Q11. WHAT WAS THE NET COST THAT S&L CALCULATED TO DISMANTLE THE COMPANY'S GENERATING STATIONS THAT YOU STUDIED?

A. The total estimated net cost to dismantle ETI's generating facilities is $186,586,030 on a total cost basis. The estimated costs to demolish these sites are summarized in Table 1 below:

Table 1: Estimated Net Demolition Cost for ETI Generating Facilities

Plant	2022 Estimate****
Big Cajun 2, Unit 3*	$114,976,063
Hardin County	$1,137,432
Lewis Creek 1-2	$9,440,535
Montgomery County Power Station	$7,220,911
Nelson Unit 6**	$30,996,553
Sabine Units 1-5***	$22,814,536
TOTAL	$186,586,030

* Estimated demolition costs for Big Cajun 2, Unit 3 include 100% of Unit 3 and common costs. ETI is a part owner on Big Cajun 2, Unit 3 and associated common facilities.

** Estimated demolition costs for Nelson Unit 6 include 100% of common costs. ETI is a part owner on Nelson common facilities.

*** Estimated demolition costs for Sabine Units 1–5 also include cost for demolition of Spindletop gas storage facility.

**** These estimates reflect current costs, as of the first quarter of 2022.

Q12. WHAT DO YOU MEAN BY THE TERM "ESTIMATED NET COST?"

A. By the term "estimated net cost," I mean that this is our estimate of the cost to dismantle the specific generating station after crediting the estimated positive salvage value for certain scrap materials.

Q13. PLEASE DESCRIBE HOW THE VALUE OF SCRAP MATERIALS WAS DETERMINED IN THE DEMOLITION COST STUDIES.

A. S&L used industry-wide publications, as well as input from an area scrap dealer to estimate the cost of scrap materials. The value of scrap for carbon steel and #2 copper was determined by considering the five-year average (May 2017 through April 2022) applicable to the time of the cost estimate using the Scrap Metals Market Watch, a recognized publication that presents the current market value of various scrap materials. To further refine the final scrap value considered in the estimate, we contacted a scrap dealer in the region who provided a price range for the tubing materials and copper wiring. All the scrap prices are considered to be delivered prices to the scrap buyer. In other words, the price obtained was adjusted for cost of transportation to the buyer and is included in that value. The demolition cost estimates consider various scrap metals such as steel and copper based on the volume of materials at each plant site.

Q14. PLEASE GENERALLY DESCRIBE THE SCRAP METAL MARKET.

A. The price of scrap metal is determined by a mature market and prices are governed by regional demand, imports, and economic conditions. The price of scrap material has been extremely volatile in recent years. Exhibit SCM-3 demonstrates the volatility in scrap value over the last five years (May 2017 through April 2022) for ETI's scrap metal region. As can be seen, scrap value has varied widely between 2017 and 2022. In the past two years, the scrap value of steel has more than doubled. However, the unpredictability of the value makes it difficult to predict whether that trend can continue. The risk of reduced salvage value of scrap is a higher net cost of demolition. Therefore, we have considered the average over the five year period to provide a better long term assessment.

Q15. ARE THE SCRAP METAL PRICES REASONABLE?

A. Yes. The prices and value of scrap metal that are contained in the demolition cost studies reflect the current realities of the scrap metal market and are determined using the same methodology that S&L has used in previous years to estimate the net cost of demolition for these facilities.

Q16. WILL ANY OF THE MATERIALS IN THE GENERATING STATIONS PROVIDE A POSITIVE SALVAGE VALUE?

A. Yes. We have estimated the amounts of recoverable materials such as steel and copper in each of the stations. In Exhibit SCM-2, the estimated total salvage value is shown as a credit to the cost of dismantling the stations.

Q17. DID YOU INCLUDE AN ALLOWANCE FOR INDIRECT EXPENSES AT THE GENERATING STATIONS YOU STUDIED?

A. Yes. These amounts are intended to capture ETI's administrative and overhead costs associated with the dismantling of the generating stations. This is intended to cover such costs as administrative oversight of the contractor; obtaining permits; construction services such as water and electricity; security facilities; and additional expenses such as engineering assistance, particularly for complex dismantling.

Q18. HOW WAS THIS NUMBER DERIVED?

A. Based upon S&L's 131 years of experience, its experience with numerous projects of similar complexity, and discussions with ETI's engineering personnel, we developed an estimated Owner's staffing profile, and converted that into Full-Time

Equivalent ("FTE") for estimating purposes. This was then compared against the historical average (10% of the direct construction costs) as a reasonable estimate for these indirect expenses.

Q19. DID S&L APPLY ANY ESCALATION FACTOR TO THESE ESTIMATES?

A. No, we did not. S&L estimates reflect the current costs as of the first quarter of 2022. It is my understanding Mr. Watson applies an escalation factor for purposes of his depreciation study.

Q20. IS THERE ANY CONTINGENCY BUILT INTO THE ESTIMATE?

A. Yes, there is. Based on the level of detail included in these estimates and the uncertainties of future costs, S&L would typically include a 15% contingency on the labor, a 15% contingency on materials, a negative 15% contingency on scrap value, and a 15% contingency on the indirect portions of the estimates. However, in its recent decisions in SWEPCO Docket Nos. 46449 and 51415, the Commission concluded that a 10% contingency rate was more appropriate for purposes of Commission rate-setting proceedings. Although S&L does not necessarily agree with the Commission's conclusions in Docket Nos. 46449 and 51415, we have included a 10% contingency for the categories just listed in the demolition cost studies, consistent with Commission precedent.

Q21. ARE THE DEMOLITION TECHNIQUES USED IN PREPARATION OF THE S&L DEMOLITION COST ESTIMATES EFFICIENT AND COST EFFECTIVE?

A. Yes. The demolition techniques and crew mixes assumed in the S&L cost estimates are efficient and cost effective. They are typical demolition techniques that are used in the industry and are comparable to techniques used by major demolition contractors who have competitively bid and successfully executed the subject work for many years.

Q22. WHAT IS YOUR OPINION CONCERNING THE REASONABLENESS OF THE ESTIMATES OF DISMANTLING COSTS CONTAINED IN EXHIBIT SCM-2?

A. Based on my industry experience, these estimates were carefully prepared using accepted estimating techniques and the best information available. It is my opinion that the assumptions made in the studies are reasonable.

Q23. HAVE PREVIOUS DEMOLITION STUDIES CONDUCTED BY S&L BEEN FOUND TO BE REASONABLE BY THE COMMISSION?

A. Yes. S&L used the same approach to develop its demolition estimates for this proceeding as it did for SWEPCO in Commission Docket Nos. 40443 and 46449. In its October 10, 2013 Final Order in Docket No. 40443, the Commission found in its Finding of Fact No. 193 that "[t]he plant demolition studies SWEPCO used to develop terminal removal cost and salvage for each of SWEPCO's generating facilities are reasonable. These studies were prepared by an experienced consulting engineering firm and incorporate reasonable methodology, data, assumptions, and engineering judgment." In Docket No. 46449, the Commission found in its Finding of Fact No. 177 that "[t]he plant demolition studies SWEPCO used to develop terminal removal cost and salvage for each of SWEPCO's generating facilities, when adjusted to account for a 10% contingency factor, are reasonable."

Q24. WHAT IS YOUR UNDERSTANDING OF HOW ETI USES S&L'S DEMOLITION STUDIES IN THIS RATE CASE?

A. I understand that Mr. Watson uses these studies to determine net salvage values for calculating production plant depreciation rates.

V. CONCLUSION

Q25. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

AFFIDAVIT OF SEAN C. MCHONE

THE STATE OF ILLINOIS)
)
COUNTY OF COOK)

This day, Sean C. McHone 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 Sean C. McHone. I am of legal age and a resident of the State of Illinois. 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.

Sean C. McHone

Sean C. McHone

SUBSCRIBED AND SWORN TO BEFORE ME, notary public, on this the 7th day of June 2022.

Lydia A Jackson Joshua

Notary Public, State of Illinois

My Commission expires:
Jan 18, 2023

OFFICIAL SEAL
LYDIA A JACKSON JOSHUA
NOTARY PUBLIC - STATE OF ILLINOIS
MY COMMISSION EXPIRES:01/18/23

Sean C. McHone
Senior Vice President – Project Director
Energy & Industrial Group

Sargent & Lundy

Summary

Sean is a registered professional engineer with 25 years of experience in power plant engineering and project management. His experience includes both new power plant projects, as well as several retrofit projects at existing plants.

Sean currently is the Project Director for multiple clients and projects in the Energy & Industrial Group. These projects involve multiple advanced class combined cycle projects, environmental retrofit projects, and new generation combined heat and power projects.

Education

University of Illinois at Chicago - B.S. Mechanical Engineering

Registrations

Registered Professional Engineer – Arkansas, Georgia, Illinois, Kansas, Louisiana, Michigan, Mississippi, New Mexico, Puerto Rico, and Texas

Proficiencies

- Project management and engineering
- Project scoping and proposal development
- Engineer, procure, construct (EPC) contract development and management
- Combined cycle and simple cycle power plants
- Power plant betterment and backfit work
- Natural gas systems and compression
- Project studies and development

Responsibilities

Sean serves as the primary executive point of contact for his group of clients. In this capacity, he advises the client on project development concerns, as well as ongoing projects' status via regular progress reports, during review meetings, and in day-to-day communications.

Sean is responsible for the overall planning, coordination, and performance monitoring of Sargent & Lundy project work. He leads the project staff in the preparation of the project's scope of work, including detailed engineering, procurement, and installation specifications, coordinating project engineering across all disciplines. He is also responsible for oversight and direction on project capital cost estimating, planning, and scheduling.

He is also responsible for providing home office support to the field erection staff. He ensures that the project work conforms to applicable Sargent & Lundy standards, procedures, and specifications. On major purchases, he works with the client and vendors to select equipment best suited for specialized plant operating duty. He also works with clients in evaluating, selecting, and negotiating with construction contractors.

Sargent & Lundy Experience

Calpine

- Deer Park Energy Center – CO2 Capture Project. Project Director for the Front-End Engineering and Design (FEED) Study of installing a carbon capture system at an existing natural gas-fired cogeneration combined cycle facility in Texas Gulf Coast region. The project scope includes the complete balance of plant (BOP) systems to support the CO_2 capture system, as well as coordination of the CO_2 capture technology OEM. The S&L scope of work includes:
  - Project design basis development
  - BOP engineer of record
  - Overall project management support
  - Project permitting management and coordination
  - Procurement management and support
  - Development of full scope EPC capital cost estimate

Confidential Client | 2021

Fleet Winterization Assessment - Project Director. Evaluation of client's entire fleet of power generation facilities to assess winter readiness. Facility review included evaluation of heat tracing condition / extent, enclosures, heating, material handling, etc. as required to ensure operational status during next extreme weather event. Project output included recommended physical changes as well as operational changes. Physical changes to be implemented under separate projects. Responsible for coordination of multiple walkdowns teams performing simultaneous evaluations.

Enchant Energy

- San Juan Generating Station – CO2 Capture Project. Project Director for the US Department of Energy funded Front-End Engineering and Design of the retrofit of the two coal-fired units with a post-combustion carbon capture system. The project scope includes the complete balance of plant (BOP) systems to support the CO_2 capture system, as well as selection and coordination of the CO_2 capture technology OEM. The S&L scope of work includes:
  - Project design basis development
  - BOP engineer of record
  - Overall project management support
  - Project permitting management and coordination
  - Procurement management and support
  - Development of full scope EPC capital cost estimate

Confidential Client

- Confidential Combined Cycle Plant – CO2 Capture Project. Project Director for the Techno-Economic Assessment of installing a carbon capture system at an existing natural gas-fired combined cycle facility in the western U.S. The project scope includes evaluating the various technology options for hydrogen generation and co-firing as well as post-combustion carbon capture and compression. The S&L scope of work includes:
  - Project design basis development
  - Conceptual engineering
  - Capital and operating cost estimate development
  - Permitting assessment
  - Assessment of carbon capture basis
  - Evaluation of levelized “cost of capture” and tax credit opportunity

Star West Generation

- Arlington Valley Energy Center – Gas Pipeline and Metering Project. Project Director for the addition of a new natural gas pipeline interconnection to the Arlington Valley Energy Center. The plant is an operating combined cycle plant located inside an operating refinery. The project includes a new metering and regulating skid, and interconnecting piping. The S&L scope of work includes:
  - Detailed engineering and design.
  - Procurement support and technical specification development.
  - Construction Management.
  - Startup and Commissioning Management

Consumers Energy Company

- Freedom Compressor Station Project (2016 - Present). Project Director as Engineer of Record for the new Plant 3 natural gas compressor station. The project will consist of five (5) 3,750 HP engine driven industrial high-speed separable reciprocating compressors. The S&L scope of work includes:
  - Detailed engineering and design.
  - Procurement support and technical specification development.
  - Construction Management.
  - Startup and Commissioning Management

Consumers Energy Company

- JH Campbell Units 1 & 2 Dry Fly Ash Upgrade Project (2016 – 2019). Project Director for the conceptual and detailed design phases of Dry Fly Ash Upgrade. The project will upgrade the existing Unit 1 and 2 dry fly ash system to achieve a capacity factor of 2.0 through the installation and integration of a third transfer station. Engineer of Record for the new Plant 3 natural gas compressor station. The S&L scope of work includes:
  - Detailed engineering and design.
  - Procurement support and technical specification development.
  - Construction Management.
  - Startup and Commissioning Management

Cogen Technologies Linden

- Linden Cogen Facility – Gas Pipeline and Metering Project. Project Director for the addition of two (2) new natural gas pipeline interconnections to the Linden Cogeneration Facility. The Plant is a six (6) unit cogen plant located inside an operating refinery. The project includes two (2) new metering and regulating skids, and interconnecting piping. The S&L scope of work includes:
  - Detailed engineering and design.
  - Procurement support and technical specification development.
  - Construction Management.
  - Startup and Commissioning Management

Entergy

- St. Charles Combined Cycle Project (2015 – 2020)
- Lake Charles Combined Cycle (2017 – 2020)
- Montgomery County Combined Cycle (2017 – Present)

Project Director as Owner's Engineer for three (3) combined cycle projects in parallel with staggered starts. Three (3) 2x2x1 MHI 501 GAC combined cycle. The S&L scope of work includes:

- Technology studies.
- Capital cost estimates.
- Layout and general arrangements.
- Project design criteria.
- Project management support to Entergy.
- Execution schedules.
- EPC Contract development support
- Oversight and management of EPC Contractor

Invenergy Mexico

- Cactus Cogeneration Facility (2015 – 2018). Project Director for a new natural gas fired combined cycle cogeneration project located in Mexico. The project scope includes a new natural gas cogeneration facility consisting of multiple gas turbine/HRSG combinations supplying electricity and steam to a gas processing facility, as well as power into the grid. The S&L scope of work includes:
  - Power generation technology selection.
  - Basic engineering and design.
  - Layout development.
  - Capital cost estimate.
  - Permit support.
  - Procurement support and technical specification development.

Confidential Client

- New Natural Gas-Fired Cogeneration Facility (2014). Project Director for a new combined heat and power (cogeneration) facility in Canada. The project scope includes a new natural gas cogeneration facility consisting of one or more gas turbine/HRSG combinations at an existing industrial facility. The S&L scope of work includes:
  - Power generation technology selection.
  - Balance of Plant engineering and design.
  - Electrical interconnect with industrial plant and local transmission system
  - Layout development.
  - Capital cost estimate.
  - Permit support.
  - Procurement support and technical specification development.

Air Liquide

- Auxiliary Boiler Project (2012-2015). Project Director for detailed design engineering scope of new gas-fired boiler project. The scope of the project includes the procurement of, and installation of three (3) new 400,000 lb./hr. natural gas-fired boilers. The S&L scope of work includes:
  - BOP engineering and design.
  - Project management support for Air Liquide.
  - Capital cost estimates.
  - Permit support.
  - Procurement support and technical specification development.

Entergy

- Multi-Station MATS Compliance Project (2012 – 2015). Project Director for Owner's Engineering scope of work on Entergy MATS Compliance Project. The project covers seven units at three stations: White Bluff, Independence, and Nelson. The S&L scope of work includes:
  - Technology studies.
  - Capital cost estimates.
  - Layout and general arrangements.
  - Project design criteria.
  - Project management support to Entergy.
  - Process flow diagrams.
  - Execution schedules.
  - EPC execution specification (bid and evaluation).
  - Oversight and management of EPC Contractor
  - Construction and commissioning management in field

Confidential Client

- New Natural Gas-Fired Cogeneration Facility (2012). Project Manager for conceptual engineering phase of the new cogeneration facility. The project scope includes a new natural gas cogeneration facility consisting of one or more gas turbine/HRSG combination and multiple gas-fired boilers. The S&L scope of work includes:
  - Power generation technology study.
  - Layout development.
  - Capital cost estimates.
  - Permit support.
  - Procurement support and technical specification development.

