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SOAH Docket No. 473-22-04394
PUC Docket No. 53719

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

REDACTED

DIRECT TESTIMONY AND EXHIBITS

OF

MARK E. GARRETT

ON BEHALF OF

CERTAIN CITIES SERVED BY ENTERGY TEXAS, INC. ("CITIES")

Mark E. Garrett
Garrett Group Consulting, Inc.
Edmond, Oklahoma

October 26, 2022

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I. WITNESS IDENTIFICATION

Q: PLEASE STATE YOUR NAME AND OCCUPATION.

A: My name is Mark Garrett. I am the President of Garrett Group Consulting, Inc., a firm specializing in public utility regulation, litigation and consulting services.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND YOUR PROFESSIONAL EXPERIENCE RELATED TO UTILITY REGULATION.

A: I am a licensed attorney and a certified public accountant. I work as a consultant in public utility regulation. I received my bachelor's degree from the University of Oklahoma and completed post-graduate hours at Stephen F. Austin State University and at the University of Texas at Arlington and Pan American. I received my juris doctorate degree from Oklahoma City University Law School and was admitted to the Oklahoma Bar in 1997.

I am a Certified Public Accountant licensed in the States of Texas and Oklahoma with a background in public accounting, industry, and utility regulation. In public accounting, as a staff auditor for a firm in Dallas, I primarily audited financial institutions in the State of Texas. In private industry, as controller for a mid-sized ($300 million) corporation in Dallas, I managed the Company's accounting function, including general ledger, accounts payable, financial reporting, audits, tax returns, budgets, projections, and supervision of accounting personnel. In utility regulation, I served as an auditor in the Public Utility Division of the Oklahoma Corporation Commission from 1991 to 1995. In that position, I managed the audits of major gas and electric utility companies in Oklahoma.

Since my departure from the Oklahoma Corporation Commission, I have worked on numerous rate cases and regulatory proceedings on behalf of various consumers, consumer groups, public utility commission staffs and offices of attorneys general. I have provided testimony before the public utility commissions in the states of Alaska, Arizona, Arkansas, Colorado, Florida, Indiana, Massachusetts, Nevada, Oklahoma, Pennsylvania, Texas, Utah, and Washington. My clients include industrial customers and groups of customers, hospitals and hospital groups, universities, municipalities, and large commercial customers. I have also testified on behalf of the commission staff in Utah and the offices of attorneys general in Oklahoma, Indiana, Washington, Nevada, and Florida. I have also served as a presenter at the NARUC subcommittee on Accounting and Finance on the issue of incentive compensation, and as a regular instructor at the New Mexico State University's Center for Public Utilities course on basic utility regulation.

Q: HAVE YOUR QUALIFICATIONS BEEN ACCEPTED BY THE PUBLIC UTILITY COMMISSION OF TEXAS IN PRIOR PROCEEDINGS?

A: Yes, they have. I have testified before the Public Utility Commission of Texas ("Commission" or "PUCT") in several prior proceedings. A more complete description of my qualifications and a list of the proceedings in which I have been involved are attached as Exhibit MG-1.

Q: ON WHOSE BEHALF ARE YOU APPEARING IN THESE PROCEEDINGS?

A: I am appearing on behalf of Certain Cities Served by Entergy Texas, Inc. ("Cities").[1]

II. PURPOSE OF TESTIMONY AND SUMMARY OF ADJUSTMENTS

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: The purpose of my testimony is to provide the Commission with recommendations regarding various revenue requirement issues in the Company's rate case application. Specifically, I recommend adjustments to reduce the Company's requested revenue requirement related to its payroll, incentive compensation, self-insurance accrual, directors' and officers' insurance expense, and proposed accelerated depreciation for retiring plants. I also address the Company's proposed ROE adder. A summary of my proposed adjustments is shown in Table 1 below:

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[1] Cities of Anahuac, Beaumont, Bridge City, Cleveland, Dayton, Groves, Houston, Huntsville, Liberty, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Pinehurst, Port Arthur, Port Neches, Roman Forest, Rose City, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, West Orange, and Willis, Texas.

Table 1: Cities' Revenue Requirement Adjustments

Cities' Proposed Adjustments in This Testimony	Revenue Req. Impact
Reduce Short Term Incentive Compensation to Target Market Level	(1,930,041)
Remove 50% of Indirect Financial Based STI Compensation	(2,120,482)
Remove Long Term Incentive RSUs	(2,516,320)
Remove Post-Test Year Payroll Adjustments	(2,597,284)
Non-Qualified Retirement Plans	(1,329,420)
Reduce Self-Insurance Reserve Amortization	(4,939,235)
Remove 50% of Directors' and Officers' Insurance Expense	(65,844)
Amortize Pension and OPEB regulatory Asset of 4 Years	(978,016)
Amortize COVID-19 Bad Debt Regulatory Asset over 4 Years	(1,532,659
Remove ROE Premium	(8,580,220)
Remove Accelerated Depreciation for Retiring Plants[2]	(59,349,569)
Total Adjustments	(85,939,090)

[2] This adjustment to Remove Accelerated Depreciation for Retiring Plants in the amount of $59.3 million is included in the total depreciation adjustment of $69.3 million recommended by Cities' witness, David J. Garrett.

III. INCENTIVE COMPENSATION ADJUSTMENTS

Q: PLEASE DESCRIBE THE COMPANY'S COMPENSATION PACKAGE.

A: The Company's compensation package includes base salary, annual short-term incentives ("STI"), long-term incentives ("LTI"), and benefits. The Company seeks to include total incentive compensation of $10.9 million in rates as shown in the table below:

Table 2: Entergy's Requested Incentive Compensation in Cost of Service[3]

Incentive Compensation Programs	ETI Expense	Affiliate Expense	Total
Annual Incentive Plans (STI)	$3,614,836	$4,992,967	$8,607,803
Equity-based long-term Incentives (LTI)	$237,672	$2,071,726	$2,309,398
Totals	**$3,852,508**	**$7,064,693**	**$10,917,201**

The Company's incentive compensation program consists of formal written plans available to its various employee groups, as described in the direct testimony and exhibits of Jennifer A. Raeder. Most of the Company's incentive compensation awards in the test year are based on a combination of financial and operational performance measures.

Q: HAS THE COMPANY REMOVED ALL INCENTIVE COMPENSATION COSTS ASSOCIATED WITH FINANCIAL PERFORMANCE MEASURES IN A MANNER CONSISTENT WITH THE COMMISSION'S CURRENT STANDARD?

A: No. The Company removed a very small portion of its STI compensation costs, the amount it claims is *directly* tied to financial performance metrics, however, it did not

[3] *See* Exhibit MG-2.1 and Exhibit MG-2.3.

adhere to the Commission's standard by removing incentive compensation costs indirectly tied to financial performance due to the Company's earnings per share ("EPS") financial trigger/funding mechanism in its plans. Although the Commission's current policy requires removal of all financially-based incentive compensation, the Company relied on an outdated methodology from its 2012 litigated rate case, Docket No. 39896[4] to seek recovery of significant amounts of financially-based incentive compensation. In addition, the Company failed to adjust its STI compensation payout to target levels. As a result, the incentive compensation the Company seeks to recover exceeds market-based levels.

In the sections below, I recommend three adjustments to incentive compensation. First, consistent with the Commission's clear standard, I recommend an adjustment to remove the incentive compensation costs tied to financial performance as result of the Earnings Per Share ("EPS") triggers in the Company's plans. Second, I recommend that the Company's requested STI level be adjusted to ensure that amounts recovered are market-based. Finally, I recommend an adjustment to remove LTI expense because the Company's equity-based long-term incentives are tied to financial performance. Each of these adjustments are presented separately below.

III. A. SHORT-TERM INCENTIVE COMPENSATION

Q: PLEASE DESCRIBE THE COMPANY'S ANNUAL INCENTIVE PLANS.

A: Entergy has a total of six short-term incentive plans, including four plans for exempt employees and two plans for non-exempt employees, as shown in the table below:

[4] Direct Testimony of Jennifer A. Raeder p. 29, lines 11-12.

Table 3: Entergy's Annual Incentive Programs[5]			
	Plan Name		Eligible Employees
1	Executive Annual Incentive Plan	(EAIP)	Chief Executive Officer, Presidents, Executive Vice Presidents, Senior Vice Presidents and some Vice Presidents;
2	System Management Incentive Plan	(SMIP)	Selected exempt management personnel and key high-level employees;
3	Operational Supervisor Incentive Plan	(OSIP)	Exempt employees who are operational supervisors or work in the field;
4	Exempt Incentive Plan	(EXIP)	Exempt employees not eligible for another incentive plan;
5	Teamsharing Incentive Plan	(TSIP)	Non-Exempt non bargaining employees not eligible for other plans;
6	Teamsharing Plan for Selected Bargaining Units	(TSBP)	Plan for employees covered by the collective bargaining agreement;

The first four plans – the EAIP, SMIP, OSIP and EXIP – provide incentive compensation for the Company's exempt employees. Each of these plans is discretionary and is dependent on a financial trigger funding mechanism, the Entergy Achievement Multiplier ("EAM"). According to Ms. Raeder, "the EAM is used to assess: (1) the financial feasibility of awarding annual incentive compensation, and (2) the payout level the performance of the corporation indicates is appropriate." In other words, the EAM operates as both a financial trigger (to assess the financial feasibility of the incentive awards) and as a financial funding mechanism (to set the actual payout level). The vast majority of the Company's incentive compensation awards are paid under these four plans

[5] See Direct Testimony of Jennifer A. Raeder p. 7, line 10 – p. 8, line 5.

which depend on the EAM. The two Teamsharing plans (which are not based on EAM) comprise only a miniscule percentage of the incentive compensation awarded.[6] (We made no adjustments to the Teamshare wards).

Q: WHAT ADJUSTMENT DID THE COMPANY MAKE TO REMOVE FINANCIALLY-BASED STI COMPENSATION?

A: The Company removed a total of $256,998 short-term incentive costs.[7] This adjustment is based on Entergy's claim that only nine of its affiliate-allocated employees (the ESL Office of the Chief Executive) received incentive compensation based on direct financial metrics.[8] Ms. Raeder claims the remainder of the Company's incentive compensation awards are discretionary based ***solely*** on the achievement of operations-based metrics[9] and on operational workgroup and individual goals."[10]

Q: DO YOU AGREE WITH THE COMPANY'S CLAIM THAT THE ITS INCENTIVE COMPENSATION AWARDS ARE BASED *SOLELY* ON ACHIEVEMENT OF OPERATIONAL GOALS?

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[6] The total payout from the two Teamshare plans comprises only [redacted] of the 2021 Award Payout. See ETI's Highly Sensitive Response to OPUC 1-10 [Att. TP-53719-00OPC001X010_HSPM_A-E]. This schedule sets forth the Company's actual incentive award payouts for the 2021 test year by Company plan. Calculations and analysis based on the actual payout data in the schedules.

[7] *See* AJ22B – Affiliate Incentive Comp.xlsx.

[8] Direct Testimony of Jennifer A. Raeder, p. 9, lines 11 - 13.

[9] *Id.* p. 9, lines 13-15. (Emphasis added).

[10] *Id.* p. 13, Table 1.

A: No. The Company's claim is inconsistent with the plan data in Exhibit JAR-1 (HSPM), a series of slide presentations describing the Company's 2021 plans. My review of Exhibit JAR-1(HSPM) indicates that most of the Company's incentive award payouts depend on financial and operational measures because they are discretionary plans that are funded *only* if the EAM is achieved at or above a minimum level set prior to the start of the incentive year.[11] Moreover, the annual funding levels are adjusted [redacted] based upon the Company's EAM achievement.[12]

Q: HOW DID YOU DETERMINE THE AMOUNTS OF INCENTIVE AWARD PAYOUTS THAT ARE BASED ON FINANCIAL AND OPERATIONAL MEASURES?

A: In response to OPUC 1-10, the Company provided its actual 2021 Incentive Compensation award payout data by plan type.[13] Based on this payout data, I computed the amount of test year incentive compensation awards paid each of the Company's six STI plans. The results of these calculations are set forth in the table below:

[11] See Exhibit JAR-1, pp. 28-31, 34-37, 46-47, 52-53, 55.

[12] *Id.*, p. 28.

[13] See ETI's Highly Sensitive Response to OPUC 1-10 [Att. TP-53719-00OPC001X010_HSPM_A-E].

Table 4: 2021 Annual Incentive Payout (Performance in 2021 paid in 2022)[14]

[redacted]

The four plans with EAM triggers make up [redacted] of the total 2021 payout, while the two Teamshare plans account for only [redacted] of the payout. The data above also shows that the Company's plans provide more than [redacted] of the annual incentive compensation awards to executives, officers, selected management personnel, and key high-level employees. For the 2021 plan year, employees in the top two plans (EAIP and SMIP) were awarded [redacted] of the total payout. Operational supervisors, field workers, and other non-exempt employees in the OSIP and EXIP plans were awarded only [redacted] of the total payout.

Q: IF THE COMPANY'S EAM TARGET LEVELS ARE NOT MET IN A GIVEN YEAR WOULD THESE PLANS BE FUNDED?

[14] See ETI's Highly Sensitive Response to OPUC 1-10 (Att. TP-53719-00OPC001X010_HSPM_A-E). See also, Confidential WORKPAPER MG-2.1 Incentive Compensation Analysis.

A: No. Ms. Raeder acknowledges that annual award payouts depend on the funding of the plans to assure that "Entergy has the financial wherewithal to award incentive compensation for the performance year."[15] Exhibit JAR-1(HSPM) also states, [redacted][16]

Q: IS THE EAM AN INDIRECT FINANCIAL MEASURE THAT SHOULD BE REMOVED FOR RATEMAKING PURPOSES UNDER THIS COMMISSION'S STANDARD?

A: Yes. the Commission in numerous decisions over the past decade has required that financially-based incentive compensation, both direct and indirect, be removed for ratemaking purposes. The EAM is based 60% on earnings per share (EPS),[17] and is therefore an indirect financial measure. Ms. Raeder acknowledges that the inclusion of EPS is a "threshold matter" that ensures Entergy "has generated sufficient profit to assure the financial feasibility of awarding any annual incentive compensation for the year."[18] This approach clearly puts the profit interests of shareholders first. As such, the financial component of the EAM a financial trigger and funding mechanism that must be removed.

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[15] Direct Testimony of Jennifer A. Raeder, p. 11, lines 18-19.

[16] See Exhibit JAR-1 (HSPM) p. 36 (Emphasis added).

[17] Direct Testimony of Jennifer A. Raeder, p. 11, lines 18-19.

[18] *Id.*, p. 12, lines 3-6.

Q: HOW DOES THE COMPANY JUSTIFY ITS DECISION NOT TO FOLLOW THE COMMISSION'S POLICY ON THIS ISSUE?

A: The Company suggests that the Commission should reconsider its policy of disallowing a portion of annual incentive compensation expense where a financially based funding mechanism is used.[19] Ms. Raeder claims that its so-called "affordability trigger" merely ensures that utilities only pay compensation when they are financially able to do so.[20] She argues that a utility needs to be financially sound to have access to capital on reasonable terms, and that denying recovery of costs would "deprive ETI of reasonable and necessary expense incurred to provide customers safe and reliable service."[21] The problem with this argument, again, is that the Commission has repeatedly found that recovery of such costs are ***not*** reasonably necessary for the provision of service as financial measures primarily benefit shareholders, not ratepayers.

Q: PLEASE DESCRIBE COMMISSION'S POLICY ON SHORT-TERM INCENTIVE COMPENSATION EXPENSE.

A: The Commission has a longstanding policy of disallowing incentive payments that are tied to financial performance measures. To my knowledge, in every litigated rate case since the 2005 AEP Texas Central case (Docket No. 28840) the Commission has disallowed the portion of incentive compensation costs it determined was related to financial performance

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[19] Direct Testimony of Jennifer A. Raeder, p. 31, lines 6-10.

[20] *Id.*, p. 31, lines 13-15.

[21] *Id.*, p. 31, line 22—p. 32, line 9.

measures, as summarized in the table below:

Table 5: Overview of Cases before the Public Utility Commission of Texas in which Financially-Based Incentive Compensation was Litigated			
Date	**PUC Docket No.**	**Utility Company**	**Excluded Financially-Based Incentive Comp.**
8/15/2005	**28840**	AEP Texas Central Co.	YES [22]
3/4/2008	**33309**	AEP Texas Central Co.	YES [23]
11/30/2009	**35717**	Oncor Electric Delivery Co., LLC	YES [24]
6/23/2011	**38339**	CenterPoint Electric Delivery Co., LLC	YES[25]
11/2/2012	**39896**	Entergy Texas, Inc.	YES [26]
3/6/2014	**40443**	Southwestern Electric Power Co. (SWEPCO)	YES [27]
2/23/2016	**43695**	Southwestern Public Service Company (SPS)	YES [28]
3/19/2018	**46449**	Southwestern Electric Power Co. (SWEPCO)	YES [29]
	49421	CenterPoint Electric Delivery Co., LLC	YES[30]
1/14/2022	**51415**	Southwestern Electric Power Co. (SWEPCO)	YES[31]

[22] See *Application of AEP Texas Central for Authority to Change Rates,* Docket No. 28840, Proposal for Decision at 92-97, Findings of Fact Nos. 164-170, Order at 35 (Aug. 15, 2005).

[23] See *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Proposal for Decision at 93-98, Finding of Fact No. 82, Order on Rehearing at 12 (March 4, 2008).

[24] See *Application of Oncor Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 35717, Proposal for Decision at 96-100, Order on Rehearing at 22 (Nov. 30, 2009).

[25] See *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Proposal for Decision at 65-68, Findings of Fact Nos. 81-83, Order on Rehearing at 22 (June 23, 2011). (Financial-based long term incentives were excluded. STI incentives not disallowed because the issue was not raised until the briefing phase of the case, with insufficient evidence for disallowance).

[26] See *Application of Entergy Texas, Inc., for Authority to Change Rates*, Docket No. 39896, Findings of Fact Nos. 127-133, Order on Rehearing at 24 (November 2, 2012).

[27] See *Application of Southwestern Electric Power Co., for Authority to Change Rates*, Docket No. 40443, Findings of Fact Nos. 214-220 Order on Rehearing at 38 (March 6, 2014).

[28] See *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Findings of Fact Nos. 83A-85A Order on Rehearing at 27 (February 23, 2016).

[29] See *Application of Southwestern Electric Power Co., for Authority to Change Rates*, Docket No. 46449, Findings of Fact Nos. 194-198, Order on Rehearing at 34 (March 19, 2018)

[30] See *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 49421, Proposal for Decision at 231-245, (Sept. 16, 2019); Order (Mar. 9, 2020).

[31] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 51415, Proposal for Decision, p. 209-216 (Aug. 27, 2021) and Commission Order, p. 23 (Jan. 14, 2022).

The Commission's decisions prior to Entergy's 2012 rate case (Docket No. 39386) clearly disallowed financially-based incentives, but the treatment of indirect financial triggers and funding mechanisms were not specifically addressed in those earlier cases. However, Ms. Raeder's reliance Docket No. 39896 for the Company's treatment in this application is misplaced because, as Ms. Raeder acknowledges, the Commission's policy on recovery of incentive compensation has evolved since that 2012 decision. In the cases following Docket No. 39896, the Commission has consistently strengthened and clarified its policy on excluding financial based incentives from rates.

