds in the ETI Fund at that time. Consequently, municipal bonds must be included in the calculation of projected returns.

Equity is also included in the calculation of projected returns and taxed at 20% where appropriate.

Q16. WHAT IS THE UNDERLYING ASSET ALLOCATION ASSUMED BY THE COMPANY FOR PURPOSES OF CALCULATING THE WEIGHTED AVERAGE AFTER-TAX RETURNS SHOWN ON EXHIBITS ESH-2 AND ESH-4?

A. The target portfolio weighting of 60% equity and 40% fixed income securities is assumed for calculating weighted average after-tax returns before decommissioning begins. The 40% fixed income allocation includes 2.5% assumed to be in cash.

Q17. PLEASE DISCUSS THE CHANGE IN ASSET ALLOCATION ASSUMPTIONS THROUGHOUT THE FORECAST PERIOD SHOWN IN EXHIBIT ESH-4 (HSPM).

A. First, it is important to recognize that the asset allocation assumptions shown on Exhibit ESH-4 (HSPM) are the basis for estimating the projected weighted average after-tax ETI Fund earnings rates used in calculating the River Bend decommissioning revenue requirement. The actual asset allocation at any one time is influenced by market conditions and could vary from the targeted allocation (or assumed allocation) within allowed parameters. The April 30, 2022 actual ETI Fund equity allocation was at 60%. This equity level would be maintained at a target of about 60% for the next 20 years. In 2042, the Company would begin reducing the equity allocation in the ETI Fund until it reaches 0% by year-end 2045. In August 2045, the River Bend operating license expires and decommissioning activities are assumed to begin. There would be no equities in the ETI Fund while the plant is being decommissioned between August 2045 and 2054; likewise, there would be no equities during the period between the completion of decommissioning of the reactor facilities and when the Department of Energy completes removal of spent fuel from the site. Between 2045 and 2078, the portfolio would comprise of a mix of fixed income securities as designated by the investment manager based on current market conditions.

Q18. WHY WILL THE COMPANY BEGIN PHASING OUT OF EQUITY IN THE ETI FUND BEGINNING IN 2042?

A. Equity is assumed to be reduced in the ETI Fund to 0% by the beginning of the decommissioning period to provide an emphasis on current income and preservation of the fund's assets. Equities have exhibited more volatility than fixed income investments in price and return throughout the history of capital markets. Sound financial management would suggest that as the Company approaches the time that cash will be needed to decommission River Bend, it will become more important to be invested in less volatile investments in order to better assure the availability of adequate funds. Asset return volatility can have a much greater impact on the availability of funds in later years because it affects a larger amount of assets and there is less time in the following years to recover any shortfalls.

The issue of equity return volatility and the prudence of phasing out of equities as the time to begin decommissioning nears are highlighted in the Nuclear Plant Decommissioning Trust Fund Guidelines issued by the FERC in Docket No. RM94-14-000 dated June 16, 1995 ("Order 580"). On page 65 of Order 580, the FERC states:

> We also agree that a reasonable approach would be to decrease the percentage of equity investment in a portfolio, and increase the amount of lower risk investments, as the time for expending the funds approaches.

In addition, FERC Commissioners Hoecker and Massey in concurring with Order 580 further state:

> [A]s the time nears when fund assets will be spent on decommissioning work, assets should be phased out of equity investments and into less volatile and more conservative investments.

Q19. PLEASE EXPLAIN THE METHODOLOGY USED BY THE COMPANY TO ESTIMATE THE ETI FUND'S ANNUALIZED AFTER-TAX EARNING RATES PRESENTED ON EXHIBIT ESH-4 (HSPM).

A. The Company's estimate of the ETI Fund's annualized after-tax earning rates is based on the asset allocation described above. A weighted average after-tax return estimate for the ETI Fund was calculated for each of the years 2022 through 2078. Although there are currently no contributions, the ETI Fund will continue to earn a rate of return on its balance, including on its decreasing balances through the decommissioning period.

The calculation of the weighted average after-tax returns is outlined as follows:

- Obtain or develop forecasted pre-tax returns for asset classes allowed in the ETI Fund;
- Convert the forecasted pre-tax returns for each asset class in the ETI Fund to an after-tax return by multiplying the pre-tax return by one minus the effective tax rate for each asset class within the Fund;
- Determine a reasonable expected portfolio weighting for each asset class included in the ETI Fund (the weightings will change with asset allocation changes as previously described);
- Multiply the ETI Fund's forecasted after-tax return for each asset class by the assumed portfolio weighting for each asset class to determine the weighted after-tax return by asset class; and
- Sum the weighted after-tax returns by asset class to calculate the forecasted weighted average after-tax portfolio return for the ETI Fund.

Q20. WHAT ASSET CLASSES DID THE COMPANY INCLUDE IN CALCULATING THE WEIGHTED AVERAGE AFTER-TAX RETURNS FOR THE ETI FUND?

A. The asset classes included in the calculations were U.S. treasury securities, tax-exempt municipal bonds, corporate bonds, large capitalization common stocks, and cash.

Q21. HOW DID THE COMPANY OBTAIN FORECASTED PRE-TAX RETURNS FOR THE FIXED INCOME ASSET CLASSES LISTED ABOVE?

A. The Company obtained forecasted fixed income returns from IHS Markit ("IHS"), a global leader in modeling and forecasting. Included in the forecasts are pre-tax returns for various fixed income asset classes and inflation as measured by the Consumer Price Index – Urban ("CPI-U").

IHS provided the Company forecasts of the Federal Funds rate ("Cash"), the two-year, five-year, and ten-year U.S. Treasury Note rates ("Treasuries"), the Bond Buyer Municipal Bond Index ("Municipals"), and the Moody's Aaa and Baa Corporate bond rates ("Corporates"). The two Moody's bond rates were averaged to arrive at an estimated Aa bond rate since that is the average credit quality mandated by the ETI Fund's investment guidelines. The projected returns by asset class for the years 2022 through 2051 are shown on Exhibit ESH-2 (HSPM).

Q22. HOW DID THE COMPANY FORECAST THE ETI FUND'S PRE-TAX RETURNS FOR EQUITY INCLUDED IN EXHIBIT ESH-2 (HSPM)?

A. The Company projected equity returns by adding the geometric mean of the historical inflation-adjusted large cap equity return to the IHS CPI-U projections, as calculated in Exhibit ESH-3 (HSPM). The geometric mean of the historical inflation-adjusted large capitalization stocks (as represented by the Standard and Poor's 500 ("S&P 500") stock index) from 1926 through 2020 is 7.22%. The 7.22% can be derived from Table 5-2: Inflation Adjusted Series in the 2021 Stocks, Bonds, Bills, and Inflation Yearbook ("SBBI Yearbook").[3] The inflation-adjusted equity return represents the cumulative real return since 1926 for large company stocks. In other words, the Ibbotson table shows the growth of large cap

[3] The 2022 SBBI Yearbook was not yet available at the time of this testimony.

equity in constant dollars, or in real terms.

The addition of the historical 7.22% inflation-adjusted equity return to CPI-U forecasts produces a range of pre-tax forecasted equity returns between 9.3% and 10.5% for 2022 through 2051.

Q23. WHY DOES THE COMPANY USE THE GEOMETRIC MEAN OF HISTORICAL EQUITY RETURNS TO PROJECT EQUITY RETURNS AS OPPOSED TO THE ARITHMETIC MEAN?

A. The Company uses the geometric mean in forecasting equity returns for determining the River Bend decommissioning revenue requirement because it more closely corresponds with the functioning of the decommissioning revenue requirement model than would the arithmetic mean. The geometric mean return is a compound average return, and in the decommissioning revenue requirement model, the returns are compounded in each year's calculation. Compounding returns are also a factor in the real-life application of investment returns, which is why they are used in the model. The use of a geometric mean to establish the equity return, and the way the returns are used in the model, therefore are consistent. The geometric mean is appropriate to use anytime several quantities multiply together to produce a product, as opposed to the arithmetic mean, which is appropriate any time several quantities add together to produce a sum. In the River Bend decommissioning revenue requirement model, returns are being compounded or multiplied by each other. Therefore, a geometric average rate of return is appropriate.

Although the arithmetic mean is useful in forecasting the expected return for the next single year, the geometric mean measures the historical growth rate, taking volatility into account. The arithmetic mean does not take into account the variability of returns. Since variability of returns year to year is a characteristic of financial markets, it would be inappropriate to use the historical arithmetic mean to project multi-year compound growth.

Consider the following very simplistic example as an illustration of why the geometric mean return is more appropriate. If one starts with a portfolio worth $100 and a year later the value of the portfolio is $200, a 100% return is achieved in year one. Assume the value of the portfolio drops back to $100 at the end of year two. The return for year two is a negative 50%. The arithmetic mean of the two returns would be 25%, derived by adding 100% plus the negative 50% and dividing by two. The arithmetic mean return for the two-year period would be 25%, but the portfolio has not gained even one dollar for the two-year period. The geometric mean for the two-year period would be 0% (the square root of the quotient of the $100 ending value divided by the $100 beginning value, minus 1), which is perfectly reasonable with a $0 return over the two-year period. This example illustrates why the Company should use the geometric mean in developing equity returns that will be compounded over several years.