NRG Energy

- Multi-Station MATS Compliance Project (2012). Project Manager for the balance-of-plant (BOP) scope on NRG Energy's MATS Compliance Project at the Big Cajun II, Limestone, and WA Parish stations. The scope of the project includes all selection of the mercury control technologies, as well as development of equipment specifications to purchase the equipment. Also includes all BOP systems to support the installation of the selected environmental control technologies. The S&L scope of work includes:
  - Project management support to NRG.
  - BOP engineering and design.
  - Procurement support and technical specification development.
  - Development and management of integrated project schedule and controls between S&L, NRG, and all other project participants.

NRG Energy / Petra Nova

- Parish Carbon Capture / Combustion Turbine Cogeneration Project (2010-2012). Project Manager for Owner's Engineering and Balance-of-Plant (BOP) scope on the WA Parish Carbon Capture / Combustion Turbine Cogeneration Project. The scope of the project includes all BOP systems to support the installation of a CO2 capture system on an existing coal-fired unit at the Parish Station. The BOP scope includes the installation of a new combustion turbine generator (CTG) and heat recovery steam generator (HRSG) to provide the auxiliary power and steam supply for the CO2 Capture project. The S&L scope of work includes:
  - BOP engineering and design.
  - Project management support to NRG.
  - Owner's engineer oversight of the CO2 capture vendor.
  - Development and management of integrated project schedule and controls between S&L, NRG, and all other project participants.
- St. Lucie County Plasma Gasification Project (2011). Project Manager for S&L as the BOP engineer on the St. Lucie County Gasification Project. The S&L scope of work includes:
  - Conceptual engineering and design.
  - Development of capital cost estimate.
  - Permitting support.

- ACUA Plasma Gasification Project (2010-2011). Project Manager for S&L as the BOP engineer on the ACUA Gasification Project. The scope of the project includes:
  - Conceptual engineering and design.
  - Permitting support.
- Oswego RACT / BART Engineering Evaluation (2010). Project Manager for preparation of a Reasonably Available Control Technology / Best Available Retrofit Technology evaluation for NOX, PM, and SO2 on Units 5 and 6 at NRG Energy's Oswego Station.

Confidential Client

- New Coal-Fired Power Plant (2010). Project Manager for the conceptual engineering and permitting phase of a new two-unit coal-fired power plant.

Kansas City Power & Light

- La Cygne Station 1 and 2 Environmental Retrofit Project (2008 – 2010). Engineering Manager for the conceptual engineering phase of two-unit multi-pollutant air-quality control retrofit project. The project consists of two wet-FGD systems, two fabric filters, one SCR and Low-NOX burner/overfire air system installation. Engineering manager responsible for overseeing and coordinating all engineering and design disciplines.

Duke Energy

- FGD Retrofit Conceptual Design and Cost Estimate (2008). Project Manager for development of conceptual design and cost estimate for addition of multiple unit FGD system at an existing plant. Primary responsibilities included:
  - Working with client to determine the FGD retrofit design basis and criteria.
  - Coordination of multiple engineering disciplines' development of conceptual plant designs and project cost estimate inputs.
  - Development of conceptual site general arrangements. These GAs provide the basis for estimating commodity quantities for input to the order of magnitude cost estimate.
  - Development of conceptual system designs for major BOP systems.
- New Supercritical Unit Conceptual Technology Evaluation (2008). Project Coordinator for study to evaluate the feasibility of, and issues associated with, constructing a new supercritical unit at an existing station. Primary responsibilities included:
  - Working closely with the client to identify the technology configurations, and performance conditions to study.
  - Preparation of a technology assessment, including developing heat balance calculations to establish the viability of the available technologies to be considered in the conceptual plant development.
  - Development of conceptual site general arrangements and evaluating constructability issues associated with the station.
  - Development of a plant water balance to identify water demands, and wastewater flows.
  - Develop proposed conceptual wastewater system, including equipment layout as well as an assessment of applicable regulatory requirements and their impacts.

- Combustion Turbine Multiple Site Retirement Plan (2008). Project Coordinator for engineering support to client in developing a plan for the retirement of three combustion turbine facilities. Prepared capital cost estimates to dismantle and prepare for shipment salvageable major equipment at each facility. Developed plans for rig out and shipment of equipment for sale off site.

Lansing Board of Water & Light

- Station Expansion Study and Generation Technology Evaluation (2007-2008). Project Coordinator for study to evaluate different generating technology options for the addition of a new unit at an existing station. Primary responsibilities included:
  - Worked closely with client to identify technology/capacity combinations to study.
  - Preparation of a technology assessment to establish the viability of the available technologies to be considered in the conceptual plant development.
  - Development of conceptual site general arrangements. These GAs provided the basis for estimating commodity quantities for input to the order of magnitude cost estimate.
  - Development of conceptual system designs for major BOP systems.
  - Coordination of multiple engineering disciplines' development of conceptual plant designs and project cost estimates.
  - Coordination of financial evaluation model development.
  - Preparation of the study report.
- Mercury Regulation Study (2007). Project Coordinator for study to evaluate the costs and impacts of proposed mercury control legislation on the Owner's generating assets.

Confidential IPP Client

- CFB Cost Estimate and Conceptual Design (2007). Lead Mechanical Engineer for development of conceptual design and cost estimate for new 660 MW CFB cogeneration facility. Primary responsibilities included:
  - Development of conceptual site and power block area general arrangements. These GAs provide the basis for estimating commodity quantities for input to the detailed cost estimate.
  - Working closely with client to establish design basis and design criteria for the plant.
  - Development of conceptual system designs for major BOP systems.
  - Review of conceptual P&IDs based on preliminary sizing for critical systems.
  - Coordination and development of detailed cost estimate.
  - Interfacing with various equipment/component suppliers to obtain budgetary pricing and lead times.

Duke Energy (formerly Cinergy)

- Gibson 1-3 FGD Retrofit Project (2003 to 2007). Lead Mechanical Engineer for Flue Gas Desulfurization (FGD) System Retrofit. Primary responsibilities included:
  - Preliminary system layout and design.
  - Coordination of preparation and review of all BOP P&IDs.
  - Coordination of all BOP mechanical calculations.
  - Preparation, bid evaluation, and coordination of mechanical installation contract.
  - Provide Chicago office field support during construction and startup.

  - Preparation/review of equipment specifications.

GE International/Dominion Energy

- Possum Point and Dresden Stations (550 MW 2x2x1 sister stations). BOP Design – Lead Mechanical Engineer. Responsible for overseeing, supervising, development and approval of all mechanical engineering work associated with the design of the Possum Point 6 and Dresden Energy combined cycle projects. Possum Point 6 is a new generation project at an existing facility, requiring some retrofit work. Existing intake structure modified to accept new raw water pumps and replacement traveling screens for the new combined cycle units. (2001 to 2003)

Dairyland Power Cooperative

- Elk Mound Generating Station. Mechanical Engineer – Provided mechanical engineering and design for a new two-unit simple cycle facility with GEEPE PG6581B (Frame 6B) Gas Turbines. (2000 to 2001)

Constellation Power Source

- 2001 Peaker Program. Mechanical Engineer – Provided mechanical engineering and design for three new five and six-unit simple cycle facilities with Pratt and Whitney FT8 Twin-Pac Gas Turbines. (2000 to 2001)

Cinergy Corporation

- Gibson 2 / Miami Fort 8. Provided engineering support and design calculations in support of selective catalytic reduction (SCR) retrofit design. Responsibilities included conceptual and detailed mechanical system design, system and equipment sizing calculations, preparation of P&IDs, and preparation of procurement specifications. Additional scope of work included performing life-cycle cost analyses to aid client in selecting the better equipment procurement option, as well as overall mechanical interface of systems with other disciplines. (1999 to 2000)

Calpine Corporation

- Magic Valley Generating Station. Provided engineering support on a 2x2x1 Siemens-Westinghouse 501G combined cycle power plant being built near Edinburg, Texas. Scope of work included detailed system design, preparation of P&ID's and associated system design calculations, equipment sizing, and preparation of plant water balance. Additional responsibilities included the preparation of equipment lists and bills of material for procurement, and support of prime contractor specification preparation. (1998 to 1999)

Other Experience

Nuclear Power Experience

Commonwealth Edison Company

- Byron/Braidwood 1 and 2, nuclear, 1105/1130 MW
  - Validated existing FLO-SERIES model using the results of an approved calculation. Additional cases were created and computed to determine maximum pump flowrate during a postulated LOCA. (1998)
  - Using the validated FLO-SERIES Containment Spray (CS) model, the degradation level of the CS pumps during a postulated LOCA was investigated. Using the new pump degradation, a minimum nozzle flowrate and pressure drop determination was performed. (1998)

- LaSalle 1 and 2, nuclear, 1132 MW each
  - Performed independent technical review of calculation for reactor building transient conditions following Reactor Water Clean Up (RWCU) and Reactor Core Isolation Cooling (RCIC) High Energy Line Breaks (HELB). (1998)
  - Performed independent technical review of Core Standby Cooling System (CSCS) hydraulic model calculation performed using FLO-SERIES. (1998)
  - Assisted in preparation of calculation analyzing transient conditions following HELBs. (1997 to 1998)

Wisconsin Electric Power Company

- Point Beach 1 and 2, nuclear, 485 MW. Provided independent technical review of calculation regarding service water pump house differential pressure during a tornado. (1998)

Memberships

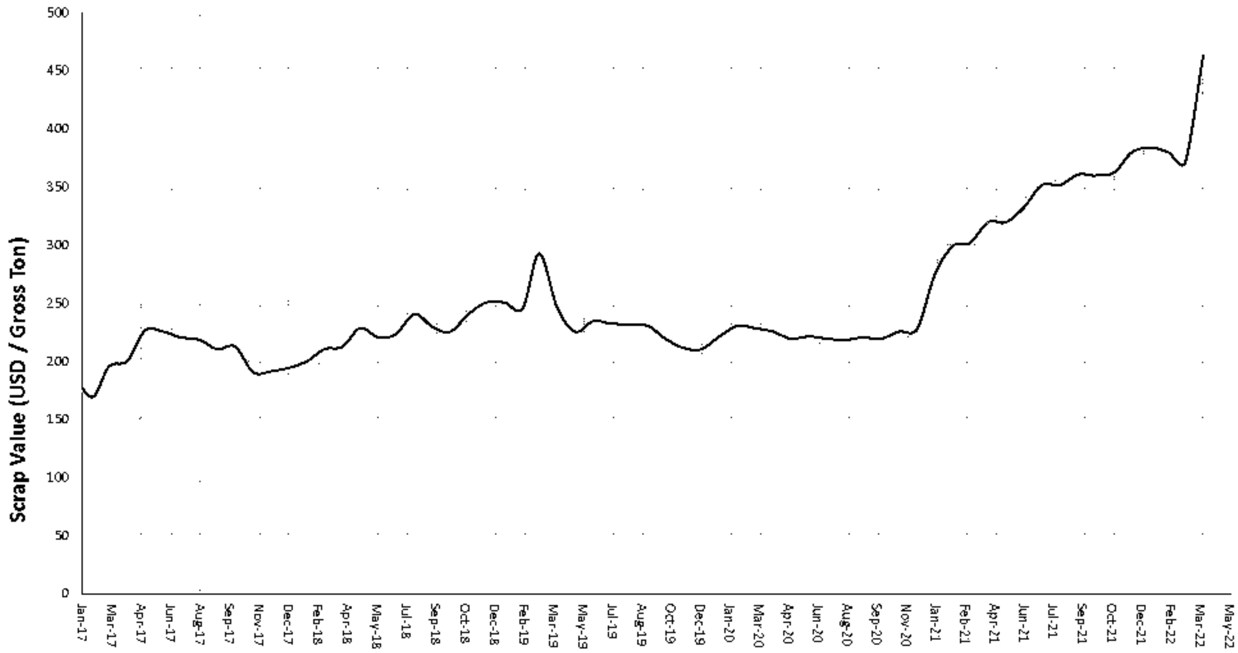
- University of Illinois, Master of Energy Advisory Council Member
- American Society of Mechanical Engineers

Publications

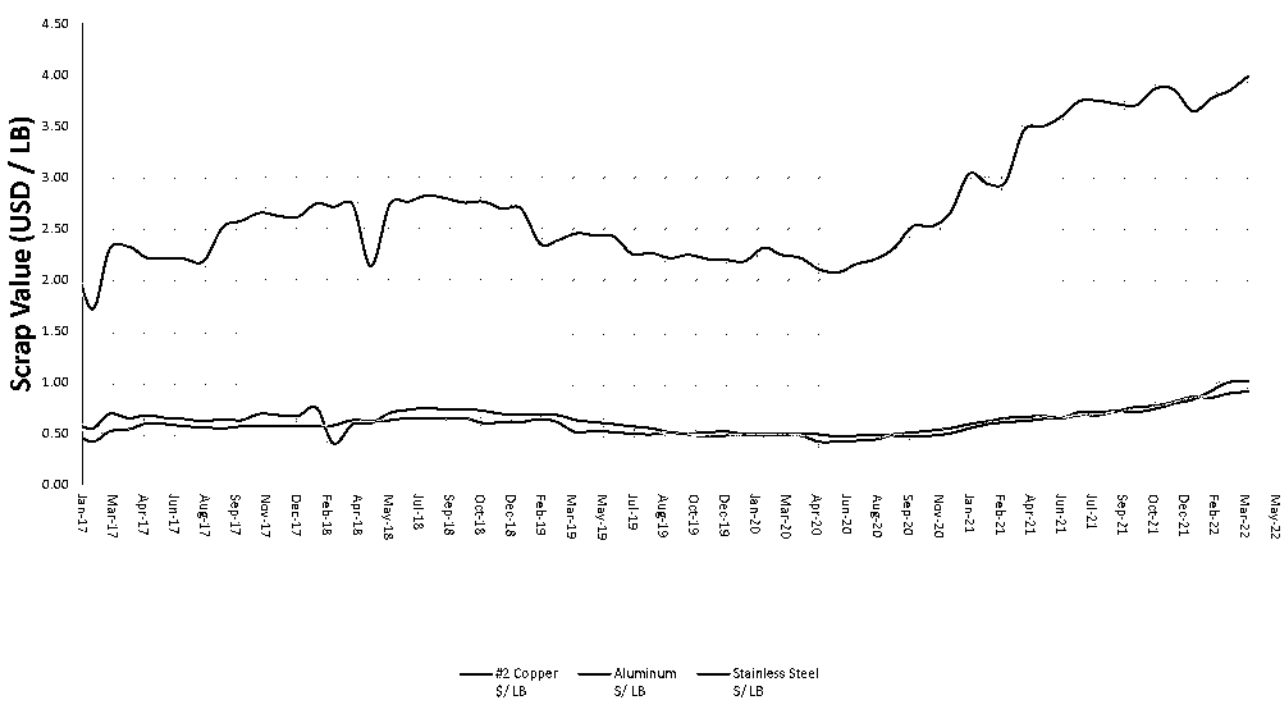
- "Repowering Coal-, Gas-, and Oil-Fired Plants, Benefits and Opportunities with Reusing Existing Equipment," POWER-GEN International 2011

This exhibit contains voluminous information that is being provided electronically.