Q: PLEASE DISCUSS THE COMMISSION'S DECISIONS IN LITIGATED RATE CASES DECIDED AFTER DOCKET NO. 39896.

A: In its 2013 rate case, Docket No. 40443, SWEPCO raised several of the same arguments that Entergy presents here seeking that the Commission reconsider its policy to exclude financial based incentive compensation. SWEPCO claimed that "unique aspects of its overall compensation program" supported the inclusion of financial measures in rates.[32] The ALJs and the Commission carefully considered and rejected SWEPCO's request that the Commission reconsider its policy on removing financial based incentive compensation for ratemaking purposes.[33]

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[32] See *Application of Southwestern Electric Power Co., for Authority to Change Rates*, Docket No. 40443, Proposal for Decision at 78-83 (May 20, 2013) Comm'n. Order on Rehearing at 38); Findings of Fact Nos. 214-220 (March 6, 2014).

[33] *Id.*

In the 2015 SPS rate case, Docket No. 43695, the Commission addressed the issue of indirect financial incentive measures. SPS initially removed what it asserted were the *direct* financially-based incentive costs, however the Commission determined that this treatment was insufficient. Instead, the Commission required that *all* incentive costs tied to financial measures (direct and indirect) must be removed. The Commission's order adopted the current two-tiered approach in which it disallows 100% of short-term incentives *directly* tied to financial performance measures, and 50% of the remaining financial based incentives *indirectly* tied to financial performance through an earnings-per-share funding mechanism.[34] The Commission stated:

> It is well-established that a utility may not include in its rates the costs of incentives that are tied to financial performance measures. The Commission agrees with the SOAH ALJs' characterization of the annual incentive plan as "complicated" and notes that when a utility elects to adopt a compensation plan that involves both financially-based and performance-based metrics, *the utility still must show it has removed all aspects of the financially-based goals from its requested expense*.[35]

In SWEPCO's 2017 rate case, Docket No. 46449, the ALJ's stated:

> Again, the Commission made no distinction between financially-based metrics that trigger incentive payments and financially-based metrics that trigger *funding* for incentive plans. Hence, the ALJs conclude that the Commission's longstanding precedent, including the most recent pronouncement in SPS Docket No. 43695 make very clear that *any incentive compensation plan included in rates must be performance or operationally based. It cannot contain a financial trigger, whether the financial metric* ***triggers payment*** *or merely* ***funding*** *of an incentive compensation plan*.[36]

[34] *See* Docket No. 43695, Order on Rehearing at 5-6. This was the approach taken by the witness whose recommendations were adopted by the Commission.

[35] *Id.*, at 5. (Emphasis added).

[36] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Proposal for Decision, p. 243 (Sept. 22, 2017). (Emphasis added).

In approving the ALJs proposal for decision, the Commission confirmed its policy that indirect financial costs associated with an EPS funding trigger must be removed, stating:

> **194.** The Commission has _repeatedly ruled_ that a utility cannot recover the cost of financially-based incentive compensation because _financial measures are of more immediate benefit to shareholders and financial measures are not necessary or reasonable to provide utility services_.[37]

In the 2019 CenterPoint Energy Houston Electric LLC rate case, Docket No. 49421, the ALJs addressed the impact of CenterPoint's financial trigger and the dispute as to whether the achievement of O&M goals constitutes a financial metric. Ultimately, the ALJ's excluded 100% of costs tied to direct financial metrics, and 50% of the operational costs to reflect the indirect effect of the financial trigger. The ALJs also concluded that CenterPoint's _O&M Expenditures Goal is a financial metric_ that should be disallowed:

> The ALJs further conclude that CenterPoint's O&M Expenditures Goal is a _financial metric_ and that the costs tied to that goal should be disallowed, as proposed by Staff, OPUC, and COH (and supported by GCCC and HEB). _The ALJs find that the achievement of this goal, more directly and immediately, benefits the shareholders instead of the customers. Accordingly, the ALJs find that the goal is financially-based, and that the associated costs should be disallowed_. CenterPoint's ratepayers might benefit from the achievement of this goal (i.e., reduced O&M expenses may mean a lower overall revenue requirement) but that benefit might not be achieved and would not benefit customers until CenterPoint's next rate case. _In contrast, the savings of O&M expenses achieved by this goal result in a financial benefit immediately available to CenterPoint and its shareholders_.[38]

This point is important because in Entergy's 2021 incentive compensation plans, all of the

[37] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Finding Nos. 194-198, Order on Rehearing at pp. 34-35 (March 19, 2018). (Emphasis added).

[38] See *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 49421, Proposal for Decision at 244, (Sept. 16, 2019). (Emphasis added).

Company's Business Units continue to have plan metrics for O&M costs which are labeled "operational," in conflict with the Commission's treatment in Docket No. 49421. Although I have not proposed an additional adjustment to disallow the costs related to Entergy's O&M metrics, it would be appropriate for the Commission to remove these costs from rates.

In the CenterPoint case, the ALJs recommended that the Commission disallow 92% of CenterPoint's total requested STI expense because it found those costs were impermissible financially-based incentive costs.[39] Following the issuance of the ALJ's PFD the parties reached a black-box settlement agreement without a specific determination of the incentive compensation issues, which the Commission subsequently approved.[40]

Finally, in SWEPCO's 2020 rate case, Docket No. 51415, SWEPCO followed the Commission's current approach by voluntarily removing both the direct and indirect financial based incentives as shown in the Commission's order:

> 141. SWEPCO's application excluded financial-based short-term incentive compensation expense and 50% of the financial-based funding mechanism related to its short-term incentive compensation plans.[41]

Q: HAS ENTERGY PRESENTED ANY COMPELLING REASONS FOR THE COMMISSION TO RECONSIDER ITS LONGSTANDING POLICY?

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[39] *Id.*, at 245.

[40] *Application of CenterPoint Electric Delivery Co., LLC, for Authority to Change Rates*, Docket No. 49421, Order (Mar. 9, 2020).

[41] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 51415, Proposal for Decision, p. 209 (Aug. 27, 2021); and Commission Order, p. 23 (Jan. 14, 2022).

A: Not at all. The Company argues that recovery of its financial based funding mechanism in rates is necessary to attract and retain highly qualified individuals to provide service to customers.[42] Entergy also claims it must "provide compensation comparable to its competitors, or it will experience high rates of attrition, leading to higher costs for training and lower quality of service, negatively impacting customers.[43] This is not a compelling argument. As shown in the overview above, this Commission has consistently implemented this policy over the last decade, so Entergy certainly will not be placed at any competitive disadvantage by the continuation of the Commission's sound policy. To the contrary, Entergy will be in precisely the same competitive position as the other regulated utilities serving Texas ratepayers.

Q: IS THIS APPROACH CONSISTENT WITH HOW ENTERGY'S INCENTIVES ARE TREATED IN OTHER STATES?

A: Yes. In Arkansas, in Docket No. 13-028-U, the Arkansas commission disallowed 50% of Entergy's short-term incentive compensation because the plans included the financial-based EAM funding mechanism. The Arkansas commission then reaffirmed this approach in Energy's next rate case, Docket No. 15-015-U. In fact, in that case, the Arkansas commission rejected a settlement stipulation because the stipulation did not exclude 50% of Entergy's short-term incentives. The commission accepted the settlement only after the 50% exclusion was added.

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[42] Direct Testimony of Jennifer A. Raeder, p. 32, lines 3-13.

[43] *Id.*, p. 32, lines 13-15.

Q: HOW DOES THIS COMMISSION'S TREATMENT OF INCENTIVES COMPARE TO THE TREATMENT OF INCENTIVES IN OTHER JURISDICTIONS?

A: The Commission's treatment is consistent with the majority of jurisdictions. The results of an Incentive Compensation Survey of 24 western states taken by the Garrett Group LLC ("Garrett Group Survey") in 2007, and updated in 2009, 2011, 2015, and 2018, shows that a clear majority of the states surveyed follow the rule that incentive payments associated with financial performance are *excluded* from rates, as shown in the table below:

Table 6: Garrett Group LLC's STI Compensation Survey Summary

Garrett Group, LLC Short Term Incentive Compensation 24 Western States Incentive Survey Results			
No Incentive Costs Allowed in Rates	**Financial Performance Rule Followed**	**Other Sharing Approach**	**Incentives Not at Issue**
Hawaii			
	Arizona		
	Arkansas		
	California		
	Idaho		
	Kansas		
	Louisiana		
	Minnesota		
	Missouri		
	Nebraska		
	Nevada		
	New Mexico		
	North Dakota		
	Oklahoma		
	Oregon		
	South Dakota		
	Texas		
	Utah		
	Washington		
	Wyoming		
		Alaska[44]	
		Colorado[45]	
			Iowa
			Montana

As shown in the table above most of the western states disallow a portion of incentive compensation costs where the incentive plans contain both financial and operational measures. Of those jurisdictions, several use a sharing approach to allocate costs between shareholders and ratepayers.

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44 Incentive compensation has not been an issue in Alaska, partly because many utilities are municipalities and cooperatives. In one recent case the Reg. Comm'n of Alaska approved inclusion of incentives in rates.

45 Colorado followed the financial performance rule in the past. In one recent case, however, the Colorado Public Utilities Commission approved a different approach.

Q: IN YOUR EXPERIENCE, WHEN REGULATORS EXCLUDE THE PORTION OF A UTILITY'S INCENTIVE PLAN TIED TO FINANCIAL PERFORMANCE MEASURES, DOES THE UTILITY STOP OFFERING INCENTIVE COMPENSATION TO HELP ACHIEVE ITS FINANCIAL GOALS?

A: No. Even though regulators generally disallow incentive compensation tied to financial performance for ratemaking purposes, utilities continue to include financial performance as a key component of their plans. In my opinion, utilities continue to tie incentive payments to financial performance because by doing so they achieve the primary objective of the incentive plans: to increase corporate earnings and, thereby, earnings per share ("EPS"). However, since the utility retains the increased earnings that these plans help achieve, payments for these plans should be made from a portion of the increased earnings. These plans need not be subsidized by ratepayers. Recovery of plan costs through rates ***is not necessary to attract a talented workforce*** because the Company has other means of cost recovery—through the increased earnings generated by the plan.

Q: HAS THE COMPANY DEMONSTRATED THAT ITS INCENTIVE COMPENSATION COSTS ARE SET AT COMPETITIVE LEVELS?

A: No. Although the Company states that it "established reasonable target incentive compensation payments" for its 2021 incentive plans,[46] the Company's application does *not* include an adjustment to limit recovery to those reasonable target levels. Instead, the

[46] Direct Testimony of Jennifer A. Raeder, pp. 21-26.

Company seeks to recover its actual payout levels which are significantly ***higher*** than the market-based target levels discussed in Ms. Raeder's testimony.

Q: SHOULD THE INCENTIVE COMPENSATION COSTS BE ADJUSTED TO MARKET COMPETITIVE LEVELS?

A: Yes. The Commission should require that Entergy's adjust its incentive compensation costs included in rates down to target levels. Based on the actual payout data provided by Entergy in response to OPC 1-10, the actual incentive awards payouts exceed target levels by [redacted].[47] The response to OPC 1-10 is classified as highly sensitive protected material because it includes the payroll information for individual positions. My calculations show that the test year incentive awards were twenty six percent above the target levels, or twenty six percent above the competitive compensation requirement.[48]

Q: ARE YOU AWARE OF OTHER INSTANCES IN WHICH A UTILITY'S INCENTIVE COMPENSATION COSTS HAVE BEEN ADJUSTED TO TARGET LEVELS?

A: Yes. In 46449, SWEPCO indicated that it did not request recovery for its incentive compensation expenses above target levels.[49] Similarly, in Docket No. 51415, SWEPCO again indicated that it only was requesting inclusion of its a target-level test year STI

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[47] See ETI's Highly Sensitive Response to OPUC 1-10 (Att. TP-53719-00OPC001X010_HSPM_A-E).

[48] See Confidential WORKPAPER MG-2.1 Incentive Compensation Analysis.

[49] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Proposal for Decision, p. 235 (Sept. 22, 2017).

expense, *<u>which is the market-competitive level</u>*, rather than the larger actual per-books expense.[50]

Q: ENTERGY CITES UTILITY INDUSTRY SURVEYS TO CLAIM ITS OVERALL INCENTIVE COMPENSATION LEVELS ARE COMPARABLE TO MARKET BASED LEVELS. ARE THESE COMPARISONS SUFFICIENT?

A: No. The actual payout data clearly shows that Entergy seeks to recover its actual payout levels which are [redacted] above the company's market-based target levels. Jennifer A. Raeder provided a list of third-party surveys utilized by the Company as Exhibit JAR-4. However, Ms. Raeder did not provide the details of those surveys and did not establish that Entergy's compensation does not exceed lowest cost necessary to attract and retain competent employees. Generally, compensation surveys will compare the components of compensation as well as the total cost. Ms. Raeder presented a comparison of Entergy's employee benefits[51] but did not provide the same information of its compensation programs. Even so, by ETI's own calculation, their total employee compensation came in at 101.13% of the market median.[52] Any comparison of employee costs should include total compensation, including base pay and target levels of short-term and long-term incentives. Since substantive information was not provided, the Company's claims that its compensation is set at levels that are competitive with other companies cannot be verified.

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[50] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 51415, Proposal for Decision, pp. 207-208 (Aug. 27, 2021) (Emphasis added).

[51] See Exhibit JAR-6 (HSPM).

[52] Direct Testimony of Jennifer A. Raeder, p. 27, Table 4.

Q: WHY IS IT IMPORTANT FOR THE COMMISSION TO CONTINUE ITS PRACTICE OF EXCLUDING FINANCIALLY BASED INCENTIVE COMPENSATION AND ENSURING COST LEVELS ARE MARKET-BASED?

A: The Commission's policy of excluding financially-based incentive compensation balances the interests of ratepayers and shareholders. Entergy presents compensation studies in support of its claim that "the presence of a financial funding trigger is aligned with customer interests."[53] However, Entergy's conclusions are misplaced. It is undisputed that such plans provide some benefit to both shareholders and ratepayers. The issue is not whether the utility should continue to offer incentive compensation plans, or whether such plans provide any customer benefits. The issue instead is who should pay for the incentive compensation costs. The Commission has established the correct policy on this issue. Because the Commission serves as the surrogate for competition for regulated utilities such as Entergy, it is equally important the Commission limit Entergy's incentive compensation recovery to target levels.

Q: WHAT IS THE GENERAL RATIONALE FOR EXCLUDING INCENTIVE COMPENSATION TIED TO FINANCIAL PERFORMANCE?

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[53] Direct Testimony of Jennifer A. Raeder, p. 27, Table 4.

A: In many jurisdictions, the cost of incentive plans which are tied to financial performance measures are excluded for ratemaking purposes.[54] When the costs associated with these plans are excluded, the rationale is generally based on one or more of the following reasons:

(1) Payment is uncertain. Often, payment of incentive compensation is conditioned upon meeting some predetermined financial goal such as achieving a certain increase in earnings, reaching a targeted stock price or meeting budget objectives. If the predetermined goals are not met, the incentive payment is not made, or payment is made at some lesser amount. Therefore, one cannot know from year to year what the level of the payment may be or whether the payment will be made at all. It is generally considered inappropriate to set rates to recover a tentative level of expense.[55]

(2) Many of the factors that significantly impact earnings are outside the control of most company employees and have limited value to customers. For example, an unusually hot summer can easily trigger an incentive payment based on company earnings for an electric utility. Obviously, weather conditions are outside the control of utility employees and customers receive no benefit from the higher utility bills that result from an unusually hot summer. Similarly, company earnings may increase, thus triggering incentive payments, as a result of customer growth, which commonly occurs without significant influence from company personnel. In fairness, since shareholders enjoy the benefits of customer growth between rate

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[54] *See* the results of the Survey of Western States outlined below. *See also, e.g.*, *U.S. West Communications, Inc. v. Public Service Comm'n*, 901 P.2d 270, 276-77 (Utah 1995); *Central Illinois Public Service Company Proposed General Increase In Natural Gas Rates*, Docket No. 02-0798 (Cons.), 2003 Ill. PUC LEXIS 824, p. 115 (Illinois Commerce Comm'n 2003); *Application of Wisconsin Power and Light Company as an Electric, Natural Gas and Water Utility for Authority to Change Electric, Natural Gas, and Water Rates*, Docket No. 6680-UR-113, 2003 Wisc. PUC LEXIS 822, pp. 40-41 (Wisconsin Public Service Comm'n 2003); *Petition of Northern States Power Company's Gas Utility for Authority to Change its Schedule of Gas Rates for Retail Customers Within the State of Minnesota*, 146 P.U.R.4th 1, pp. 40-43 (Minnesota Public Util. Comm'n 1993); *Application of Minnegasco, a Division of NorAm Energy Corp., for Authority to Increase its Natural Gas Rates in Minnesota*, 170 P.U.R.4th 193, pp. 69-77 (Minnesota Public Util. Comm'n 1996).

[55] Public Service Company of Oklahoma's experience in a 2008 rate case is a good example of this problem. In 2009, AEP's below target EPS reduced the funding available for incentive compensation payments by 76.9%. Although in the Company's 2008 rate case, the Commission had included more than $4 million in rates for incentives, the Company chose not to use all of that money to pay incentives but instead retained some of those funds for its shareholders to help bolster the Company's lower earnings that year.

cases, shareholders should also bear the cost of any incentive payments such growth may trigger. Finally, utility earnings may increase substantially if the utility is able to successfully argue for a higher ROE in a rate case proceeding. Utility efforts to maximize ROE in a rate proceeding, however, have little to do with improving overall employee performance across the company. If utility employees gear their efforts toward securing an *unreasonably* high ROE in a rate proceeding, the incentive mechanism actually would work to the detriment of the utility customers.

(3) **Earnings-based incentive plans can discourage conservation.** When incentive payments are based on earnings, employees may not support conservation programs designed to reduce usage if they perceive these programs could adversely impact incentive payment levels. To the extent that earnings-based incentive plans discourage conservation and demand-side management programs, these plans do not serve the public interest. The growing focus on energy efficiency at both the national and state level renders this point especially important.

(4) **The utility and its stockholders assume none of the financial risks associated with incentive payments.** Ratepayers assume the risk that the utility will instead retain the amounts collected through rates for incentive payments whenever targeted increases are not reached. Employees assume the risk that the incentive payments will not be made in a given year. The utility and its stockholders, however, assume no risk associated with these payments. Instead, the company's only responsibility is to decide who gets the money, the stockholders or the employees.[56]

(5) **Incentive payments based on financial performance measures should be made out of increased earnings.** Whatever the targets or goals may be that trigger an incentive payment, when the plan is based in whole or in part on financial performance measures the company always obtains a financial benefit from achieving these objectives. This financial benefit should provide ample funds from which to make the payment. If not, the incentive plan was poorly conceived in the first place. As such, employees should be compensated out of the increased earnings, and not through rates.[57]

(6) **Incentive payments embedded in rates shelter the utility against the risk of earnings erosion through attrition.** When utilities are allowed to embed amounts for incentive payments in rates, that money is available to the utility not only to

[56] This occurred in PSO's 2008 rate case. In 2009, when AEP's EPS fell below targeted levels, the Company simply retained for its stockholders the funds that had been provided in rates for incentive plans.