The Company calculates the geometric mean of the historical return of the S&P 500 stock index, taken directly from the 2021 SBBI Yearbook, as the basis to project the future growth rate for approximately the next 20 years for the equity component of the ETI Fund. The S&P 500 stock index is appropriate to use because the Company's equity investments are in an S&P 500 stock index fund designed specifically for nuclear decommissioning trust funds. Given that the return is being used over a multi-year period, the geometric mean is the appropriate one to use for purposes of determining the River Bend decommissioning revenue requirement.

C. **<u>Fund Administrative Costs</u>**

Q24. HOW DID THE COMPANY DEVELOP ADMINISTRATIVE FEES FOR PURPOSES OF CALCULATING THE REVENUE REQUIREMENT IN RFP SCHEDULE M-2?

A. The administrative fees used in RFP Schedule M-2 are based on the current trustee and manager fee schedules in place for the River Bend-related decommissioning funds.

The Bank of New York Mellon is the trustee for the Funds. The trustee fees are calculated and paid quarterly. There are two types of trustee fees: market value driven and non-market value driven. The market value driven fees are calculated at the annual rate of one basis point (0.01%) applied to the market value of the decommissioning trust assets in the Funds; the ETI Fund is charged one basis point annually on the market value in the ETI Fund. There are also certain annual trust administration fees that are charged directly to each individual trust account without regard to market value.

Investment management fees are calculated based on the aggregate market value of the collective Entergy decommissioning trust assets in the Funds, using a declining fee structure. The total investment management fee is allocated pro rata (based on market value of investments) to the Funds and all other Entergy-affiliated investment accounts that use the same investment manager.

Because the calculation of the River Bend decommissioning revenue requirement model is specific to ETI's retail jurisdiction, the Company modified the current declining fee structures for investment manager fees. This was done so that the manager fees used to calculate the revenue requirement in RFP Schedule M-2 more accurately recognize the benefits achieved with the declining fee structures for the whole River Bend Fund, including other jurisdictional shares. The breakpoints can be thought of as the point, or asset market value, where the fee declines, or breaks, down to the next lowest level. The breakpoints also take into account the total funds needed in the trust for the equity or fixed income accounts to reach a certain breakpoint. If, for example, the equity manager fee declines from 0.10% to 0.08% when assets reach $4 million, the equation considers that for $4 million to be present in the trust, since the target equity allocation is 60%, then the total assets in the trust would need to be $6.67 million ($4 million divided by 60%). The equity investment manager fee would be 0.10% until the breakpoint of approximately $6.67 million, after which point the investment manager fee would be 0.08% until the next breakpoint is reached.

For the administrative fee calculation, the equity manager fees for the ETI Fund were calculated by first dividing the actual investment manager declining fee structure breakpoints by ETI's pro rata share of assets within the fund, because several other Entergy Operating Companies own jointly managed funds that receive a declining fee structure for utilizing a single equity manager. Similar calculations were made for the fixed income manager fees in order to recognize the benefits of the declining fee schedules quicker. The breakpoints can be seen in the modified fee structure described above and included as a workpaper to RFP Schedule M-2. The administrative fees can be seen on the same workpaper.

III. COMPLIANCE WITH INVESTMENT GUIDELINES

Q25. IS THE ETI FUND BEING INVESTED IN COMPLIANCE WITH PUC SUBSTANTIVE RULE 25.301(C)?

A. Yes. My testimony above demonstrates that the ETI Fund is invested in a prudent manner consistent with the goals set forth in 16 TAC § 25.301(c)(1). In addition, the ETI Fund meets the requirements set forth in 16 TAC § 25.301(c)(2)-(3), as discussed below.

Q26. YOU HAVE DISCUSSED TRUSTEE AND INVESTMENT MANAGER FEES ABOVE. DO THE TOTAL TRUSTEE AND INVESTMENT MANAGER FEES PAID ON AN ANNUAL BASIS EXCEED 0.7% OF THE ENTIRE PORTFOLIO'S AVERAGE ANNUAL BALANCE?

A. No, they do not.

Q27. IS ANY MORE THAN 5.0% OF THE SECURITIES IN THE ETI FUND ISSUED BY ONE ENTITY?

A. No, no single entity's securities constitute more than 5.0% of the ETI Fund.

Q28. DOES THE ETI FUND HOLD AT LEAST 20 DIFFERENT ISSUES OF SECURITIES?

A. Yes, it does.

Q29. HAS THE ETI FUND BEEN STRUCTURED FOR OPTIMUM TAX EFFICIENCY?

A. Yes. As I have noted previously, all of the funds are considered qualified under the U.S. tax laws.

Q30. DOES THE ETI FUND INCLUDE ANY PROHIBITED DERIVATIVE SECURITIES AS DEFINED IN THE SUBSTANTIVE RULE?

A. No.

Q31. DOES THE ETI FUND BORROW TO PURCHASE SECURITIES ON MARGIN?

A. No.

Q32. DOES THE ETI FUND COMPLY WITH EQUITY LIMITS SPECIFIED IN THE SUBSTANTIVE RULE?

A. Yes. The ETI Fund is closely monitored and, if necessary, rebalanced to maintain compliance. The ETI Fund equity allocation as of April 30, 2022 was 60%.

Q33. DOES THE ETI FUND INVEST IN ETI'S OR ANY ETI AFFILIATES' SECURITIES?

A. No.

Q34. DOES THE ETI FUND INVEST IN ANY DEBT SECURITIES THAT HAVE A BOND RATING BELOW INVESTMENT GRADE?

A. No.

Q35. DO AT LEAST 70% OF THE AGGREGATE MARKET VALUE OF THE ETI FUND EQUITIES HAVE A QUALITY RANKING FROM A MAJOR RATING SERVICE?

A. Yes.

Q36. DOES THE OVERALL EQUITY PORTFOLIO OF THE ETI FUND HAVE A WEIGHTED AVERAGE QUALITY RATING EQUIVALENT TO THE COMPOSITE RATING OF THE S&P 500 INDEX ASSUMING EQUAL RATING OF EACH RANKED SECURITY IN THE INDEX?

A. Yes.

Q37. DOES THE ETI FUND INCLUDE ANY INVESTMENT IN EQUITY SECURITIES WHERE THE ISSUER HAS A CAPITALIZATION OF LESS THAN $100 MILLION?

A. No.

IV. CONCLUSION

Q38. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT OF ELIZABETH S. HUNTER

THE STATE OF LOUISIANA)
)
ORLEANS PARISH)

This day, Elizabeth S. Hunter, the affiant, appeared in person before me, a notary public, who knows the affiant to be the person whose signature appears below. The affiant stated under oath:

My name is Elizabeth S. Hunter. I am of legal age and a resident of the State of Louisiana. The foregoing testimony and exhibits offered by me are true and correct, and the opinions stated therein are, to the best of my knowledge and belief, accurate, true and correct.

Elizabeth S. Hunter
Elizabeth S. Hunter

SUBSCRIBED AND SWORN TO BEFORE ME, notary public, on this the 14th day of June, 2022.

Jennifer Favalora
Notary Public, State of Louisiana

My Commission expires:
upon my death.

JENNIFER B. FAVALORA
Notary Public (ID# 57639)
Orleans Parish, Louisiana
Commission Issued For Life

ENTERGY TEXAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED PORTFOLIO LIQUIDATION VALUES
April 30, 2022 (Thousands)

	River Bend Tax Qualified
Portfolio Market Value 4/30/2022	$299,733
Estimated Accrued Taxes and Accrued Fees	(25,787)
Estimated Liquidation Value 4/30/2022	$273,947

*Amounts may not sum due to rounding

This exhibit contains information that is highly sensitive and will be provided under the terms of the Protective Order (Confidentiality Disclosure Agreement) entered in this case.

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DOCKET NO. 53719

APPLICATION OF ENTERGY	§	PUBLIC UTILITY COMMISSION
TEXAS, INC. FOR AUTHORITY TO	§	
CHANGE RATES	§	OF TEXAS

DIRECT TESTIMONY

OF

KRISTIN SASSER

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2022

ENTERGY TEXAS, INC.
DIRECT TESTIMONY OF KRISTIN SASSER
2022 RATE CASE

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EXHIBITS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kristin Sasser. My business address is 639 Loyola Avenue, New Orleans, Louisiana 70113.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Entergy Services, LLC. ("ESL") as Manager of Revenue Forecasting and Analysis for the Finance organization of ESL,[1] which is the service company affiliate of Entergy Texas, Inc. ("ETI" or the "Company").

Q3. ON WHOSE BEHALF ARE YOU FILING THIS DIRECT TESTIMONY?

