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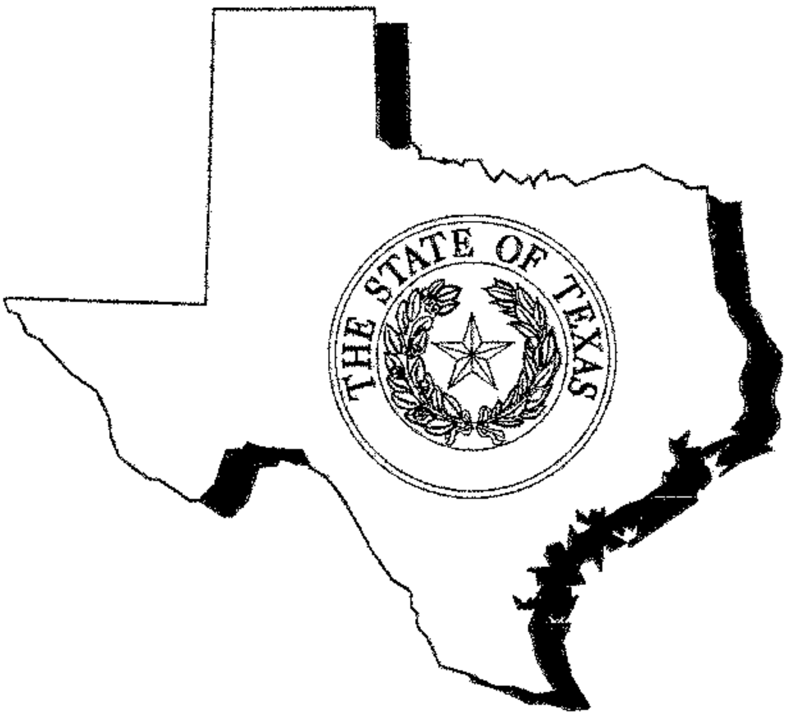
APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR AUTHORITY TO CHANGE RATES	§ § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**



WORKPAPERS TO THE DIRECT TESTIMONY OF RUTH STARK

RATE REGULATION DIVISION

PUBLIC UTILITY COMMISSION OF TEXAS
JUNE 26, 2024

PUBLIC UTILITY COMMISSION OF TEXAS
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
I-A-1 TOTAL COST OF SERVICE BY FUNCTION
TEST YEAR ENDING 12/31/2023
DOCKET NO. 56211
SPONSOR: K. COLVIN

			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Description	Reference Schedule	Test Year Total Electric	Company Adjustments	Company Total Request	Transmission Function (TRAN)	Distribution Function (DIST)	Metering Function (MET)	T&D Customer Service (TDCS)	Total TX-Retail
1										
2	Operations and Maintenance Expense	II-D-2	1,674,846,443	271,394,176	1,946,240,619	105,863,939	1,742,164,990	51,620,279	46,591,411	1,946,240,619
3	Depreciation & Amortization	II-E-1	568,462,586	14,699,432	583,162,018	149,934,687	376,695,427	35,356,098	21,175,807	583,162,018
4	Taxes Other Than Federal Income Tax	II-E-2	306,719,436	22,861,986	329,581,422	61,300,412	261,755,102	4,798,818	1,727,089	329,581,422
5	Federal Income Tax	II-E-3	128,901,122	3,410,867	132,311,989	56,008,283	72,086,440	3,035,507	1,181,759	132,311,989
6										
7	Return on Rate Base	II-B	962,210,914	(111,950,153)	850,260,761	354,989,751	467,876,311	19,748,551	7,646,148	850,260,761
8										
9	**TOTAL COST OF SERVICE**		**3,641,140,501**	**200,416,308**	**3,841,556,809**	**728,097,071**	**2,920,578,270**	**114,559,253**	**78,322,214**	**3,841,556,809**
10										
11	Decommissioning Expense [1]	II-G	-	-	-	-	-	-	-	-
12										
13	Other Non-Bypassable Charges [2]		-	-	-	-	-	-	-	-
14										
15	Minus: Other Revenues	II-E-5	550,813,090	(477,536,320)	73,276,770	32,003,060	41,244,138	29,573	-	73,276,770
16										
17	**TOTAL ADJUSTED REVENUE REQUIREMENT**		**3,090,327,411**	**677,952,628**	**3,768,280,038**	**696,094,011**	**2,879,334,132**	**114,529,680**	**78,322,214**	**3,768,280,038**