[57] As is discussed above, the fact is ETI only makes incentive payments each year to the extent its earnings are sufficient to cover the costs of the payments.

pay the incentive payment when financial performance goals are met but also to supplement earnings in those years when the company does not perform well. In those years when financial performance measures are met, the increased earnings of the company provide ample additional funds from which to make the incentive payments to employees, and the incentive payment amount embedded in rates is not needed. In those years when financial performance measures are not met and the incentive payments are not made, the amount embedded in rates for incentive payments acts as a financial hedge to shelter the poor financial performance of the company.

Q: THE COMPANY ASSERTS THAT ITS VARIABLE COMPENSATION PLAN IS CUSTOMARY FOR MANY INDUSTRIES INCLUDING UTILITIES. ARE YOU RECOMMENDING THAT THE COMPANY CHANGE ITS COMPENSATION STRUCTURE?

A: No, not at all. Even though regulators routinely exclude financial-based incentive compensation payments based on one or more of the reasons outlined above, this does not mean that regulated companies will not continue to offer financial-based incentives. They do. When a financial-based incentive package is properly constructed, however, there will be ample increased earnings to fund these payments to utility employees. Thus, ratepayers do not need to subsidize incentive compensation plans that are designed to enhance financial performance.

Q: WHY IS THE DISTINCTION BETWEEN FINANCIAL PERFORMANCE MEASURES AND CUSTOMER SATISFACTION AN IMPORTANT DISTINCTION FOR INCENTIVE COMPENSATION ANALYSIS?

A: When incentive compensation payments are based on financial performance measures, the compensation agreement between shareholders and employees could be loosely stated in this manner: "if you increase shareholder earnings, we will pay you a bonus." The intended beneficiaries to this agreement are the shareholders and the employees. Ratepayers have no stake in this agreement; therefore, they should bear none of the costs that result from such an agreement. If, instead, the agreement was stated in this manner: "if you increase reliability and quality of service to the customers, we will pay you a bonus," then, ratepayers would have a stake in the agreement, and could share in a portion of the costs. However, so long as the overriding goal of the incentive plan is to increase shareholder earnings, the entire incentive compensation should be funded out of the increased earnings that trigger the payments.

Q: IN YOUR EXPERIENCE, WHEN REGULATORS EXCLUDE THE PORTION OF A UTILITY'S INCENTIVE PLAN TIED TO FINANCIAL PERFORMANCE MEASURES, DOES THE UTILITY STOP OFFERING INCENTIVE COMPENSATION TO HELP ACHIEVE ITS FINANCIAL GOALS?

No. Even though regulators generally disallow incentive compensation tied to financial performance for ratemaking purposes, utilities continue to include financial performance as a key component of their plans. In my opinion, utilities continue to tie incentive payments to financial performance because by doing so they achieve the primary objective of the incentive plans: to increase corporate earnings and, thereby, earnings per share (EPS). However, since the utility retains the increased earnings these plans help achieve, payments for the plans should be made from a portion of these increased earnings. Thus, properly designed incentive compensation plans need not be subsidized by ratepayers.

Q: UNDER THE COMPANY'S INCENTIVE PLANS, IS ANNUAL PAYMENT UNCERTAIN AND DEPENDENT UPON FINANCIAL PERFORMANCE OF THE COMPANY?

A: Yes. The incentive award payouts each year are paid each year to the extent the Company reaches its EPS goals. Because the funding mechanism for incentive compensation is primarily calculated based on EPS, the Company may significantly reduce incentive payments if the threshold EPS goals are not met. In these situations, amounts collected through rates for incentive programs would be retained by the shareholders.

Q: WILL ENTERGY BE FINANCIALLY HARMED FROM YOUR RECOMMENDATION TO EXCLUDE FINANCIALLY-BASED INCENTIVE COMPENSATION?

A: No. Energy's incentive compensation payments are discretionary payments limited by the Company's financial performance funding mechanism. This mechanism ensures that the incentive payments are not made at the expense of the Company's financial goals. In those years when the financial targets are achieved, the additional funds needed to make the incentive payments to employees will have been made available through the increased earnings that resulted from reaching those goals.

Q: WHAT RATIONALE DOES THE COMPANY PROVIDE FOR INCLUDING ITS ANNUAL INCENTIVE PLAN IN RATES?

A: The Company argues that incentives are part of an overall compensation package that is designed to attract and retain qualified personnel. Since other utilities offer incentive plans to their employees, the Company would run the risk of not being able to compete for key personnel if it did not offer a comparable plan.[58]

Q: IS THIS ARGUMENT PLAUSIBLE?

A: No. The problem with the Company's argument is that when utilities such as ETI compete with other utilities for qualified personnel, and the incentive compensation plans of these other utilities are being reduced, for ratemaking purposes, for the portion of the plans tied to financial performance, ETI is not put at a competitive disadvantage when its incentive compensation costs are similarly reduced.

Further, when incentive payments are based on financial performance goals, there should be a financial benefit to the company that comes from achieving these goals and this financial benefit should provide ample additional funds from which to make the incentive payments. Thus, a utility is not placed at a competitive disadvantage when incentive payments tied to financial performance are not collected through rates.

Q: HOW DID YOU DETERMINE THE AMOUNT OF YOUR ADJUSTMENT TO OPERATING EXPENSE FOR SHORT-TERM INCENTIVES?

A: In those incentive plans that use the EAM funding mechanism, I removed 30% of the expenses remaining after the Company's adjustments to remove, in its opinion, costs

[58] *See* Direct Testimony of Jennifer A. Raeder at p. 16, lines 12-24.

directly tied to financial performance. I allowed all of the incentives in the TeamShare plan and the TeamShare plan for bargaining employees. These two plans do not use the EAM as a funding mechanism and do not appear to have metrics tied to financial performance.

Q: WHAT ARE YOU RECOMMENDING WITH RESPECT TO THE COMPANY'S SHORT-TERM INCENTIVE EXPENSE?

A: I recommend two adjustments. (1) I recommend reducing the requested level of incentive compensation expense to target levels to remove the above-market costs included by the Company; and (2) I recommend a 50% reduction to the 60% financial portion of the EAM consistent with the Commission's longstanding policy.

Q: WHAT ARE YOUR PROPOSED ADJUSTMENTS TO ENTERGY'S ANNUAL INCENTIVE PLANS?

A: I propose two adjustments, as follows:

(1) An adjustment to reduce Entergy's STI expenses by $1,771,330 to target levels and an adjustment to reduce related payroll taxes by an additional $158,711. These adjustments are set forth at Exhibit MG-2.1.

(2) An adjustment to remove the indirect financial based incentive costs related to the EAM funding trigger in the amount of $1,946,111 with an adjustment to reduce related payroll taxes by an additional $174,372, as set forth at Exhibit MG-2.2.

III.B. LONG-TERM EXECUTIVE STOCK INCENTIVE PLAN

Q: WHAT HAS ETI PROPOSED WITH RESPECT TO THE RECOVERY OF ITS LONG-TERM STOCK INCENTIVE PLANS FOR MANAGEMENT EMPLOYEES?

A: The Company is proposing to recover $2,309,398 for its restricted stock program.[59]

Q: PLEASE DESCRIBE THE COMPANY'S LONG-TERM COMPENSATION PLANS.

A: In addition to the company-wide incentive plans discussed above, executives and managers of the Company are provided Long-Term Incentive Plan ("LTIP") compensation.[60] The LTIP awards are composed of *stock options*, *performance units*, *restricted stock awards* and *restricted stock units* (RSUs).

ETI has removed the cost of its stock options and performance units from the revenue requirement. ETI, however, seeks to include the costs of its restricted stock program because the Commission had allowed those costs to be recovered in another case.[61]

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[59] *See* Exhibit MG-2.3.

[60] *See* Direct Testimony of Jennifer A. Raeder, p. 15, lines 8-18.

[61] See Direct Testimony of Jennifer A. Raeder, p. 35, lines 9-10.

Q: DO YOU BELIEVE ETI SHOULD BE ABLE TO RECOVER ITS RESTRICTED STOCK COSTS SOLELY BECAUSE ANOTHER COMPANY WAS ALLOWED TO RECOVER ITS RSU COSTS IN ANOTHER CASE?

A; No. The issues affecting each company, ratepayers, and other issues that the Commission must balance in reaching a decision are different. ETI did not identify the precedent that it is relying on to support the inclusion of its restricted stock costs so the Commission has no basis to determine if these costs are appropriate for recovery for this Company and in the current economic climate.

Q: HAS THE COMPANY INDICATED IN PRIOR RATE CASES THAT ITS RESTRICTED STOCK PROGRAM IS RELATED TO FINANCIAL PERFORMANCE?

A: Yes. In Docket No. 39896, the Company indicated that 100% of the equity-based long-term incentive plans, which include the restricted stock program, were related to financial performance.[62] In that case, the Commission disallowed all of ETI's long-term incentive plans. Moreover, in that rate case, the Commission disallowed $730,734 of ETI's rate case expenses for costs associated with ETI's attempt to recover financially-based long-term incentives. The order states:

> Specifically, the Commission agrees with the ALJ that reductions should be made to Entergy's recoverable rate-case expenses for Entergy attempting to recover financially-based incentive compensation in base rates. _*The Commission has repeatedly ruled that a utility cannot recover the cost of financially-based incentive*_

[62] *See* Direct Testimony of Mark E. Garrett at page 39 and ETI responses to Cities' RFI 10-9(k) and Cities' RFI 10-10(k) in that case.

> *compensation because financial measures are of more immediate benefit to shareholders* and financial measures are not necessary or reasonable to provide utility services.[63]

Q: ARE THERE OTHER CASES IN WHICH ETI HAS INDICATED THAT THE RESTRICTED STOCK PROGRAM IS RELATED TO FINANCIAL PERFORMANCE?

A: Yes. In ETI's next rate case, Docket No. 44704, the Company voluntarily excluded the restricted stock program from the revenue requirement because it was related to financial performance.

Q: ARE THERE OTHER CASES IN WHICH ENTERGY HAS INDICATED THAT THE RESTRICTED STOCK PROGRAM IS RELATED TO FINANCIAL PERFORMANCE?

A: Yes. The Arkansas commission has consistently excluded EAI's (Entergy Arkansas, Inc.) long-term stock-base awards, including the restricted stock program awards.[64] In fact, Entergy no longer seeks recovery of these costs in Arkansas.

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[63] *(Emphasis added). Order at p. 2 in* PUC Docket No. 40295 (the rate case expense docket for Docket No. 39896). In that Order, p.2, note 6, the Texas PUC cited the following prior decisions: *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840, Proposal for Decision at 92-97, Findings of Fact Nos. 164-170, Order at 35 (Aug. 15, 2005); *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Proposal for Decision at 116-121, Finding of Fact No. 82, Order on Rehearing at 12 (March 4, 2008); *Application of Oncor Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 35717, Proposal for Decision at 96-100, Finding of Fact No. 93, Order on Rehearing at 22 (Nov. 30, 2009); and *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Proposal for Decision at 66-67, Findings of Fact Nos. 81-83, Order on Rehearing at 22 (June 23, 2011).

[64] *See* Docket No. 13-028-U.

Q: HAS THE ARKANSAS COMMISSION SPECIFICALLY RULED ON THE TREATMENT OF RESTRICTED STOCK UNITS ("RSUs") IN THAT STATE?

A: Yes. In SWEPCO's 2021 rate case, Docket No. 21-070-U, the Arkansas commission found that SWEPCO's RSUs should be excluded:

> Based upon review of the testimony and exhibits of SWEPCO, Staff, and WALEC, the Commission finds that there is not sufficient evidence to vary from its precedent and allow SWEPCO recovery of its LTI Plan, which includes RSUs. The Commission relies on its precedent in past-litigated proceedings and accepts WALEC's recommendation on this issue, which is consistent with precedent.[65]

Q: DO YOU BELIEVE ETI'S RESTRICTED STOCK AWARDS ARE <u>NOT</u> TIED TO FINANCIAL PERFORMANCE OF THE COMPANY?

A: No. Restricted stock awards are equity-based awards and are excluded for ratemaking purposes by virtually every commission. Restricted stock is tied to financial performance because the value of the award is directly tied to the value of the Company's common stock. Restricted stock granted to employees generally vest over future vesting dates, which are usually slightly more than one, two, and three years after the grant date. Dividend credits are generally awarded as additional units when a dividend is paid on common stock. Like all equity-based awards, restricted stock awards are tied to financial performance because the value of the award is tied to the appreciation, or depreciation, of the Company's stock price over the vesting period. Restricted stock programs are very common in the industry and like all other equity-based plans restricted stock plans are

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[65] See Docket No. 21-070-U Order No. 14, pp. 56-57.

designed to align the interest of management with the interest of shareholders to promote the financial success and growth of the utility, or more precisely, the holding company. More importantly, restricted stock programs, like all other equity-based programs, are disallowed by commissions as a general rule.

Q: IS THERE FURTHER EVIDENCE THAT RESTRICTED STOCK AWARDS ARE FINANCIALLY-BASED AND DESIGNED PREDOMINANTLY TO BENEFIT SHAREHOLDERS RATHER THAN ELECTRIC CUSTOMERS?

A: Yes. My opinion that equity-based awards should be disallowed for ratemaking purposes is further based on my review of ETI's Long-Term Incentive Compensation Overview, provided as an attachment to Ms. Raeder's testimony. According to the Entergy Equity Ownership Plan, which includes the restricted stock program, the purpose of the plan is to align the interests of management with those of the shareholders through participation in the long-term financial growth of Entergy.

> **Section 1. Purpose of Plan.**
> 1 The purposes of this Entergy Corporation 2019 Omnibus Incentive Plan are to (a) provide an additional incentive to selected key personnel of the Company or its Affiliates whose contributions are essential to the growth and success of the Company, (b) strengthen the commitment of such individuals to the Company and its Affiliates, (c) motivate those individuals to faithfully and diligently perform their responsibilities, and (d) **<u>attract and retain competent and dedicated individuals whose efforts will result in the long-term growth and profitability of the Company for the benefit of its stakeholders</u>**. To accomplish these purposes, the Plan provides that the Company may grant Options, Share Appreciation Rights, Restricted Shares, Restricted Stock Units, Other Share-Based Awards, Cash Awards, or any combination of the foregoing.[66] (Emphasis added).

[66] Direct Testimony of Jennifer A. Raeder, Exhibit JAR-3 at 1.

Aside from the clear language of the plan that seeks to align the interest of management through participation in the financial success of the Company, it is intuitive that management will be more interested in the financial success of the company if a portion of their compensation is awarded in the form of stock units that must be held over a period of time where they can either increase with the financial success of the company or decrease with its financial failures.

Thus, in accordance with the Texas PUC's policy of excluding financially-based incentive compensation that is designed to align management's decision making with the interests of shareholders rather than customers, I recommended disallowing the costs associated with the restricted stock awards in this case.

Q: WHAT IS THE RATIONALE FOR EXCLUDING ALL FINANCIALLY-BASED LONG-TERM INCENTIVE COMPENSATION EXPENSE?

A: Incentive compensation payments to officers, executives and key employees of a utility are generally excluded for ratemaking purposes. Since officers of any corporation have fiduciary duties of loyalty and care to the corporation itself and not to the customers of the company, these duties require the individuals to put the interests of the company first. Undoubtedly, the interests of the company and the interests of the customer are not always the same, and at times, can be quite divergent. This natural divergence of interests creates a situation where not every cost associated with executive compensation is presumed to be a necessary cost of providing utility service. Many regulators are inclined to exclude executive bonuses, incentive compensation and supplemental benefits from utility rates, understanding that these costs would be better borne by the utility shareholders.

It has been my experience that some utilities treat long-term executive incentive compensation costs as a below-the-line item even without a Commission order directing them to do so. Further, long-term executive incentive plans are specifically designed to tie executive compensation to the financial performance of the company. This is done to further align the interest of the employee with those of the shareholder. Since the compensation of the employee is tied over a long period of time to the company's stock price, it motivates employees to make business decisions from the perspective of long-term shareholders. This intentional alignment of employee and shareholder interests means the costs of these plans should be borne solely by the shareholders. It would be inappropriate to require ratepayers to bear the costs of incentive plans designed to encourage employees to put the interests of the shareholders first.

Q: SHOULD LONG-TERM INCENTIVE COMPENSATION BE RECOVERED IN RATES IF IT IS INCLUDED AS PART OF A "MARKET-COMPETITIVE TOTAL COMPENSATION" PLAN?

A: No. Utilities often argue that executive incentives are part of an overall compensation package that is designed to attract and retain qualified personnel. They claim that since other utilities offer incentive plans to their executives, a company would run the risk of not being able to compete for key personnel if it did not offer a comparable plan.[67]

[67] *See, e.g.,* Direct Testimony of Jennifer A. Raeder at p. 17, lines 9-13.

Q: DO YOU AGREE WITH THIS ARGUMENT?

A: No. When utilities, such as ETI, compete with other utilities for qualified executives, and the executive incentive compensation plans of those other utilities are not being recovered through rates, ETI is not placed in a competitive disadvantage when its executive incentive compensation is excluded as well. Since most states exclude executive incentive pay as a matter of course, ETI would actually be given an unfair advantage if its long-term equity plans were included in rates. The fact that other utilities offer executive incentive plans is not relevant; what is relevant is the fact that other utilities are not recovering the costs of these plans in rates. In an order disallowing Nevada Power's long-term incentive plan, the Nevada commission articulated this important ratemaking concept as follows:

> Therefore, the Commission accepts BCP's and SNHG's recommendations to disallow recovery of expenses associated with LTIP. Both parties provide a valid argument that this type of incentive plan is mainly for the benefit of shareholders. Further, both BCP and SNHG provide examples of numerous other jurisdictions that do not allow the recovery of these costs and, therefore, disallowance in this instance would not place NPC in a competitive disadvantage.[68] (Emphasis added).

Q: WHAT IS THE TEXAS COMMISSION'S POLICY REGARDING THE RATEMAKING TREATMENT OF LONG-TERM INCENTIVE COMPENSATION?

A: The Texas Commission has consistently held that financially-based annual and long-term incentives are excluded for ratemaking purposes. As discussed earlier, in the Entergy

[68] *See* Final Order in Docket 08-12002 at paragraph 549.

Texas, Inc. (ETI) rate case, PUC Docket No. 40295, the Commission disallowed rate case expense associated with ETI's attempt to recover financially-based long-term incentives:

> Specifically, the Commission agrees with the ALJ that reductions should be made to Entergy's recoverable rate-case expenses for Entergy attempting to recover financially-based incentive compensation in base rates. *The Commission has repeatedly ruled that a utility cannot recover the cost of financially-based incentive compensation because financial measures are of more immediate benefit to shareholders* and financial measures are not necessary or reasonable to provide utility services.[69]

Q: HOW WERE ENTERGY'S RESTRICTED STOCK AWARDS TREATED IN PAST RATE CASES BY THE TEXAS COMMISSION?