A. I am testifying on behalf of ETI.

A. Qualifications

Q4. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from Loyola University, New Orleans with a Bachelor of Science degree in Finance. I have earned a Masters of Business Administration degree from Tulane University with an emphasis in Finance.

I joined ESL in 1995 as an Accountant II in the Accounting department. I remained in the Accounting department, with positions of increasing responsibility,

[1] ESL is an affiliate of the Entergy utilities that provides engineering, planning, accounting, legal, technical, regulatory, and other administrative support services to each of the Entergy utilities.

for a little over five years. During my tenure in the Accounting department, I was responsible for fuel and purchased power accounting, revenue accounting, and preparing variance analysis.

In 2001, I joined the Finance department as a Senior Staff Analyst in the Utility Financial Planning group. I was responsible for developing revenue forecasts for the Entergy utilities, preparing variance analyses, and implementing planning models.

In 2006, I joined the Accounting department as the Manager, Revenue Accounting. The responsibilities of that role were expanded to include revenue forecasting for the Entergy utilities. In 2016, I transitioned to the role of Manager, Revenue Forecasting and Analysis and expanded my expertise to include weather normalization.

Q5. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY AS MANAGER, REVENUE FORECASTING AND ANALYSIS?

A. I am responsible for managing staffs that provide all retail revenue forecasting, retail revenue and sales variance analyses, and weather normalization analyses for the Entergy utilities, including ETI.

Q6. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS ("COMMISSION") OR ANY OTHER REGULATORY AUTHORITY?

A. Yes. I have provided a list of the proceedings in which I have submitted testimony in Exhibit KS-1.

B. Purpose of Testimony

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony provides data and support for the calculation of the weather factors used in the cost of service to weather normalize the test year loads and billing determinants.

Q8. HOW ARE THESE ANALYSES USED IN THE RATE FILING?

A. Crystal Elbe uses the adjusted test year weather normalized sales and demand numbers from my analyses to design the proposed rates.

Q9. PLEASE DESCRIBE THE EXHIBITS ATTACHED TO YOUR TESTIMONY.

A. I sponsor the following exhibits attached to my testimony:

- Exhibit KS-1 provide a list of proceedings in which I have submitted testimony;
- Exhibit KS-2 provides a list of the Rate Filing Package ("RFP") schedules I sponsor or cosponsor;

- Exhibit KS-3 presents the sales (kilowatt-hour or "kWh") weather adjustment factors calculated for ETI; and
- Exhibit KS-4 presents the demand (kilowatt or "kW") weather adjustment factors calculated for ETI.

Q10. DO YOU SPONSOR ANY SCHEDULES IN THE RFP?

A. Yes. Exhibit KS-2 provides a list of the schedules I am sponsoring.

II. <u>WEATHER FACTORS</u>

Q11. WHAT WEATHER FACTORS DO YOU PRESENT?

A. I am presenting the weather factors used in the adjustment of sales (kWh) and demand (kW) for ETI, which Exhibits KS-3 and KS-4, respectively, contain. These factors were calculated using the same general methodology used in ETI's last base rate case, Docket No. 48371, with some modest revisions and updates.

Q12. WHAT IS THE PURPOSE OF THE SALES AND DEMAND WEATHER FACTORS YOU PREPARED?

A. As I mentioned, Ms. Elbe uses the weather factors to adjust sales and demand for rate design purposes.

A. Sales (MWh) Weather Factor

Q13. PLEASE PROVIDE A GENERAL DESCRIPTION OF WEATHER ADJUSTMENTS.

A. The purpose of a utility energy weather adjustment is to calculate what the sales (MWh) for the Test Year would have been after adjusting actual Test Year sales to account for the impact of unusual weather, usually defined as temperature deviation from average (or normal). The resulting weather adjusted sales are considered a better measure of the "true" sales of the utility for the purposes of designing rates. When the MWh weather adjustment is presented as a percentage of MWh sales, it is commonly referred to as the weather factor.

Q14. PLEASE DESCRIBE THE PROCESS YOU USED TO PREPARE THE WEATHER FACTORS FOR SALES (MWH).

A. The weather normalization methodology used in this filing involved the following four steps:

1. Obtain measurements of actual hourly temperatures for both the Test Year for this filing (January 2021 through December 31, 2021) and a normalization period (January 2001 through December 2020);
2. Calculate Heating Degree Days ("HDDs") and Cooling Degree Days ("CDDs") corresponding to these temperatures;
3. Establish the relationship of HDD and CDD to monthly usage; and

4. Quantify the amount of Test Year monthly utility sales that were due to the HDD/CDD variances using the relationships derived in Step 3.

The analyses were conducted at the revenue class level for each of the three rate classes – residential, commercial, and governmental – that historically have exhibited significant sensitivity to weather. I will now discuss each step in greater detail.

Step 1 – Actual measured temperatures for both the Test Year and the normalization period were obtained from the National Weather Service stations at Beaumont and Houston, Texas through a third-party vendor, DTN. Normal temperatures were defined as the average over the 20-year period ending December 2020.

Step 2 – Previous analyses indicated that the sensitivity of usage to temperature varies across the range of ambient temperatures and that the switch from heating to cooling occurs in the upper 50 to low 60-degree range. Standard five degree "temperature bands" (ranges within which the relationship remains linear) were used for this analysis to reflect that knowledge. The first cooling band starts below where cooling starts to occur and, likewise, the first heating band is above the point where heating occurs. This overlap enables multiple heating and cooling bands to be tested first for theoretical soundness and then statistically-valid relationships of weather to sales.

The specific break points for the heating and cooling bands are as follows:

	Temperature Bands
Heating 5	45
Heating 4	50
Heating 3	55
Heating 2	60
Heating 1	65
Cooling 1	55
Cooling 2	60
Cooling 3	65
Cooling 4	70
Cooling 5	75
Cooling 6	80
Cooling 7	85
Cooling 8	90

Degree hours were calculated for each band for each hour and summed up into degree days for all further analyses. A degree hour for a band is defined as the difference between the temperature for a particular hour and the edge of the band. This calculation better captures temperature variations within each day rather than calculating degree days for each day using average daily temperature.

For example, a temperature of 74 degrees in an hour would result in the following cooling hours by band:

Hourly Temperature		**74**
		Degree Hours
Band	55	19
Band	60	14
Band	65	9
Band	70	4
Band	75	0
Band	80	0

Degree days from the Houston and Beaumont stations are then weighted reflecting the average distribution of residential and commercial customers across the service territory over the most recent three years.

Once the cooling and heating hours were aggregated into HDDs and CDDs and weighted, they were then summed into monthly totals that correspond to the time periods covered by the billing cycles rather than calendar months. This adjustment is made so that the temperature variances driving the weather adjustment match the time period in which the billed sales occur. For example, in September, billing cycle 1 generally starts in late July and ends in late August, so the appropriate temperatures to use in the analyses would be from calendar days in July and August. To make this adjustment, the Company weights the degree days for each day by the percentage of the 21 billing cycles in which the day falls in that billed month. If that day occurs in only one of the 21 billing cycles, for example, then 4.8% of that day's degree days (1 divided by 21, multiplied by 100) are included in the monthly total.

Step 3 – Linear (least squares) regression analysis was performed on historical data from the residential, commercial, and governmental revenue classes to determine the relationship between monthly CDD/HDD and utility sales over an analytical period consisting of nine years beginning January 2012. Other analyses have indicated that the relationship of sales to explanatory variables, including weather, are likely changing with time due to improved efficiencies of new appliances and buildings, so the relatively short analytical period (shorter than the normalization period, for example) was chosen to reflect this trend. The regression equations used for each analysis had the following general structure:

UPC/Day = Constant + Trend + Monthly Binaries + (H1* DDH1) + (H2*DDH2) …+ (C1* DDC1) + etc.

Where:

- *UPC/Day* = usage per customer per day (i.e., UPC/days in revenue month);
- *Monthly Binaries* = variables that capture factors unique to particular months;
- *H1* and *C1* etc. = heating and cooling coefficients by temperature band; and
- *DDH1* and *DDC1* etc. = degree days in the heating and cooling bands.

The regression analyses were evaluated using a variety of statistical measures. These include R-squared (a measure of the success of the regression in predicting the value of the dependent variable, 0.95 is a good target for the

Residential class), p values for each individual coefficient (the probability that the coefficient is not valid, .05 or less is good), the Durbin-Watson statistic (a measure of serial correlation, something close to 2.0 is desirable), and Mean Absolute Percentage Error ("MAPE", under 3% is targeted). Usage per customer per day was used instead of total usage to remove the effects of changing customer counts and billing cycle days on usage.

If the resulting equation from the regression analysis for a class or a specific temperature band did not meet statistical criteria, it was not accepted. This occurred for the industrial class, so there are no coefficients and no adjustment for weather variances for industrial. This does not necessarily mean there is no relationship between temperature and sales for that class, but rather a statistical relationship could not be established with a minimum degree of confidence. The specific formulation of the resulting regressions and the attendant statistics are included in RFP Schedule O-2.1 for reference.