[1] CenterPoint Energy Houston Electric, LLC does not own or have a leasehold interest in a nuclear-fueled generation unit.
[2] See Schedule I-A for Other Non-Bypassable Charges

CENTERPOINT HOUSTON ELECTRIC

2023 RATE CASE REVENUE REQUIREMENT

(Thousands)

	Prior Rate Case Docket No. 49421 1	Test Year Ending December 31, 2023 Proposed Rates	ERRATA 2	ERRATA 3
Total Rate Base	$ 6,233,718	~~$ 12,098,346~~	~~$ 12,106,254~~	$ 12,091,978
Rate of Return	6.51%	7.03%	7.03%	7.03%
Operating and Maintenance Expense	$ 586,317	~~$ 542,431~~	~~$ 538,459~~	$ 539,419
Wholesale Transmission from Others	$ 929,972	~~$ 1,407,120~~	~~$ 1,406,982~~	$ 1,406,821
Depreciation and Amortization Expense	$ 352,141	~~$ 583,418~~	$ 583,162	$ 583,162
Taxes Other Than Federal Income Tax	$ 275,047	$ 329,581	$ 329,581	$ 329,581
Federal Income Tax Expense	$ 39,218	~~$ 132,409~~	~~$ 132,484~~	$ 132,312
Return on Rate Base	$ 394,594	~~$ 850,898~~	~~$ 851,238~~	$ 850,281
Total Cost of Service	$ 2,577,292	~~$ 3,845,777~~	~~$ 3,842,912~~	$ 3,841,557
Other Revenues	$ 67,903	$ 73,277	$ 73,277	$ 73,277
Total Adjusted Revenue Requirement	$ 2,509,389	~~$ 3,772,600~~	~~$ 3,769,635~~	$ 3,768,280
Total Revenue Requirement not includeing Wholesale Transmission from others	$ 1,579,414	~~$ 2,365,320~~	~~$ 2,362,648~~	$ 2,361,459

(1) Prior Rate Case information from Rev 1.18.2020 Final Version-49421-Settlement Model of CEHE's CCOSS-Final Order.xlsx attached to Kristie L. Colvin Testimony in Support of Agreement filed 1-24-2020 Case 49421-786, approved by PUCT in its March 9, 2020 Order (49421-792); Rate of Return from Conclusion of Law 15 in PUCT March 9, 2020 Order (49421-792).

PUBLIC UTILITY COMMISSION OF TEXAS
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
II-B SUMMARY OF RATE BASE
TEST YEAR ENDING 12/31/2023
DOCKET NO. 56211
SPONSOR: K. COLVIN