A: The Texas Commission disallowed 100% of ETI's long-term incentive plan costs, including the restricted stock awards, in Docket No. 39896. In its next rate case, ETI did not seek recovery of any long-term stock-based costs, including the restricted stock units.

Q; HAS THE TEXAS PUC ALLOWED RSUs IN OTHER RATE CASES?

A: Yes. The Commission has allowed SWEPCO RSUs in the past because the SWEPCO RSUs were not financial-based incentives. Here, ETI's Restricted Stock Units clearly are

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[69] *(Emphasis added). See Docket No. 40295, (the rate case expense docket for Docket No. 39896), Order, at p. 2.* In that Order, p.2, note 6, the Texas PUC cited the following prior decisions: *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840, Proposal for Decision at 92-97, Findings of Fact Nos. 164-170, Order at 35 (Aug. 15, 2005); *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Proposal for Decision at 116-121, Finding of Fact No. 82, Order on Rehearing at 12 (March 4, 2008); *Application of Oncor Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 35717, Proposal for Decision at 96-100, Finding of Fact No. 93, Order on Rehearing at 22 (Nov. 30, 2009); and *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Proposal for Decision at 66-67, Findings of Fact Nos. 81-83, Order on Rehearing at 22 (June 23, 2011).

financial-based incentives. As shown in the words of the Company's plan quoted above, the Restricted Stock Units are designed to result in the long-term profitability of the Company for the benefit of shareholders.

> **(d) <u>attract and retain competent and dedicated individuals whose efforts will result in the long-term growth and profitability of the Company for the benefit of its stakeholders</u>**.

Since the RSUs are designed to benefit shareholders, through long-term growth and profitability, shareholders should pay for their costs. Moreover, the Commission disallowed the RSUs in ETI's last litigated rate case.

Q: WERE THE SWEPCO ORDERS CLEAR ON THE POINT THAT THE RSUs WERE BEING ALLOWED BECAUSE THEIR PERFORMANCE MEASURES WERE NOT FINANCIAL MEASURES?

A: Yes. The final order in SWEPCO's last rate case, Docket No. 51415, specifically states that SWEPCO's RSUs were allowed because the RSU awards "are not based on financial performance measures."[70] In fact, the SWEPCO RSU awards are not based on the recipient achieving any performance measures whatsoever, according to the Company's witness in that case.[71]

Q: IS THAT THE CASE WITH THE ENTERGY RSUs?

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[70] See Final Order in Docket No. 51415 at paragraph 145.

[71] See Rebuttal Testimony of Mr. Carlin in Docket No. 51415 at p. 11.

A: No. That is not the case with ETI's RSUs. ETI's RSU awards are based on performance measures. The Company's incentive plan specifically states that the RSUs are based on performance measures that will be set at the sole discretion of the Administrator each year.[72] Ms. Raeder acknowledges the Performance Share Units ("PSU") are based on financial performance measures (shareholder returns and funds from operations over debt).[73] But, she omits what the performance measures are for the RSUs – which is actually the only essential information relevant to this issue.

Q: DO YOU BELIEVE THE ENTERGY RSUs CAN BE JUSTIFIED FOR RATEMAKING PURPOSES BASED ON THE SWEPCO ORDER?

A: No. The SWEPCO RUS's were included because they had no performance measures, but the Energy RSUs clearly do have performance measures and those measures are subject to the sole discretion of the Administrator each year. This makes them objectionable from a ratemaking perspective – because they may or may not be made from year to year (making them uncertain for setting rates) and because they are indirectly tied to financial performance because they will only be paid if there are sufficient earnings from year to year. Moreover, the actual performance measures for these awards are likely financial, since they are paid to upper management, or could be at any time, since they are subject to the sole discretion of the Administrator.

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[72] See the 2019 Entergy Corporation Omnibus Incentive Plan at Section 9(a), attached to Ms. Raeder's testimony as Exhibit JAR-3.

[73] See Direct Testimony of Jennifer A. Raeder at p. 16, lines 19-21.

Q: HOW IS LONG-TERM INCENTIVE COMPENSATION TREATED IN OTHER STATES?

A: The results of the Garrett Group Incentive Compensation Survey, discussed in the previous section of this testimony, show that most states follow the general rule that incentive pay associated with financial performance is not allowed in rates. This means that long-term, stock-based incentives are excluded in virtually every state. In the synopsis of the incentive survey results from each state that was included in the prior section of this testimony, the treatment of long-term stock-based incentives in each state was underlined. According to the survey, 20 of the 24 western states tend to <u>exclude</u> all or virtually all long-term stock-based incentive pay, either through an outright ban on stock-based incentives or through applying the *financial performance* rule, which has the effect of excluding long-term earnings-based and stock-based awards. These states include Arizona, Arkansas, California, Colorado, Hawaii, Idaho, Kansas, Louisiana, Minnesota, Missouri, Nevada, New Mexico, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Utah, Washington and Wyoming. In the other four states, Alaska, Iowa, Montana and Nebraska, the issue has not been addressed.

Q: ARE THERE OTHER REASONS WHY STOCK-BASED INCENTIVES SHOULD NOT BE ALLOWED FOR RATEMAKING PURPOSES?

A: Yes. There is no cash expense associated with stock-based incentive awards, such as restricted stock units. So, if these awards are included in rates, the utility will collect cash from ratepayers to cover a cash expense that does not exist.

Q: WHY IS THERE NO CASH ASSOCIATED WITH STOCK AWARDS?

A: For stock awards, such as restricted stock units, the accounting entries, both the debit and credit, are effectively to the same account, the capital account. Thus, when the utility awards stock-based incentives, there is no impact on the financial position of the utility. The debit and the credit, each to the same account, effectively wash each other out. This is not true for any other recoverable expense for ratemaking purposes, where there is a cash outlay that reduces the financial position of the utility. For stock-based awards, there is no financial impact to the company. When the restriction period expires and the stock is actually awarded to the employee there is still no change in the financial position of the company. The only change is that the value of the stock held by the other stockholders is minutely diminished. In effect, the utility is trying to collect from ratepayers the diminution in value to its other stockholders caused by its incentive award using stock units. In other words, the utility is trying to collect cash from ratepayers for a cash expense that does not really exist. This is certainly not a cost that ratepayers should be burdened with.

Q: WHAT IS THE IMPACT OF YOUR ADJUSTMENT TO EXCLUDE THE COMPANY'S LONG-TERM STOCK INCENTIVE PLAN COSTS?

A: My adjustment removes the restricted stock expense in the amount of $2,309,398 and related employment taxes of $206,922. The calculations supporting this adjustment are set forth at *Exhibit MG-2.3*.

IV. <u>POST-TEST YEAR PAYROLL EXPENSE</u>

Q: PLEASE EXPLAIN THE ADJUSTMENTS THAT ETI IS PROPOSING FOR PAYROLL RELATED EXPENSES.

A: ETI first adjusted the test year payroll for the net increase in employees in 2021 then restated the payroll for the impact of pay increases awarded during the test year and finally added post-test year pay increases to the restated payroll. ETI then added the impact of the increased payroll on employee benefits and payroll taxes. ETI made these adjustments for the ETI direct payroll and for the allocated affiliate payroll. These adjustments increased expenses by $2.3 million for ETI and $1.4 million for ESL.[74]

Q: DO YOU AGREE WITH ETI'S PAYROLL ADJUSTMENTS?

A: No, not entirely. I believe the Company's adjustments to test year payroll for *known and measurable changes* – that occurred during the test year – are reasonable. However, I do not agree with the Company's adjustments for additional *known and measurable changes* <u>after</u> test year end – the post-test year adjustments.

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[74] See Direct Testimony of Allison P. Lofton, p. 21, line 10 – p. 22, line 4.

Q: WHY DO YOU NOT AGREE WITH THE POST-TEST YEAR ADJUSTMENTS TO PAYROLL?

A: The post-test test year adjustments to payroll are impermissible piecemeal ratemaking. For ratemaking purposes, investment levels (rate base), revenues and expense are all synchronized at the same moment in time. For example, when an historical test year is used, rate base is measured at the end of the test year, and revenues and expense are adjusted, either annualized or normalized, to reflect the expected level at test year end. This synchronization is important because it allows regulators to set rates based on the expense levels required to support and maintain the actual investment levels that exist at the same period of time. This way we set rates based on the revenues and expense that are associated with the investment levels in rate base. It is not appropriate to go beyond the test year in a piecemeal fashion to pick up rate increases from one area, such as payroll expense, without also recognizing rate decreases from other areas, such as revenue growth. From a ratemaking perspective, it is not reasonable for ETI to include adjustments that go beyond the end of the test year for one expense item such as payroll, unless all costs and revenues are also accurately measured at the same date.

Q: HOW SHOULD TEST YEAR PAYROLL LEVELS BE ADJUSTED?

A: When rates are based on an historical test year, as they are in Texas, payroll expense should be annualized – provided the period annualized is representative of ongoing levels – and the inquiry should end there. An annualization adjustment incorporates all of the financial impacts of pay raises, productivity improvements and employee turnover on overall payroll expense. Additional estimates for future, post-test year changes should not be allowed. Again, it is not appropriate to adhere to a test year cut-off for rate base, operating expenses, depreciation, taxes, and revenues, but then go beyond the test year for payroll expense alone.

Q: IN YOUR EXPERIENCE, DO REGULATORY COMMISSIONS IN OTHER JURISDICTIONS TYPICALLY ALLOW UTILITIES TO GO BEYOND THE TEST YEAR FOR PAY RAISES?

A: No, they typically do not. States like Oklahoma and Nevada have statutes that allow the commissions in those states to update the test year for *known and measurable changes* that occur within a specified period after test year end. In both of those states, however, ***all components*** of the revenue requirement, including rate base, revenues and operating expenses, taxes and depreciation are updated to the post-test year period cut-off date and no increases or decreases past that date are allowed. This means that pay raises after the cut-off date are prohibited. Effectively, this means that all costs and revenues are updated to the same date and no piecemeal adjustments are allowed beyond that date.

Q: ARE THERE OTHER REASONS TO REJECT THE POST-TEST YEAR RAISES?

A: Yes. The post-test year component of ETI's payroll related expense adjustment is based solely on the estimated impacts of pay raises and ignores other offsetting factors that impact payroll costs, such as reductions in the employee levels.

Q: DO THE COMMISSION RULES ALLOW POST-TEST YEAR CHANGES TO OPERATING EXPENSE OR RATE BASE?

A: The Commission rules allow for known and measurable post-test year adjustments to rate base under certain circumstances, but they do not have a similar provision for post -test year changes to operating expense. The operating expense rules appear in TAC § 25.231:

> **(b) Allowable expenses**.
> Only those expenses which are reasonable and necessary to provide service to the public shall be included in allowable expenses. In computing an electric utility's allowable expenses, only the electric utility's historical test year expenses as adjusted for known and measurable changes will be considered, except as provided for in any section of these rules dealing with fuel expenses.

The words "post-test year" are never mentioned in section (b). Instead, the rule states that "only the electric utility's historical test year expenses as adjusted for known and measurable changes will be considered." In traditional ratemaking, known and measurable changes would be changes that occur ***during*** the test year, not after test year end. For example, if there is a pay raise in December, the effects of that raise are annualized to include a full year of the increase in rates. This would be a change that occurred during that test year that is known and measurable and should be included in rates.

Q: WHY DO YOU SAY THAT THIS IS THE TREATMENT UNDER TRADITIONAL RATEMAKING?

A: Known and measurable changes in traditional ratemaking are those that occur during the test year. Changes that occur after the test year are not included because their inclusion would result in piecemeal ratemaking. This is evidenced by the fact that states that allow post-test year adjustments require that all components of the ratemaking formula be updated to the same point in time, as discussed above. Moreover, all states with projected test years also require that all components of the ratemaking formula be included in the projected year. In other words, states that use post-test year periods and projected test years require that all components of the ratemaking formula – include rate base, operating expense, revenues, depreciation and taxes – all be updated to the same date.

Q: DO THE COMMISSION RULES PROVIDE FOR ANY POST-TEST YEAR ADJUSTMENTS?

A: Yes. The rules have a specific section entitled *Requirements for Post-Test Year Adjustments*. This section of the rules provides for post-test year adjustments to (1) plant in service when (2) the adjustment is great than 10% of rate base and when (3) the plant will be in service before the rate year begins and when (4) all attendant offsetting impacts have been included in the adjustment. The requirements for post-test year adjustments are set forth at §25.231(c)(2)(F):

(F) Requirements for post test year adjustments.

(i) Post test year adjustments for known and measurable rate base additions (increases) to historical test year data will be considered only as set out in subclauses (I)-(IV) of this clause.

(I) Where the addition represents plant which would appropriately be recorded:

(-a-) for investor-owned electric utilities in FERC account 101 or 102;
(-b-) for electric cooperatives, the equivalent of FERC accounts 101 or 102.

(II) Where each addition comprises at least 10% of the electric utility's requested rate base, exclusive of post test year adjustments and CWIP.

(III) Where the plant addition is deemed by this commission to be in-service before the rate year begins.

(IV) Where the attendant impacts on all aspects of a utility's operations (including but not limited to, revenue, expenses and invested capital) can with reasonable certainty be identified, quantified and matched. Attendant impacts are those that reasonably follow as a consequence of the post test year adjustment being proposed.

Q: WHAT IS THE SIGNIFICANCE OF THIS RULE?

A: The Post-Test Year Adjustments rule shows that the Commission understood what post-test year adjustments were when it issued its rules. It further shows that the Commission chose to extend post-test year treatment only to plant in service and then under special circumstances.

Q: WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S PAYROLL EXPENSE?

A: I recommend the Commission reject the Company's adjustment to increase payroll expense for post-test year pay raises.

Q: ARE THERE OTHER REASONS WHY THE COMMISSION SHOULD ADOPT THIS TREATMENT?

A: Aside from the fact that the Company's treatment is piecemeal ratemaking and aside from the fact that the Commission rules do not allow post-test year adjustments to operating expenses, yes, from a policy perspective, this is a time when the Commission should be looking for every opportunity available to reduce rates. Severe storms and escalating gas prices have caused utility rates to be significantly higher than expected, causing significant financial hardship on ratepayers in every class of service. If the Commission has allowed post-test year adjustment to payroll costs in the past, this would be right time for a policy change in that area.

Q: PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENT TO PAYROLL EXPENSE.

A: My recommended adjustment reverses the Company's proposed post-test year increases to ETI direct payroll expense in the amount of $1,056,454 and associated payroll-related expense of $146,425, for a total adjustment of $1,202,879. The calculations supporting Cities' recommended ETI payroll adjustment is set forth at *Exhibit MG-2.4*.

Q: DOES THIS ADJUSTMENT AFFECT THE AFFILIATE PAYROLL ADJUSTMENT?

A: Yes. The adjustment to reverse the post-test year component of the affiliate payroll expense adjustment reduces payroll expenses by $1,220,379 and associated payroll-related expenses by $174,026 for a total adjustment of $1,394,405. The calculations supporting Cities' recommended affiliate payroll adjustment is set forth at *Exhibit MG-2.5*.

V. <u>NON-QUALIFIED RETIREMENT PLAN EXPENSE</u>

Q: PLEASE DESCRIBE THE SUPPLEMENTAL EMPLOYEE PENSION PLAN.

A: The Company provides supplemental retirement plan benefits to certain highly-compensated individuals at the Company. These supplemental retirement plans for highly compensated individuals are provided because benefits under the general retirement plans are subject to limitations under the Internal Revenue Code. Benefits payable under these supplemental plans are typically equivalent to the amounts that would have been paid but for the limitations imposed by the Code. In general, the limitations imposed by the Code allow for the computation of benefits on annual compensation levels of up to $285,000 for 2020, $290,000 for 2021, $305,000 for 2022. Retirement benefits on compensation levels in excess of annual compensation limits are paid through supplemental plans. Thus, supplemental retirement plans for highly compensated employees are designed to provide benefits in addition to the benefits provided under the general pension plans of the company. These plans are referred to as *non-qualified* plans because they do not qualify as a deductible tax expense under the code.

Q: WHAT AMOUNTS WERE INCLUDED IN PRO FORMA OPERATING EXPENSE FOR THE SUPPLEMENTAL EMPLOYEE RETIREMENT PLANS?

A: The Company included $1.329M for non-qualified plan in pro forma operating expense for ratemaking purposes in the Company's application.[75]

Q: WHAT DO YOU RECOMMEND WITH RESPECT TO NON-QUALIFYING COSTS FOR HIGHLY COMPENSATED EMPLOYEES?

A: I recommend that supplemental costs be disallowed in their entirety. If these supplemental costs are disallowed, ratepayers will pay for all of the executive benefits included in the Company's *regular* pension plans, and shareholders will pay for the additional executive

[75] *See* Exhibit MG-6.

benefits included in the *supplemental* plan. For ratemaking purposes, shareholders should bear the additional costs associated with supplemental benefits to highly compensated executives, since these costs are not necessary for the provision of utility service but are instead discretionary costs of the shareholders designed to attract, retain and reward highly compensated employees. Further, officers of any corporation have fiduciary duties of *loyalty* and *care* to the corporation, which require these individuals to put the interest of the company first. This creates a situation where not every cost associated with executive compensation is presumed to be a cost appropriately passed on to ratepayers. Many regulators are inclined to exclude executive bonuses, incentive compensation and supplemental benefits from utility rates, understanding that these costs would be better borne by the utility shareholders.

Q: IN YOUR EXPERIENCE, HOW ARE THESE COSTS TREATED IN OTHER STATES?

A: In the states where I have testified on this issue, such as Oklahoma,[76] Nevada,[77] and Arkansas, these costs are disallowed.[78]

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[76] See, for example, Cause No. PUD 200600285, Cause No. PUD 200800144, Cause No. PUD 201500208, Cause No. PUD 201700151.

[77] See, for example, Docket Nos. 01-10001, 03-10001, 06-11022, 08-12002, and 11-06006.

[78] In the Entergy Arkansas, Inc. litigated rate case (Docket No. 13-028-U), the Arkansas Public Service Commission agreed that shareholders, not ratepayers, should pay for the cost of Entergy Arkansas' Supplemental Executive Retirement Plans. In the Commission's Order No. 21 entered in this Docket, the Arkansas Commission determined that SERP expenses are not necessary to provide utility service, but rather are discretionary costs implemented by Entergy Arkansas and therefore should be disallowed.

Q: HOW IS NON-QUALIFIED PAY TREATED IN TEXAS?

A: In Texas, in Entergy's rate case, Docket No. 39896, the Texas PUC disallowed all of the Company's SERP costs.