The coefficients resulting from this process are as follows:

Entergy Texas
Coefficient Summary[2]

Cooling	**CDD65**
Residential	1.32
Commercial	4.12
Governmental	2.54
Heating	**HDD60**
Residential	1.46
Commercial	1.39
Governmental	0.00

Step 4 – Simulations were run using the equations derived in Step 3 to determine what the cycle sales for a particular class and month would have been under normal weather and under actual weather. The difference between the two simulations is the weather adjustment.

Q15. WHAT WAS THE RESULT OF THE WEATHER ANALYSIS PERFORMED FOR THIS PROCEEDING?

A. As summarized in Exhibit KS-3, the impact of weather during the Test Year was to decrease residential sales by 0.45%, decrease commercial sales by 0.23%, and decrease governmental sales by 0.17% (i.e., the weather factors were positive 0.45%, positive 0.23%, and positive 0.17%, respectively). Temperatures were lower than normal in February and March and higher than normal in December during the heating months. Temperatures were lower than normal in May, June,

2 Coefficients are rounded to the second decimal in this document for illustrative purposes and presented as an average of monthly cooling and heating coefficients.

July, August, and October and higher than normal in September and November during the cooling months.

Q16. WHY DID THE COMPANY CHOOSE TO EMPLOY A 20-YEAR WEATHER NORMALIZATION PERIOD?

A. A 20-year weather normalization period strikes the right balance between the statistical notion that at least 30 data points are necessary to obtain reliable estimates and recent weather trends. As recognized by the National Oceanic and Atmospheric Administration ("NOAA"), "a general rule in statistics says that you need at least thirty numbers to get a reliable estimate of their mean or average."[3] NOAA publishes Climate Normals, which covers a 30-year period, updated every 10 years. However, while more data points are generally better, in the case of climate, using 30 years of data may dampen recent weather trends.

I understand the Commission found a 10-year normalization period to be reasonable in Docket No. 40443, the Southwestern Electric Power Company's ("SWEPCO") rate case, and concluded that the 30-year period SWEPCO used for normalizing weather in that case was not a reasonable means of capturing weather trends. In its recent rate case, Docket No. 51415, SWEPCO used a rolling 10-year average of heating and cooling degree days while still advocating for the industry standard of a 30-year normalization. Since its rate case in Docket No. 43695, Southwestern Public Service Company ("SPS") has employed a 10-year

[3] https://www.ncei.noaa.gov/products/land-based-station/us-climate-normals.

normalization when it had previously proposed a 30-year normalization period in its rate cases. However, SPS included in its most recent rate case, Docket No. 51802, that it still agrees with NOAA's practice that normal weather should be measured based on a 30-year period of time.

The climate in ETI's service territory in Southeast Texas is quite distinguishable from the climate in areas served by SWEPCO and SPS—i.e., the Panhandle, South Plains, and Northeast regions of the state. In a state as large as Texas, weather can vary significantly among the different regions. For instance, major hurricanes and coastal flooding events, while not common from year to year, are much more likely to affect ETI's service area than those of SWEPCO and SPS. Weather events such as these would skew the data to a much greater extent if ETI were to use the shorter 10-year period adopted in Docket Nos. 40443, 43695, 51802, and 51415. I do not believe the Commission should apply a "one size fits all" approach to the various utilities across the state.

I understand the Commission found that the 30-year period proposed by SWEPCO and SPS would not be a reasonable means of capturing recent weather trends. As I mentioned above, I agree the Company should consider such weather trends. Therefore, I am proposing a 20-year normalization period, which I believe balances my concern with using too short of a normalization period with the need to appropriately consider recent weather trends.

Q17. DOES YOUR PROPOSAL REDUCE VOLATILITY?

A. Yes, a 20-year normalization period moderates the effects of extreme temperatures and thereby reduces the volatility that can occur within the normal calculation. Lower volatility in the normal calculation will yield reduced volatility in the resulting weather factors and, therefore, should enhance rate stability. Extreme weather events such as the "polar vortex" of early 2014 or Winter Storm Uri in 2021 will disproportionately swing a ten-year normal definition.

B. Demand (kW) Weather Factor

Q18. PLEASE DESCRIBE THE PROCESS USED IN THE CALCULATION OF THE WEATHER FACTORS FOR DEMAND (KW).

A. A weather normalization adjustment was estimated for the monthly Coincident Peak ("CP") and Maximum Diversified Demand ("MDD") over the Test Year for the following ETI rate classes: Residential, Small General Service, General Service and Large General Service. The Large Industrial Power Service and Standby and Maintenance Services rate classes did not exhibit a statistically significant response to variations in temperature, so no weather factors were developed for these classes.

Estimating the weather normalization adjustment for peak demands involved a three-step process similar to that used for developing the sales weather factors: (1) a normal weather peaking condition was defined; (2) weather response functions were developed for each of the four rate classes; and (3) the weather response functions were applied with actual and normal weather on peak days for each month and peaking condition to calculate the weather normalization factors.

Step 1 – Average Daily Temperature was selected as an appropriate weather variable to estimate peak loads for all analyses and was defined as the average of each day's 24-hourly temperature readings. As with the weather normalization of sales, temperatures were converted into HDD and CDD and calculated by five-degree bands to account for any non-linearity of weather response across the temperature range.

Normal HDD and CDD were calculated using the average daily temperatures on the day in each month that the peaking condition occurred. Twenty years of historical data from 2001 to 2020 was used to calculate these average peak day temperatures and degree days. For purposes of determining the CP, the peak days are defined as the day each month where the ETI system load peaks. For the MDD concept, the peak days are defined for each class as the day of maximum load for that individual rate class.

Step 2 – The weather response functions for each class were estimated using daily load data from the Test Year. When plotted in the form of daily temperature on the horizontal axis and daily peak load on the vertical axis, the data exhibits signs of a non-linear relationship, forming an almost U-shape that reflects the higher loads on days with low temperatures or high temperatures. Hence, a piece-wise linear regression technique was warranted. The specific formulation of the resulting regressions and the attendant statistics are included in RFP Schedule O-2.1 for reference.

Step 3 – The weather response functions for each class and peaking condition were run using actual and normal degree days on the relevant peak days each month of the Test Year. The percentage difference between the two results was the calculated weather factor for that month. For example, the residential class MDD for April occurred on April 28, 2021. The average temperature that day was 79 degrees, versus the average peak day temperature across the 20 April peak days of the normalization period of 73 degrees. Solving the residential model using the actual degree days resulted in a predicted value 26.1% higher than the predicted value resulting when the model was solved using the normal degree days. So, the MDD weather factor for April was negative 26.1%. The system CP occurred on August 31, 2021 and solving the residential model for the CP weather factor resulted in a CP weather factor of a positive 1.9% for August.

The monthly weather factors calculated using this procedure are summarized in Exhibit KS-4. A positive percentage implies that actual temperatures on the peak day were milder than normal and that actual peak loads need to be adjusted upward by that percentage. A negative percentage implies that actual temperatures on the peak day were more severe than normal and that actual peak loads need to be adjusted downward by that percentage.

The MDD adjustment factors for the Residential, Small General Service, and Large General Service rate classes have been adjusted to ensure that the weather adjusted CP value does not exceed the weather adjusted MDD value. Specifically, the Residential MDD factors were recalibrated for April, June, and September; the Small General Service factors were adjusted for May; and the Large General Service factors were recalibrated for January. The models used to predict these values had a high explanatory factor (R-squared) using temperature as the explanatory variable, but there are other factors that may obscure the relationship between load and temperature, such that the models will produce results that do not follow the logic that the CP cannot exceed the MDD. The factors for these months have been adjusted to produce a MDD that will be no smaller than the CP.

III. CONCLUSION

Q19. ARE THE SALES AND DEMAND WEATHER FACTORS AND FORECAST ANALYSES PRESENTED IN THIS FILING REASONABLE AND APPROPRIATE?

A. Yes. The factors and forecasts use generally accepted statistical procedures and data in the preparation of the normal weather analyses for the Test Year.

Q20. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT OF KRISTIN SASSER

THE STATE OF LOUISIANA)
)
PARISH OF ORLEANS)

This day, Kristin Sasser the affiant, appeared in person before me, a notary public, who knows the affiant to be the person whose signature appears below. The affiant stated under oath:

My name is Kristin Sasser. I am of legal age and a resident of the State of Louisiana. The foregoing testimony and exhibits offered by me are true and correct, and the opinions stated therein are, to the best of my knowledge and belief, accurate, true and correct.

Kristin Sasser
Kristin Sasser

SUBSCRIBED AND SWORN TO BEFORE ME, notary public, on this the 8th day of June 2022.