			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Description	Reference Schedule	Test Year Total Electric	Company Adjustments	Company Total Request	TRAN	DIST	MET	TDCS	Total TX Retail
1										
2	Original Cost of Plant	II-B-1	16,467,080,444	(21,311,221)	16,445,769,223	6,186,443,088	9,620,708,094	483,150,873	155,467,168	16,445,769,223
3	General Plant	II-B-2	695,855,112	(12,974,246)	682,880,865	108,495,480	533,353,741	33,603,949	7,427,696	682,880,865
4	Communication Equipment	II-B-3	669,741,463	(3,225,386)	666,516,077	127,548,026	428,079,902	49,246,600	61,641,549	666,516,077
5										
6	**Total Plant**		17,832,677,019	(37,510,853)	17,795,166,166	6,422,486,595	10,582,141,737	566,001,422	224,536,412	17,795,166,166
7										
8	Minus: Accumulated Depreciation	II-B-5	4,427,157,386	(22,714,368)	4,404,443,018	920,384,941	3,163,580,580	228,207,195	92,270,302	4,404,443,018
9										
10	Net Plant in Service		13,405,519,632	(14,796,485)	13,390,723,148	5,502,101,654	7,418,561,157	337,794,227	132,266,110	13,390,723,148
11										
12	**Other Rate Base Items:**									
13	CWIP	II-B-4	1,067,127,699	(1,067,127,699)	-	-	-	-	-	-
14	Plant Held for Future Use	II-B-6	10,452,078	(4,192,438)	6,259,640	6,042,505	217,135	-	-	6,259,640
15	Accumulated Provisions	II-B-7	18,550,490	5,684,575	24,235,065	(5,057,838)	31,130,150	(1,266,179)	(571,067)	24,235,065
16	Accumulated Deferred Income Taxes	II-B-7	(1,428,931,365)	157,952,565	(1,270,978,800)	(448,441,177)	(751,023,980)	(47,610,933)	(23,902,710)	(1,270,978,800)
17	Materials and Supplies	II-B-8	449,428,267	(64,222,156)	385,206,111	214,939,567	166,578,016	3,688,528	-	385,206,111
18	Cash Working Capital	II-B-9	62,592,133	(50,423,773)	12,168,360	2,388,107	7,564,768	1,164,464	1,051,021	12,168,360
19	Prepayments	II-B-10	35,532,670	34,957,557	70,490,227	15,732,066	45,727,535	6,186,665	2,843,961	70,490,227
20	Other Rate Base Items:									
21	Customer Deposits & Advances	II-B-11	(37,446,336)	37,106,170	(340,166)	(340,166)	-	-	-	(340,166)
22	Regulatory Liabilities	II-B-11	(933,697,180)	167,231,322	(766,465,858)	(264,527,922)	(459,741,236)	(29,841,394)	(12,355,306)	(766,465,858)
23	Regulatory Assets	II-B-12	1,034,925,341	(794,265,360)	240,659,981	25,639,214	194,875,274	10,738,039	9,407,454	240,659,981
24										
25	Total Other Rate Base Items		278,533,797	(1,577,299,227)	(1,298,765,439)	(453,625,644)	(764,672,339)	(56,940,811)	(23,526,646)	(1,298,765,439)
26										
27	**TOTAL RATE BASE**		13,684,053,430	(1,592,095,722)	12,091,957,708	5,048,476,010	6,653,888,818	280,853,416	108,739,464	12,091,957,708
28										
29	Rate of Return	II-C-1.1	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%
30										
31	**RETURN ON RATE BASE**		962,210,914	(111,950,155)	850,260,761	354,989,751	467,876,311	19,748,551	7,646,148	850,260,761

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PROJECT NO. 50664

ISSUES RELATED TO THE STATE OF DISASTER FOR THE CORONAVIRUS DISEASE 2019	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER
RELATED TO ACCRUAL OF REGULATORY ASSETS

On March 13, 2020, in response to the growing threat of the coronavirus disease (COVID-19), Governor Greg Abbott issued a Declaration of State of Disaster for all counties in Texas. This Commission Order addresses the effects of COVID-19 for services provided by electric utilities and water and sewer utilities in the state of Texas.

Through this Order, the Commission takes steps to provide regulated utility companies some regulatory certainty by authorizing the use of an accounting mechanism and a subsequent process through which regulated utility companies may seek future recovery of expenses resulting from the effects of COVID-19.

The Commission issues this accounting order under its statutory authority to preserve on utilities' books the effects of unpaid customer accounts until the Commission approves rate changes that adjust charges to Texas customers.[1] The Commission authorizes each electric, water, and sewer utility to record as a regulatory asset expenses resulting from the effects of COVID-19, including but not limited to non-payment of qualified customer bills as specified by separate order issued on this same date. In future proceedings, the Commission will consider whether each utility's request for recovery of these regulatory assets is reasonable and necessary. The Commission will also consider in the future proceeding other issues, such as the appropriate period of recovery for the approved amount of regulatory assets, any amount of carrying costs thereon, and other related matters.

[1] Public Utility Regulatory Act, Tex. Util. Code Ann. § 14.151 (West 2016 & Supp. 2017); Tex. Water Code Ann. § 13.131(a) (West 2008 & Supp. 2017).

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Consistent with the above discussion, the Commission orders the following:

1. Each electric utility and water and sewer utility in the state of Texas shall record as a regulatory asset expenses resulting from the effects of COVID-19.

2. In future proceedings, the Commission will consider, on a case-by-case basis, the appropriate adjustment to a utility's rates to reflect the recovery of the approved amount of regulatory assets recorded in accordance with this Order.