> 140. ETI provides non-qualified supplemental executive retirement plans for highly compensated individuals such as key managerial employees and executives that, because of limitations imposed under the Internal Revenue Code, would otherwise not receive retirement benefits on their annual compensation over $245,000 per year.
>
> 141. ETI's non-qualified supplemental executive retirement plans are discretionary costs designed to attract, retain, and reward highly compensated employees *whose interests are more closely aligned with those of the shareholders than the customers*.
>
> 142. ETI's non-qualified executive retirement benefits in the amount of $2,114,931 *are not reasonable or necessary to provide utility service to the public, not in the public interest, and should not be included in ETI's cost of service*.[79]

Similarly, in Docket No. 40443, the Commission denied SWEPCO's request to recover its non-qualified executive retirement benefits:

> 227. SWEPCO's non-qualified executive retirement benefits in the amount of $191,007 *are not reasonable or necessary to provide utility service to the public, are not in the public interest, and should not be included in SWEPCO's cost of service*.[80]

Again, in Docket No. 46449, the Commission denied SWEPCO's request for recovery of non-qualified supplemental executive compensation costs:

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[79] See *Application of Entergy Texas, Inc., for Authority to Change Rates*, Docket No. 39896, Findings of Fact Nos. 140-142, Order on Rehearing at 25-26 (November 2, 2012).

[80] See *Application of Southwestern Electric Power Co., for Authority to Change Rates*, Docket No. 40443, Findings of Fact No. 227 Order on Rehearing at 40 (March 6, 2014).

> 202. SWEPCO provides non-qualified supplemental executive retirement plans for highly compensated individuals such as key managerial employees and executives that, because of limitations imposed under the Internal Revenue Code, would otherwise not receive retirement benefits on their annual compensation over $270,000 per year.
>
> 203. SWEPCO's non-qualified supplemental executive retirement plans are discretionary costs designed to attract, retain, and reward highly compensated employees *whose interests are more closely aligned with those of the shareholders than the customers*.
>
> 204. SWEPCO's requested non-qualified supplemental executive retirement benefits *are not reasonable or necessary to provide utility service to the public, are not in the public interest, and should not be included in SWEPCO's cost of service*.[81]

Q: WHAT ADJUSTMENT ARE YOU RECOMMENDING?

A: The impact of this adjustment is set forth below and is shown at *Exhibit MG 2.6*.

Adjustment to Remove Supplemental Retirement Plan Expense $(1,329,421).

VI. SELF-INSURANCE ACCRUAL

Q: PLEASE DISCUSS ETI'S SELF-INSURANCE RESERVE AND THE ADJUSTMENTS PROPOSED BY THE COMPANY.

A: Entergy requested and received approval for the establishment of a self-insurance reserve to cover storm damages in Docket No. 39896 which provided an annual loss accrual of $4.4 million and an annual accrual of $3.87 million to establish a reserve over a 20-year period.[82] The current approved accrual includes $4.972 million for expected storm losses

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[81] See *Application of Southwestern Electric Power Co., for Authority to Change Rates*, Docket No. 46449, Findings of Fact Nos. 202-204, Order on Rehearing at 34 (March 19, 2018).

[82] See Docket No. 39896, Order on Rehearing, November 1, 2012, p. 27, line 157.

and $3.570 million for the 20-year accrual to establish the loss reserve.[83] The Company proposed adjustments in the current rate case to increase the annual loss accrual to $6.315 million and the annual reserve accrual to $8.240 million to establish the reserve within four years.[84] The Company's proposal would increase the self-insurance expense accrual by $6.013 million from $8.542 million to $14.555 million.[85] The updated loss accrual and reserve request considers the provisions for hurricane cost recovery and securitization provisions provided through legislation.[86]

Q: DO YOU AGREE WITH THE PROPOSED INCREASE IN THE SELF-INSURANCE ACCRUAL?

A: No. I disagree with the proposal to shorten the time to accrual costs to establish the self-insurance reserve. As discussed above, the reserve accrual was set at twenty years in Docket No. 39896, and that amortization period is included in the current rate recovery. The order in Docket No. 39896 was signed on November 1, 2012, so only half of the original amortization period has elapsed since that time. The Company provided no justification for reducing the remaining amortization from ten years to four years at an annual cost of $4.67 million as proposed by the Company which is in addition to the $1.343 million increase in the loss accrual. The current accrual will recover the $17.7

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[83] See the Direct Testimony of Gregory S. Wilson, p. 5, lines 27-30.

[84] See the Direct Testimony of Gregory S. Wilson, p. 4, line 33 – p. 5, line 7.

[85] See AJ26 Property Insurance Reserve.xlsx.

[86] See the Direct Testimony of Gregory S. Wilson, p. 8, line 17 – p. 9, line 15.

million deficiency and provide funding for the requested $15.3 million reserve in nine years and three months, which is nine months sooner than originally proposed by ETI and adopted by the Commission.[87] The current reserve accrual of $3.57 million should be retained by the Commission.

Q: WHAT ADJUSTMENT DO YOU RECOMMEND TO THE ANNUAL SELF-INSURANCE RESERVE ACCRUAL?

A: I recommend the current annual reserve accrual of $3.57 million be ordered by the Commission. This adjustment reduces the requested self-insurance reserve accrual by $4.67 million. This adjustment is found on Exhibit MG-2.6.

VII. DIRECTORS' AND OFFICERS' LIABILITY INSURANCE

Q: WHAT AMOUNT IS THE COMPANY REQUESTING IN RATES FOR D&O LIABILITY INSURANCE IN THIS PROCEEDING?

A: During the test year, ETI incurred $263,580 for D&O liability insurance. In 2021, the Company began amortizing the premium over 12 months, beginning in July 2021, or $131,687. The Company is seeking full recovery of this expense.

Q: WHAT IS DIRECTORS' AND OFFICERS' LIABILITY ("D&O") INSURANCE?

A: D&O liability insurance generally protects the assets of a company's directors and officers from the financial impact of litigation that results from their actions and decisions taken

[87] Calculation: ($17.7 million + $15.3 million = $33.0 million; $33.0 million/$3.57 million = 9.25 years).

on the company's behalf. D&O liability insurance also neutralizes the impact of ETI's Board of Directors' and senior leadership's decisions and actions upon shareholders.[88]

Q: IF AN OFFICER OF ETI WAS FOUND NEGLIGENT IN THE INJURY OF ANOTHER PARTY, WOULD IT BE APPROPRIATE TO RECOVER THOSE COSTS FROM RATEPAYERS?

A: No. The costs of a director's or officer's negligent acts is not a necessary cost of providing utility service. Moreover, since directors and officers have a fiduciary duty to put the interests of shareholders first, some of the costs of their compensation and benefits should be paid by shareholders. This would include the cost of D&O liability insurance.

Q: PLEASE DISCUSS THE RATEMAKING POLICY REASONS FOR RECOMMENDING THE SHARING OF D&O INSURANCE COSTS.

A: The D&O insurance is in place to protect not only the directors and officers of the Company, but ultimately, the shareholders. Ratepayers should not be expected to bear the full amount of BOD compensation and expenses, including D&O insurance, because officers and directors have legal, fiduciary duties of loyalty and care to the corporation itself and not to its customers. These individuals are required by law to put the interests of the Company first. Undoubtedly, the interests of the Company and the interests of customers are not always the same, and at times, can be quite divergent. This natural

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[88] Martin M. Boyer, *Directors' and Officers' Insurance and Shareholder Protection*, (Mar. 2005), http://papers.ssrn.com/sol3/papers.cfm?abstract_id=886504.

divergence of interests creates a situation where not every compensation cost is presumed to be a necessary cost of providing utility service. Sharing of D&O liability insurance is appropriate because it provides benefits to shareholders and ratepayers alike.

Q: ARE YOU AWARE OF REGULATORY COMMISSIONS IN OTHER JURISDICTIONS THAT REQUIRE SHARING OF D&O LIABILITY INSURANCE COSTS?

A: Yes. I am aware that regulatory commissions in Arkansas, Connecticut, Nevada, and New Mexico have required the sharing of these costs, as discussed below:

Arkansas. The Arkansas Public Service Commission ("APSC") has for many years required a 50/50 sharing of these costs between shareholders and ratepayers. In the 2004 rate case of CenterPoint Energy/Arkla, the APSC found that because shareholders receive the benefit of D&O insurance payouts, they should bear a portion of the cost of buying the insurance.[89] Similarly, the in the 2006 Entergy rate case, the APSC stated:

> The Commission agrees that ratepayers, as well as shareholders, benefit from good utility management, which D&O Insurance helps secure. However, as found in prior dockets, the direct monetary benefits of D&O Insurance flow to shareholders as recipients of any payment made under these policies. That monetary protection is not enjoyed by ratepayers. The Commission therefore finds that, *because shareholders materially benefit from this insurance, the costs of D&O Insurance should be equally shared between shareholder and ratepayer*.[90]

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[89] *See* *Application for a General Change or Modification in CenterPoint Energy Arkla, a Division of CenterPoint Energy Resources Corp. Rates, Charges and Tariffs,* Ark. Pub. Svc. Comm'n, Docket No. 04-121-U, Order No. 16, Sept. 19, 2005, pp. 39-40.

[90] *Application of Entergy Arkansas, Inc. for Approval of Changes in rates for Retail Electric Service*, Ark. Pub. Svc. Comm'n, Docket No. 06-101-U, Order No. 10, June 15, 2007, p. 70. (Emphasis added).

California. The California Public Utilities Commission ("CPUC") similarly ordered a 50/50 sharing of D&O insurance costs in a case involving Pacific Gas and Electric Company. The CPUC explained:

> We reduce PG&E's D&O insurance forecast by 50%, resulting in a $1.423 million reduction. Past Commission policy of equal sharing of cost responsibility for D&O insurance should continue for this GRC [base rate case]. In situations such as this, where a corporate service or product offers separate benefits both to ratepayers and shareholders, imposing cost sharing does not conflict with cost-of service ratemaking principles. By allowing 50% of such costs for ratepayer funding, we provide reimbursement for a reasonable level of costs attributable to D&O insurance to the extent that ratepayers benefit. It is not reasonable for ratepayers to bear all of the costs related to D&O insurance when a share of those insurance benefits flow to shareholders.[91]

Connecticut. In a 2014 Connecticut Light & Power rate case, the Connecticut Public Utilities Regulatory Authority ("CPURA") allowed recovery of only 25% of D&O insurance costs in rates. The CPURA stated:

> The OCC agreed that DOL protects the officers of the Company from lawsuits brought against them by shareholders that arise as a result of decisions that they make while performing their duties. Therefore, *the shareholders, who receive the payout, are the primary beneficiaries of this insurance. Ratepayers receive very little of the benefit and should not be responsible for all of the costs*. . . The OCC noted that the Company failed to recognize that many legitimate expenses (e.g., image building advertisements, lobbying expenses) are not recoverable. . . The Authority finds no convincing reason to deviate from its previous treatment of DOL insurance. *Consistent with the determinations in previous*

[91] *Application of Pacific Gas & Elec.*, Application 12-11-009, 2014 Cal. PUC LEXIS 395 (Cal. P.U.C. Aug. 14, 2014).

Decisions regarding BOD expense and DOL expense, the Authority will allow only 25% of DOL costs in rates.[92]

Nevada. The Nevada Public Utility Commission ("PUCN") has issued several orders requiring a 50/50 sharing of D&O insurance costs between shareholders and ratepayers. One such order was issued in a recent Southwest Gas rate case. The PUCN stated:

> The Commission agrees with Staff that D&O insurance benefits both shareholders and ratepayers, and consequently, those costs should be shared. Based on the foregoing analysis, the Commission finds that a 50/50 apportionment of the cost of D&O Liability Insurance between ratepayers and SWG is just and reasonable.[93]

New Mexico. The New Mexico Public Regulation Commission ("NMPRC") addressed the issue of D&O cost sharing in a recent El Paso Electric rate case. The ALJ's Recommended Decision (RD) discussed why allocation of D&O insurance cost is consistent with balancing the interests of ratepayers and shareholders. The ALJ stated:

> What is unique about D&O insurance is that it is a cost specifically incurred for directors and officers, who have a fiduciary duty to put the interests of shareholders first. Therefore, the responsibility for the cost of D&O insurance goes to the heart of the Commission's obligation to balance the interests of shareholders and ratepayers.[94]

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[92] *Application of the Connecticut Light and Power Co., to Amend its Rate Schedules*, Conn. Pub. Util. Reg. Authority, Docket No. 14-05-06, Order issued Dec. 17, 2014, pp. 76-77 (Emphasis added).

[93] See *Application of Southwest Gas Corporation for Authority to Increase Rates*, Pub. Util. Comm'n of Nev., Docket No. 18-05031, Modified Order, May 15, 2019, p. 152. The PUCN has followed this ruling in later cases involving SWG. *See Application of Southwest Gas Corp. for Authority to Increase Its Retail Natural Gas Util. Serv. Rates et al*., Docket No. 20-02023, 2020 WL 6119350, at *86 (Nev. P.U.C. Sept. 20, 2020).

[94] *Application of El Paso Electric Co. for Revision of its Retail Electric Rates;* New Mex. Pub. Reg. Comm'n, Case No. 20-00104-UT, Recommended Decision (RD) issued April 6, 2021, p. 167. The treatment of D&O insurance was not raised as an exception, and the NMPRC adopted, approved and accepted the ALJ's RD in its Order Adopting Recommended Decision with Modifications, issued June 23, 2021, pp. 33-34.

It is my understanding that the regulatory commissions in New York,[95] and Florida[96] have also allocated these expenses on a 50-50 basis on the determination that both shareholders and customers both benefit from D&O liability insurance.

Q: WHAT DO YOU RECOMMEND FOR THE RECOVERY OF D&O LIABILITY INSURANCE?

A: I recommend that the Commission allocate the cost of ETI's D&O liability insurance expense on a 50/50 basis between ETI's customers and shareholders.

Q: WHAT IS THE AMOUNT OF THE ADJUSTMENT TO THE D&O LIABILITY INSURANCE EXPENSE?

A: The adjustment to share the costs of the D&O liability insurance expense removes 50% of the cost from recoverable expenses. This adjustment reduces ETI's revenue requirement by $65,844. These adjustments are found on Attachments MEG-2.7.

VIII. ACCELERATED DEPRECIATION OF RETIRING PLANTS

Q: PLEASE DISCUSS ETI'S PROPOSED TREATMENT OF GENERATING PLANTS NEAR RETIREMENT IN THIS APPLICATION.

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[95] Order Setting Electric Rates. State of New York Pub. Serv. Comm'n. Cases 08-E-0539 and 08-M-0618. (April 24, 2009), pp. 90-91.

[96] Final Order Granting in Part and Denying in Part Petition For Rate Increase and Approving Stipulations. Order No. PSC-12-0179-FOF-EI. Florida Public Service Commission. Docket No. 110138-EI. (Apr. 3, 2012), pp. 100-101.

A: ETI accelerated the retirement dates for three production units and materially increased the depreciation rates of three other units near retirement. The Company moved up the retirement dates for Nelson Unit 6 and for Big Cajun Units 2 and 3. The retirement dates for Sabine Units 1, 3, and 4 were kept materially the same, but their depreciation rates were significantly increased to collect recent expenditures on these units before they retire.[97] I address, from a ratemaking perspective, why the Company's proposal is inconsistent with Commission precedent and should be rejected. David Garrett incorporates the corrected depreciation rates in his depreciation study analysis.

Q: HOW HAVE THESE APPROACHING PLANT RETIREMENTS AFFECTED ETI'S REQUESTED RATE INCREASE?

A: As shown in Exhibit MG-2.8 and in the table below, these approaching retirements add approximately $59.3 million in increased depreciation expense to ETI's requested revenue requirement.[98]

[97] Meyer Direct Testimony, p. 12, lines 1-8.

[98] Responses to OPUC RFI 3-6 and 6-2.

Table 7: Impact of ETI's Early Retirement of Generation Units				
Ln	Unit	Retirement Dates 48371	Proposed Retirement	Rate Increase
1	**Accelerated Depreciation**		(Confidential)	
2	Nelson Unit 6	2042	[redacted]	$13,610,003
3	Big Cajun Units 2 and 3	2043	[redacted]	$16,897,635
4	Big Cajun 2 Common	2043	[redacted]	$467,274
			[redacted]	
5	**Increased Depreciation Rates**		[redacted]	
6	Sabine Unit 1	2022	[redacted]	$10,678,080
7	Sabine Unit 2	2026	[redacted]	$5,605,900
8	Sabine Unit 3	2026	[redacted]	$12,090,677
			[redacted]	
9	Total		[redacted]	$59,349,569

Q: WHAT IS THE PROPER SEQUENCE OF EVENTS FROM A RATEMAKING PERSPECTIVE WHEN A PLANT IS RETIRED EARLY?

A: If the Commission were to find that the retirement is prudent, the following steps would occur: (1) the undepreciated plant balance would be transferred to a regulatory asset account where it could be easily tracked by the Commission, (2) the balance would be removed from rate base because the plant is no longer *used and useful*, and (3) the balance would be amortized (recovered) over the remaining useful life of the plant when the retirement decision was made. In other words, depreciation should ***not*** be accelerated.

If the retirement were found to be *imprudent*, the balance would be removed from rate base and ***no recovery*** of the remaining balance should be allowed.

Q: IS THIS ORDER OF EVENTS SPELLED OUT IN ANY RECENT COMMISSION ORDERS?

A: Yes. In a recent rate case before this Commission, Docket No. 46449, SWEPCO proposed early treatment for the Welsh 2 unit. In that case, SWEPCO sought to transfer the remaining plant balance to accumulated depreciation (as a debit) and accelerate its depreciation. The Commission rejected all of SWEPCO's proposals. Specifically, the Commission: (1) rejected the transfer to accumulated depreciation, (2) rejected accelerated depreciation and (3) rejected allowing any return on the remaining balance. These are discussed separately below.

1. Regarding the ***<u>transfer to accumulated depreciation</u>***, the Texas Commission set forth the appropriate accounting treatment for early-retired plant in its final order:

> 71. The appropriate accounting treatment that results in the appropriate ratemaking treatment is to record the undepreciated balance of Welsh Unit 2 in a *<u>regulatory-asset account</u>*.[99]

The Commission decided to place the stranded balance of the Welsh 2 unit in a regulatory asset account so it could be removed from rate base and recovered over whatever period the Commission deemed reasonable, and not over the artificially shortened life of the plant.

2. Regarding ***<u>accelerated depreciation</u>***, the Commission rejected SWEPCO's proposal to accelerate depreciation on the early-retired Welsh 2 and instead ordered that the Company recover the remaining costs of that plant unit over its remaining original useful life of 24 years.

[99] *In re Southwestern Elec. Power Co.*, Docket No. PUD 46449, (Pub. Util. Comm'n of Tex) Order, p.20, ¶ 71 (Jan. 11, 2018); *see also*, ALJ's Proposal for Decision, pp. 93-94 (Sept. 22, 2017).

> 70. It is reasonable for SWEPCO to recover the remaining undepreciated balance of Welsh 2 over the 24-year remaining lives of Welsh Units 1 and 3.[100]

3. Regarding a ***return on the remaining balance***, the Commission allowed no return because once the plant was retired, it would no longer be *used and useful* and should not be included in rate base earning a return at that point. The Commission was clear on this point.