Jennifer Favalora
Notary Public, State of Louisiana

My Commission expires:
upon my death

JENNIFER B. FAVALORA
Notary Public (ID# 57639)
Orleans Parish, Louisiana
Commission Issued For Life

PREVIOUS TESTIMONY FILED BY KRISTIN SASSER

Before the Public Utility Commission of Texas

Docket No. 47233, *Application of Entergy Texas, Inc. for Approval to Amend its Distribution Cost Recovery Factor* (2017).

Docket No. 48371, *Entergy Texas, Inc.'s Statement of Intent and Application for Authority to Change Rates* (2018).

Docket No. 49392, *Application of Entergy Texas, Inc. for Approval to Amend its Distribution Cost Recovery Factor* (2019).

Docket No. 50714, *Application of Entergy Texas, Inc. for Approval to Amend its Distribution Cost Recovery Factor* (2020).

Docket No. 51381, *Application of Entergy Texas, Inc. to Establish a Generation Cost Recovery Rider Related to the Montgomery County Power Station* (2020).

Docket No. 51416, *Application of Entergy Texas, Inc. for Approval to Amend its Distribution Cost Recovery Factor* (2020).

Docket No. 51557, *Application of Entergy Texas, Inc. to Amend its Generation Cost Recovery Rider to Reflect the Acquisition of the Hardin County Peaking Facility* (2020).

Docket No. 52354, *Application of Entergy Texas, Inc. to Update its Generation Cost Recovery Rider to Reflect the Acquisition of the Hardin County Peaking Facility* (2021).

Docket No. 52457, *Application of Entergy Texas, Inc. for Approval to Amend its Distribution Cost Recovery Factor* (2021).

Schedules Sponsored

Schedule	Description	Co-Sponsors	Pages or Data Sponsored
O-1.5	System Information	Andrew L. Dornier	System Peak Demand
O-1.8	Operating Statistics Narrative	Crystal K. Elbe	Weather Adjustment
O-2.1	Model Information-Op Statistcs		All
O-2.2	Model Data		All
O-2.3	Raw Model Data		All
O-7.1	Sales & Demand Data		All
O-7.2	Historical Sales Data		All
O-8.1	Historical Weather Data		All
O-8.2	Historical Weather Data After Weighting and Bill Cycle Adjs		All
O-8.3	Norm Htng & Coolng Degree Days		All
O-8.4	65 Degree Base Temptre Resp		All
O-9.1	Rate Year Forecast Model Info		All
O-9.2	Model Data		All
O-9.3	Raw Model Data		All
O-10.1	Historical Econom & Demogr Data		All
O-10.2	Personal Income Data		All
O-10.3	Price Of Electricity-Nominal/Real		All

Entergy Texas
Calculation of Weather Adjustment Factor, Year Ending December 31, 2021
Residential (MWh)
Twenty Year Normal Weather Period 2001-2020

	Customers	Actual Sales	Usage Per Customer	HDD		CDD		Change in		Weather Adjustment	Weather Factor	Weather Adjusted Usage
				Actual	Normal	Actual	Normal	HDD	CDD			
	[1]	[2]	[3]= [2]/[1]	[4]	[5]	[6]	[7]	[8]= [5]-[4]	[9]= [7]-[6]	[10]	[11]= [10]/[2]	
Jan-21	416,552	554,219	1.330	274	279	0	0	5	0	4,175	0.75%	558,393
Feb-21	378,682	452,459	1.195	251	245	0	0	(6)	0	(4,001)	(0.88%)	448,457
Mar-21	454,044	532,267	1.172	246	153	0	0	(93)	0	(69,585)	(13.07%)	462,682
Apr-21	417,643	345,787	0.828	55	54	128	133	(2)	5	1,133	0.33%	346,920
May-21	428,209	412,814	0.964	0	0	223	242	0	20	8,427	2.04%	421,241
Jun-21	427,223	559,858	1.310	0	0	377	418	0	41	24,631	4.40%	584,489
Jul-21	423,531	657,590	1.553	0	0	511	528	0	17	11,755	1.79%	669,345
Aug-21	424,291	681,152	1.605	0	0	538	549	0	11	7,702	1.13%	688,853
Sep-21	424,132	680,156	1.604	0	0	526	520	0	(6)	(4,300)	(0.63%)	675,856
Oct-21	415,565	500,733	1.205	0	0	357	378	0	21	12,855	2.57%	513,588
Nov-21	433,325	427,049	0.986	47	45	217	191	(1)	(25)	(10,310)	(2.41%)	416,739
Dec-21	424,701	397,023	0.935	98	159	0	0	62	0	45,511	11.46%	442,534
Total	422,325	6,201,106		971	936	2,876	2,959	(35)	83	27,991	0.45%	6,229,098

Entergy Texas
Calculation of Weather Adjustment Factor, Year Ending December 31, 2021
Commercial (MWh)
Twenty Year Normal Weather Period 2001-2020

	Customers	Actual Sales	Usage Per Customer	HDD		CDD		Change in		Weather Adjustment	Weather Factor	Weather Adjusted Usage
				Actual	Normal	Actual	Normal	HDD	CDD			
	[1]	[2]	[3]= [2]/[1]	[4]	[5]	[6]	[7]	[8]= [5]-[4]	[9]= [7]-[6]	[10]	[11]= [10]/[2]	
Jan-21	50,354	343,871	6.829	274	279	0	0	5	0	135	0.04%	344,006
Feb-21	47,327	342,099	7.228	251	245	0	0	(6)	0	(392)	(0.11%)	341,707
Mar-21	52,751	313,719	5.947	246	153	0	0	(93)	0	(10,801)	(3.44%)	302,918
Apr-21	50,840	331,721	6.525	0	0	128	133	0	5	715	0.22%	332,436
May-21	52,208	348,213	6.670	0	0	223	242	0	20	3,483	1.00%	351,697
Jun-21	51,771	405,241	7.828	0	0	377	418	0	41	8,276	2.04%	413,516
Jul-21	50,935	416,461	8.176	0	0	511	528	0	17	3,630	0.87%	420,091
Aug-21	51,656	438,864	8.496	0	0	538	549	0	11	2,499	0.57%	441,363
Sep-21	51,521	434,987	8.443	0	0	526	520	0	(6)	(1,530)	(0.35%)	433,457
Oct-21	50,507	395,168	7.824	0	0	357	378	0	21	5,200	1.32%	400,368
Nov-21	52,548	372,764	7.094	0	0	217	191	0	(25)	(5,515)	(1.48%)	367,249
Dec-21	52,360	351,312	6.710	98	159	0	0	62	0	4,759	1.35%	356,071
Total	51,232	4,494,420		869	837	2,876	2,959	(32)	83	10,459	0.23%	4,504,879

Entergy Texas
Calculation of Weather Adjustment Factor, Year Ending December 31, 2021
Governmental (MWh)
Twenty Year Normal Weather Period 2001-2020

	Customers [1]	Actual Sales [2]	Usage Per Customer [3]= [2]/[1]	HDD Actual [4]	HDD Normal [5]	CDD Actual [6]	CDD Normal [7]	Change in HDD [8]= [5]-[4]	Change in CDD [9]= [7]-[6]	Weather Adjustment [10]	Weather Factor [11]= [10]/[2]	Weather Adjusted Usage
Jan-21	2,065	21,146	10.240	0	0	28	39	0	11	60	0.29%	21,206
Feb-21	1,935	21,411	11.065	0	0	25	31	0	6	28	0.13%	21,440
Mar-21	2,123	19,815	9.334	0	0	65	62	0	(3)	(16)	(0.08%)	19,799
Apr-21	2,076	19,996	9.632	0	0	128	133	0	5	25	0.13%	20,021
May-21	2,101	20,416	9.717	0	0	223	242	0	20	106	0.52%	20,521
Jun-21	2,105	20,324	9.655	0	0	377	418	0	41	218	1.07%	20,543
Jul-21	2,041	20,627	10.107	0	0	511	528	0	17	88	0.43%	20,716
Aug-21	2,063	22,076	10.701	0	0	538	549	0	11	57	0.26%	22,133
Sep-21	2,119	22,019	10.391	0	0	526	520	0	(6)	(32)	(0.15%)	21,987
Oct-21	2,029	23,413	11.539	0	0	357	378	0	21	108	0.46%	23,521
Nov-21	2,116	21,800	10.302	0	0	217	191	0	(25)	(136)	(0.62%)	21,664
Dec-21	2,120	22,036	10.394	0	0	90	74	0	(15)	(82)	(0.37%)	21,954
Total	2,074	255,080		0	0	3,084	3,165	0	82	425	0.17%	255,505

Entergy Texas
Coefficient Summary

Cooling	Cooling 1	Cooling 2	Cooling 3	Cooling 4	Cooling 5	Cooling 6	Cooling 7	Cooling 8
Residential	0.772	0.996	1.416	1.635	1.680	1.693	1.476	0.890
Commercial	2.941	3.376	3.925	4.198	4.479	4.957	4.911	4.163
Governmental	2.544	2.544	2.544	2.544	2.544	2.544	2.544	2.544