Scrap Metal Value - Steel



Scrap Metal Volatility Chart - Copper / Aluminum / Stainless Steel



Source - Scrap Metals Marketwatch
(www.americanrecycler.com)

Date	Steel $ / Gross Ton
01-Jan-17	186
01-Feb-17	169
01-Mar-17	195
01-Apr-17	200
01-May-17	226
01-Jun-17	225
01-Jul-17	220
01-Aug-17	218
01-Sep-17	210
01-Oct-17	212
01-Nov-17	190
01-Dec-17	191
01-Jan-18	194
01-Feb-18	200
01-Mar-18	210
01-Apr-18	212
01-May-18	228
01-Jun-18	220
01-Jul-18	223
01-Aug-18	240
01-Sep-18	229
01-Oct-18	225
01-Nov-18	240
01-Dec-18	250
01-Jan-19	250
01-Feb-19	245
01-Mar-19	292
01-Apr-19	245
01-May-19	225
01-Jun-19	234
01-Jul-19	232
01-Aug-19	231
01-Sep-19	230
01-Oct-19	219
01-Nov-19	211
01-Dec-19	210
01-Jan-20	221
01-Feb-20	230
01-Mar-20	228
01-Apr-20	225
01-May-20	219
01-Jun-20	221
01-Jul-20	219
01-Aug-20	218
01-Sep-20	220
01-Oct-20	219
01-Nov-20	225
01-Dec-20	227
01-Jan-21	275
01-Feb-21	299
01-Mar-21	301
01-Apr-21	319
01-May-21	319
01-Jun-21	332
01-Jul-21	351
01-Aug-21	351
01-Sep-21	360
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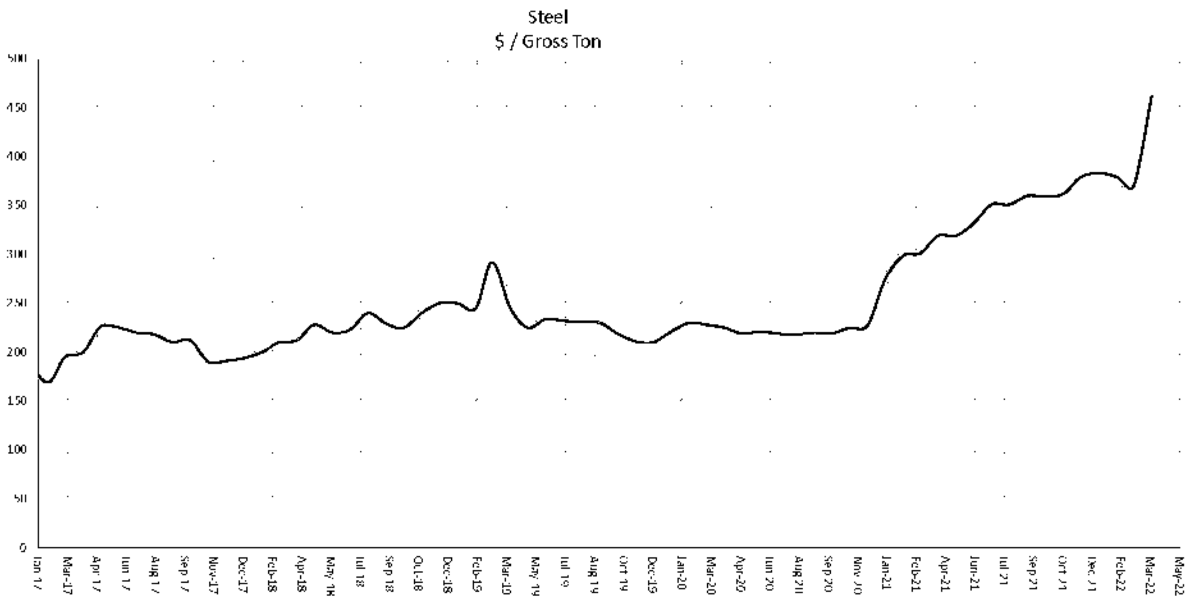
01-Mar-22	370
01-Apr-22	462

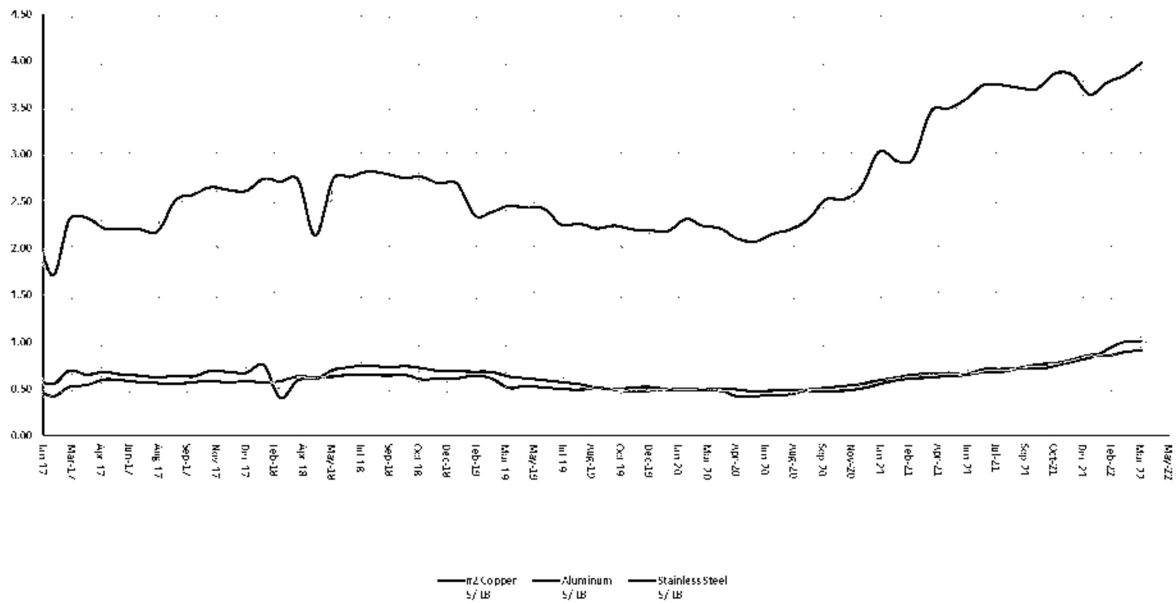


	Jan-18	194
	Mar-18	210
	Mar-22	370
	Apr-22	462
3-mos Ave (J-M)		377
	5-yr Ave	253

Source - Scrap Metals Marketwatch
(www.americanrecycler.com)

Date	#2 Copper $/ LB	Aluminum $/ LB	Stainless Steel $/ LB
01-Jan-17	2.20	0.60	0.50
01-Feb-17	1.71	0.55	0.42
01-Mar-17	2.30	0.69	0.52
01-Apr-17	2.32	0.65	0.54
01-May-17	2.21	0.68	0.60
01-Jun-17	2.21	0.65	0.59
01-Jul-17	2.20	0.64	0.57
01-Aug-17	2.18	0.62	0.56
01-Sep-17	2.51	0.64	0.55
01-Oct-17	2.57	0.63	0.57
01-Nov-17	2.65	0.69	0.58
01-Dec-17	2.62	0.68	0.57
01-Jan-18	2.61	0.67	0.58
01-Feb-18	2.74	0.75	0.57
01-Mar-18	2.71	0.40	0.58
01-Apr-18	2.73	0.59	0.63
01-May-18	2.13	0.60	0.62
01-Jun-18	2.74	0.70	0.63
01-Jul-18	2.76	0.73	0.65
01-Aug-18	2.82	0.75	0.65
01-Sep-18	2.79	0.73	0.64
01-Oct-18	2.75	0.74	0.65
01-Nov-18	2.76	0.72	0.60
01-Dec-18	2.69	0.69	0.61
01-Jan-19	2.69	0.69	0.61
01-Feb-19	2.35	0.68	0.64
01-Mar-19	2.38	0.68	0.61
01-Apr-19	2.45	0.63	0.51
01-May-19	2.43	0.61	0.53
01-Jun-19	2.42	0.59	0.51
01-Jul-19	2.25	0.57	0.50
01-Aug-19	2.26	0.55	0.49
01-Sep-19	2.21	0.51	0.51
01-Oct-19	2.24	0.50	0.49
01-Nov-19	2.20	0.51	0.47
01-Dec-19	2.19	0.52	0.48
01-Jan-20	2.18	0.49	0.49
01-Feb-20	2.31	0.48	0.50
01-Mar-20	2.24	0.49	0.49
01-Apr-20	2.21	0.50	0.48
01-May-20	2.10	0.49	0.42
01-Jun-20	2.07	0.47	0.42
01-Jul-20	2.15	0.48	0.43
01-Aug-20	2.20	0.49	0.44
01-Sep-20	2.31	0.48	0.49
01-Oct-20	2.52	0.47	0.51
01-Nov-20	2.52	0.48	0.53
01-Dec-20	2.65	0.50	0.55
01-Jan-21	3.03	0.55	0.59
01-Feb-21	2.93	0.59	0.62
01-Mar-21	2.95	0.61	0.65
01-Apr-21	3.46	0.62	0.66
01-May-21	3.49	0.64	0.67
01-Jun-21	3.59	0.65	0.65
01-Jul-21	3.74	0.71	0.68
01-Aug-21	3.74	0.71	0.68
01-Sep-21	3.71	0.72	0.72
01-Oct-21	3.70	0.71	0.76
01-Nov-21	3.86	0.74	0.77
01-Dec-21	3.85	0.79	0.81
01-Jan-22	3.64	0.83	0.86
01-Feb-22	3.77	0.92	0.85
01-Mar-22	3.84	1.00	0.89
01-Apr-22	3.98	1.01	0.91

Scrap Metal Volatility Chart

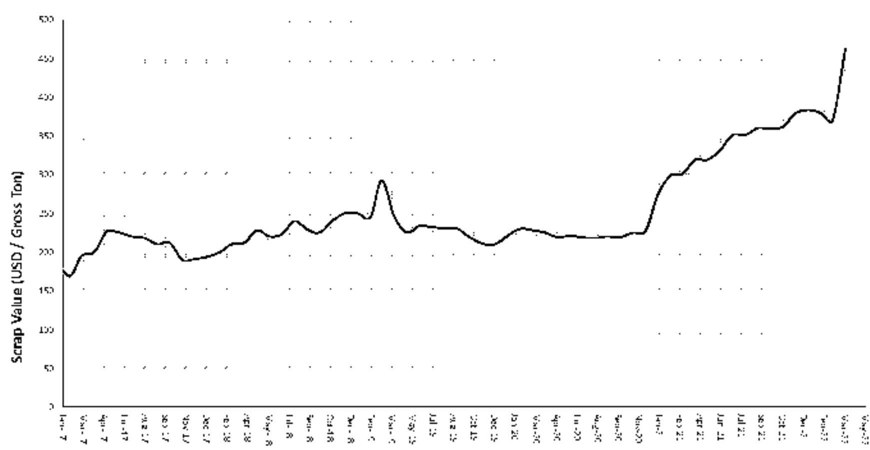


Historical Scrap Values 4/12/2022

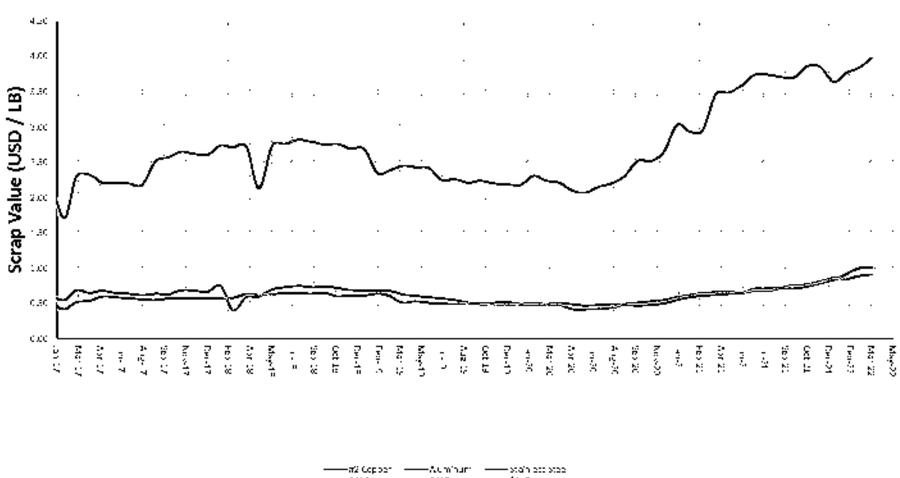
Scrap Value Historical Averages				
	#2 Copper $/ LB	Aluminum $/ LB	Stainless Steel $/ LB	Steel $ / Gross Ton
3 month	$3.86	$0.93	$0.83	$404
6 month	$3.82	$0.88	$0.85	$389
1 year avg	$3.74	$0.79	$0.77	$367
3 year avg	$2.86	$0.61	$0.60	$280
5 year avg	$2.74	$0.63	$0.60	$258
1/17-4/22 avg	$2.70	$0.63	$0.59	$253

Sabine Estimate Scrap	
	($M)
2018 (Final)	$20.9
2022 (Rev. B)	$38.8
2022 (revised)	$24.5

Scrap Metal Value - Steel



Scrap Metal Volatility Chart - Copper / Aluminum / Stainless Steel



DOCKET NO. 53719

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

DIRECT TESTIMONY

OF

DANE A. WATSON

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2022

ENTERGY TEXAS, INC.
DIRECT TESTIMONY OF DANE A. WATSON
2022 RATE CASE

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dane A. Watson. My business address is 101 E. Park Blvd., Suite 220, Plano, Texas 75074.

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

A. I am a Partner in Alliance Consulting Group ("Alliance"), which provides consulting and expert services to the utility industry.

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

A. I am testifying on behalf of Entergy Texas, Inc. ("ETI" or "the Company"). I performed the Company's last three depreciation studies, which were presented in Public Utility Commission of Texas ("PUCT" or "Commission") Docket Nos. 39896, 44704, and 48371, respectively.

Q4. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. I hold a Bachelor of Science degree in Electrical Engineering from the University of Arkansas at Fayetteville and a Master's Degree in Business Administration from Amberton University. Since graduation from college in 1985, I have worked in the area of depreciation and valuation. I founded Alliance Consulting Group in 2004 and am responsible for conducting depreciation, valuation, and certain other accounting-related studies for utilities in various regulated industries.

My duties related to depreciation studies include the assembly and analysis of historical and simulated data, conducting field reviews, determining service life and net salvage estimates, calculating annual depreciation, presenting recommended depreciation rates to utility management for its consideration, and supporting such rates before regulatory bodies.

My prior employment from 1985 to 2004 was with Texas Utilities ("TXU"). During my tenure with TXU, I was responsible for, among other things, conducting valuation and depreciation studies for the domestic TXU companies. During that time, I also served as Manager of Property Accounting Services and Records Management in addition to my depreciation responsibilities.

Q5. PLEASE DESCRIBE THE DUTIES OF YOUR PRESENT POSITION.

A. My current responsibilities with Alliance Consulting Group revolve around the preparation and support of depreciation studies for various entities across the United States.

Q6. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals (the "Society") has established national standards for depreciation professionals. The Society administers an examination and has certain required qualifications to become certified in this field. I have met all requirements and am a Certified Depreciation Professional ("CDP").

Q7. PLEASE DESCRIBE YOUR INVOLVEMENT WITH ANY PROFESSIONAL SOCIETIES OR COMMITTEES.

A. I have twice been Chair of the Edison Electric Institute ("EEI") Property Accounting and Valuation Committee and have been Chairman of EEI's Depreciation and Economic Issues Subcommittee. I am a Registered Professional Engineer ("PE") in the State of Texas and a CDP. I am a Senior Member of the Institute of Electrical and Electronics Engineers ("IEEE") and have held numerous offices on the Executive Board of the Dallas Section of IEEE as well as national and worldwide offices. I have twice served as President of the Society, most recently in 2015. I also teach depreciation seminars on an annual basis for EEI and the American Gas Association (both basic and advanced levels), and I develop and teach the advanced training for the Society and other venues.

Q8. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE TEXAS PUBLIC UTILITY COMMISSION?

A. Yes. I have conducted depreciation studies, filed written testimony and testified before the PUCT for more than two decades in PUCT Docket Nos. 11735, 12160, 15195, 16650, 18490, 20285, 22350, 23640, 24040, 32766, 34040, 35763, 35717, 36633, 38147, 38339, 38480, 38929, 39896, 40020, 40604, 40606, 40824, 41474, 42004, 42469, 43695, 43950, 43950, 44704, 44746, 45414, 46957, 47527, 48371, 48231, 48401, 49421, 49831, 50288, 50557, 50944, 51536, 51611, 51802, and 53601 on behalf of TXU Electric Company, TXU Fuel Company, TXU Mining Company, Oncor Electric Delivery, Texas New Mexico Power Company, CenterPoint Energy Houston Electric, LLC, Southwestern Public Service Company, City Public Service Board of San Antonio, Entergy Texas, Sharyland Utilities, Lone Star Transmission, Cross Texas Transmission, and Wind Energy Transmission Texas, Brownsville Public Utilities Board, Corix Utilities, Kerrville Public Utility District, and Monarch Utilities.

Q9. HAVE YOU PREVIOUSLY TESTIFIED BEFORE OTHER REGULATORY BODIES?

A. Yes. I have conducted depreciation studies, filed written testimony, and appeared before numerous other state and federal agencies in my 37-year career in performing depreciation studies. A listing of my testimony appearances is found in Exhibit DAW-1.

II. <u>PURPOSE</u>

Q10. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Alliance Consulting Group was retained by ETI to conduct a depreciation rate study for its depreciable tangible assets subject to the Commission's jurisdiction. The purpose of my testimony is to sponsor and explain the recent Depreciation Study completed for ETI and to support and justify the recommended depreciation rate changes for ETI's facilities based on the results of the Depreciation Study.

Q11. DO YOU SPONSOR ANY EXHIBITS?

A. Yes. I am sponsoring the Depreciation Study conducted by Alliance Consulting Group for ETI. The Depreciation Study is attached to my testimony as Exhibit DAW-2.