> Under PURA, a utility may earn a return only on invested capital that is "used and useful in providing service to the public." The Commission rules are in accord, providing that a major component of rate base is: "Original cost, less accumulated depreciation, of electric utility plant used by and useful to the electric utility in providing service."[101]

The Commission removed the remaining balance of the early-retired Welsh 2 plant from rate base and authorized the collection of the remaining balance from ratepayers over the useful life of the plant before retirement. This treatment allowed a return *of* the undepreciated remaining balance, but not a return *on* the balance once the plant was no longer being used to serve ratepayers. In its final order, the Texas Commission stated:

> 68. Because Welsh unit 2 is no longer used and useful, SWEPCO may not include its investment associated with the plant in its rate base, and may not earn a return on the remaining investment.[102]

In other words, even though the Commission found that the Welsh 2 early retirement was

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[100] *Id.*, p.20, ¶ 70.

[101] *In re Southwestern Elec. Power Co.*, Docket No. PUD 46449, (Pub. Util. Comm'n of Tex) Proposal for Decision, p. 90 (Sept. 22, 2017).

[102] *In re Southwestern Elec. Power Co.*, Docket No. PUD 46449, (Pub. Util. Comm'n of Tex) Order, p.19, ¶ 68 (Jan. 11, 2018).

a *prudent* decision, the appropriate ratemaking treatment was to exclude the remaining Welsh 2 balance from rate base recovery because it was no longer used and useful.

Q: HAS THE COMMISSION CONSISTENTLY FOLLOWED THIS APPROACH?

A: Yes. This same treatment was followed in SWEPCO's most recent rate case, Docket No. 51415, with respect to the early retirement of the Dolet Hills plant.

> 61. SWEPCO's recovery of Dolet Hills' remaining net book value (whether through depreciation during the operative-plant phase or recovery from the regulatory asset during the post-retirement phase) should be amortized in accordance with the asset's useful life ending in 2046.
>
> 62. DELETED.
>
> 63. Amortizing these assets in accordance with Dolet Hills' useful life ending in 2046 equitably balances the interests of SWEPCO and both its current and future customers.
>
> 64. It would be inequitable to SWEPCO's current customers to accelerate SWEPCO's recovery of these assets, as SWEPCO proposes to do, through offsetting the excess accumulated deferred federal income taxes (ADFIT) SWEPCO owes to its current customers and amortizing the balance over only four years.[103]

Q: HAS THIS TREATMENT BEEN UTILIZED ELSEWHERE?

A: Yes. In its 2015 rate case, Public Service Company of Oklahoma ("PSO") sought approval to retire its two coal units pursuant to a Regional Haze plan.[104] Under the plan, PSO would retire Northeastern 4 in 2016 and Northeastern 3 in 2026. PSO sought approval in its rate

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[103] *In re Southwestern Elec. Power Co.*, Docket No. PUD 51415, (Pub. Util. Comm'n of Tex) Order, p.12, ¶¶ 61-64 (Jan. 14, 2022).

[104] *See In re Pub. Serv. Co. of Okla.*, Cause No. PUD 201500208, (Okla. Corp. Comm'n). Final Order No. 657877, p. 5 (Nov. 10, 2016).

case application to accelerate the depreciation of both units so that the entire costs of the plants would be recovered by 2026 when the second unit was retired. The request would have increased rates by about $13 million per year. Oklahoma Commission Staff, the Attorney General, the Oklahoma Industrial Energy Consumers ("OIEC"), and the Department of Defense ("DOD") all opposed the recommendation. In its final order, the Oklahoma Commission rejected PSO's proposal to increase depreciation rates to recover the entire cost of the plants by the early retirement date of 2026.

> The Commission finds that PSO should be denied cost recovery for the accelerated depreciation that PSO seeks to recover for Northeastern Units 3 and 4 over the 2016 to 2026 period and that to mitigate rate increases, depreciation for the undepreciated, "original" costs of these two units should continue on its current pace to 2040. [105]

Q: ARE YOU AWARE OF INSTANCES IN WHICH UTILITIES ARE RECOVERING STRANDED COAL PLANT BALANCES OVER RELATIVELY LONG AMORTIZATION PERIODS AFTER THE PLANTS ARE RETIRED?

A: Yes. American Electric Power ("AEP") retired thirteen coal plants in 2015 in four different states. As shown in the table below, all of these plants had stranded cost balances that were recovered over 25- and 30-year amortization periods in line with their original retirement dates. The AEP plants retired in 2015 along with their stranded cost balances and amortization periods are set forth in the table below. These longer recovery periods

[105] *Id.*

give regulators an opportunity to avoid implementing higher rates that would otherwise result from these early retirements to the detriment of current ratepayers.

Table 8: AEP's Coal Units Retired in 2015[106]					
AEP Coal Units	Retired	Amortized Through	Amortized Over	State	Balance
Tanner Creek Unit 1	2015	2044	30	Michigan	$43.401M
Tanner Creek Unit 2	2015	2044	30	Michigan	$43.401M
Tanner Creek Unit 3	2015	2044	30	Indiana	$43.401M
Tanner Creek Unit 4	2015	2044	30	Indiana	$43.401M
Big Sandy Unit 1	2015	2040	25	Kentucky	$92.491M
Big Sandy Unit 2	2015	2040	25	Kentucky	$92.491M
Kawona River 1-2	2015	2040	25	W Virginia	$43.924M
Sporn Unit 1	2015	2040	25	W Virginia	$6.982M
Sporn Unit 3	2015	2040	25	W Virginia	$6.982M
Glen Lyn Unit 5	2015	2040	25	W Virginia	$3.703M
Glen Lyn Unit 6	2015	2040	25	W Virginia	$3.703M
Clinch River 1-2	2015	2040	25	W Virginia	$8.211M
Clinch River Units 3	2015	2040	25	W Virginia	$56.967M
Total Stranded Costs					$489.065M

Q: ARE THERE SIMILAR EXAMPLES FROM OTHER STATES?

A: Yes. Recently, in New Mexico, El Paso Electric Company ("EPE" or "Company") proposed to accelerate depreciation on gas generation units that it "anticipates" may not be providing energy to EPE's New Mexico customers after 2045. The plants, their size, installation dates, initial retirement dates and new proposed retirement dates are set forth in the table below.

[106] Provided by AEP-PSO in PSO's Oklahoma 2015 rate case, Cause No. PUD 201500208, in response to OIEC Data Request 17-2.

Table 9: EPE's Accelerated Retirement of Gas Plants[107]					
Unit	Peak Capacity	Installation Date	Initial Retirement	Proposed Retirement	Shortened Lives
Newman 5-GT3	70	2009	2061	2045	16
Newman 5-GT4	70	2009	2061	2045	16
Newman 5-ST	128	2011	2061	2045	16
Rio Grande 9	88	2013	2058	2045	13
Montana 1	88	2015	2060	2045	15
Montana 2	88	2015	2060	2045	15
Montana 3	88	2016	2061	2045	16
Montana 4	88	2016	2061	2045	16

EPE's proposal to accelerate depreciation rates on its retired gas plants would have increased rates by $8,358,755 annually.[108] In its final order in that case, the New Mexico commission rejected accelerated depreciation for these plants and ordered that the current authorized retirement dates be retained.[109]

Q: ARE THERE COMPELLING REASONS WHY REGULATORS SHOULD NOT ACCELERATE DEPRECIATION ON EARLY-RETIRED PLANTS?

A: Yes. Many regulators recognize that, for several reasons, current ratepayers should not be forced to pay the accelerated costs of early plant retirements. With respect to environmental regulations or policies, a primary reason is that future ratepayers should share in the costs of achieving a cleaner, safer environment in that these future ratepayers are the primary beneficiaries of these improvements. Spreading some of these costs into

[107] *In re El Paso Elec. Co.*, Docket No. 20-00104-UT, (New Mex. Pub. Reg. Comm'n) EPE's response to CLC/DAC Data Request 3-1.

[108] *Id.* EPE's response to CLC/DAC 3-1(f).

[109] See Final Order of New Mexico Public Regulation Commission Docket No. 20-00104-UT.

the future affords opportunities to offset these costs with other savings. These savings can come from improved technologies, increased operating efficiencies, lower capital costs, load growth, or merely with the passage of time. Over time, rate bases that are inflated with other environmental compliance costs have time to subside to more reasonable levels. Thus far, I have yet to hear many good arguments against spreading the higher costs of early plant terminations over some reasonable period into the future.

Q: DOES THIS POLICY OF SPREADING INCREASED COSTS OVER A REASONABLE PERIOD APPLY TO THE SABINE UNITS?

A: Yes. The increase in the Sabine units is not from early retirements but from a high level of recent investments in the plants that has resulted in unrecovered costs. The Company identified $66.8 million in plant additions to the Sabine Station since the last rate case, with the largest identified projects related to Sabine Unit 4.[110] The Company is seeking to recover the remaining investments in a relatively short period of time. The Company provided information showing the annual increase in depreciation is $10.7 million for Sabine Unit 1, $5.6 million of Sabine Unit 3, and $12.1 million for Sabine Unit 4.[111] My calculations show that the Sabine Units 1, 3, and 4 would have their costs fully recovered in 6, 11, and 13 years at the *current* depreciation rates.[112] In the case of Sabine Unit 1, the Company is requesting a major increase in the rates when the unit will be taken out of

[110] See Direct Testimony of Beverley Gale, page 17, Table 1 and 22:7 – 23:41.

[111] See Response to OPUC 3-6 and Exhibit MG-2.8.

[112] See Exhibit MG-2.9

service next year. If the Company's depreciation rate increase is granted, it will over recover the cost of Sabine Unit 1 for several years until it files another rate case.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Commission deny ETI's request to increase depreciation rates on plants it plans to retire early and on plants with substantial end-of-life unrecovered balances. According to the Company, this recommendation will decrease the Company's requested depreciation expense by approximately $59.3 million. *There is no reason to burden ratepayers now with higher costs in a short period of time* before those plants are retired, especially before the Commission rules that such retirements are prudent.

Q: WHAT ADDITIONAL REGULATORY ACTIONS SHOULD BE TAKEN AT THIS TIME?

A: As for the plants which ETI plans to retire prior to the test year for the Company's next general rate case, Sabine Units 1, 3 and 4, these plants should be fully recovered when they retire. For these plants, the Commission should require ETI to create a *regulatory liability* for each plant to record the revenue requirement components – including the return *on* and return *of* investment as well as depreciation, O&M expenses and ad valorem taxes – from the time the plant is taken out of service until the Company's next rate case, where the Commission can return the over-recovered costs in the liability account to ratepayers.

Also, please see the testimony of David Garrett who also recommends that depreciation not be accelerated on the Nelson and Big Cajun units and that depreciation rates not be increased for increased end-of-life expenditures on the Sabine units.

IX. REGULATORY ASSET AMORTIZATION PERIODS

Q: WHAT IS THE ISSUE WITH THE REGULATORY ASSET AMORTIZATION PERIODS?

A: The Company has recommended a 3-year amortization period for two regulatory assets. These assets should be amortized instead over a 4-year period to coincide with the Company's next scheduled rate case. Otherwise, the Company will over-collect the balance in these accounts. The two regulatory asset accounts that should be adjusted are set forth below. The revenue requirement impact of changing to a 4-year amortization is also shown for each account. These adjustments can be seen at Exhibit MG-2

Pension and OPEB Regulatory Asset	$1,532,659
COVID-19 Bad Debt Regulatory Asset	$978,016

X. ETI PROPOSED ROE ADDER

Q: PLEASE DESCRIBE THE COMPANY'S PROPOSED ROE BONUS BASED ON ENTERGY TEXAS' ("ETI") PERFORMANCE.

A: In addition to its proposed 10.5 percent rate of return on common equity ("ROE"),[113] the Company proposes an additional 30 basis points[114] performance adder based on the

[113] Buckley Direct p. 4, lines 4-6.

[114] In this context, the phrase "basis point" shall refer to 0.01 percent of common equity.

following factors. First, the Company claims that ETI's customers have experienced low retail rates due to the Company's effective cost discipline. Second, ETI claims it responded well to several significant storms that impacted its service area since its last rate case. Third, the Company contends it brought the benefits of its recently constructed Montgomery County Power Station to its customers early and under budget.[115]

Q: DID THE COMPANY PROVIDE ANY COST BENEFIT STUDIES SUPPORTING THE 30 BASIS POINT ADJUSTMENT IN EQUITY RETURN?

A: No. As shown in Response to Cities' RFI 5-6, the Company did not conduct any cost benefit analysis regarding its request for an ROE Adder adjustment.

Q: WHAT IS THE IMPACT ON ETI'S REVENUE REQUIREMENT OF A 30 BASIS POINT PERFORMANCE ADDER?

A: As shown in Exhibit MG-2.10, the impact on the Company's revenue requirement of a 30-basis point performance adder is approximately $8.6 million.

Q: WHAT POLICY CONSIDERATIONS DOES ETI BELIEVE THAT THE COMMISSION SHOULD CONSIDER WHEN EVALUATING THE COMPANY'S PROPOSAL FOR A 30 BASIS POINT PERFORMANCE ADDER?

A: The Company points to statutory language which directs the Commission to consider several factors to establish a reasonable rate of return on invested capital for an electric

[115] Totten Direct p. 3, lines 7-13.

utility. Additionally, the Company asserts that an adder would encourage the utility to continue its good performance and encourage other jurisdictional utilities to do the same. Finally, the utility asserts that a performance adder would better align utility and customer goals by allowing both groups to share in the utility's success.

Q: WHAT IS THE STATUTORY LANGUAGE THE COMPANY RELIES ON IN SUPPORT OF ITS REQUESTED ADDER?

A: The Company points to Public Utility Regulatory Act, Texas Utility Code §36.052:

> ESTABLISHING REASONABLE RETURN. In establishing a reasonable return on invested capital, the regulatory authority shall consider applicable factors, including: (1) the efforts and achievements of the utility in conserving resources; (2) the quality of the utility's services; (3) the efficiency of the utility's operations; and (4) the quality of the utility's management.

Q: CAN THE COMMISSION COMPLY WITH THIS STATUTORY LANGUAGE WITHOUT IMPLEMENTING A PERFORMANCE ADDER?

A: Yes. As in every rate case, there will be sufficient evidence in the record in this case for the Commission to comply with this statutory language without resorting to the use of a performance adder. Moreover, as shown below, there is evidence that an adder based on performance would not be appropriate for this utility at this time.

Q: SHOULD THE TWO PROCEEDINGS WHICH THE COMPANY CITES AS EXAMPLES IN WHICH THE COMMISSION WAS ASKED TO CONSIDER AN

ROE PENALTY FOR A UTILITY'S POOR PERFORMANCE BE USED AS SUPPORT FOR THE COMPANY'S REQUESTED ROE ADDER IN THIS CASE?

A: No. The two examples that ETI cites are not that helpful, because the Commission did not actually reduce the utility's ROE for poor performance in those cases. In the first example, although the administrative law judge ("ALJ") agreed with an intervening party that a utility's ROE should be reduced by three basis points due to poor service, the parties ultimately reached, and the Commission approved, a settlement agreement that did not include a specific ROE reduction due to the utility's performance. In the second example, the Commission Staff recommended a 12.5 basis point reduction in another utility's ROE due to a transmission line outage and poor reliability metrics. The ALJ did not recommend that the Commission adopt Staff's proposal. At the Commission's open meeting to discuss the ALJ's recommendations, there was a vibrant discussion regarding the utility's reliability metrics and the appropriate ROE, given current financial conditions. The Commission eventually adopted a 9.25 percent ROE, lower than the ALJ's recommended 9.45 percent, but the Commission's order did not explicitly and discretely reduce the utility's ROE for poor performance.[116]

Q: DO YOU AGREE WITH ETI'S JUSTIFICATION FOR A 30 BASIS POINT PERFORMANCE ADDER?

A: No. Even if the Commission should accept that Company performed well in the three areas listed previously, superior historical performance does not justify a performance

[116] Docket No. 51415, SOAH Docket No. 473-21-0538, Order p. 2 (Jan. 14, 2022).

adder. During this historical period, ETI charged its customers Commission approved rates for retail electric service, and the Company was provided the opportunity to earn a fair return through those rates. Although its tariffs do not contemplate that a nexus exists between superior historical performance and higher future returns to shareholders, ETI is inappropriately requesting that the Commission look back at the Company's past performance to rationalize higher future returns. Furthermore, the Commission approved a settlement agreement among the parties which established ETI's current base rates.[117] The settlement agreement does not consider any performance criteria during the term of settlement agreement that would justify higher future shareholder returns.[118]

Q: WHAT ARE THE CUSTOMERS' EXPECTATIONS OF THE COMPANY'S PERFORMANCE?

A: Similar to other regulated electric utilities, ETI's customers expect the Company's management to make prudent decisions that lead to ETI providing the highest reasonable performance in return for recovery of prudently incurred expenses and an opportunity to earn a fair and reasonable return compared to firms with a similar risk profile. However, the Company's prior ability to meet these expectations neither guarantees future performance nor justifies ETI's proposed performance adder.

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[117] Order. PUC Docket No. 48371. SOAH Docket No. 473-18-3733. December 20, 2018.

[118] Unopposed Stipulation and Settlement Agreement. PUC Docket No. 48371. SOAH Docket No. 473-18-3733. October 5, 2018.

Q: THE COMPANY INDICATES A PERFORMANCE ADDER WOULD ENCOURAGE ETI TO CONTINUE SELF-IDENTIFIED GOOD BEHAVIOR.[119] HOW DO YOU RESPOND?

A: In return for its monopoly franchise, ETI is already obligated to provide safe and reliable service at the lowest reasonable cost. In other words, ETI is already obligated to do all of the things it points to as exemplary behavior. Its reward is the privilege to serve captive utility customers, not a 30-basis point ROE adder. Moreover, the Company already has several substantial incentives to continue such behavior. Utilities, such as ETI, have been granted the privilege to be the sole provider of retail electric service to a designated geographic area. However, ETI has not been granted this privilege into perpetuity. Municipalities may revoke this privilege when franchise agreements expire for poor performance. Furthermore, ETI must pro-actively anticipate and respond to market forces and technological advances that can erode the Company's monopoly privileges over time.

Q: THE COMPANY INDICATES A PERFORMANCE ADDER WOULD ENCOURAGE ETI TO MEET THE CHALLENGE OF IMPLEMENTING CONFLICTING POLICY GOALS, SUCH AS PROVIDING SAFE, RELIABLE ELECTRIC SERVICE THAT IS AFFORDABLE TO THE CUSTOMERS, BETTER.[120] HOW DO YOU RESPOND?

A: Again, the utility is already obligated to provide safe, reliable service at the *lowest*

[119] Totten Direct p.17, line 20.

[120] Totten Direct p. 18, lines 3-6.

reasonable cost, in return for its monopoly position. Customers should not be asked to pay an ROE adder for something the utility is already required to do.

Q: ETI STATES THAT ITS PERFORMANCE ADDER WOULD INCENTIVIZE GOOD PERFORMANCE BY OTHER UTILITIES WHOSE RATES ARE REGULATED BY THE COMMISSION.[121] HOW DO YOU RESPOND?

A: This argument is without merit. It is unfair, unjust, and unreasonable to increase ETI's shareholders' return through higher customer rates to incent better performance ***from other utilities***. If another utility's performance is not meeting Commission standards, the Commission has more direct, more effective, and more efficient methods to mandate that the utility improve its performance.

Q: THE COMPANY INDICATES A PERFORMANCE ADDER WOULD ALLOW THE UTILITY AND ITS CUSTOMERS TO SHARE IN THE SUCCESS OF THE UTILITY.[122] HOW DO YOU RESPOND?