Signed at Austin, Texas the 26th day of March 2020.

PUBLIC UTILITY COMMISSION OF TEXAS

DeAnn T. Walker

DEANN T. WALKER, CHAIRMAN

ARTHUR C. D'ANDREA, COMMISSIONER

Shelly Botkin

SHELLY BOTKIN, COMMISSIONER

Q. DID EPE INCUR COSTS FOR PROMOTING UTILITY-SUPPLIER DIVERSITY DURING THE TEST YEAR?

A. EPE has promoted supplier diversity for many years and continued to do so in the Test Year. In the Test Year, EPE's suppliers included 592 diverse suppliers (56% of total suppliers) with owners classified as small businesses, women-owned, veteran-owned, and minority-owned. EPE spent $99.4 million (30% of total spent) with these vendors in the Test Year. Due to COVID-19 restrictions, several events planned to promote supplier diversity in 2020 were postponed until 2021. Total costs incurred in 2020 for this program were less than $6,000.

Q. WHAT IS THE NEXT COMMITMENT THAT YOU ADDRESS?

A. The next commitment is that EPE, along with the other applicants, committed that they "will study and evaluate growth opportunities related to electric vehicles, distributed generation, and battery storage in collaboration with the University of Texas at El Paso, El Paso Community College, and New Mexico State University. All signatories reserve the right to challenge inclusion of these expenses in rates. To the extent EPE seeks to recover these costs in rates, the inclusion of such costs must be described in the executive summary of the rate filing package." (FoF 56 g).

Q. DID EPE INCUR COSTS FOR SUCH PROGRAMS DURING THE TEST YEAR?

A. No. Due to COVID-19, these programs were postponed until 2021. However, in 2021, EPE has already collaborated with NMSU on an application to the Department of Energy for a "Connected Communities" grant and initiated discussions with UTEP on a potential collaboration around electrification.

VII. COVID-19 Expenses

Q. WAS THE COMPANY IMPACTED BY THE COVID-19 PANDEMIC DURING THE TEST YEAR?

A. Yes. The Company's Test Year end for this rate case is December 31, 2020. Consequently, the government imposed COVID-19 restrictions in 2020 and the accompanying business changes had a significant impact on the Company, its employees, and its customers.

Q. HOW WAS THE COMPANY IMPACTED BY COVID-19 DURING THE TEST YEAR?

A. The Company was impacted in many ways by the COVID-19 pandemic. Like many other companies, our employees had to adjust to remote work routines, new safety protocols, and the stresses of a national health emergency all while continuing to provide reliable service to customers. The COVID-19 pandemic also substantially increased costs associated with the provision of electric service to customers in two major ways: (1) increased bad debt expenses; and (2) other COVID-19 specific costs.

Q. HOW DID THE COVID-19 PANDEMIC AFFECT THE COMPANY'S BAD DEBT EXPENSE?

A. As discussed in Section IV of my direct testimony, the Company's bad debt expense for the Test Year was approximately $4 million higher (on a total company basis) than bad debt expenses in prior years.

Q. WHAT OTHER COSTS DID THE COMPANY INCUR AS A RESULT OF THE COVID-19 PANDEMIC?

A. In compliance with federal, state, and local government public health orders, the Company had to reset its operations to accommodate remote access, virtual business interactions, and expanded technological infrastructure. These increased costs were necessary for the Company to continue providing reliable electric service to customers while its employees were ordered to stay home. Moreover, the COVID-19 pandemic increased administrative and other operational costs primarily related to additional cleaning services, supplies, and increased medical costs for testing, treatment and consulting.

Q. HOW MUCH DID THE COMPANY INCUR IN NON-BAD DEBT COSTS RELATING TO COVID-19?

A. For the Test Year, the Company incurred approximately $4 million in additional non-bad debt related COVID-19 costs.

Q. WERE THE COMPANY'S COVID-19 RELATED COSTS REASONABLE AND NECESSARY TO PROVIDE RELIABLE ELECTRIC SERVICE TO CUSTOMERS?

A. Yes. The Company incurred the costs as a direct result of state and local government public health orders. The Company had to comply in order to continue providing reliable electric service to its customers.