Q12. WERE THE EXHIBITS YOU ARE SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

Q13. DO YOU SPONSOR ANY SPECIFIC RATE FILING PACKAGE SCHEDULE?

A. Yes, I co-sponsor Schedule D-5, which is the Depreciation Study attached to this testimony as Exhibit DAW-2.

III. <u>DEPRECIATION STUDY RESULTS</u>

Q14. WHAT DEPRECIATION RATES ARE BEING USED TO CALCULATE DEPRECIATION EXPENSE IN THIS CASE?

A. Exhibit DAW-2, Appendix A shows the computation of the proposed depreciation rates. Exhibit DAW-2, Appendix B demonstrates the changes in depreciation expense for the various accounts when the proposed depreciation rates are applied to plant balances at December 31, 2021. In summary, the study supports my proposal of the following relative changes in annual depreciation expense:

Steam Production	Increase	$66,549,518
Other Production	Increase	$5,455,644
Transmission	Increase	$1,338,369
Distribution	Increase	$9,869,247
General Depreciated Assets	Increase	$932,131
General Amortized Assets	Increase	$436
General Plant Reserve Deficiency	Decrease	$(473,346)
Total	Increase	$83,672,000

These figures are based on plant balances at December 31, 2021, and are provided to show the relative change in annual accrual associated with the proposed rates as reflected in Appendix B of Exhibit DAW-2.

Q15. ARE THE RESULTS OF YOUR DEPRECIATION STUDY REFLECTED IN THE TEST YEAR ENDING DECEMBER 31, 2021 COST OF SERVICE CALCULATION?

A. Yes. The testimony of Allison P. Lofton addresses how the proposed depreciation rates are reflected in ETI's cost of service.

Q16. DO YOU HAVE ANY PRO FORMA AMOUNTS TO BE CONSIDERED BY THE COMMISSION?

A. No.

Q17. WHEN DID THE LAST CHANGE IN THE COMPANY'S DEPRECIATION RATES OCCUR?

A. The last change in the Company's depreciation rates occurred in 2018. The depreciation rates were established in ETI's prior base rate case, Docket No. 48371, and were based on a depreciation study of plant in service at December 31, 2017.

Q18. WHY IS THERE A LARGE INCREASE IN THE PRODUCTION FUNCTION?

A. The Company has moved earlier the terminal retirement dates for two of its production units. In addition, the estimated dismantling costs have been updated in a Sargent & Lundy decommissioning study discussed by Company witness Sean McHone. The revised terminal retirement dates result in shorter remaining lives for those units, which creates the need to recover the remaining net book value in each generating unit over a shorter period, resulting in a significant increase in depreciation expense. Also, the additional investment in the Company's production assets since the last study will increase the depreciation expense needed to be recovered over the remaining lives of the generating facilities.

Q19. HOW DID YOU INCORPORATE THE DECOMMISSIONING STUDY RESULTS INTO YOUR DEPRECIATION STUDY?

A. In cases where ETI has partial ownership of a unit, I prorated the decommissioning cost based on ownership percentage. Then, the total cost was allocated across plant accounts based on gross investment within each generating station. No escalation of the estimated dismantling cost to the retirement date of the facility has been incorporated in the calculation of the proposed depreciation rates.

I then included those amounts in the net salvage for each unit and account. The only items that were not included in the dismantling cost allocation were (1) railcars at the Nelson plant in account 312.1, which were not included in the dismantling study, and (2) the fully accrued portion of the Spindletop natural gas facility.

Q20. HOW HAS PRODUCTION INVESTMENT AND RESERVE, WHICH IS THE BASIS OF THE CURRENT DEPRECIATION RATES, CHANGED SINCE 2017?

A. The first change is that there were substantial interim retirements between 2017 and 2021. Per Commission order,[1] projected interim retirement curves were not included in the approved depreciation rates. That means that any actual interim retirements from that era must now be made up by the remaining investment in the group. ETI retired over $37.6 million in production assets between 2018 and 2021.[2] The full cost of those assets has been charged to accumulated depreciation in accordance with Federal Energy Regulatory Commission ("FERC") rules.[3]

[1] *See, e.g., Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Order on Rehearing at Finding of Fact 195 (Mar. 6, 2014).

[2] This excludes retirement of Toledo Bend Hydro assets.

[3] FERC Uniform System of Accounts, Instruction 10F.

Due to the lack of projected interim retirements in historical rates, the remaining depreciation for those interim retirements will be recovered from future customers. While the Company is not seeking approval of interim retirements in this proceeding, I urge the Commission to approve in future proceedings the use of interim retirements in order to prevent significant depreciation expense increases and intergenerational inequity to customers in the future due to future interim retirements.

The second change that occurred was substantial interim removal cost was incurred between 2017 and 2021 related to the retirements mentioned above. Per Commission order, projected interim removal cost was not included in the approved depreciation rates. Instead, only an estimated negative 5 percent for terminal dismantling cost was included. ETI incurred over $13.6 million in interim removal cost between 2017 and 2021. The related interim removal cost was charged to accumulated depreciation in accordance with FERC rules.[4] That means that any actual interim removal cost from that period must now be recovered from future customers over the remaining life of the investment in the group. While the Company is not including interim net salvage cost here, I encourage the Commission to consider in future proceedings approving the use of interim net salvage in order to prevent significant depreciation expense increases and intergenerational inequity to customers in the future due to future interim retirements.

[4] *Id.*

The third change is that the Company has made significant capital expenditures in order to allow its production units to remain in service. The plant balance has grown by $118.2 million,[5] an increase of 10.56% in the period from 2018 to 2021. Those capital expenditures will need to be recovered over the remaining lives of the production facilities. Given the recent changes to the generating retirement unit schedule, this additional investment must be recovered over a shorter period than the original investment in the plants.

IV. ADJUSTMENT OF DEPRECIATION RESERVE

Q21. AS PART OF YOUR DEPRECIATION ANALYSIS, HAVE YOU TAKEN ANY ACTION TO PROPERLY ALIGN THE COMPANY'S DEPRECIATION RESERVE WITH THE LIFE CHARACTERISTICS OF THE PRODUCTION, TRANSMISSION, DISTRIBUTION, AND GENERAL PLANT FUNCTIONS?

A. Yes. In the process of analyzing the Company's depreciation reserve, I observed that the depreciation reserve positions of a number of accounts were generally not in line with the life characteristics found in the analysis of the Company's assets. For the production, transmission, distribution and general plant accounts, the reserves were reallocated within each function based on the theoretical reserves for each account to allow the relative reserve positions of each account within a function to mirror the life characteristics of the underlying assets. This is most evidenced by the fact that ETI is moving earlier two retirement dates for its production units. Reserve reallocation reduces the impact of recovering these

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[5] This amount is for the production function only.

investments by allocating the recovery across the remaining life of the generation still in service.

Q22. DOES THE REALLOCATION OF THE DEPRECIATION RESERVE CHANGE THE TOTAL RESERVE?

A. No. The depreciation reserve represents the amounts that customers have contributed to the return of the investment. The reallocation process does not change the total reserve for each function; it simply reallocates the reserve between accounts in the function.

Q23. IS DEPRECIATION RESERVE REALLOCATION A SOUND DEPRECIATION PRACTICE?

A. Yes. The practice of depreciation reserve reallocation is endorsed in the 1968 publication of "Public Utility Depreciation Practices," National Association of Regulatory Utility Commissioners ("NARUC"), which explains that reallocation of the depreciation reserve is appropriate "…where the change in the view concerning the life of property is so drastic as to indicate a serious difference between the theoretical and the book reserve." Additionally, the 1996 edition of the NARUC publication states that "theoretical reserve studies also have been conducted for the purpose of allocating an existing reserve among operating units or accounts." With respect to ETI, my Depreciation Study demonstrates that there have been significant changes in the life of the property over the last 5 years. These changes have created differences between the theoretical and the book reserve in each functional group that make the reallocation of the depreciation reserve appropriate in this instance.

Q24. WHY IS IT IMPORTANT FOR THE DEPRECIATION RESERVE TO CONFORM TO THE THEORETICAL RESERVE?

A. This is important because it sets the reserve at a level necessary to sustain the regulatory concept of intergenerational equity among ETI's customers, as well as set the depreciation rates at the appropriate level based on current parameters and expectations.

Q25. HAS THE COMMISSION APPROVED DEPRECIATION RESERVE REALLOCATION IN OTHER RATE PROCEEDINGS?

A. Yes. The Commission approved a reserve reallocation within each functional group in the recent cases for CenterPoint Energy Houston Electric, LLC in Docket No. 38339, ETI in Docket No. 39896, Sharyland Utilities, L.P. in Docket No. 41474, and Southwestern Public Service Company in Docket No. 43695.

Q26. HOW WILL THE COMPANY IMPLEMENT THE REALLOCATION OF ITS DEPRECIATION RESERVES IF THE PROPOSED DEPRECIATION RATES ARE APPROVED?

A. If the proposed depreciation rates are approved, the Company will reallocate the reserves on its books to match the allocation performed in this study using investment and depreciation reserve information at the time the new rates are implemented.

Q27. ARE ANY BALANCES FOR RETIRED PRODUCTION PLANTS INCLUDED IN THE REALLOCATION?

A. No.

V. OVERVIEW OF DEPRECIATION STUDY METHODOLOGY

Q28. WHAT DEFINITION OF DEPRECIATION HAVE YOU USED FOR THE PURPOSES OF CONDUCTING THE DEPRECIATION STUDY AND PREPARING YOUR TESTIMONY?

A. The term "depreciation," as used herein, is considered in the accounting sense; that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. Depreciation is a process of allocation, not valuation. Depreciation expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. Thus, depreciation is considered an expense or cost, rather than a loss or decrease in value. ETI accrues depreciation based on the original cost of all property included in each depreciable plant account. On retirement, the full cost of depreciable property, less the net salvage amount, if any, is charged to the depreciation reserve.

Q29. PLEASE DESCRIBE YOUR DEPRECIATION STUDY APPROACH.

A. I conduct a depreciation study in four phases as shown in my Exhibit DAW-2. The four phases are: Data Collection, Analysis, Evaluation, and Calculation. During the initial phase of the study, I collect historical data to be used in the analysis. After the data is assembled, I perform analyses to determine the life and net salvage percentage for the different property groups being studied. The information obtained from field personnel, engineers, and/or managerial personnel, combined with the study results, are then evaluated to determine how the results of the historical asset activity analysis, in conjunction with the Company's expected future plans, should be applied. Using all of these resources, I then calculate the depreciation rate for each function.

Q30. WHAT PROCESS HAVE YOU UNDERTAKEN TO GIVE EFFECT TO BOTH HISTORICAL DATA AND THE COMPANY-SPECIFIC EXPECTATIONS IN DEVELOPING YOUR SERVICE LIFE RECOMMENDATIONS FOR TRANSMISSION, DISTRIBUTION AND GENERAL PLANT?

A. In order to achieve a reasonable balance between these critical components of the life analysis, I evaluated the statistical historical data and then applied informed judgment to make the most appropriate service life selections. The objective in any depreciation study is to project the remaining cost (installation, material and removal cost) to be recovered and the remaining periods in which to recover the costs. This necessarily requires that the service life selections reflect both the Company's historic experience and its current expectations of asset lives. In order to understand the Company's expectations regarding asset lives, I interviewed Company engineers working in both operations and maintenance to confirm the historical activity and indications, current and future plans, expectations and their applicability to the future surviving assets. The interview process provides important information regarding changes in materials, operation and maintenance, as well as the Company's current expectations regarding the service life of the assets currently in use. This information is then considered along with the historical statistical data to develop the most reasonable and representative expected service lives for the Company's assets.[6] The result of all of this analysis is reflected in the service life recommendations set forth in my Depreciation Study.

Q31. WHAT DEPRECIATION SYSTEM DID YOU USE?

A. The straight-line method, Average Life Group ("ALG") procedure, and remaining-life technique comprise the depreciation system that was employed to calculate the annual accrual for depreciation expense in the study.

Q32. HOW ARE DEPRECIATION RATES DEVELOPED UNDER THE ALG SYSTEM?

A. In the ALG system, the annual depreciation expense for each account is computed by dividing the original cost of the asset, less allocated depreciation reserve, less estimated net salvage, by its respective remaining life. The resulting annual

[6] For production facilities, the Company provided terminal retirement dates.

accrual amount of depreciable property within an account is divided by the original cost of the depreciable property in the account to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The comparison of the current and recommended annual depreciation rates is shown in my Exhibit DAW-2, Appendix B. The remaining life calculations are discussed below and are shown in Exhibit DAW-2, Appendix F.

A. Service Lives

Q33. WHAT IS THE SIGNIFICANCE OF AN ASSET'S USEFUL LIFE IN YOUR DEPRECIATION STUDY?

A. An asset's useful life was used to determine the remaining life over which the remaining cost (original cost plus or minus net salvage, minus accumulated depreciation) can be allocated to normalize the asset's cost and spread it ratably over future periods.

Q34. HOW DID YOU DETERMINE THE AVERAGE SERVICE LIVES FOR EACH ACCOUNT?

A. The establishment of an appropriate average service life for each account within a functional group was determined by using actuarial analysis. Specifically, the service life for each account within the Transmission and Distribution, and General functional groups was determined by using the actuarial method of life analysis. Graphs and tables supporting the actuarial analysis and the chosen Iowa Curves used to determine the average service lives for each account are found in Exhibit DAW-2 and my Depreciation Study workpapers.

Q35. DOES YOUR DEPRECIATION STUDY REFLECT THE CHANGES IN THE USEFUL LIVES OF THE TRANSMISSION, DISTRIBUTION, AND GENERAL PLANT FUNCTION ASSETS?

A. Yes. My study strikes a reasonable balance between the historical statistical indications seen in the analysis and Company-specific expectations for the use of the assets to serve its customers.

Q36. HAVE YOU PREPARED A SUMMARY OF THE LIFE CHANGES BY ACCOUNT?

A. Yes. Figure 1 below provides the current and proposed life by account for all four functions; Production, Transmission, Distribution, and General Plant.

Figure 1

Account	Description		Current			Proposed	
				Iowa			Iowa
			Life	Curve		Life	Curve
	Production Plant						
311.0	Structures & Improvements			SQ			SQ
312.0	Boiler Plant Equip			SQ			SQ
314.0	Turbogenerator Equip			SQ			SQ
315.0	Accessory Elect Equip			SQ			SQ
316.0	Misc Power Plant Equip			SQ			SQ

		Current		Proposed	
			Iowa		Iowa
Account	**Description**	**Life**	**Curve**	**Life**	**Curve**
	Other Production Plant				
341.0	Structures & Improvements		SQ		SQ
342.0	Fuel Holders, Producers, & Acc		SQ		SQ
343.0	Prime Movers		SQ		SQ
344.0	Generators		SQ		SQ
345.0	Accessory Elect Equip		SQ		SQ
346.0	Misc Power Plant Equip		SQ		SQ
	Transmission Plant				
350.0	Land Rights	85	R3	85	R3
352.0	Structures & Improvements	82	R2.5	81	R3
353.0	Station Equipment	64	R1	64	R1
354.0	Towers & Fixtures	75	R4	75	R4
355.0	Poles & Fixtures	65	R1.5	70	R1.5
356.0	OH Conductors & Devices	70	R1.5	82	R1.5
358.0	UG Conductors & Devices	50	R2	50	R2
359.0	Roads & Trails	65	R5	65	R5
	Distribution Plant				
360.2	Land Rights	70	R3	70	R3
361.0	Structures & Improvements	83	R2.5	80	R1.5
362.0	Station Equipment	65	R1	65	R1
364.0	Poles, Towers & Fixtures	43	R1	45	R1
365.0	OH Conductors & Devices	42	R0.5	45	R1
366.0	UG Conduit	60	L0.5	50	R3
367.0	UG Conductors & Devices	42	R1	40	R2.5
368.0	Line Transformers	34	L0	37	L0.5
369.1	Services - Overhead	27	S4	29	S4
369.2	Services - Underground	36	R5	37	R5
370.0	Meters (Customer)	26	R1.5	17	L0
370.1	Meters (Substation)	26	R1.5	17	L0
370.15	Meters Smart	7	SQ	7	SQ
371.0	I.O.C.P	56	R4	32	R0.5
373.0	Street Lighting & Signal Sys	45	R2	32	R0.5

Account	Description	Current Life	Current Iowa Curve	Proposed Life	Proposed Iowa Curve
	General Depreciated Plant				
390.0	Structures & Improvements	50	R1	50	R1.5
397.2	Microwave & Fiber Optic	23	S5	23	S4
	General Amortized Plant				
390.1	Leasehold Improvements	Amortize over lease term			
391.1	Office Furniture & Equip	15	SQ	15	SQ
391.2	Computer Equip	5	SQ	5	SQ
391.3	Data Handling Equip	15	SQ	15	SQ
392.0	Transportation Equip	15	SQ	10	SQ
393.0	Stores Equip	15	SQ	15	SQ
394.0	Tools, Shop & Garage Equip	15	SQ	15	SQ
395.0	Laboratory Equip	10	SQ	10	SQ
396.0	Power Operated Equip	15	SQ	15	SQ
397.1	Communication Equip	10	SQ	10	SQ
398.0	Misc. Equipment	10	SQ	10	SQ

B. Net Salvage

Q37. WHAT IS NET SALVAGE?