Heating	Heating 1	Heating 2	Heating 3	Heating 4	Heating 5	Heating 6
Residential	1.901	1.715	1.656	0.568	1.163	1.740
Commercial	0.507	1.345	2.213	1.476		
Governmental						

Entergy Texas, Inc.
Summary of Monthly Adjustment Percentages by Rate Class
January 2021 - December 2021

	Coincident Peak Factors (CP)				Maximum Diversified Demand Factors (MDD)			
	Residential Electric Service	Small General Service	General Service	Large General Service	Residential Electric Service	Small General Service	General Service	Large General Service
Jan-21	5.4%	5.3%	0.0%	0.0%	1.4%	5.0%	0.0%	-5.2%
Feb-21	-16.0%	-18.2%	0.0%	0.0%	-15.8%	-19.9%	0.0%	-2.6%
Mar-21	-3.0%	-4.5%	-12.2%	-9.1%	0.7%	-12.7%	-7.6%	-3.0%
Apr-21	-12.2%	-9.1%	-3.3%	-2.6%	-18.9%	-8.7%	-3.2%	-2.2%
May-21	8.7%	5.6%	2.2%	1.7%	11.8%	5.7%	0.2%	1.4%
Jun-21	-6.6%	-4.3%	-2.0%	-1.5%	-8.7%	7.5%	-2.0%	1.7%
Jul-21	1.0%	0.7%	0.3%	0.2%	2.9%	2.7%	1.0%	0.7%
Aug-21	1.9%	1.3%	0.5%	0.4%	4.4%	1.5%	1.9%	-0.7%
Sep-21	-6.5%	-4.4%	-3.1%	-1.4%	-6.5%	0.2%	0.6%	-0.6%
Oct-21	-0.8%	-0.7%	-0.3%	-0.2%	-0.3%	-1.4%	-2.3%	-1.4%
Nov-21	-13.1%	-10.3%	-11.6%	-8.6%	-10.8%	-10.3%	1.4%	0.9%
Dec-21	24.9%	20.1%	-15.5%	-11.6%	15.0%	13.7%	-14.3%	-13.5%

DOCKET NO. 53719

APPLICATION OF ENTERGY	§	PUBLIC UTILITY COMMISSION
TEXAS, INC. FOR AUTHORITY TO	§	
CHANGE RATES	§	OF TEXAS

DIRECT TESTIMONY

OF

RICHARD E. LAIN

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2022

ENTERGY TEXAS, INC.
DIRECT TESTIMONY OF RICHARD E. LAIN
2022 RATE CASE

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EXHIBITS

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard E. Lain. My business address is 919 Congress, Suite 740, Austin, Texas 78701.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Manager of Regulatory Affairs for Entergy Texas, Inc. ("ETI" or the "Company").

Q3. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am submitting this direct testimony to the Public Utility Commission of Texas ("Commission") on behalf of ETI.

Q4. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. A summary of my education and work experience, as well as a list of my previous direct testimonies filed at the Commission, is included as Exhibit REL-1.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my direct testimony in this proceeding is to:

- Address the Company's requested River Bend decommissioning revenue requirement;
- Sponsor certain pro forma adjustments to current test year revenues and expenses;

- Discuss the methodology employed in preparing the Company's class cost of service study presented in Schedule P of the Commission's Rate Filing Package ("RFP");
- Present the results of the Company's class cost of service study for the 12 months ending December 31, 2021 (the "Test Year");
- Present the level of adjusted affiliate expenses reflected in the Company's class cost of service study;
- Provide a list of waivers the Company seeks from various Commission rules and describe why the waivers are reasonable based on good cause; and
- Support the Company's proposed recovery of rate case expenses for this and the Company's most recent fuel reconciliation proceeding.[1]

Q6. WHAT EXHIBITS ARE YOU SPONSORING OR CO-SPONSORING?

A. The exhibits I sponsor in this proceeding are listed in the Table of Contents to my testimony. Unless otherwise indicated, the exhibits that I sponsor were prepared by me or under my direct supervision and control. In addition, I co-sponsor Exhibits APL-3, APL-4, and APL-5 with ETI witness Allison P. Lofton. These exhibits reflect the Company's proposed baselines for the Distribution Cost Recovery Factor ("DCRF"), Transmission Cost Recovery Factor ("TCRF"), and the Purchased Power Capacity Cost Recovery Factor ("PCRF") that are derived from the Company's proposed cost of service.

[1] *Application of Entergy, Texas Inc. for Approval to Reconcile Fuel and Purchased Power Costs*, Docket No. 49916, Order (Aug. 27, 2020).

Q7. DO YOU SPONSOR OR CO-SPONSOR ANY SCHEDULES IN THE COMPANY'S RFP?

A. Yes. Exhibit REL-2 lists the schedules I sponsor or co-sponsor. Unless otherwise indicated, the schedules I sponsor were prepared by me or under my direct supervision and control.

II. RIVER BEND DECOMMISSIONING REVENUE REQUIREMENT

Q8. WHAT DECOMMISSIONING REVENUE REQUIREMENT IS ETI REQUESTING FOR RIVER BEND?

A. ETI requests the River Bend decommissioning trust fund revenue requirement be set at $0.00 in this proceeding. Highly sensitive Exhibit REL-3 sets forth the calculation of the actual amount of -$7.45 million, which supports Schedule M-2 of the RFP. Establishing the decommissioning revenue requirement at zero will allow time for the Company to conduct an updated decommissioning cost study and file at the Commission, consistent with 16 Texas Administrative Code ("TAC") § 25.231(b)(1)(F)(iv), and in which the Company can also provide an updated calculation of the trust fund revenue requirement.

Q9. WHAT ASSUMPTIONS WERE USED TO DETERMINE THE ANNUAL DECOMMISSIONING TRUST FUND REVENUE REQUIREMENT?

A. The revenue requirement amount reflects the current projections of trust fund earning rates and other parameters that affect the calculation. ETI witnesses Elizabeth S. Hunter and Alyssa Maurice-Anderson discuss these parameters in their direct testimonies. In addition, ETI witness Lori A. Glander, in her direct testimony, provides the minimum funding value needed to meet the decommissioning funding requirements of the U.S. Nuclear Regulatory Commission ("NRC") set forth in 10 CFR § 50.75(c).

Q10. WHAT METHODOLOGY DID ETI USE TO DETERMINE THE ANNUAL DECOMMISSIONING TRUST FUND REVENUE REQUIREMENT?

A. The Company determined the annual revenue requirement utilizing the straight-line ("Levelized-Nominal") funding method, which was approved for Entergy Gulf States, Inc.[2] in Docket Nos. 12852 and 16705. The Company subsequently utilized this method in Docket Nos. 37744, 41791, and 48371.

Q11. PLEASE DISCUSS THE CALCULATION OF THE ANNUAL DECOMMISSIONING REVENUE REQUIREMENT SET OUT ON PAGE 1 OF HIGHLY SENSITIVE EXHIBIT REL-3.

A. The calculation is based on the $469.5 million (2021 dollars) estimate of the minimum funding amount to decommission River Bend as determined by the Company according to NRC regulations, which Ms. Glander discusses in her direct testimony. ETI allocated the decommissioning cost to reflect only the Company's 42.5% funding responsibility for River Bend per the Power Purchase Agreement (known as the "River Bend 70 Amended PPA") between ETI and Entergy

[2] Entergy Gulf States, Inc. was ETI's predecessor.

Louisiana, L.L.C. ("ELL"), whereby ETI acquires its share of River Bend output. River Bend is owned by ELL, but 42.5% of the regulated portion (the regulated portion makes up 70% of the total output) is sold to ETI under the River Bend 70 Amended PPA. The Federal Energy Regulatory Commission ("FERC") accepted the River Bend 70 Amended PPA effective September 1, 2016. This PPA replaced a prior purchased power agreement that had been in effect pursuant to Service Schedule MSS-4 of the Entergy System Agreement ("ESA") until termination of the ESA on August 31, 2016. Thus, the -$7.45 million annual revenue requirement set out in highly sensitive Exhibit REL-3 is for ETI.

In addition, Ms. Maurice-Anderson's and Ms. Hunter's direct testimonies describe that the revenue requirement calculation reflects the use of the following parameters:

1. Projected after-tax April 30, 2022 liquidation values for the River Bend Decommissioning Funds ("Funds") for ETI;
2. Projected weighted average after-tax earning rates for the Funds;
3. Estimated administrative fees related to the Funds; and
4. Annual decommissioning cost escalation rate.

The revenue requirement model utilizes the estimated liquidation values of the Funds as of April 30, 2022, and calculates the decommissioning revenue requirement for each remaining year of the operating life of River Bend through August 29, 2045.

The annual revenue requirement calculations are made through an iterative process that determines the level, or fixed, annual revenue amount necessary to provide sufficient balances (including both Company contributions and earnings on the balances in the Funds) to pay the Company's portion of the estimated annual costs of decommissioning River Bend once that process begins in 2044, while reducing the balances in the Funds to zero at the end of the last year of the decommissioning process in 2078.