A: ETI and its customers already share in the Company's ability to exercise cost discipline which keeps its rates low. The Company's shareholders are the beneficiaries of operating efficiencies that ETI implements between rate cases. Then, the customers receive the benefits of ETI's cost discipline as base rates are reset at the next rate case. To maintain and increase shareholder returns, the Company must subsequently continue to be

[121] Totten Direct p. 17, lines 23-24.

[122] Totten Direct p. 18, lines 1-2.

innovative in developing and implementing operating efficiencies which lead to lower rates after the following rate case.

Q: ETI POINTS TO ITS RESPONSE TO HURRICANES LAURA AND DELTA THAT MADE LANDFALL NEAR ITS SERVICE AREA DURING THE 2020 HURRICANE SEASON AS AN EXAMPLE OF ITS EFFECTIVE AND EFFICIENT MANAGEMENT TO JUSTIFY ITS REQUESTED PERFORMANCE ADDER.[123] HOW DID THE COMPANY'S RELIABILITY METRICS COMPARE WITH OTHER ELECTRIC UTILITIES IN 2021 OUTSIDE OF MAJOR EVENT DAYS?

A: I compared ETI's reliability metrics during 2021 with other investor-owned electric utilities which comply with the IEEE's reliability standards with more than 10,000 customers. After excluding major event days,[124] the Company's reliability metrics during the test year significantly lagged its regional and national peers. For example, the Company's SAIDI (System Average Interruption Duration Index) and SAFI (System Average Interruption Frequency Index) were below average in the test year. As illustrated

[123] Totten Direct, p. 8, line 9—p. 11, line 9.

[124] In this context, the phrase "major event days" refers to events that are beyond the design and/or operational limits of a utility, such as major weather events, major substation events, or unexpected catastrophic events.

in Exhibit MG-10, ETI ranked third highest for SAIDI[125] and second highest for SAIFI[126] among 13 utilities in states bordering the Gulf of Mexico. Nationwide, the Company ranked eighth highest for SAIDI and seventh highest for SAIFI among 110 utilities.

Q: AS THE COMPANY WAS RESTORING SERVICE DURING THE 2020 HURRICANE SEASON, DID ETI ALLOW OTHER PRIORITIES TO BE DEFERRED?

A: Yes. As ETI was impacted by Hurricanes Laura and Delta as well as the threat of other hurricanes from 2019 to 2021, resources were diverted away from the Company's advanced metering system ("AMS") implementation to respond to storm preparation and restoration activities.[127] The revenue requirement for AMS is now greater than estimated[128] and the benefits forthcoming to customers were temporarily delayed.[129]

Q: WAS IT REASONABLE TO DIVERT RESOURCES AWAY FROM AMS IMPLEMENTATION IN ORDER TO PREPARE FOR PENDING TROPICAL WEATHER AND RESTORE SERVICE AS NEEDED?

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[125] In this context, the acronym "SAIDI" refers to a utility's System Average Interruption Duration Index which is calculated as the sum of all customer interruption durations divided by total number of customers served.

[126] In this context, the acronym "SAIFI" refers to a utility's System Average Interruption Frequency Index which is calculated as the total number of customer interruption divided by total number of customers served.

[127] Phillips Direct, p. 19, line 18—p. 20, line 1.

[128] Phillips Direct p. 11, lines 1-2.

[129] Phillips Direct p. 19, line 7—p. 20, line 2.

A: Yes. The Company's management allocated its finite resources to a more important, more urgent need compared to AMS implementation. When considering whether ETI should receive a performance adder based on its effective and efficient management, however, the Commission should also not overlook that the Company's AMS implementation was more costly than estimated, and customers waited longer than expected to experience its benefits. If the Commission should ever provide a ROE adder for excellent performance, the Commission should do so for utilities which have performed beyond expectations in all areas of service.

Q: DO YOU RECOMMEND THAT THE COMMISSION PROVIDE A 30 BASIS POINT PERFORMANCE ADDER?

A: No. I believe that the Commission can comply with statutory language to establish a reasonable rate of return on invested capital for an electric utility without resorting to a performance adder. Furthermore, ETI's justifications for its request for a performance essentially increase its customers' rates to recognize the Company's past performance and incent the Company's and *other utilities'* future performance. Nothing in the Company's tariffs or the Commission rules contemplate such ratemaking treatment. Finally, the Commission should not overlook ETI's reliability performance during the test year relative to its regional and national peers and its delay in rolling out its AMS implementation.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes. It does.

EXHIBIT MG-1

QUALIFICATIONS OF MARK E. GARRETT

EXHIBIT MG-1

MARK E. GARRETT

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EDUCATION:
Juris Doctor Degree, With Honors, Oklahoma City University Law School, 1997
Post Graduate Hours in Accounting, Finance and Economics, 1984-85:
University of Texas at Arlington; University of Texas at Pan American;
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Bachelor of Arts Degree, University of Oklahoma, 1978

CREDENTIALS:
Member Oklahoma Bar Association, 1997, License No. 017629
Certified Public Accountant in Oklahoma, 1992, Certificate No. 11707-R
Certified Public Accountant in Texas, 1986, Certificate No. 48514

WORK HISTORY:

GARRETT GROUP CONSULTING, INC. – Regulatory Consulting Practice (1996 - Present) Participates as a consultant and expert witness in gas and electric regulatory proceedings and other matters before regulatory agencies in rate case proceedings to determine just and reasonable rates. Reviews management decisions of regulated utilities regarding the reasonableness of prices paid for electric plant, gas plant, purchased power, renewable energy projects, natural gas supplies and transportation, and coal supplies and transportation. Participates in legislative advisory role regarding regulated utilities. Participates as an Instructor at NMSU Center for Public Utilities and as a Speaker at NARUC Staff Subcommittee on Accounting and Finance.

OKLAHOMA CORPORATION COMMISSION - Coordinator of Accounting and Financial Analysis (1991 - 1994) Planned and supervised the audits of major public utility companies doing business Oklahoma for the purpose of determining revenue requirements. Presented both oral and written testimony as an expert witness for Staff in defense of numerous accounting and financial recommendations related to cost-of-service based rates. Audit work and testimony covered all areas of rate base and operating expense. Supervised, trained and reviewed the audit work of numerous Staff CPAs and auditors. Promoted from Supervisor of Audits to Coordinator in 1992.

FREEDOM FINANCIAL CORPORATION - Controller (1987 - 1990) Responsible for all financial reporting including monthly and annual financial statements, cash flow statements, budget reports, long-term financial planning, tax planning and personnel development. Managed the General Ledger and Accounts Payable departments and supervised a staff of seven CPAs and accountants. Reviewed all subsidiary state and federal tax returns and facilitated the annual independent financial audit and all state or federal tax audits. Received promotion from Assistant Controller in September 1988.

SHELBY, RUCKSDASHEL & JONES, CPAs - Auditor (1986 - 1987) Audited the financial statements of businesses in the state of Texas, with an emphasis in financial institutions.

Previous Experience Related to Cost-of-Service, Rate Design, Pricing and Energy-Related Issues

1. **Oklahoma Gas and Electric Company, 2022 (Oklahoma), (Cause No. PUD 202200097) –** Participating as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in PUD's show cause investigation into OG&E's fuel and purchased power under-recovered balance

2. **Northern Indiana Public Service Company, 2022 (Indiana), (Docket No. 45772) –** Participating as an expert witness on behalf of the Office of Utility Consumer Counselor in NIPSCOs rate case application, sponsoring testimony to address various revenue requirement and tax issues.

3. **Oncor Electric Delivery Company (Texas), 2022 (PUC Docket No. 53601) –** Participating as an expert witness on behalf of the Steering Committee of Cities before the Texas Public Utility Commission in Oncor's General Rate Case proceeding to provide testimony on various revenue requirement issues.

4. **York Waterworks (2022) (Pennsylvania), (Docket No. 061522) –** Participating as an expert witness on behalf of Office of Consumer Advocate ("OCA") before the Pennsylvania Public Utility Commission to address various revenue requirement issues in York rate case.

5. **Sierra Pacific Power Company, 2022 (Nevada), (Docket No. 22-06) –** Participated as an expert witness on behalf of Bureau of Consumer Protection ("BCP") before the Nevada Public Utility Commission to address various revenue requirement issues.

6. **NV Energy, 2022 (Nevada), (Docket No. 22-003028) –** Participating as an expert witness on behalf of Bureau of Consumer Protection ("BCP") before the Nevada Public Utility Commission to address various issues in the merger application of Sierra Pacific Power Company and Nevada Power Company.

7. **Atmos MidTex (Texas), 2022 (Texas), (Dallas Annual Rate Review) –** Participating as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in Atmos's Dallas Annual Rate Review ("DARR") proceeding. Sponsoring recommendations on various revenue requirement issues.

8. **CenterPoint Energy Resources Corp., 2022 (Texas) (Docket No. 53442) –** Participating as an expert witness for the City of Houston before the Texas Public Utility Commission the Company's Distribution Cost Recovery Factor sponsoring testimony on various cost recovery issues.

9. **Cascade Natural Gas, 2021 (Washington) –** Participating as an expert witness on behalf of Public Counsel in Cascade's limited issue rate case application, sponsoring Public Counsel's revenue requirement schedules and testimony to address various revenue requirement and tax issues.

10. **Oklahoma Gas and Electric Company, 2021 (Oklahoma), (Cause No. PUD 202100164) –** Participating as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in OG&E's general rate case application addressing various revenue requirement and rate design issues.

11. **Southwestern Electric Power Company, 2021 (Texas), (PUC Docket No. 52397) –** Participating as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's application to recover Uri storm costs.

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12. **Southwestern Public Service Co., 2021 (Texas) (Docket No. 52210)** – Participating as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") before the Texas Public Utility Commission in SWEPCO's application to recover Uri storm costs.

13. **CenterPoint Energy Resources Corp., 2021 (Texas) (Docket No. OS—00007061)** – Participating as an expert witness for the City of Houston before the Texas Rail Road Commission in a consolidated application from the large natural gas distribution utilities in Texas to securitize and recover URI storm costs from February 2021.

14. **Indiana Michigan Power, 2021 (Indiana), (Docket No. 45576)** – Participating as an expert witness on behalf of the Office of Utility Consumer Counselor in I&M's rate case application, sponsoring testimony to address various revenue requirement and tax issues.

15. **Chugach Electric Association, 2021 (Alaska), (Docket No. U-21-059)** – Participating as an expert witness on behalf of Providence Health and Services before the Alaska Regulatory Commission. Sponsoring testimony to address Chugach's application to address a shortfall in revenues after its acquisition of Municipal Light and Power.

16. **Southwestern Public Service Co., 2021 (Texas) (Docket No. 51802)** – Participating as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues.

17. **El Paso Electric Company, 2021 (Texas), (Docket No. 52195)** – Participating as an expert witness on behalf of the City of El Paso in the El Paso Electric Company general rate case to provide recommendations to the Texas Public Utility Commission regarding rate base and operating expense issues.

18. **NV Energy, 2021 (Nevada), (Docket No. 21-06001)** – Participating as an expert witness on behalf of the Southern Nevada Gaming Group ("SNGG") before the Nevada PUC. Sponsoring written and oral testimony in the Nevada Power and Sierra Pacific Joint Integrated Resource Plan ("IRP") to provide analysis of the proposed generation additions and cost allocations.

19. **Summit Utilities Arkansas (Arkansas), (Docket No. 21-060-U)** – Participating as an expert witness on behalf of Arkansas Gas Consumers and the Hospitals and Higher Education Group before the Arkansas Public Service Commission in Summit's proposed acquisition of CenterPoint Energy's Arkansas assets. Sponsoring testimony regarding the acquisition premium, ratepayer benefits and affiliate transactions.

20. **Doyon Utilities, 2021 Alaska (Regulatory Commission of Alaska)** – Participating as an expert witness on behalf of the Department of Defense to provide expert testimony in twelve rate case reviews for the utility systems of Fort Wainwright, Fort Greely and Joint Base Elmendorf-Richardson before the Regulatory Commission of Alaska.

21. **NV Energy, 2021 (Nevada), (Docket No. 21-03040)** – Participating as an expert witness on behalf of the Southern Nevada Gaming Group ("SNGG") before the Nevada PUC to provide written and oral testimony in the Nevada Power and Sierra Pacific Joint Natural Disaster Protection Plan ("NDPP").

22. **Public Service Company of Oklahoma, 2021 (Oklahoma) (Cause No. PUD 202100022)** – Participating as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case

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application to provide testimony on various revenue requirement, cost of service and rate design issues.

23. **Oklahoma Gas and Electric Company, 2021 (Oklahoma), (Cause No. PUD 202100072)** – Participating as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in OG&E's application for securitization of its winter storm costs.

24. **Southwestern Electric Power Company, 2021 (Arkansas), (Docket No. 19-008-U)** – Participating as an expert witness on behalf of Western Arkansas Large Energy Consumers ("WALEC")1 before the Arkansas Public Service Commission in SWEPCO's Formula Rate Plan review and extraordinary winter storm cost recovery plan.

25. **Atmos MidTex (Texas), 2021 (Texas), (Dallas Annual Rate Review)** – Participating as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in Atmos's Dallas Annual Rate Review ("DARR") proceeding. Sponsoring recommendations on various revenue requirement issues.

26. **PNM Resources / Avangrid Merger, 2021 (New Mexico), (Case No. 20-00222-UT)** – Participating as an expert witness for the Albuquerque Bernalillo County Water Utility Authority ("ABCWUA") before the New Mexico Public Regulation Commission to address various merger-related issues.

27. **Oklahoma Gas & Electric Co., 2020 (Arkansas) (Docket No. 18-046-FR)** – Participating as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC")[2] before the Arkansas Public Service Commission in OG&E's Formula Rate Plan application to provide testimony on cost of service issues.

28. **Public Service Company of Oklahoma, 2020 (Oklahoma) (Cause No. PUD 202000097)** – Participating as an expert witness on behalf of OIEC before the OCC in AEP/PSO's application for approval of facilities proposed for Fort Sill to address cost recovery and rate design issues.

29. **El Paso Electric Company, 2020 (Texas), (Docket No. 51348)** – Participating as an expert witness on behalf of the City of El Paso in the El Paso Electric Company annual Distribution Cost Recovery Factor ("DCRF") application to provide recommendations to the Texas Public Utility Commission regarding the Company's requested DCRF increase.

30. **NV Energy, 2020 (Nevada), (Docket No. 20-07023)** – Participating as an expert witness on behalf of the Southern Nevada Gaming Group ("SNGG") before the Nevada PUC. Sponsoring written and oral testimony in the Nevada Power and Sierra Pacific Joint Integrated Resource Plan ("IRP") to provide analysis of the proposed transmission additions and cost allocations.

31. **Southwestern Electric Power Company, 2020 (Texas), (PUC Docket No. 51415)** – Participating as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's general rate case application to provide testimony on various revenue requirement issues.

32. **Dominion Energy South Carolina, 2020 (South Carolina), (Docket No. 2020-125-E)** – Participating as an expert witness on behalf of DOD/FEA in DESC's rate case application,

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[1] WALEC is an association of industrial manufacturing facilities in Arkansas.
[2] ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.

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sponsoring testimony to address various revenue requirement, rate design and tax issues.

33. **Cascade Natural Gas, 2020 (Washington), (NG-UG-200568)** – Participating as an expert witness on behalf of Public Counsel in Cascade's rate case application, sponsoring testimony to address various revenue requirement and tax issues.

34. **Nevada Power Company, 2020 (Nevada) (Docket No. 20-06003)** – Participating as an expert witness on behalf of Bureau of Consumer Protection ("BCP") before the Nevada Public Utility Commission to address various revenue requirement issues in the case.

35. **El Paso Electric Company, 2020 (New Mexico), (Docket RC-20-00104-UT)** – Participating as an expert witness on behalf of the City of Las Cruces and Dona Ana county in EPE's rate case application, sponsoring testimony to address various revenue requirement and tax issues.

36. **Oklahoma Gas and Electric Company, 2020 (Oklahoma), (Cause No. PUD 202000021) –** Participating as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in OG&E's Grid Enhancement Plan application. Sponsoring testimony to address the utility's proposed cost recovery mechanism and cost of service allocations.

37. **Philadelphia Gas Works, 2020 (Pennsylvania), (Docket No. R-2020-3017206)** – Participating expert witness on behalf of Office of Consumer Advocate ("OCA") before the Pennsylvania Public Utility Commission to address various revenue requirement issues in PGW's rate case.

38. **Atmos MidTex (Texas), 2020 (Texas), (Dallas Annual Rate Review)** – Participating as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in Atmos's Dallas Annual Rate Review ("DARR") proceeding. Sponsoring recommendations on various revenue requirement issues.

39. **Southwest Gas Corporation, 2020 (Nevada) (Docket No. 20-02023)** – Participated as an expert witness on behalf of Bureau of Consumer Protection ("BCP") before the Nevada Public Utility Commission to address various revenue requirement issues.

40. **El Paso Electric Company, 2019 (Texas), (Docket No. 49849)** – Participating as an expert witness on behalf of the City of El Paso in the merger of El Paso Electric Company with Sun Jupiter Holdings LLC and IIF US Holdings 2 LLP to provide recommendations to the Texas Public Utility Commission regarding the treatment of tax issues in the proposed merger agreement.

41. **Nevada Senate Bill 300 Rulemaking, 2019 (Nevada), (Docket No. 19-069008)** – Participating as an expert witness on behalf of the Southern Nevada Gaming Group before the Nevada PUC to assist with the development of alternative ratemaking regulations under SB 300.

42. **Entergy Arkansas, 2019 (Arkansas), (Docket No.** 19-020-TF) – Participating as an expert witness on behalf of the Arkansas industrial consumer group to review EAI's application to allocate its perceived under-recovery of off-system sales margins to Arkansas customers.

43. **Public Service Company of Oklahoma, 2019 (Oklahoma) (Cause No. PUD 201900201)** – Participating as an expert witness on behalf of OIEC before the OCC in AEP/PSO's application for approval for the cost recovery of selected wind facilities.

44. **Oklahoma Gas & Electric Co., 2019 (Arkansas) (Docket No. 15-034-U)** – Participated as an expert

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witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC") before the Arkansas Public Service Commission in OG&E's Act 310 Environmental Compliance Plan ("ECP") Rider case to provide testimony on whether OG&E can apply for an ECP rider now that it has elected to utilize an annual Formula Rate Plan with a 4% annual cap.

45. **Oklahoma Gas & Electric Co., 2019 (Arkansas) (Docket No. 18-046-FR)** – Participating as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC") before the Arkansas Public Service Commission in OG&E's Formula Rate Plan application to provide testimony on various revenue requirement, cost of service and rate design issues.

46. **Southwestern Public Service Co., ("SPS") 2019 (Texas), (Docket No. 49831)** – Participating as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.

47. **Southwestern Electric Power Company, 2019 (Arkansas), (Docket No. 19-008-U)** – Participated as an expert witness on behalf of Western Arkansas Large Energy Consumers ("WALEC") before the Arkansas Public Service Commission in SWEPCO's rate case to address various revenue requirement and rate design issues.