A. While discussed more fully in the study itself, net salvage is the difference between the gross salvage (what is received in scrap value for the asset when retired) and the removal cost (cost to remove and dispose of the asset). Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset.

Q38. DOES ETI HAVE ANY NET SALVAGE REFLECTED IN ITS EXISTING DEPRECIATION RATES?

A. Yes. Both the Company's statistical data and input from Company engineers confirms that the net salvage reflected in the Company's current depreciation rates is no longer representative of the costs incurred to retire some of ETI's assets. These retirement costs continue to increase and require that net salvage rates be adjusted to reflect this reality, which I have done in my study.

Q39. HOW DID YOU DETERMINE THE NET SALVAGE PERCENTAGES FOR EACH ASSET GROUP?

A. I examined the experience realized by the Company by observing the actual net salvage for various bands (or combinations) of years. Using averages (such as the three-year and five-year bands) allows the smoothing of the timing differences between when retirements, removal cost, and salvage are booked. By looking at successive average bands ("rolling bands"), an analyst can see trends in the data that would indicate the future net salvage in the account. This examination, in combination with the feedback of Company engineers related to any changes in operations or maintenance that would affect the future net salvage of the asset, allowed the selection of the best estimate of future net salvage for each account. The net salvage as a percent of retirements for various bands (i.e., groupings of years such as the five-year average) for each account are shown in my Exhibit DAW-2, Appendix E. As with any analysis of this type, expert judgment was applied in order to select a net salvage percentage reflective of the future expectations for each account.

Q40. IS THIS A REASONABLE METHOD FOR DETERMINING NET SALVAGE RATES?

A. Yes. The method used to establish appropriate net salvage percentages for each account was determined by using the same methodology that was approved by the Commission in numerous prior cases that I have been involved in, as listed earlier in my testimony and in Exhibit DAW-1. It is also a methodology commonly employed throughout the industry and is a method recommended in authoritative texts.

Q41. WHAT FACTORS CAN CAUSE PLANT ASSETS TO EXPERIENCE SIGNIFICANT LEVELS OF NEGATIVE NET SALVAGE?

A. Some plant assets can experience significant negative removal cost percentages due to the timing of the addition versus the retirement. For example, a Transmission asset in FERC Account 355 with a current installed cost of $500 (2021) would have had an installed cost of $31.66[7] in 1951. A removal cost of $50 for the asset calculated (incorrectly) on current installed cost would only have a -10 percent removal cost ($50/$500). However, a correct removal cost calculation would show a -158 percent removal cost for that asset ($50/$31.66). Inflation from the time of installation of the asset until the time of its removal

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[7] Using the Handy-Whitman Bulletin No. 194, E-4, line 36, $31.66 = $500 x 38/600.

must be taken into account in the calculation of the removal cost percentage because the depreciation rate, which includes the removal cost percentage, will be applied to the <u>original</u> installed cost of assets. Other factors such as the synchronization of net salvage data can also affect the level of net salvage.

Q42. YOU MENTIONED EARLIER THAT THE CHANGE IN NET SALVAGE CONTINUES. CAN YOU ELABORATE?

A. Yes. The primary reason for the change in net salvage rates is that the Company continues to experience an increase in removal cost for Transmission and Distribution functions and gross salvage proceeds have declined for all functions. Increased environmental rules and regulations are a big driver for these changes. In addition, ETI is requesting terminal net salvage for Steam Production and Other Production facilities based on a dismantling study discussed in more detail by Company witness, Sean McHone. Figure 2 below provides the approved and proposed net salvage percentages for each account. More detail can be found in the Salvage Analysis section of Exhibit DAW-2 and in Exhibit DAW-2, Appendix D.

Figure 2

Account	Description	Approved Net Salvage	Proposed Net Salvage
	Production Plant[8]		
311.0	Structures & Improvements	-4.12%	-5.43%
312.0	Boiler Plant Equip	-6.66%	-10.12%

[8] Net salvage percentages for Production and Other Production are terminal net salvage percentages.

Account	Description	Approved Net Salvage	Proposed Net Salvage
314.0	Turbogenerator Equip	-3.77%	-6.22%
315.0	Accessory Elect Equip	-6.32%	-9.88%
316.0	Misc Power Plant Equip	-4.27%	-7.13%

* See Appendix D-1 through D-3 for terminal net salvage.

	Other Production		
341.0	Structures & Improvements	NA	-1.06%
342.0	Fuel Holders, Producers, & Acc	NA	-1.38%
343.0	Prime Movers	NA	-1.12%
344.0	Generators	NA	-0.95%
345.0	Accessory Elect Equip	NA	-1.05%
346.0	Misc Power Plant Equip	NA	-1.58%

	Transmission Plant		
350.0	Land Rights	0%	0%
352.0	Structures & Improvements	-20%	-30%
353.0	Station Equipment	-25%	-25%
354.0	Towers & Fixtures	-5%	-10%
355.0	Poles & Fixtures	-30%	-45%
356.0	OH Conductors & Devices	-30%	-45%
358.0	UG Conductors & Devices	0%	0%
359.0	Roads & Trails	0%	0%

	Distribution Plant		
360.2	Land Rights	0%	0%
361.0	Structures & Improvements	-10%	-15%
362.0	Station Equipment	-20%	-25%
364.0	Poles, Towers & Fixtures	-30%	-45%
365.0	OH Conductors & Devices	-20%	-30%
366.0	UG Conduit	-10%	-15%
367.0	UG Conductors & Devices	-1%	-5%
368.0	Line Transformers	-20%	-30%
369.1	Services - Overhead	-15%	-25%
369.2	Services - Underground	-10%	-15%
370.0	Meters (Customer)	-5%	-5%
370.1	Meters (Substation)	-5%	-5%
370.1	Meters Smart	0%	0%

Account	Description	Approved Net Salvage	Proposed Net Salvage
371.0	I.O.C.P	-10%	-15%
373.0	Street Lighting & Signal Sys	-20%	-30%
	General Depreciated Plant		
390.0	Structures & Improvements	-10%	-15%
397.2	Microwave & Fiber Optic	0%	0%
	General Amortized Plant		
390.1	Leasehold Improvements	0%	0%
391.1	Office Furniture & Equip	0%	0%
391.2	Computer Equip	0%	0%
391.3	Data Handling Equip	0%	0%
392.0	Transportation Equip	20%	20%
393.0	Stores Equip	0%	0%
394.0	Tools, Shop & Garage Equip	0%	0%
395.0	Laboratory Equip	0%	0%
396.0	Power Operated Equip	20%	20%
397.1	Communication Equip	0%	0%
398.0	Misc. Equipment	0%	0%

VI. CONCLUSION

Q43. PLEASE SUMMARIZE THE CONCLUSIONS YOU HAVE REACHED AS A RESULT OF YOUR ANALYSIS.

A. The Depreciation Study and analysis performed by me and under my supervision fully supports setting depreciation rates for ETI at the level I have indicated in my testimony and in Exhibit DAW-2. In this way, all customers are charged for their appropriate share of the capital expended for their benefit. The Depreciation Study of ETI depreciable property as of December 31, 2021 describes the extensive analysis performed and the resulting rates that are now appropriate for its respective property classes. ETI's depreciation rates should be set at the levels

I recommend in order to recover the Company's total investment in property over the estimated remaining life of the assets.

Q44. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

AFFIDAVIT OF DANE A. WATSON

THE STATE OF TEXAS)
)
COUNTY OF COLLIN)

This day, Dane A. Watson 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 Dane A. Watson. I am of legal age and a resident of the State of Texas. 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.

Dane A. Watson

Dane A. Watson

SUBSCRIBED AND SWORN TO BEFORE ME, notary public, on this the 9th day of June 2018.

TERESA CA. STEWART
Notary ID #132275553
My Commission Expires
December 6, 2023

Teresa C. Stewart

Notary Public, State of Texas

My Commission expires:

Dec. 3, 2023

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	53601	Oncor Electric Delivery	2022	Depreciation Rates
Michigan	Michigan Public Service Commission	U-21176	Consumers Gas	2021	Gas Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR21121254	Elizabethtown Natural Gas	2021	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	TA116-118, TA115-97, TA160-37 and TA110-290	Fairbanks Water and Wastewater	2021	Water and Waste Water Depreciation Study
Alaska	Regulatory Commission of Alaska	U-21-025	Golden Valley Electric Association	2021	Electric Depreciation Study
Colorado	Public Utilities Commission of Colorado	21AL-0317E	Public Service of Colorado	2021	Electric and Common Depreciation Study
Wisconsin	Public Serice Commission of Wisconsin	5-DU-103	WE Energies	2021	Electric and Gas Depreciation Study
Kentucky	Public Service Commission of Kentucky	2021-00214	Atmos Kentucky	2021	Gas Depreciation Study
Missouri	Missouri Public Service Commission	ER-2021-0312	Empire District Electric Company	2021	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-35951	Atmos Louisiana	2021	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015-D-21-229	Allete Minnesota Power	2021	Intangible, Transmission, Distribution, and General Depreciation Study
Michigan	Michigan Public Service Commission	U-20849	Consumers Energy	2021	Electric and Common Depreciation Study
Texas	Public Utility Commission of Texas	51802	Southwestern Public Service Company	2021	Electric Technical Update
MultiState	FERC	RP21-441-000	Florida Gas Transmission	2021	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	20-00238-UT	Southwestern Public Service Company	2021	Electric Technical Update
MultiState	FERC	ER21-709-000	American Transmission Company	2020	Electric Depreciation Study
Texas	Public Utility Commission of Texas	51611	Sharyland Utilities	2020	Electric Depreciation Study
Texas	Public Utility Commission of Texas	51536	Brownsville Public Utilities Board	2020	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	WR20110729	Suez Water New Jersey	2020	Water and Waste Water Depreciation Study
Idaho	Idaho Public Service Commission	SUZ-W-20-02	Suez Water Idaho	2020	Water Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	50944	Monarch Utilities	2020	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-20844	Consumers Energy/DTE Electric	2020	Ludington Pumped Storage Depreciation Study
Tennessee	Tennessee Public Utility Commission	20-00086	Piedmont Natural Gas	2020	Gas Depreciation Study
Texas	Railroad Commission of Texas	OS-00005136	CoServ Gas	2020	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10988	EPCOR Gas Texas	2020	Gas Depreciation Study
Florida	Florida Public Service Commission	20200166-GU	People Gas System	2020	Gas Depreciation Study
Mississippi	Federal Energy Regulatory Commission	ER20-1660-000	Mississippi Power Company	2020	Electric Depreciation Study
Texas	Public Utility Commission of Texas	50557	Corix Utilities	2020	Water and Waste Water Depreciation Study
Georgia	Georgia Public Service Commission	42959	Liberty Utilities Peach State Natural Gas	2020	Gas Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR20030243	South Jersey Gas	2020	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	20AL-0049G	Public Service of Colorado	2020	Gas Depreciation Study
New York	Federal Energy Regulatory Commission	ER20-716-000	LS Power Grid New York, Corp.	2019	Electric Transmission Depreciation Study
Mississippi	Mississippi Public Service Commission	2019-UN-219	Mississippi Power Company	2019	Electric Depreciation Study
Texas	Public Utility Commission of Texas	50288	Kerrville Public Utility District	2019	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10920	CenterPoint Gas	2019	Gas Depreciation Study and Propane Air Study
Texas, New Mexico	Federal Energy Regulatory Commission	ER20-277-000	Southwestern Public Service Company	2019	Electric Production and General Plant Depreciation Study
Alaska	Regulatory Commission of Alaska	U-19-086	Alaska Electric Light and Power	2019	Electric Depreciation Study
Delaware	Delaware Public Service Commission	19-0615	Suez Water Delaware	2019	Water Depreciation Study
Texas	Public Utility Commission of Texas	49831	Southwestern Public Service Company	2019	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	19-00170-UT	Southwestern Public Service Company	2019	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Georgia	Georgia Public Service Commission	42516	Georgia Power Company	2019	Electric Depreciation Study
Georgia	Georgia Public Service Commission	42315	Atlanta Gas Light	2019	Gas Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-19-0055	Southwest Gas Corporation	2019	Gas Removal Cost Study
New Hampshire	New Hampshire Public Service Commission	DE 19-064	Liberty Utilities	2019	Electric Distribution and General
New Jersey	New Jersey Board of Public Utilities	GR19040486	Elizabethtown Natural Gas	2019	Gas Depreciation Study
Texas	Public Utility Commission of Texas	49421	CenterPoint Houston Electric LLC	2019	Electric Depreciation Study
North Carolina	North Carolina Utilities Commission	Docket No. G-9, Sub 743	Piedmont Natural Gas	2019	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-121	Municipal Power and Light City of Anchorage	2018	Electric Depreciation Study
Various	FERC	RP19-352-000	Sea Robin	2018	Gas Depreciation Study
Texas New Mexico	Federal Energy Regulatory Commission	ER19-404-000	Southwestern Public Service Company	2018	Electric Transmission Depreciation Study
California	Federal Energy Regulatory Commission	ER19-221-000	San Diego Gas and Electric	2018	Electric Transmission Depreciation Study
Kentucky	Kentucky Public Service Commission	2018-00281	Atmos Kentucky	2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-054	Matanuska Electric Coop	2018	Electric Generation Depreciation Study
California	California Public Utilities Commission	A17-10-007	San Diego Gas and Electric	2018	Electric and Gas Depreciation Study
Texas	Public Utility Commission of Texas	48401	Texas New Mexico Power	2018	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	18-05031	Southwest Gas	2018	Gas Depreciation Study
Texas	Public Utility Commission of Texas	48231	Oncor Electric Delivery	2018	Depreciation Rates
Texas	Public Utility Commission of Texas	48371	Entergy Texas	2018	Electric Depreciation Study
Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power and Light	2018	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	18-027-U	Liberty Pine Bluff Water	2018	Water Depreciation Study
Kentucky	Kentucky Public Service Commission	2017-00349	Atmos KY	2018	Gas Depreciation Rates
Tennessee	Tennessee Public Utility Commission	18-00017	Chattanooga Gas	2018	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Railroad Commission of Texas	10679	Si Energy	2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-104	Anchorage Water and Wastewater	2017	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-18488	Michigan Gas Utilities Corporation	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	10669	CenterPoint South Texas	2017	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	17-061-U	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Kansas	Kansas Corporation Commission	18-EPDE-184-PRE	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Oklahoma	Oklahoma Corporation Commission	PUD 201700471	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Missouri	Missouri Public Service Commission	EO-2018-0092	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Michigan	Michigan Public Service Commission	U-18457	Upper Peninsula Power Company	2017	Electric Depreciation Study
Florida	Florida Public Service Commission	20170179-GU	Florida City Gas	2017	Gas Depreciation Study
Michigan	FERC	ER18-56-000	Consumers Energy	2017	Electric Depreciation Study
Missouri	Missouri Public Service Commission	GR-2018-0013	Liberty Utilities	2017	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18452	SEMCO	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	47527	Southwestern Public Service Company	2017	Electric Production Depreciation Study
MultiState	FERC	ER17-1664	American Transmission Company	2017	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-008	Municipal Power and Light City of Anchorage	2017	Generating Unit Depreciation Study
Mississippi	Mississippi Public Service Commission	2017-UN-041	Atmos Energy	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	46957	Oncor Electric Delivery	2017	Electric Depreciation Study
Oklahoma	Oklahoma Corporation Commission	PUD 201700078	CenterPoint Oklahoma	2017	Gas Depreciation Study
New York	FERC	ER17-1010-000	New York Power Authority	2017	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10580	Atmos Pipeline Texas	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10567	CenterPoint Texas	2016	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
MultiState	FERC	ER17-191-000	American Transmission Company	2016	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR16090826	Elizabethtown Natural Gas	2016	Gas Depreciation Study
North Carolina	North Carolina Utilities Commission	Docket G-9 Sub 77H	Piedmont Natural Gas	2016	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18195	Consumers Energy/DTE Electric	2016	Ludington Pumped Storage Depreciation Study
Alabama	FERC	ER16-2313-000	SEGCO	2016	Electric Depreciation Study
Alabama	FERC	ER16-2312-000	Alabama Power Company	2016	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-18127	Consumers Energy	2016	Natural Gas Depreciation Study
Mississippi	Mississippi Public Service Commission	2016 UN 267	Willmut Natural Gas	2016	Natural Gas Depreciation Study
Iowa	Iowa Utilities Board	RPU-2016-0003	Liberty-Iowa	2016	Natural Gas Depreciation Study
Illinois	Illinois Commerce Commission	GRM #16-208	Liberty-Illinois	2016	Natural Gas Depreciation Study
Kentucky	FERC	RP16-097-000	KOT	2016	Natural Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-16-067	Alaska Electric Light and Power	2016	Generating Unit Depreciation Study
Florida	Florida Public Service Commission	160170-EI	Gulf Power	2016	Electric Depreciation Study
California	California Public Utilities Commission	A 16-07-002	California American Water	2016	Water and Waste Water Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-16-0107	Southwest Gas	2016	Gas Depreciation Study
Texas	Public Utility Commission of Texas	45414	Sharyland	2016	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	16A-0231E	Public Service Company of Colorado	2016	Electric Depreciation Study
Multi-State NE US	FERC	16-453-000	Northeast Transmission Development, LLC	2015	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	15-098-U	CenterPoint Arkansas	2015	Gas Depreciation Study and Cost of Removal Study
New Mexico	New Mexico Public Regulation Commission	15-00296-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Atmos Energy Corporation	Tennessee Regulatory Authority	14-00146	Atmos Tennessee	2015	Natural Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00261-UT	Public Service Company of New Mexico	2015	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Hawaii	NA	NA	Hawaii American Water	2015	Water/Wastewater Depreciation Study
Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Atmos Kansas	2015	Gas Depreciation Study
Texas	Public Utility Commission of Texas	44704	Entergy Texas	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-15-089	Fairbanks Water and Wastewater	2015	Water and Waste Water Depreciation Study
Arkansas	Arkansas Public Service Commission	15-031-U	Source Gas Arkansas	2015	Underground Storage Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00139-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	44746	Wind Energy Transmission Texas	2015	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	15-AL-0299G	Atmos Colorado	2015	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	15-011-U	Source Gas Arkansas	2015	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10432	CenterPoint- Texas Coast Division	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power and Light	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-120	Alaska Electric Light and Power	2014-2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43950	Cross Texas Transmission	2014	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	14-00332-UT	Public Service of New Mexico	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43695	Xcel Energy	2014	Electric Depreciation Study
Multi State – SE US	FERC	RP15-101	Florida Gas Transmission	2014	Gas Transmission Depreciation Study
California	California Public Utilities Commission	A.14-07-006	Golden State Water	2014	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-17653	Consumers Energy Company	2014	Electric and Common Depreciation Study
Colorado	Public Utilities Commission of Colorado	14AL-0660E	Public Service of Colorado	2014	Electric Depreciation Study
Wisconsin	Wisconsin	05-DU-102	WE Energies	2014	Electric, Gas, Steam and Common Depreciation Studies
Texas	Public Utility Commission of Texas	42469	Lone Star Transmission	2014	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Nebraska	Nebraska Public Service Commission	NG-0079	Source Gas Nebraska	2014	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-055	TDX North Slope Generating	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-054	Sand Point Generating LLC	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-045	Matanuska Electric Coop	2014	Electric Generation Depreciation Study
Texas, New Mexico	Public Utility Commission of Texas	42004	Southwestern Public Service Company	2013-2014	Electric Production, Transmission, Distribution and General Plant Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR13111137	South Jersey Gas	2013	Gas Depreciation Study
Various	FERC	RP14-247-000	Sea Robin	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-078-U	Arkansas Oklahoma Gas	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-079-U	Source Gas Arkansas	2013	Gas Depreciation Study
California	California Public Utilities Commission	Proceeding No.: A.13-11-003	Southern California Edison	2013	Electric Depreciation Study
North Carolina/South Carolina	FERC	ER13-1313	Progress Energy Carolina	2013	Electric Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	4220-DU-108	Northern States Power Company - Wisconsin	2013	Electric, Gas and Common Transmission, Distribution and General
Texas	Public Utility Commission of Texas	41474	Sharyland	2013	Electric Depreciation Study
Kentucky	Kentucky Public Service Commission	2013-00148	Atmos Energy Corporation	2013	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	13-252	Allete Minnesota Power	2013	Electric Depreciation Study
New Hampshire	New Hampshire Public Service Commission	DE 13-063	Liberty Utilities	2013	Electric Distribution and General
Texas	Railroad Commission of Texas	10235	West Texas Gas	2013	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-154	Alaska Telephone Company	2012	Telecommunications Utility
New Mexico	New Mexico Public Regulation Commission	12-00350-UT	Southwestern Public Service Company	2012	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1269ST	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Colorado	Colorado Public Utilities Commission	12AL-1268G	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-149	Municipal Power and Light City of Anchorage	2012	Electric Depreciation Study
Texas	Public Utility Commission of Texas	40824	Xcel Energy	2012	Electric Depreciation Study
South Carolina	Public Service Commission of South Carolina	Docket 2012-384-E	Progress Energy Carolina	2012	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-141	Interior Telephone Company	2012	Telecommunications Utility
Michigan	Michigan Public Service Commission	U-17104	Michigan Gas Utilities Corporation	2012	Gas Depreciation Study
North Carolina	North Carolina Utilities Commission	E-2 Sub 1025	Progress Energy Carolina	2012	Electric Depreciation Study
Texas	Public Utility Commission of Texas	40606	Wind Energy Transmission Texas	2012	Electric Depreciation Study
Texas	Public Utility Commission of Texas	40604	Cross Texas Transmission	2012	Electric Depreciation Study
Minnesota	Minnesota Public Utilities Commission	12-858	Northern States Power Company - Minnesota	2012	Electric, Gas and Common Transmission, Distribution and General
Texas	Railroad Commission of Texas	10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10174	Atmos West Texas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10182	CenterPoint Beaumont/ East Texas	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-KCPE-764-RTS	Kansas City Power and Light	2012	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	12-04005	Southwest Gas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10147, 10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-ATMG-564-RTS	Atmos Kansas	2012	Gas Depreciation Study
Texas	Public Utility Commission of Texas	40020	Lone Star Transmission	2012	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16938	Consumers Energy Company	2011	Gas Depreciation Study
Colorado	Public Utilities Commission of Colorado	11AL-947E	Public Service of Colorado	2011	Electric Depreciation Study
Texas	Public Utility Commission of Texas	39896	Entergy Texas	2011	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
MultiState	FERC	ER12-212	American Transmission Company	2011	Electric Depreciation Study
California	California Public Utilities Commission	A1011015	Southern California Edison	2011	Electric Depreciation Study
Mississippi	Mississippi Public Service Commission	2011-UN-184	Atmos Energy	2011	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-16536	Consumers Energy Company	2011	Wind Depreciation Rate Study
Texas	Public Utility Commission of Texas	38929	Oncor	2011	Electric Depreciation Study
Texas	Railroad Commission of Texas	10038	CenterPoint South TX	2010	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-070	Inside Passage Electric Cooperative	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	36633	City Public Service of San Antonio	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10000	Atmos Pipeline Texas	2010	Gas Depreciation Study
Multi State – SE US	FERC	RP10-21-000	Florida Gas Transmission	2010	Gas Depreciation Study
Maine/ New Hampshire	FERC	10-896	Granite State Gas Transmission	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38480	Texas New Mexico Power	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38339	CenterPoint Electric	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10041	Atmos Amarillo	2010	Gas Depreciation Study
Georgia	Georgia Public Service Commission	31647	Atlanta Gas Light	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38147	Southwestern Public Service	2010	Electric Technical Update
Alaska	Regulatory Commission of Alaska	U-09-015	Alaska Electric Light and Power	2009-2010	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-043	Utility Services of Alaska	2009-2010	Water Depreciation Study
Michigan	Michigan Public Service Commission	U-16055	Consumers Energy/DTE Energy	2009-2010	Ludington Pumped Storage Depreciation Study
Michigan	Michigan Public Service Commission	U-16054	Consumers Energy	2009-2010	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15963	Michigan Gas Utilities Corporation	2009	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-15989	Upper Peninsula Power Company	2009	Electric Depreciation Study
Texas	Railroad Commission of Texas	9869	Atmos Energy	2009	Shared Services Depreciation Study
Mississippi	Mississippi Public Service Commission	09-UN-334	CenterPoint Energy Mississippi	2009	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Railroad Commission of Texas	9902	CenterPoint Energy Houston	2009	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	09AL-299E	Public Service Company of Colorado	2009	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-30689	Cleco	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35763	Southwestern Public Service Company	2008	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Wisconsin	Wisconsin	05-DU-101	WE Energies	2008	Electric, Gas, Steam and Common Depreciation Studies
North Dakota	North Dakota Public Service Commission	PU-07-776	Northern States Power Company - Minnesota	2008	Net Salvage
New Mexico	New Mexico Public Regulation Commission	07-00319-UT	Southwestern Public Service Company	2008	Testimony – Depreciation
Multiple States	Railroad Commission of Texas	9762	Atmos Energy	2007-2008	Shared Services Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015/D-08-422	Minnesota Power	2007-2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35717	Oncor	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	34040	Oncor	2007	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15629	Consumers Energy	2006-2009	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	06-234-EG	Public Service Company of Colorado	2006	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	06-161-U	CenterPoint Energy – Arkla Gas	2006	Gas Distribution Depreciation Study and Removal Cost Study
Texas, New Mexico	Public Utility Commission of Texas	32766	Southwestern Public Service Company	2005-2006	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Texas	Railroad Commission of Texas	9670/9676	Atmos Energy Corp	2005-2006	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9400	TXU Gas	2003-2004	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9313	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9225	TXU Gas	2002	Gas Distribution Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	24060	TXU	2001	Line Losses
Texas	Public Utility Commission of Texas	23640	TXU	2001	Line Losses
Texas	Railroad Commission of Texas	9145-9148	TXU Gas	2000-2001	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	22350	TXU	2000-2001	Electric Depreciation Study, Unbundling
Texas	Railroad Commission of Texas	8976	TXU Pipeline	1999	Pipeline Depreciation Study
Texas	Public Utility Commission of Texas	20285	TXU	1999	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	18490	TXU	1998	Transition to Competition
Texas	Public Utility Commission of Texas	16650	TXU	1997	Customer Complaint
Texas	Public Utility Commission of Texas	15195	TXU	1996	Mining Company Depreciation Study
Texas	Public Utility Commission of Texas	12160	TXU	1993	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	11735	TXU	1993	Electric Depreciation Study

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

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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

ALYSSA MAURICE-ANDERSON

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2022

ENTERGY TEXAS, INC.
DIRECT TESTIMONY OF ALYSSA MAURICE-ANDERSON
2022 RATE CASE

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EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, EMPLOYER AND JOB TITLE.

A. My name is Alyssa Maurice-Anderson. I am employed by Entergy Services, LLC ("ESL")[1] as Director, Regulatory Filings & Policy. My business address is 639 Loyola Avenue, Mail Unit 16-A, New Orleans, Louisiana 70113.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

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

Q3. PLEASE STATE YOUR EDUCATIONAL, PROFESSIONAL AND WORK EXPERIENCE.

A. I hold a Master of Business Administration (concentration in Finance) from Tulane University's Freeman School of Business (2011), a Juris Doctor from Loyola University New Orleans School of Law (2002) and a Bachelor of General Studies from the University of New Orleans (1998). I joined the ESL Legal Department in 2001 and until August 2020, I held varying levels of responsibility supporting regulatory litigation matters. Beginning in 2008, my practice focused on leading rate matters filed by regulated subsidiaries of Entergy Corporation;

[1] ESL is a subsidiary of Entergy Corporation that provides technical and administrative services to all the Entergy Operating Companies. ESL frequently acts as agent on behalf of all the Operating Companies in proceedings before FERC. The Entergy Operating Companies ("EOCs") include Entergy Arkansas, LLC; Entergy Louisiana, LLC; Entergy Mississippi, LLC; Entergy New Orleans, LLC; and Entergy Texas, Inc.

first for Entergy New Orleans, LLC ("ENO") and then for Entergy Louisiana, LLC ("ELL") (and one of its predecessors), and then for both ENO and ELL. My responsibilities included providing legal advice and developing legal strategies necessary to file and manage regulatory/litigation proceedings, and obtain approval of rate making treatments that resulted in rates that were just and reasonable to customers, the investor-owned utility and other stakeholders, as well as various related duties, such as issuing probability assessments, drafting and reviewing inserts to disclosure documents and serving as an internal regulatory subject matter expert on various projects that aided the company in managing regulatory matters.

In 2020, I transitioned from the ESL Legal Department to ENO as Director, Regulatory Operations (Affairs), reporting directly to the President and Chief Executive Officer of ENO. As Director, Regulatory Operations, I contributed to the development of regulatory strategy, appeared on behalf of ENO before its regulator, the Council of the City of New Orleans, and interfaced with customers. Additionally, with the support of several analysts and ESL's Regulatory Services Department, I was responsible for the submission of retail regulatory filings. In May 2021, I returned to ESL and since then have worked as Director, Regulatory Filings and Policy reporting directly to the Vice President, Regulatory Services.

Q4. WHAT IS THE FUNCTION OF REGULATORY SERVICES AND YOUR ROLE IN THE ORGANIZATION?

A. ESL's Regulatory Services Department is comprised of several sections: Regulatory Filings, Fuel & Special Riders, Utility Pricing and Analysis, and Regulatory Research. Regulatory Services falls under the umbrella of Utility Strategy & Regulatory.[2] Regulatory Services & Strategy works in concert with each jurisdiction's Regulatory and Public Affairs departments (among others) to support the EOCs in the development of regulatory policy underlying the analysis, preparation, and review of filings submitted to each of their respective retail regulators and to the Federal Energy Regulatory Commission ("FERC"). In my role, I provide oversight for those activities related to regulatory filings made across all of the EOCs, including ETI's various regulatory filings with the Public Utility Commission of Texas (the "Commission") and FERC.

II. <u>PURPOSE</u>

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am providing testimony on two issues:

1. The calculation of the Nuclear Decommissioning Escalation Rate. This rate is a component of ETI's cost to provide funding to decommission its share of the River Bend Nuclear Facility at the end of its service period.
2. The Regulatory Services Class of affiliate costs. I explain why this class

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[2] Throughout my testimony, I refer to these collectively as "Regulatory Services & Strategy" to distinguish between the department and the Regulatory Services Class of affiliate costs.

and its costs are reasonable and necessary, that the prices charged to ETI by affiliates for the costs reflected in this class are no higher than the prices charged to other affiliates for the same or similar services or items, and that the prices charged represent the actual cost of these services or items.

Q6. DO YOU SPONSOR ANY EXHIBITS IN THIS FILING?

A. Yes. I sponsor the exhibits listed in the Table of Contents to this testimony.

III. NUCLEAR DECOMMISSIONING ESCALATION RATES

Q7. PLEASE DESCRIBE RIVER BEND AND THE AGREEMENT UNDER WHICH ETI PURCHASES POWER FROM RIVER BEND.

A. River Bend is a nuclear power plant located in St. Francisville, Louisiana with a maximum dependable capacity of 974 MW. River Bend is owned by ELL, but an approximate 43% share of the regulated portion (the regulated portion is 70% of the total) of River Bend is sold to ETI under a Purchased Power Agreement ("PPA") filed with and approved by the FERC. Although the PPA is a FERC-jurisdictional and FERC-approved contract for wholesale power and capacity, provisions of the PPA allow the Commission to set the decommissioning and depreciation costs related to River Bend that will be recovered from Texas retail customers. Recovery of River Bend decommissioning costs under the PPA has been requested and included in the rates of ETI's customers in ETI's last four base rate cases, Docket Nos. 37744, 39896, 41791, and 48371 as a reasonable and necessary cost of purchasing power from River Bend. Recovery of River Bend decommissioning costs by ETI's predecessors, Entergy Gulf States, Inc. and Gulf States Utilities Company, was also permitted prior to the PPA arrangement.[3] Such recovery of decommissioning costs in the revenue requirement is also one of the permitted means of meeting mandatory Nuclear Regulatory Commission ("NRC") financial assurance requirements for River Bend decommissioning.

Q8. AS A GENERAL MATTER, HOW ARE REVENUE REQUIREMENTS ASSOCIATED WITH DECOMMISSIONING COSTS DETERMINED FOR RATEMAKING PURPOSES?

A. As a general proposition, a current dollar estimate of decommissioning cost is determined as a starting point. That cost is then escalated to determine the amount of decommissioning costs expected to be incurred in the time period of anticipated decommissioning. The amount of revenue requirement to be reflected in customer rates represents the need for payments that together with existing and projected trust funds will provide an amount equal to the final cost of decommissioning.

In this proceeding, the Company is using the NRC "minimum value" rather than a site-specific decommissioning study to determine the current dollar estimate for the decommissioning of River Bend. Lori Glander of TLG Services, LLC presents the NRC minimum value, the calculation of which uses the Nuclear

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[3] *See,* e.g., Docket Nos. 7195 and 6755, *Application of Gulf States Utilities for Authority to Change Rates*, 14 P.U.C. Bull. 1943 at 2411-12, Findings of Fact 199-202, Order (May 16, 1988).