Q12. PLEASE EXPLAIN WHY YOU ARE RECOMMENDING A DECOMMISSIONING TRUST FUND REVENUE REQUIREMENT OF ZERO WHEN YOUR MODEL CALCULATES A NEGATIVE NUMBER?

A. A negative revenue requirement would not be appropriate for the nuclear decommissioning trust fund for several reasons. First, I have been informed by counsel that NRC regulations do not allow withdrawals from the River Bend decommissioning trust fund for purposes of returning funds to ratepayers until the decommissioning of River Bend is complete. NRC regulations at 10 CFR § 50.82(a)(8)(i) provide that nuclear plant "[d]ecommissioning trust funds may be used by licensees if . . . the withdrawals are for expenses for legitimate decommissioning activities." It is my understanding that only when the River Bend NRC license is finally terminated, upon completion of radiological decommissioning, would this regulation no longer constrain use of the trust funds to decommissioning activities. Moreover, Section IV of the River Bend Decommissioning Trust Agreement provides that the trustee of the decommissioning trust fund is only allowed to distribute funds for payment of decommissioning costs, normal and extraordinary expenses for trust administration (e.g., legal and engineering services), and trustee fees. Section 5.01 of the Decommissioning Trust Agreement provides for termination of the trust upon "substantial completion of the nuclear decommissioning of the Plant," so that the aforementioned limitations on distribution of funds apply until then. Moreover, the negative revenue requirement computed is relatively small, and could easily be erased by relatively small changes in the value of funds in the trust.

In summary, there are legal and practical reasons the Company proposes a zero revenue requirement for River Bend decommissioning.

Q13. COULD THE COMMISSION REDUCE THE COMPANY'S OVERALL REVENUE REQUIREMENT BY THE NEGATIVE DECOMMISSIONING FIGURE YOU NOTED ABOVE AND LET THE COMPANY WITHDRAW FUNDS FROM THE DECOMMISSIONING TRUST TO OFFSET THE SHORTAGE?

A. No. As I mentioned above, the Company cannot withdraw funds from the decommissioning trust until River Bend's decommissioning is completed, as a matter of NRC regulations and the decommissioning trust agreement. Reducing the Company's overall revenue requirement by this amount would result in a shortage of funds needed to operate the Company. Should a surplus persist in the fund through actual River Bend decommissioning, any such surplus attributable to ratepayers would be returned to ratepayers at that time.

Further, as noted by Ms. Glander in her direct testimony, the NRC minimum value used to calculate the negative decommissioning revenue requirement l present above does not cover the entire cost of nuclear plant decommissioning. Significantly, Ms. Glander notes that the NRC minimum funding value does not include costs for site restoration and spent fuel management, such that the decommissioning revenue requirement for the entire project would be expected to be higher than that just for the NRC minimum value. The Company will be presenting a new site-specific River Bend decommissioning cost estimate in 2023 that will include those costs not subsumed within the NRC minimum value.

It is also appropriate to note that a current surplus is not guaranteed to persist—adverse changes in trust fund earnings or in the cost of the decommissioning of nuclear facilities could reverse any surplus.

Q14. HAS THE RIVER BEND LICENSE BEEN RENEWED WITH THE NRC?

A. Yes. The licensee filed a license renewal application with the NRC on May 31, 2017, seeking a 20-year extension to the River Bend operating license. In December 2018, the NRC issued a renewed operating license for River Bend extending the license to August 29, 2045.[3] The Company used the renewed license life of 60 years for River Bend in calculating the NRC Minimum Funding Requirement.

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[3] The renewed license is publicly available on the NRC website, nrc.gov, in the ADAMS document management system, using Accession No. ML18284A369.

Q15. PLEASE DESCRIBE SCHEDULES M-1 AND M-2 THAT YOU CO-SPONSOR WITH MS. MAURICE-ANDERSON AND MS. HUNTER.

A. Schedule M-1 (Decommissioning Information) provides information concerning the decommissioning funds the Company has established. Schedule M-2 (Decommissioning Funding Plan) provides the accumulated balance on a year-by-year basis for the funds. The projected data for Schedule M-2 is based on information from highly sensitive Exhibit REL-3.

III. CLASS COST OF SERVICE STUDY

A. Process

Q16. WHAT IS THE OBJECTIVE OF PREPARING A CLASS COST OF SERVICE STUDY?

A. The objective of preparing a class cost of service study is to determine the portion of a utility's costs, as measured by its revenue requirement, for which each of the various customer groups is responsible. The allocation of costs then becomes one of the factors to consider in determining the revenue level appropriate for each rate class. In addition, a class cost of service study provides revenue requirement information by function (i.e., production, transmission, distribution, etc.) that is often useful in the rate design process.

Q17. PLEASE BRIEFLY OUTLINE THE GENERAL METHODS EMPLOYED IN THE CLASS COST OF SERVICE STUDY THAT YOU ARE SPONSORING TO APPORTION RATE BASE, REVENUE, AND OPERATING EXPENSES.

A. The class cost of service study I sponsor utilizes the industry-accepted approach of incorporating the successive application of the processes of functionalization, classification, and allocation with respect to all components of rate base, revenue, and operating expenses.

Q18. PLEASE DISCUSS THE FUNCTIONALIZATION PROCESS.

A. Functionalization is the separation of costs by the major functions of generation (or production), transmission, and distribution/customer service in order to facilitate the determination of how to allocate the Company's costs to the various customer groups.

Q19. ARE ALL COSTS ASSIGNABLE TO ONE OF THESE THREE FUNCTIONS?

A. No. There are many items that represent a combination of more than one of these functions and must be addressed as an aggregated amount. For example, although certain parts of general plant may be assigned to one or more of these three functions, the majority of general plant supports all three functions and, thus, must be addressed on a composite basis.

Q20. PLEASE DESCRIBE THE CLASSIFICATION PROCESS.

A. Classification is the separation of functionalized costs into demand-related, energy-related, or customer-related categories. An example of a demand-related cost is the cost associated with distribution substations. Energy-related costs, while not strictly the same as variable costs, are generally costs associated with sales rather than demand. The cost of fuel consumed by production facilities is the best example of an energy-related cost. Certain production maintenance expenses, although not variable in an economic sense, are generally treated as energy-related for cost of service purposes. Expense charged to Account 512 (Maintenance of boiler plant) is one such example. Customer-related costs are those incurred even if a customer does not impose demand on the system or consume energy. Costs associated with reading meters and preparing bills are examples of customer-related costs. Finally, there are typically a few costs that are revenue-related. Expense charged to Account 904 (Uncollectible Accounts) is an example of a revenue-related cost.

Q21. PLEASE GENERALLY DESCRIBE HOW ETI STRUCTURED THE CLASS COST OF SERVICE STUDY PRESENTED IN SCHEDULE P.

A. The starting point for the study's preparation was the unadjusted, or "per book," rate base, revenues, and operating expenses for the Test Year, aggregated by FERC account level, as discussed by Ms. Lofton. Next, adjustments were made to the per book data. The Company incorporates the adjustments into the cost of service model at the point where the adjusted data was functionalized, classified, and allocated to the rate classes. Exhibit REL-4 identifies the adjustments made to the per book data and indicates the witnesses sponsoring each adjustment. The rate base, revenue, and expense components in the class cost of service study reflected in Schedule P are presented on a total adjusted level (per book plus or minus adjustments, if applicable). Schedule P also presents summaries of the adjusted values for the major rate base, revenue, and expense components (e.g., plant in service).

Q22. PLEASE DESCRIBE CERTAIN ADJUSTMENTS TO BASE RATE REVENUES AND EXPENSES MADE PRIOR TO ALLOCATING COSTS TO THE RATE CLASSES.

A. Adjustment 1, which I co-sponsor with ETI witness Crystal K. Elbe, adjusts base rate revenues to present rate revenues and reclassifies certain special rate revenues. Adjustment 5, sponsored by Ms. Lofton, removes eligible fuel and purchase power expense from the Company's Test-Year operating expenses. Adjustment 3, which I sponsor, adjusts certain revenue-related expenses. Each of these adjustments is described below.

Q23. PLEASE DISCUSS THE PORTION OF ADJUSTMENT 1 RELATING TO SPECIAL RATE REVENUE.

A. In connection with Adjustment 1, I sponsor the reclassification of special rate revenues from "rate schedule revenue" to "other operating revenue." To accomplish this, Ms. Elbe provided the revenues for the Experimental Economic As-available Power Service ("EAPS") and Standby and Maintenance Service ("SMS") rate schedules as well as for Rate Schedule LQF (Non-firm Energy

Purchased from Large Qualifying Facilities). Ms. Elbe also provided revenues for Datalink (a service that provides web-based viewing access to interval load data collected by the Company), Drawdraft (a service that facilitates customer-authorized payments for services rendered by the Company), and the renewable portfolio standard calculation opt-out credit rider. These revenues were recorded on the Company's books as rate schedule revenue but are not included in the present retail Rate Schedule revenue prepared by Ms. Elbe. As such, they were reclassified in Adjustment 1 from "rate schedule revenue" to "other operating revenue" and allocated to all rate classes in the same general manner as their costs. The effect of this treatment is to reduce the revenue requirement for each rate class by an allocated amount of the revenues from the above rate schedules.