48. **Anchorage Municipal Light and Power and Chugach Electric Association, 2019 (Alaska), (Docket No. U-19-020)** – Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on pending acquisition of ML&P by Chugach to address the proposed acquisition premium and other issues associated with the public interest.

49. **Sierra Pacific Power Company, 2019 (Nevada), (Docket No. 19-06002)** – Participated as an expert witness on behalf of Bureau of Consumer Protection ("BCP") before the Nevada Public Utility Commission to address various revenue requirement issues.

50. **Air Liquide Hydrogen Energy U.S., 2019 (Nevada), (704B Exit Application, Docket No. 19-02002)** – Participated as an expert witness on behalf of Air Liquide before the Nevada PUC. Sponsoring written and oral testimony in Air Liquide's application to purchase energy and capacity from a provider other than NV Energy.

51. **Empire District Electric Company, 2019 (Oklahoma), (Cause No. PUD 201800133)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in Empire's general rate case to address various revenue requirement, rate design and tax issues.

52. **Indiana Michigan Power, 2019 (Indiana), (Docket No. 45235)** – Participating as an expert witness on behalf of the Office of Utility Consumer Counselor in I&M's rate case application, sponsoring testimony to address various revenue requirement and tax issues.

53. **Puget Sound Energy, 2019 (Washington), (Docket No. 190529-30)** – Participating as an expert witness on behalf of Public Counsel in PSE's rate case application, sponsoring testimony to address various revenue requirement and tax issues.

54. **Anchorage Municipal Light and Power, 2019 (Alaska), (Docket No. U-18-102)** – Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on the ratemaking treatment of ML&P's acquired interest in the Beluga

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River Unit gas field with ratepayer funds.

55. **Oklahoma Gas and Electric Company, 2019 (Oklahoma), (Cause No. PUD 201800140) –** Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in OG&E's General Rate Case application. Sponsoring testimony to address the utility's overall revenue requirement and rate design proposals.

56. **Cascade Natural Gas, 2019 (Washington) (Docket No. 190210)** – Participated as an expert witness on behalf of Public Counsel in Cascade's rate case application. Sponsoring testimony to address various revenue requirement and tax issues.

57. **CenterPoint Energy Houston Electric, 2019 (Texas) (Docket No. 49421)** – Participated as an expert witness on behalf of City of Houston before the Public Utility Commission of Texas in CenterPoint Energy's rate case application to provide testimony on various revenue requirement issues.

58. **Oklahoma Gas & Electric Co., 2018 (Arkansas) (Docket No. 18-046-FR** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC") before the Arkansas Public Service Commission in OG&E's Formula Rate Plan application to provide testimony on various revenue requirement, cost of service and rate design issues.

59. **Southwest Gas Corporation, 2018 (Nevada) (Docket No. 18-05031)** – Participated as an expert witness on behalf of Bureau of Consumer Protection ("BCP") before the Nevada Public Utility Commission to address various revenue requirement issues.

60. **Puget Sound Energy, 2018 (Washington) (Docket No. UE 18089)** - Participated as an expert witness on behalf of Public Counsel in PSE's Emergency Rate Relief proceeding. Sponsoring testimony to address the application itself and various revenue requirement and TCJA issues.

61. **Public Service Company of Oklahoma, 2018 (Oklahoma) (Cause No. PUD 201800097) –** Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.

62. **Entergy Texas Inc., 2018 (Texas) (PUC Docket No. 48371)** – Participated as an expert witness on behalf of the Cities in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

63. **Atmos Energy Corp., Mid-Tex Division, 2018 (Texas) (Docket No. GUD No. 10779) –** Participated as an expert witness on behalf of the Atmos Texas Municipalities to review the utility's requested revenue requirement including TCJA adjustments.

64. **CenterPoint Energy Houston Electric, LLC, 2018 (Texas) (Docket No. 48226)** – Participated as an expert witness on behalf of City of Houston before the Public Utility Commission of Texas in CenterPoint Energy's application for approval to amend its distribution cost recovery factor (DCRF) to address the utility's treatment of the Tax Cuts and Jobs Act of 2017 ("TCJA").

65. **NV Energy, 2018 (Nevada) (Docket No. 17-10001)** – Participated as an expert witness on behalf of the Energy Choice Initiative ("ECI") before the Governor's Committee on Energy Choice, in an investigatory docket of an Issue of Public Importance Regarding the Pending Energy Choice Initiative and the Possible Restructuring of Nevada's Energy Industry.

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66. **Southwestern Electric Power Company, 2018 (Texas) (PUC Docket No. 48233)** – Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's application to implement bae rate reductions as result of the Tax Cuts and Jobs Act of 2017 ("TCJA").

67. **Oncor Electric Delivery Company (Texas), 2018 (PUC Docket No. 48325)** – Participated as an expert witness before the Texas Public Utility Commission in Oncor's application for authority to decrease rates based on the Tax Cuts and Jobs Act of 2017 ("TCJA").

68. **Public Service Company of Oklahoma ("PSO") (Oklahoma), 2018 (Cause No. PUD 201800019)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's application regarding ADIT under the Tax Cuts and Jobs Act of 2017 ("TCJA").

69. **Oklahoma Natural Gas Company, 2018 (Cause No. PUD 201800028)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission in ONG's Performance Based Rate Change Tariff, to address issues involving the impacts of the Tax Cuts and Jobs Act of 2017 ("TCJA").

70. **Oklahoma Gas & Electric Co. (Arkansas), 2018 (Docket No. 18-006-U** – Participated as an expert on behalf of the Arkansas River Valley Energy Consumers ("ARVEC") before the Arkansas Public Service Commission in the matter of an Investigation of the Effect on Revenue Requirements Resulting from Changes to Corporate Income Tax Rates under the Tax Cuts and Jobs Act of 2017 ("TCJA").

71. **Texas Gas Service, 2018** – Participated as a consulting expert on behalf of the City of El Paso regarding implementation of rate changes related to the Tax Cuts and Jobs Act of 2017 ("TCJA").

72. **Sierra Pacific Power Company (Nevada), 2018 (Docket No. 18-02011 and 18-02015)** – Participated as an expert witness on behalf of the Northern Nevada Utility Customers[3] before the Nevada PUC in SPPC's application related to the Tax Cuts and Jobs Act of 2017 ("TCJA").

73. **Nevada Power Company (Nevada), 2018 (Docket No. 18-02010 and 18-02014)** – Participated as an expert witness on behalf of the Southern Nevada Gaming Group before the Nevada PUC in NPC's application related to the Tax Cuts and Jobs Act of 2017 ("TCJA").

74. **Public Service Company of Oklahoma ("PSO") (Oklahoma), 2017 (Cause No. PUD 201700572)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's application to examine the impacts of the Tax Cuts and Jobs Act of 2017 ("TCJA").

75. **Empire District Electric Company ("EPE") (Oklahoma), 2018 (Cause No. PUD 201700471)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in Empire's application to add 800MW of wind. Sponsoring testimony to address the various ratemaking and tax issues.

76. **Oklahoma Gas and Electric Company ("OG&E"), (Oklahoma), 2018 (Cause No. PUD 201700496)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in OG&E's General Rate Case application.

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[3] The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

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Sponsoring testimony to address the utility's overall revenue requirement and rate design proposals.

77. **Public Service Company of Oklahoma ("PSO") (Oklahoma), 2017 (Cause No. PUD 201700276)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's Wind Catcher case to provide testimony on various ratemaking and tax issues.

78. **Southwestern Public Service Co. ("SPS") (Texas), 2017 (PUCT Docket No. 47527) –** Participating as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.

79. **Southwestern Electric Power Company, ("SWEPCO") (Texas), 2017 (PUC Docket No. 47461) –** Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's Wind Catcher case proceeding to provide testimony on various ratemaking and tax issues.

80. **Atmos MidTex (Texas), 2017 (Docket No. 10640)** – Participated as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in Atmos's Dallas Annual Rate Review ("DARR") proceeding. Sponsoring testimony on various revenue requirement issues.

81. **Avista Utilities (Washington), 2017 (Docket Nos. UE-170485/UG-170486)** – Participated as an expert witness on behalf of Public Counsel in Avista's general rate case proceeding. Sponsoring testimony to address various revenue requirement issues and Avista's requested attrition adjustments.

82. **Nevada Power Company (Nevada), 2017 (Docket No. 17-06003)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC in NPC's general rate case proceeding. Sponsoring testimony on various revenue requirement, depreciation, and rate design issues.

83. **Anchorage Municipal Light and Power (Alaska), 2017 (Docket No. U-17-008) –** Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony in ML&P's General Rate Case on various revenue requirement and rate design issues.

84. **Public Service Company of Oklahoma (Oklahoma), 2017 (Cause No. PUD 201700151)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various revenue requirement and rate design issues.

85. **Oncor Electric Delivery Company (Texas), 2017 (PUC Docket No. 46957)** – Participated as an expert witness on behalf of the Steering Committee of Cities before the Texas Public Utility Commission in Oncor's General Rate Case proceeding to provide testimony on various revenue requirement issues.

86. **EverSource (Massachusetts), 2017 (DPU Docket No. 17-05) –** Participated as an expert witness before the Massachusetts Department of Public Utilities EverSource's General Rate Case application on behalf of Energy Freedom Coalition of America to provide testimony to address various revenue requirement issues.

87. **El Paso Electric Company (Texas), 2017 (PUC Docket No. 46831)** – Participated as an expert witness on behalf of the City of El Paso before the Texas Public Utility Commission in El Paso's General Rate Case proceeding to provide testimony on various revenue requirement issues.

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88. **Atmos Pipeline Texas (Texas), 2017 (Docket No. 10580)** – Participated as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in APT's General Rate Case application, sponsoring testimony to address various revenue requirement proposals.

89. **Empire District Electric Company (Oklahoma), 2017 (Cause No. PUD 201600468)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in Empire's General Rate Case application. Sponsoring testimony to address the utility's overall revenue requirement and rate design proposals.

90. **Caesars Enterprise Service, LLC (Nevada), 2016 (704B Exit Application)** – Participated as an expert witness on behalf of Caesars before the Nevada PUC. Sponsoring written and oral testimony in Caesar's application to purchase energy and capacity from a provider other than Nevada Power.

91. **Southwestern Electric Power Company (Texas), 2016 (PUC Docket No. 46449)** – Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's general rate case proceeding to provide testimony on various revenue requirement issues.

92. **CenterPoint Texas, 2016 (Docket No. 10567)** – Participated as an expert witness on behalf of City of Houston before the Texas Railroad Commission in CenterPoint's general rate case application, sponsoring testimony to address the utility's overall revenue requirement and various rate design proposals.

93. **Entergy Texas, Inc., 2016 (Docket No. 46357)** – Participated as an expert witness on behalf Cities Served by Applicant before the Texas PUC in ETI's application to amend its Transmission Cost Recovery Factor.

94. **Anchorage Municipal Light and Power, 2016 (Docket No. U-16-060)** – Participated as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on the ratemaking treatment of ML&P's acquired interest in the Beluga River Unit gas field with ratepayer funds.

95. **Arizona Public Service Company, 2016 (Docket No. E-01345A-16-0036)** – Participated as an expert witness before the Arizona Corporation Commission in APS's General Rate Case application on behalf of Energy Freedom Coalition of America to provide written and oral testimony to address various revenue requirement issues.

96. **Oklahoma Gas & Electric Co. (Arkansas), 2016 (Docket No. 16-052-U** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC") before the Arkansas Public Service Commission in OG&E's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.

97. **Sierra Pacific Power Company (Nevada), 2016 (Docket No. 16-06006)** – Participated as an expert witness on behalf of the Northern Nevada Utility Customers before the Nevada PUC in SPPC's general rate case proceeding. Sponsored testimony on various revenue requirement, depreciation, and rate design issues.

98. **Tucson Electric Power, 2016 (Docket No. E-01933A-15-0322)** – Participated as an expert witness before the Arizona Corporation Commission in TEP's General Rate Case application, on behalf of Energy Freedom Coalition of America providing written and oral testimony to address the utility's

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cost of service study and rate design proposals.

99. **Texas Gas Service, 2016 (Docket No. 10506)** – Participated as an expert witness on behalf of El Paso before the Texas Railroad Commission in TGS's General Rate Case application, sponsoring testimony to address the utility's overall revenue requirement and various rate design proposals.

100. **Texas Gas Service, 2016 (Docket No. 10488)** – Participated as an expert witness on behalf of South Jefferson County Service Area ("SJCSA") before the Texas Railroad Commission in TGS's General Rate Case application, sponsoring testimony to address the utility's overall revenue requirement and various rate design proposals.

101. **Oklahoma Gas and Electric Company, 2016 (Cause No. PUD 201500273)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in OG&E's General Rate Case application. Sponsoring testimony to address the utility's overall revenue requirement and rate design proposals.

102. **Oklahoma Gas & Electric Company, 2016 (Cause No. PUD 201500273)** – Participated as an expert witness on behalf of The Alliance for Solar Choice ("TASC") before the Oklahoma Corporation Commission to address OG&E's proposed Distributed Generation ("DG") rates for solar DG customers.

103. **Anchorage Municipal Light and Power, 2016 (Docket No. U-13-097)** – Participated as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on rates and tariffs proposed for customer-owned combined heat and power plant generation.

104. **Oklahoma Natural Gas Company, 2015 (Cause No. PUD 201500213)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission in ONG's General Rate Case application. Sponsored testimony to address the utility's overall revenue requirement and rate design proposals.

105. **Oklahoma Gas & Electric Company, 2015 (Cause No. PUD 201500274)** – Participated as an expert witness on behalf of The Alliance for Solar Choice ("TASC") before the Oklahoma Corporation Commission to address OG&E's proposed Distributed Generation ("DG") rates for solar DG customers.

106. **Nevada Power Company, 2015** (Docket No. 15-07004) – Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG")[4] before the Nevada PUC. Sponsoring written and oral testimony in NPC's 2015 Integrated Resource Plan to provide analysis of the On Line transmission line allocation, the Siverhawk plant acquisition, and the Griffith contract termination.

107. **Oklahoma Gas & Electric Company, 2015 (Docket No. 15-034-U)** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC") before the Arkansas Public Service Commission in OG&E's Act 310 application to implement a rider to recover environmental compliance costs.

108. **MGM Resorts, LLC, 2015** (Docket No. 15-05017) – Participated as an expert witness on behalf of the MGM Resorts, LLC before the Nevada PUC. Sponsoring written and oral testimony in MGM's

[4] The Southern Nevada Hotel Group is comprised of Boyd Gaming, Caesars Entertainment, MGM Resorts, Station Casinos, Venetian Casino Resort, and Wynn Las Vegas.

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application to purchase energy and capacity from a provider other than Nevada Power.

109. **Entergy Arkansas, 2015 (Docket No. 15-015-U)** – Participated as an expert witness on behalf of the Hospital and Higher Education Group ("HHEG") an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy's general rate case to provide testimony on various revenue requirement issues.

110. **Public Service Company of Oklahoma, 2015 (Cause No. PUD 201500208)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.

111. **Nevada Power Company, 2014** (Docket No. 14-05003) – Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC. Sponsored written and oral testimony in NPC environmental compliance case, called the Emissions Reduction and Capacity Replacement case. The main focus of our testimony was our recommendation to eliminate the $438M Moapa solar project from the compliance plan.

112. **Nevada Power Company, 2014** (Docket No. 14-05004) – Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC to sponsor written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

113. **Oklahoma Gas and Electric Co., 2014 (Cause No. PUD 201400229)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") in OG&E's Environmental Compliance and Mustang Modernization Plan before the Oklahoma Corporation Commission to provide testimony addressing the economics and rate impacts of the plan.

114. **Sourcegas Arkansas, Inc., 2014 (Docket No. 13-079-U)** Participated as an expert witness on behalf of the Hospital and Higher Education Group ("HHEG"), an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in SGA's general rate case to provide testimony on various revenue requirement issues.

115. **Anchorage Municipal Light and Power, 2014 (Docket No. U-13-184)** – Participated as an expert witness before the Alaska Regulatory Utility Commission on behalf of Providence Health and Services to provide testimony on various revenue requirement and cost of service issues.

116. **Public Service Company of Oklahoma, 2014 (Cause No. PUD 201300217)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.

117. **Entergy Texas Inc., 2013 (PUC Docket No. 41791)** – Participated as an expert witness on behalf of the Cities[5] in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

118. **MidAmerican/NV Energy Merger, 2013 (Docket No. 13-07021)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC. Sponsored

[5] The Cities include Beaumont, Conroe, Groves, Houston, Huntsville, Orange, Navasota, Nederland, Pine Forest, Pinehurst, Port Arthur, Port Neches, Rose City, Shenandoah, Silsbee, Sour Lake, Vidor, and West Orange.

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testimony to address various issues raised in the proposed acquisition of NV Energy by MidAmerican Energy Holdings Company, including capital structure and acquisition premium recovery issues.

119. **Entergy Arkansas, 2013 (Docket No. 13-028-U)** – Participated as an expert witness on behalf of the Hospital and Higher Education Group ("HHEG") an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy's general rate case to provide testimony on various revenue requirement issues.

120. **Sierra Pacific Power Company, 2013 (Docket No. 13-06002)** – Participated as an expert witness on behalf of the Northern Nevada Utility Customers[6] before the Nevada PUC in SPPC's general rate case proceeding to provide testimony on various cost of service and revenue requirement issues. Sponsored written and oral testimony in the depreciation phase, the revenue requirement phase and the rate design phase of these proceedings.

121. **Gulf Power Company, 2013 (Docket No. 130140-EI)** – Participated as an expert witness on behalf of the Office of Public Counsel before the Florida Commission in Gulf Power's general rate case proceeding to provide testimony on various revenue requirement issues.

122. **Public Service Company of Oklahoma, 2013 (Cause No. PUD 201200054)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission ("OCC") to provide testimony in PSO's application seeking Commission approval of its settlement agreement with EPA.

123. **Southwestern Electric Power Company, 2012 (PUC Docket No. 40443)** – Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's general rate case proceeding to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

124. **Doyon Utilities, 2012 Alaska Rate Case** (Docket No. TA7-717) – Participated as an expert witness consultant on behalf of the Department of Defense to provide expert testimony in twelve rate case reviews for the utility systems of Fort Wainwright, Fort Greely and Joint Base Elmendorf-Richardson before the Regulatory Commission of Alaska.

125. **University of Oklahoma, 2012** – Participated as an expert witness on behalf of the University of Oklahoma to provide expert testimony on various revenue requirement issues in the University's general rate case with the Corix Group, which provides utility services to the University.

126. **Public Service Company of Oklahoma, 2012 (Cause No. PUD 201200079)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission to provide expert testimony addressing the utility's request to earn additional compensation on a 510MW purchased power agreement with Exelon

127. **Centerpoint Energy Texas Gas, 2012 (Docket No.** GUD 10182) – Participated as an expert witness on behalf of the Steering Committee of Cities before the Texas Railroad Commission to provide expert testimony on various revenue requirement issues.

128. **Entergy Texas Inc., 2012 (PUC Docket No. 39896)** – Participated as an expert witness on behalf of the Cities in ETI's general rate case to provide testimony on various cost of service issues and on the

[6] The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

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