Decommissioning Escalation Rate that I recommend in this testimony.

IV. NRC FINANCIAL ASSURANCE REQUIREMENTS

Q9. WHAT IS YOUR UNDERSTANDING OF THE NRC FINANCIAL ASSURANCE REQUIREMENTS?

A. Under NRC regulations codified at 10 CFR § 50.75(a)-(f), holders of nuclear operating licenses must certify to the NRC, through specific reporting requirements related to licensee-specific decommissioning funding plan data filed at a minimum of every two years, that there is a reasonable "financial assurance" that funds will be available for the decommissioning process at that time in the future when the nuclear facilities are expected to cease operation. The primary objective of the decommissioning funding plan "financial assurance" requirements of the NRC is to ensure that a licensee accumulates funds sufficient to pay for the safe dismantlement, decontamination, and disposal of its nuclear generating facility in a way that protects public health and safety. Compliance with NRC regulations is a required condition of the NRC operating license and therefore affects the ability of ELL to continue to operate the River Bend facility and in turn ETI's ability to maintain its PPA.[4]

While the NRC regulations set out several options to accomplish acceptable decommissioning funding, ELL and ETI have elected to use the external sinking fund option for River Bend, which is consistent with the

[4] *See* 10 CFR § 50.54(h).

methodology previously employed by the Commission in determining the revenue requirement needed to fund the decommissioning obligations for River Bend.[5] Under this approach, the external sinking fund is funded from annual collections from customers through an approved revenue requirement.

Q10. WHAT FACTORS DOES THE NRC CONSIDER WHEN DETERMINING WHETHER REASONABLE FINANCIAL ASSURANCE EXISTS SUCH THAT A LICENSEE WILL BE ABLE TO FUND ITS DECOMMISSIONING OBLIGATION?

A. As noted earlier, in its filing, the licensee must demonstrate to the NRC that it has a funding plan reflected in rates that is approved by the regulator that is designed to accumulate funds dedicated to decommissioning funding that are not less than a specifically derived "minimum amount" of decommissioning cost as set out in 10 CFR § 50.75(c). The regulation sets out a specific formula for determining the applicable "minimum amount." The NRC's analysis of reasonable financial assurance considers the decommissioning cost data as well as other factors related to decommissioning funding for each licensee such as the current level of decommissioning trust funds available, scheduled payments into the trust, and the projected rate of earnings in the trust. If the available trust funding with escalation does not meet the minimum decommissioning cost amount, the NRC will require the licensee to make adjustments to the funding to meet the minimum

[5] Docket Nos. 7195 and 6755, *Application of Gulf States Utilities for Authority to Change Rates*, 14 P.U.C. Bull. 1943 at 2411, Finding of Fact 199, Order (May 16, 1988).

amount. As described in Ms. Glander's testimony, the NRC requires that sufficient funding be available to meet the NRC minimum value as of the end of the current nuclear plant license, which as noted by Ms. Glander is now 2045 based upon the NRC's approval of a 20-year license extension in 2018.

Q11. PLEASE DESCRIBE HOW THE NRC DETERMINES THE "MINIMUM AMOUNT" OF DECOMMISSIONING COST REQUIRED AT A GIVEN POINT IN TIME.

A. With regard to determining the current dollar "minimum amount" of decommissioning, the NRC employs a specific historic cost escalation formula. This formula uses the cost to decommission a generic generating unit in 1986 dollars as a base cost and then adjusts that cost for the specific reactor's thermal power and escalates the adjusted amount to current dollars using NRC-specific cost indices and weights of defined nuclear cost components. In applying this formula, generating units are differentiated by reactor type in the following manner: (a) Boiling Water Reactor ("BWR") or Pressurized Water Reactor ("PWR"), and (b) reactor power level (in MWt). The costs are adjusted from a 1986 level to current 2021 (Test Year) dollars by using weighted average cost escalations based upon NRC specified labor, energy, and waste historic burial cost indices. The application of this formula to derive the minimum amount of decommissioning cost provides the starting point for the NRC financial assurance analysis (and it provides a framework that was used in developing the future cost escalation rate). Based upon the application of the NRC formula as calculated by

Ms. Glander for December 31, 2021, the minimum level is $469.5 million for the 70% regulated portion of River Bend.[6]

To determine the ETI-jurisdictional revenue requirement associated with this value, the amount must first be allocated to ETI and escalated using a decommissioning cost escalation rate in order to determine the future cost to decommission the unit. Richard Lain reports the decommissioning revenue requirement for ETI proposed in this filing for ratemaking purposes.

V. CURRENT COMMISSION RATEMAKING FOR DECOMMISSIONING FUNDING

Q12. HOW HAS THE COMMISSION DETERMINED DECOMMISSIONING FUNDING FOR RIVER BEND FOR RATEMAKING PURPOSES?

A. As noted above, the Commission has been providing for rate treatment of decommissioning funding for River Bend since around the time when NRC financial assurance regulations were first promulgated.[7] As a result of the Commission's order in Docket No. 48371, there is no current expense accrual reflected in ETI rates. As explained in the direct testimony of Mr. Lain, given the current balance of the trust and current estimated cost of decommissioning, at this time, ETI has no plans to make any additional contributions through the rate-effective period.

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[6] Richard Lain presents the Texas portion of this minimum amount.

[7] The NRC's regulations requiring the funding of decommissioning obligations were issued on June 27, 1988. *See* General Requirements for Decommissioning Nuclear Facilities, Final Rule, 53 Fed. Reg. 24018 (June 27, 1988).

Q13. WHAT COST ESCALATION RATE DO YOU PROPOSE FOR REVENUE REQUIREMENT PURPOSES IN THIS PROCEEDING?

A. The decommissioning cost escalation rate that I recommend is 4.65%. The rate relies fundamentally on the numerous aspects of the NRC formula used to measure financial assurance.

Q14. HOW SPECIFICALLY DID YOU ARRIVE AT THE RECOMMENDED 4.65% DECOMMISSIONING COST ESCALATION RATE?

A. In developing my recommendation as to the future decommissioning cost escalation rate, I have considered forecasts of the indices used in the NRC-weighted average escalation formula for its "minimum value" determination based upon the 2022-2032 period. This approach supports the 4.65% rate that I recommend and also is consistent with that previously used by ETI for ratemaking purposes.

Q15. WHAT ANALYSES WERE UNDERTAKEN TO ESTABLISH THE ESCALATION RATE?

A. The overall weighted average escalation rate uses a forecast of the same data-type employed by the NRC in its financial assurance formula used to quantify the minimum funding requirement for a BWR plant like the River Bend unit. As noted above, the NRC financial assurance formula calculates the current dollar minimum requirement for the cost of decommissioning using a specifically defined weighted average of escalation rates for labor, energy, and burial costs for purposes of estimating the historic cost of decommissioning for a generic BWR unit. The specifically defined cost category weights and their related escalation rates are set out or referenced within the NRC's NUREG-1307, Revision 18 publication (2021), with labor and energy rates published by the U.S. Bureau of Labor Statistics.[8] To be consistent with the NRC financial assurance formula, the proposed overall 4.65% River Bend decommissioning cost escalation rate was quantified using the NRC's specific cost category weights, but in this case using forecasts for the Labor, Energy-Electric Power, Energy-Fuel Oil, and Waste Burial factors. The calculation of the recommended forecasted escalation rate is shown in my Exhibit AMA-1.

Q16. PLEASE EXPLAIN HOW THE NRC COST CATEGORIES AND THEIR RESPECTIVE WEIGHTINGS WERE USED.

A. Chapter 3, Development of Cost Adjustment Factor, of NRC's NUREG-1307, Revision 18, Report on Waste Burial Charges (January 2021) provided the basis for identifying the four cost categories used to arrive at my recommended escalation rate. For purposes of developing the escalation formula, the NUREG-1307, Revision 18 explains that decommissioning costs can be divided into three general areas within which costs tend to escalate similarly. Those general areas are as follows:

1. Labor, materials, and services;

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[8] NUREG-1307, Revision 18, is publicly available at the NRC's website at: https://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1307/.

2. Electric power and diesel or other fuels for transportation; and

3. Radioactive waste burial/disposition.

For purposes of the NRC formula, each category grouping above is assigned a percentage of the generic 1986-year total dollar cost identified in 10 C.F.R. § 50.75. Those generic cost percentages are:[9]

1. Labor (i.e., labor, materials, and services): 65 percent;

2. Energy (i.e., energy and waste transportation): 13 percent; and

3. Burial (i.e., radioactive waste disposal): 22 percent.

Q17. PLEASE DESCRIBE HOW THE COST ESCALATION RATES FOR EACH OF THE COST CATEGORIES IDENTIFIED ABOVE WERE DEVELOPED.

A. Chapter 3.1 of NUREG-1307, Revision 18 relating to Labor Escalation Factors indicates that the labor category should be escalated at a rate tied to the BLS Employment Cost Index. Consistent with the NRC approach, I used the IHS Global Inc. (formerly, Economy.com) Forecast of the US Economy forecast of the Employment Cost Index for year-end 2021. This forecast was 4.03% for the relevant period, i.e., through 2032.

Chapter 3.2 of NUREG-1307, Revision 18 relating to Energy Escalation Factors indicates that the appropriate means of calculating the weighted average projected energy escalation rate is to use a weighted average Producer Price Index ("PPI") forecast rate for Industrial Electric Power and Light Fuel Oil. For this

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9 *See* NUREG-1307, Revision 18 at 11.

purpose, IHS Global Inc. forecasts of the PPI for Electric Power and Crude Petroleum were used. Consistent with the NUREG-1307 formula, a weighted average or composite of the electricity and light fuel oil rates was calculated. Using the approach employed in the NRC formula, a composite energy escalation rate of 2.38% is calculated using weightings of 54% electricity and 46% fuel oil, in accordance with the calculation methodology presented in NUREG-1307, Revision 18 as it relates to BWR generating facilities.

Finally, the waste burial component of the composite escalation factor must be estimated. Due to the unavailability of any published forecast projecting future escalation for this component, historical data must be used and extrapolated. Based on NRC published data, a 7.8% escalation rate for the waste burial component of the formula is proposed.

Q18. WHY IS AN 7.8% RATE AN APPROPRIATE ESCALATION FACTOR FOR THE WASTE BURIAL COMPONENT?

A. Given the unavailability of published forecasts for this component, the trends of past burial costs are the only data available for analysis. The NRC has established a generic disposal site index "For Generators Located in the Unaffiliated States and those Located in Compact-Affiliated States having a Disposal Facility" and notes that licensees meeting that criteria should use this value for their cost estimates.[10] I believe it is reasonable to rely on the changes in this data for a

[10] *See* NUREG-1307, Revision 18, at 7.

historical trend, and based on the expectations of the NRC, may be a conservative (i.e., not overstated) estimate of the ultimate cost of decommissioning. This is based on the NRC discussion in the Abstract of NUREG-1307 report regarding burial costs for plants that do not have access to a disposal site located within their Compact:

> Revision 18 to NUREG-1307 assumes that LLW [low-level radioactive waste] generated from day-to-day plant operations would be disposed of using the licensee's operating funds, and thus would not rely on decommissioning funds identified in the formula calculation. However, facilities located in states that are members of an LLW [Low-level radioactive waste] compact with no available LLW disposal site may be forced to provide interim storage for this waste (although most LLW could potentially be disposed of at the non-compact disposal facility located in Utah, or at the compact-affiliated disposal facility located in Texas). Accordingly, some of the LLW may ultimately need to be disposed of during the decommissioning following interim storage. For those plants operating through extended license terms, this volume can become significant and the disposal cost would not be accounted for in a decommissioning trust fund based on the formula calculation.

(NUREG-1307, Rev. 18, pp. iv-v.)

This suggests that whatever information can be inferred from historical burial data for licensees such as River Bend, future decommissioning costs may be expected to be higher. In addition, given the general uncertainty regarding the availability of additional disposal facilities for radioactive waste as well as spent fuel, it would be appropriate to err on the side of conservatism in making such estimates.

Q19. GIVEN THIS SET OF CIRCUMSTANCES, WHAT ANALYSIS SUPPORTS THE USE OF AN 7.8% ESCALATION RATE FOR BURIAL COSTS?

A. Exhibit AMA-2 shows the calculation of the historical rate of escalation beginning in 1986 and ending in 2020 for the NRC published burial data for "Generators Located in Compact-Affiliated States having no Disposal Facility" presented in NUREG 1307, Revision 18. In order to make a calculation of the average annual growth rate, the index values presented as of 2020 were used and an index value of 1.00 represents costs in 1986 dollars. Using the 34 years of costs that these indices covered, the average annual growth rate was derived solving for the value that would be needed to move from an index value of 1.00 in 1986 to the 12.837 value from the NRC Table for 2020 costs. This calculation resulted in a growth rate of approximately 7.8%. As described previously, because the applicable NRC formula does not take into account LLW spent fuel costs and uncertainty exists as to whether there will be an additional site for removal of radioactive waste, this conservative approach to assessing a future burial cost rate was used to produce the lowest reasonable escalation rate factor.

Q20. WHAT IS THE ESCALATION RATE THAT RESULTED FROM USING THE THREE FACTORS DESCRIBED ABOVE?

A. As shown in Exhibit AMA-1, the calculation yielded a rate of 4.65% based on the forecasted indices and NRC-prescribed weighted formula. This is a slight decrease as compared to the 4.70% used by the Company in the previous rate case. I believe it is appropriate based on the significant uncertainty as previously described regarding the future of decommissioning, especially as it related to the disposition of radioactive materials. For example, the recommended burial escalation rate of 7.80% has declined relative to the prior recommended escalation rate of 8.96%. This is the result of the NRC index value for 2020 declining relative to the prior year.

VI. AFFILIATE REGULATORY SERVICES CLASS

Q21. WHAT IS THE BASIS OF YOUR KNOWLEDGE OF THE REGULATORY SERVICES CLASS?

A. In my role as ESL's Director, Regulatory Filings and Policy, I report directly to the Vice President of Regulatory Services, and I am a member of the department's lead team, which is comprised of the department's directors and VPs. As such, I am familiar with the operations of the Regulatory Services & Strategy department as a whole, which as I describe later in my testimony, coordinates across several organizations to provide regulatory support to ETI.

A. Description of Regulatory Services Class and Regulatory Services and Strategy Department

Q22. PLEASE DESCRIBE THE REGULATORY SERVICES CLASS OF AFFILIATE SERVICES.

A. The Regulatory Services Class reflects costs associated with the task of providing the services outlined in my introduction above and as further discussed later in my testimony. During the Test Year, the costs incurred for the Regulatory Services

Class were billed primarily by Regulatory Services & Strategy.

Regulatory services provided to the Entergy Operating Companies are driven fundamentally by requirements imposed either through statute or regulation at both the state and federal levels, as well as activities undertaken to meet the priorities of the Operating Companies and their respective regulators, including meeting customers' expected level of utility service. In general, in the State of Texas, requirements associated with utility regulation at the state and federal levels involve the conduct of rate and other regulatory and investigative proceedings before this Commission and other state and federal regulatory bodies, e.g., FERC, the Nuclear Regulatory Commission, etc. Consequently, regulatory services activities performed for ETI are not only necessary but essential to the discharge of the Company's statutory and regulatory responsibilities as a regulated utility.

Further, none of the activities performed by the departments in this class are being performed or duplicated at the local level by ETI or the other EOCs. Although ETI employs certain regulatory personnel, those individuals do not perform the same work performed at ESL because of the organizational configuration of ESL and ETI. The departments that make up this class provide, on a cost-effective basis, centralized services that are needed to respond to the statutory and regulatory requirements applicable to ETI (and the other Entergy Operating Companies) as utility service providers at the retail and wholesale levels.

Q23. WHAT IS THE PRIMARY NATURE OF SERVICES PROVIDED BY THE REGULATORY SERVICES & STRATEGY DEPARTMENT DURING THE TEST YEAR?

A. Primary activities and services provided by the Regulatory Services & Strategy department during the Test Year for ETI are as follows:

- Utility Strategy & Regulatory Initiatives provides the principal oversight for alignment of regulatory considerations with emerging strategic initiatives designed to meet desired customer outcomes across the Entergy footprint.
- Regulatory Services provides the coordination, oversight and execution of activities necessary to meet certain regulatory requirements applicable to Entergy's Operating Companies as providers of utility service. These requirements are imposed at the local, state, and federal levels and the Regulatory Services' organizations provides support by providing:
  - Strategic analytical support to jurisdictional regulatory and executive management;
  - Per book and proformed accounting data used in the various EOC regulatory filings along with analytical support of accounting related data;
  - Support for regulatory policy issues to jurisdictional regulatory and executive management; and
  - Technical support required for the following activities:
    - Revenue requirement and cost of service analysis;
    - Design, development, implementation and administration of regulated retail tariffs, policies, and regulations, and rates/prices contained therein;
    - Support for, and facilitation of, the development of responses to discovery requests for ratemaking policy and financial information and requests for production for regulatory filings and proceedings; and
    - Coordination of process improvement activities for the Regulatory Services & Strategy.