Q24. PLEASE DISCUSS THE ADJUSTMENTS TO ADDRESS FUEL AND PURCHASED POWER EXPENSE AND REVENUE.

A. In Adjustment 5, sponsored by Ms. Lofton, eligible fuel and purchased power expense is removed from the Company's Test-Year operating expenses. As a result of Adjustment 1, in which base rate revenues are adjusted to present rate revenues, and Adjustment 5, the Company synchronized eligible fuel and purchased power expense and fuel revenues at a value of zero for each of the rate classes. These revenues and costs are associated with the Company's Fixed Fuel Factor rate schedule ("Schedule FF") and are properly accounted for and reconciled in the Commission's Fuel Reconciliation process. Applying the fuel synchronization approach allows the class cost of service study to focus on determining base-rate revenue requirements for the various rate classes.

Q25. PLEASE DISCUSS HOW THE COMPANY MADE ADJUSTMENTS TO REVENUE-RELATED EXPENSES FOR CHANGES IN REVENUES (ADJUSTMENT 3).

A. Adjustment 3 adjusts revenue-related expenses to reflect the proper amounts based on the Company's present retail Rate Schedule provided by Ms. Elbe. The expenses adjusted were uncollectible accounts expense, state and local gross receipts taxes, street rental taxes, and Commission regulatory fees, all of which vary directly with the level of Texas rate schedule revenue.

ETI adjusted the uncollectible accounts expense at the rate class level using historical bad debt rates. The Company determined the adjustment to revenue-related taxes utilizing a rate based on the adjusted Texas revenue, the riders at the adjusted level using Test-Year billing determinants, and the per book amounts for Texas revenue-related taxes.

B. <u>Allocation Process</u>

Q26. PLEASE DESCRIBE THE ALLOCATION PROCESS USED TO DEVELOP THE CLASS COST OF SERVICE STUDY REFLECTED IN SCHEDULE P.

A. The functionalization and classification processes I discussed earlier provide an understanding of the nature of the costs and thus make it possible to select the most appropriate basis on which to allocate individual costs. The allocation process apportions or distributes costs to the various customer groups through the use of allocation factors. Generally, costs are allocated on a demand, energy, or customer basis. In a limited number of instances, a revenue allocator may be used to allocate costs.

Many cost items cannot be functionalized and classified to the point that a specific demand, energy, or customer allocation factor can be determined to be the appropriate allocator. In such cases, the costs at issue are allocated using an allocation factor of related cost items. For example, synchronized interest expense, which is related to total rate base, is typically allocated using a factor consisting of the rate base allocation to the customer groups.

Q27. WHAT METHODS WERE USED TO ALLOCATE THE COMPANY'S TEST-YEAR COSTS?

A. Ms. Elbe discusses the methods to develop the allocation factors ETI utilized to allocate each of the major function/classification cost categories in preparing the class cost of service study. Costs not directly associated with one of the major function/classification cost categories were allocated using factors developed in the cost of service study that the Company deemed most reasonable for such costs.

Q28. DID ETI SERVE BOTH WHOLESALE AND RETAIL CUSTOMERS DURING THE TEST YEAR?

A. No. ETI served only retail customers during the Test Year. For this reason, the Company's filing is based on a retail-only cost of service.

Q29. IN LIGHT OF THE COMMISSION'S DECISIONS IN DOCKET NOS. 43695, 46449, AND 51415, IS THE COMPANY PROPOSING TO USE THE TEST YEAR COINCIDENT PEAK ("CP") DEMAND FOR THE LOAD FACTOR COMPONENT IN THE PRODUCTION ALLOCATION FACTOR?

A. Yes. This is consistent with the Commission's decisions in those dockets (and the Company's proposal in its 2018 base-rate case, Docket No. 48371) where the Commission approved the use of the single coincident peak demand to be applied to the average demands by class in calculating the average and excess demand for the production demand allocation factors.

Q30. HOW DID THE COMPANY ALLOCATE MUNICIPAL FRANCHISE FEES AND GROSS RECEIPT TAXES?

A. The Company allocated municipal franchise fees and gross receipt taxes in the same manner as the Commission ordered in Docket No. 39896, and as ETI proposed in Docket No. 48371.

C. <u>Results</u>

Q31. PLEASE DESCRIBE SCHEDULE P IN THE RFP.

A. Schedule P (Class Cost of Service Analysis) is the embedded cost of service study at an equal rate of return for each of the Company's rate classes. The study includes the adjustments from the present adjusted revenue requirement to the proposed level of revenue requirement.

Q32. WAS THE STUDY PROVIDED IN SCHEDULE P REFLECTED IN ALL OF THE CLASS COST OF SERVICE-RELATED RFP SCHEDULES THAT YOU SPONSOR OR CO-SPONSOR?

A. No. The class cost of service study in Schedule P (referred to as "Study A") was reflected in all but a few of the class cost of service-related filing schedules in the RFP that I either sponsor or co-sponsor. To complete the class cost of service-related filing schedules that are based on proposed rates, it was necessary to prepare a second study ("Study B"). The following items listed below were the only changes made to the input data for Study A to develop Study B (reference the workpaper to Schedule P-1.1 for details):

- Rate schedule revenue;
- Bad debt expenses;
- Revenue-related taxes;
- Current federal income taxes;
- Working cash; and
- Interest synchronization.

Q33. WHICH REQUIRED SCHEDULES IN THIS FILING UTILIZE THE COMPANY'S PROPOSED REVENUES BY RATE CLASS?

A. I developed Study B, based on proposed rates, for the purpose of preparing Schedule P-1.1, which provides summaries of the rate of return and relative rates of return under proposed rate schedules using proposed rate classes, and for Schedule P-6-1.2, which is the Unit Cost Analysis at proposed rates.

Schedule P-1.4 (Proposed Rate Schedules/Existing Rate Classes) refers to Schedule P-1.1, because ETI does not propose to change the existing rate classes.

Q34. PLEASE DESCRIBE THE RESULTS FROM THE CLASS COST OF SERVICE STUDY PRESENTED IN SCHEDULE P.

A. The class cost of service study presented in Schedule P demonstrates that the annual retail base rate schedule revenue requirement, excluding eligible fuel and purchased power expenses, is $1.2 billion as shown on page 1 at line 35. This represents a $329.9 million base-rate revenue deficiency under the Company's currently effective base rates. However, as outlined in the testimonies of Ms. Lofton and Ms. Elbe, ETI is requesting the recovery of $197.5 million in Test Year revenues associated with its current Generation Cost Recovery Rider ("GCRR"), DCRF and TCRF riders, which were previously approved by the Commission, be incorporated into base rates. ETI's request is consistent with each of the Commission's rules that authorize those riders.[4] Therefore, upon accounting for $197.5 million in rider revenues moving into base rates, ETI's revenue deficiency is $132.4 million. However, approximately one million dollars of the deficiency is collected through rates associated with Standby and Maintenance Service and the Renewable Portfolio Standard Calculation Opt-Out Credit Rider, so when those are accounted for, ETI's requested revenue deficiency is $131.4 million.

Alternatively, as outlined in Schedule Q-1, combining present base and

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4 16 TAC §§ 25.239, 25.243, and 25.248.

rider revenues, $1.173 billion,[5] and comparing them to the Company's proposed base and rider revenues, $1.304 billion,[6] the overall requested revenue increase is $131.4 million.

Q35. PLEASE DISCUSS THE SCHEDULES IN THE RFP THAT REPORT THE RESULTS FROM THE CLASS COST OF SERVICE STUDY PRESENTED IN SCHEDULE P.

A. The RFP schedules listed below are based on the results from the class cost of service study:

- Schedule P-1 (Rate of Return);
- Schedule P-1.1 (Proposed Rate Schedules/Proposed Rate Classes);
- Schedule P-1.2 (Existing Rate Schedules/Proposed Rate Classes);
- Schedule P-1.3 (Existing Rate Schedules/Existing Rate Classes);
- Schedule P-1.4 (Proposed Rate Schedules/Existing Rate Classes);
- Schedule P-2 (Allocation of Revenue Deductions to Proposed Rate Classes);
- Schedule P-3 (Allocation of Rate Base to Proposed Rate Classes);
- Schedule P-4 (Separation of Expenses), which provides a separation of the expenses on Schedule P by the following classifications:
    - Demand,
    - Energy,
    - Customer,

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[5] (Schedule Q-1, Present Revenues: $890,124,234 + $197,502,903 + $85,756,987).

[6] (Schedule Q-1, Proposed Revenues: $1,219,024,749 + $0 + $85,756,987).