Q24. WHAT IS THE PRIMARY NATURE OF SERVICES PROVIDED BY THE FEDERAL POLICY, REGULATORY & GOVERNMENTAL AFFAIRS DEPARTMENT?

A. Regulatory actions at the federal level also affect (or involve) actions at the state level. Federal Policy, Regulatory & Governmental Affairs is responsible for coordinating or facilitating interaction between the federal and state activities across the EOCs' service area, especially those that require coordination with the regional transmission organization of which the EOCs are members, i.e., Midcontinent Independent System Operator, Inc.

Q25. IS THE REGULATORY SERVICES CLASS OF SERVICES REASONABLE AND NECESSARY?

A. Yes. Any regulated utility company, such as ETI, must comply with requirements that are imposed by the statutes and regulations of the various regulatory bodies, which oversee its rates and charges, the adequacy of the provision of service to customers and whether new product offerings should be made available to customers, among other matters. In order to set customer rates at appropriate levels, periodic rate filings must be made in all jurisdictions.

In the case of ETI, this is accomplished through complex and comprehensive rate filings. These filings include detailed analysis of costs, revenue, rates, tariffs, and in many instances are supported by written testimony that presents and explains the information. Fulfillment of these duties requires that Regulatory Services & Strategy, Federal Policy, Regulatory & Governmental

Affairs and ETI Regulatory Affairs personnel coordinate with other ESL departments (e.g., Accounting, Finance Business Partners, Legal, External Reporting and functional operations representatives, etc.) to provide accurate information. These types of services are necessary to satisfy statutory or regulatory requirements that are imposed on ETI related to the provision of electric service, both now and in the future.

In this light, the Regulatory Services & Strategy and Federal Regulatory Affairs departments are charged with advisory roles with the EOCs' state and local regulatory organizations, ensuring that the activities of those organizations meet the overall corporate regulatory policy, as well as a more direct responsibility of supporting all federal regulatory matters for the EOCs' retail jurisdictions. These departments account for 97% of the costs incurred for the Regulatory Services Class. It must be emphasized that the types of services provided by the Regulatory Services Class are those services necessary to satisfy statutory and/or regulatory requirements that are imposed on ETI-related to the provision of electric service at wholesale and retail. These types of advisory and consulting services provided for ETI's benefit are generally similar across jurisdictional boundaries and are most efficiently and consistently provided through a centralized staff with specialized knowledge.

B. Overview of Costs

Q26. WHAT IS THE TOTAL ETI ADJUSTED AMOUNT FOR THE REGULATORY SERVICES CLASS OF SERVICES?

A. The Total ETI Adjusted amount for this class of services for the test year is $1,779,929. Of this amount, ESL directly billed 39% of the Total ETI Adjusted amount and allocated 61% of the total adjusted amount to ETI. This information is summarized in Table 1 for the Regulatory Services Class. Table 1 shows for each class the following information:

Table 1: Total ETI Adjusted Amount – Regulatory Services Class
Percent Direct Billed vs. Allocated[11]

Total ETI Adjusted					
Class	**Total Billings**	**Direct Amount**	**% Direct**	**Allocated Amount**	**% Allocated**
Regulatory Services	$20,689,057	$687,994	39%	$1,091,935	61%

Q27. PLEASE DESCRIBE THE EXHIBITS THAT SUPPORT THE INFORMATION INCLUDED IN TABLE 1.

A. Attached to my testimony are exhibits showing, for the Regulatory Services Class, the calculation of the Total ETI Adjusted amount. On Exhibit AMA-A, the information is shown broken down by the departments comprising the class. Exhibit AMA-B shows the same information broken down by project code and the billing method assigned to each project code. Exhibit AMA-C shows the

[11] **Total Billings** is ESL's total billings to all Entergy companies for the Test Year, plus all other affiliate charges that originated from any Entergy company. This is the amount from Column "C" of Exhibits AMA-A, AMA-B, and AMA-C. **Total ETI Adjusted Amount** is ETI's cost of service amount after pro forma adjustments and exclusions. **% Direct Billed** is the percentage of the Total ETI Adjusted Amount that was billed directly to ETI for the Test Year. **% Allocated** is the percentage of the Total ETI Adjusted Amount that was allocated to ETI for the Test Year.

information by class, department, billing method, and project code.

For a description of Columns "A" through "H" and what they represent, please refer to Ryan M. Dumas's direct testimony. Mr. Dumas also describes the calculations that take the dollars of support services in Column A to the Total ETI Adjusted figures shown on Column H.

Exhibit AMA-D is a summary of the proforma adjustments broken down by billing method and project code. For an explanation of the proforma amounts in exhibit AMA-D, please refer to the direct testimony of the sponsoring witnesses listed in that exhibit, Mr. Bobby Sperandeo and Ms. Allison Lofton.

Q28. WHAT ARE THE MAJOR COST COMPONENTS OF THE CHARGES FOR THE REGULATORY SERVICES CLASS?

A. As shown on Exhibit AMA-A, the Total ETI Adjusted Amount for the Regulatory Services Class during the test year was roughly $1.78 million. The major cost components of those costs are reflected in Table 2.

Table 2: Regulatory Services Class – Major Cost Components

Cost Component	$	% of Total
Payroll and Employee Costs	$1,492,738	83.86%
Service Company Recipient	$226,874	12.75%
Outside Services	$29,582	1.66%
Office and Employee Expenses	$20,987	1.18%
Other	$9,750	0.55%
Total (Total ETI Adjusted)	**$1,779,929**	**100.00%**

Q29. WHAT IS THE SIGNIFICANCE OF THESE COST CATEGORIES?

A. They provide context for the testimony of other Company witnesses who provide additional support for the reasonableness of the costs included in many of these categories on behalf of all the affiliate witnesses. For example, Table 2 shows that roughly 84% of the costs are for compensation and labor-related expenses. Jennifer A. Raeder addresses the reasonableness and necessity of the Company's compensation-related programs. The Outside Services row shows costs that were paid to outside consultants and vendors for this class. Office and Employee Expenses covers costs of maintaining workspaces, office supplies, business travel, etc. Workspaces and office supplies are primarily addressed by Ms. Renton, and Mr. Sperandeo supports the employee business travel and expense processes and, thus, they provide secondary support for this category of costs in this class. The Service Company Recipient row of the table pertains to costs incurred by ESL in providing services to ETI and other operating companies, such as information technology services, rents, human resources services, etc. These Service Company Recipient costs are allocated across all affiliate classes as explained by Mr. Dumas.

Q30. HOW DOES ESL DETERMINE WHETHER TO DIRECT BILL OR ALLOCATE REGULATORY SERVICES CLASS COSTS TO ETI?

A. Whenever appropriate, costs are directly billed to ETI and other affiliates. Only when costs are incurred that benefit more than one of the Entergy companies is such cost billed through an allocation.

Q31. PLEASE DESCRIBE THE TEST YEAR REGULATORY SERVICES CLASS COSTS THAT WERE DIRECTLY BILLED TO ETI.

A. As shown in Table 1 ESL directly billed ETI $687,994 for the Regulatory Services Class, which represents just below 39% of the Total ETI Adjusted amount for this class in the Test Year. Directly billing ETI for these services was appropriate because the services were rendered in connection with projects that were undertaken solely on behalf of ETI. A non-exhaustive list of examples of such services include development/updating and, where necessary filing of: annual fuel factor update, annual earnings report, the Generation Rider, the Transmission Cost Recovery Factor (TCRF), the Distribution Recovery Factor (DCRF); the introduction of new and/or administration of existing tariffs, including, among others, the securitization tariff updates, FERC Attachment O and MSS-4-like (i.e., affiliate PPA) updates and management of various other ETI-specific dockets, etc.

Q32. ON WHAT BASIS ARE REGULATORY SERVICES CLASS COSTS ALLOCATED TO ETI?

A. The Regulatory Services Class of costs is made up of numerous project codes. As Mr. Dumas explains, only one billing method is assigned to each project code. Several organizations may bill to a single project code, but the billing method for that project code remains the same.

Q33. WHAT ARE THE PREDOMINANT BILLING METHODS USED FOR THIS CLASS OF SERVICES?

A. Of the remaining 61% in Total ETI Adjusted costs (that is, those that are allocated rather than direct-billed), the following billing methods account for all but 8% of the allocated costs:

Table 3: Predominant Billing Methods of Test Year 2021

DIRECTTX	39%	100% to ETI
CUSTEGOP	31%	Average number of electric and gas customers in Entergy's service area
PKLOADAL	14%	Based on the ratio of each Client Company's load to the peak load at time of all companies' peak load
LBRFDPOL	5%	Based on ESL Labor Billed for - Federal Policy, Regulatory and Governmental Affairs
CUSEOPCO	3%	Electric customers

Other than the direct assignment billing methods, the predominant billing methods used by the Regulatory Services Class are those that rely on load data, customer count, and labor billings. These methods are selected because they most reasonably reflect the factors that drive the costs incurred by the Regulatory Services Class.

Work effort is driven by activities required to serve customers and their loads in the various jurisdictions and, as such, in most instances, the responsibility ratio and number of customers represent reasonable proxies for the factors which drive a significant portion of the costs in the Regulatory Services Class. For a detailed explanation of these predominant billing methods and why they are appropriate for the project codes to which they are assigned, please refer to Exhibit AMA-3.

Q34. HAVE YOU DETERMINED THAT THE REMAINING 8% OF COSTS ASSOCIATED WITH THIS CLASS ARE ALSO REASONABLE AND NECESSARY?

A. Yes. I have reviewed each of the project codes and billing methods used to bill the remaining 8% of the costs of this class. The cost drivers reflected in the billing methods are consistent with and reflect the cost drivers of the services captured in each respective project code. Therefore, the costs billed to ETI reasonably reflect the cost of service received by ETI and are no higher than the cost billed to other affiliates for the same or similar types of service. The applicable project codes (and billing methods) for these projects, and all project codes and billing methods applicable to the Regulatory Services Class, are shown on Exhibits AMA-B and AMA-C. Mr. Dumas includes an exhibit with his testimony that includes a copy of all ESL Project Summaries that explain the specific project codes (and the billing method applied to them) in more detail.

Q35. HAVE YOU OR PERSONS UNDER YOUR SUPERVISION REVIEWED THE REGULATORY SERVICES CLASS EXPENSES INCURRED BY OR ON BEHALF OF ETI TO ENSURE THAT THEY ARE NECESSARY?

A. Yes. Internal review mechanisms, including budget variance analyses, are in place to ensure that unnecessary costs are not incurred. Before resources are committed to a specific project, those with direct responsibility, in consultation with other appropriate staff members, determine how the work will be performed, and whether and to what extent resources external to the Entergy System will be required. For example, when the Company is involved in a regulatory proceeding, resources both internal and external to ETI and its affiliates are necessary and engaged to satisfy the applicable regulatory standards and requirements. Operating within, and guided by, the requirements of the regulator and Company policy, and in consultation with appropriate staff and other internal personnel, we decide upon a course of conduct designed to furnish the required regulatory support in the most cost-effective manner.

Q36. HOW DO YOU ENSURE THAT THE PRICE FOR REGULATORY SERVICES BILLED TO ETI IS NO HIGHER THAN THE PRICE CHARGED TO OTHER AFFILIATES AND REPRESENTS THE ACTUAL COST OF SUCH SERVICES?

A. As an initial matter, all regulatory services provided by ESL to ETI and all outside services billed by ESL to ETI are billed at cost, just as such services are billed to all other regulated companies. As a result, all regulated companies are paying ESL for services based on the same "price," (i.e., the actual cost of such service to ESL). The unit prices for amounts directly billed and for amounts allocated to ETI for services in the Regulatory Services Class are no higher than the unit prices for amounts directly billed and for amounts allocated to other affiliates for the same or similar service. Each project code has only one billing method to allocate project costs to legal entities. All charges made to a project code are billed on the same billing method, regardless of which legal entity is billed for some or all of the costs. The billing method for a project code does not vary depending upon the legal entity that is billed for the costs. This approach ensures that the per unit amount billed to ETI for a service is no higher than the per unit amount charged to other affiliates for the same or similar services. Again, this price also represents the actual cost of service.

C. Reasonableness and Necessity of Regulatory Services Class Expenses

Q37. ARE THE COSTS INCURRED DURING THE TEST YEAR ON BEHALF OF ETI IN CONNECTION WITH THE REGULATORY SERVICES CLASS REASONABLE?

A. Yes.

Q38. DOES THE REGULATORY SERVICES CLASS HAVE IN PLACE A BUDGETING PROCESS TO CONTROL COSTS?

A. Yes. Budgets for each organization are developed in coordination with Finance Business Partners. Monthly and year-to-date reports with variance explanations are reviewed and compared to budget. In addition, quarterly estimates of year-end spending are also made and submitted to finance/accounting. Variances are reviewed on a monthly basis and appropriate courses of action are taken. Variances of any major consequence are also addressed with utility executive management and a course of action determined.

Q39. WHAT WERE THE LEVELS OF AFFILIATE EXPENSE CHARGED TO ETI FOR SERVICES PROVIDED BY THE REGULATORY SERVICES CLASS FOR THE LAST THREE YEARS AND THE TEST YEAR?

A. ESL's total O&M charges to ETI for each of the past three calendar years and the Test Year for this class of services are shown in Table 4 below.

Table 4*: Affiliate Regulatory Services Provided to ETI
(Excludes pro forma adjustments)

Regulatory Services	2018	2019	2020	Test Year
Total ETI Charges	$1,613,642	$1,494,631	$1,529,504	$1,779,929

*These cost trends have been adjusted to remove Corporate Aviation costs, Nuclear and Gas department costs, and other non-ratemaking items.

Q40. PLEASE SUMMARIZE THE CHANGES IN O&M EXPENSE FROM 2018 TO THE TEST YEAR.

A. As can be seen from Table 4 above, relative to 2018, the costs charged to ETI for the Regulatory Services Class have increased approximately $166,000. This is due in part to the deferral of expenses incurred largely in 2019 associated with ETI's last rate case pursuant to the Order in Docket No. 48439,[12] organizational changes (as reflected in Table 5 below) and primarily to fluctuations in the level of regulatory activities from year to year. For example, in addition to the baseline filings that occur annually, in the Test Year (2021), ETI incurred expenses for activities associated with the Liberty County Solar Facility docket, the Orange County Advanced Power Station docket, the Montgomery County Power Station and Hardin updates to the generation rider and the TCRF and DCRF updates.

[12] *Review of Rate Case Expenses Incurred in Docket No. 48371*, Docket No. 48439, Order (Feb. 14, 2020).

Table 5: Headcount Trend

Regulatory Services Class	2018	2019	2020	Test Year 2021
Headcount	98	99	91	94

Q41. ARE THE SERVICES PROVIDED IN THE REGULATORY SERVICES CLASS DUPLICATED BY ETI OR OTHER ESL ORGANIZATIONS?

A. No. There is no duplication of the services I describe by ETI or any other ESL organization. The support necessary for ETI (and the other EOCs) to meet regulatory requirements and policy objectives is provided across several organizations, e.g., state and federal Regulatory Affairs, Governmental and Public Affairs, Regulatory Services & Strategy, etc. Each of these organizations performs different activities in support of ETI meeting applicable regulatory requirements.

D. Summary of Affiliate Costs

Q42. WHAT IS YOUR OVERALL CONCLUSION REGARDING THE TOTAL ETI ADJUSTED COSTS THAT YOU SPONSOR IN THE REGULATORY SERVICES CLASS OF AFFILIATE COSTS?

A. Based on my testimony regarding the Regulatory Services affiliate class as set out above, I conclude that the Total ETI Adjusted costs for this class are necessary, reasonable, and not higher than charges billed by the affiliates to other entities, and that these costs represent the actual costs of providing such services.

VII. CONCLUSION

Q43. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT OF ALYSSA MAURICE-ANDERSON

THE STATE OF LOUISIANA)
)
ORLEANS PARISH)

This day, 6/15/2022 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 Alyssa Maurice-Anderson. 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.

Alyssa Maurice-Anderson

SUBSCRIBED AND SWORN TO BEFORE ME, notary public, on this the 15th day of June 2022.

Notary Public, State of Louisiana

My Commission expires:
at Death

Skylar Rosenbloom
Notary Public
State of Louisiana
Louisiana Bar Roll # 31309
My Commission is issued for Life