Q. HOW DID THE COMPANY ACCOUNT FOR THESE COVID-19 RELATED COSTS?

A. On March 26, 2020, the Commission issued an Order in Project No. 50664 that allowed regulated utility companies to use an accounting mechanism to identify and recover COVID-19 related expenses. In compliance with this Commission Order, the Company recorded a regulatory asset that captures its expenses resulting from the COVID-19 pandemic. The March 26, 2020, Commission Order also provided that the Commission would evaluate and decide the recovery of COVID-19 expenses and the appropriate period of expense recovery in future rate proceedings. The Company respectfully requests that the Commission approve EPE's proposal for these COVID-19 expense recovery issues in this rate proceeding.

Q. DOES THE COMPANY PROPOSE TO RECOVER ITS TOTAL COVID-19 RELATED EXPENSES THROUGH BASE RATES?

A. No. The Company has removed COVID-19 related costs, net of savings, from its cost of service and has recorded a regulatory asset as discussed above. The adjustment removing the O&M costs from cost of service is included in Workpaper A-3, Adjustment No. 7. The Company's adjusted rate base includes the COVID-19 regulatory asset and associated carrying costs, less one year of amortization. This adjustment is included in Workpaper B-1, Adjustment No. 3.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER ITS COVID-19 EXPENSES IN THIS PROCEEDING?

A. As discussed by EPE witness Carrasco, the Company proposes a COVID-19 specific tariff that would allow the Company to recover actual COVID-19 expenses (both additional COVID-19 related bad-debt costs and other costs) over a three-year period. The total Company annual costs proposed to be recovered through this tariff are included in Workpaper A-3, Adjustment No. 11. As part of the COVID-19 rate tariff, the Company will true-up the bad-debt portion of the COVID-19 recovery at the end of each year to account for any adjustments to the COVID-19-related expenses during the period new rates are in effect. The proposed COVID-19 rate tariff is further described in EPE witness Carrasco's direct testimony and his sponsored schedules.

Q. IS THE COMPANY'S PROPOSAL TO RECOVER REASONABLE AND NECESSARY COVID-19-RELATED EXPENSES REASONABLE?

A. Yes. The Company's proposal to recover reasonable and necessary COVID-19-related expenses is reasonable and complies with the Commission's March 26, 2020, Order in Project No. 50664.

VIII. FERC Account Reclass

Q. WHY DID THE COMPANY RECLASS A&G EXPENSES TO OPERATION AND MAINTENANCE EXPENSE IN DECEMBER 2020?

A. The Division of Audits and Accounting within the Office of Enforcement of the FERC completed an audit of the Company in January 2021. The audit covered the period from January 1, 2016 to June 30, 2020. The final audit report issued in Docket No. PA19-3-000 on January 28, 2021 included an audit finding related to accounting for joint owner billing. The FERC determined the Company did not functionalize portions of third-party billings characterized as A&G expenses for O&M related to PVGS, the Palo Verde transmission switchyards and Four Corners. In compliance with the requirements in the final audit report, in December 2020, portions of the billings from Arizona Public Service Company for the O&M of PVGS that were initially recorded as A&G were reclassified by the Company into FERC Account 524, Miscellaneous Nuclear Power Expenses. Additionally, portions of the billings from the Salt River Project for the O&M of the Palo Verde transmission switchyards that were initially recorded as A&G were reclassified by the Company into FERC Account 566. No adjustments were made related to Four Corners because the Company sold its share of Four Corners prior to the Test Year, therefore were no third-party billings related to Four Corners in the Test Year. These reclassifications represent a shift from A&G into O&M accounts and do not represent an increase in costs incurred during the Test Year ended December 31, 2020.

PUBLIC UTILITY COMMISSION OF TEXAS
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
II-B-12 REGULATORY ASSETS
TEST YEAR ENDING 12/31/2023
DOCKET NO. 56211
SPONSOR: K. COLVIN

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(15)
Line No.	FERC Account	Description	Reference Schedule	Total Company	Non-Regulated or Non-Electric	Known and Measurable Changes	Company Total Electric	FF #	Functionalization Factor Name	Allocation to Texas	TRAN	DIST	MET	TDCS	Total	Authority	Order (Docket No. and Page)
1																	
2		**Other Rate Base Items**															
3		**Regulatory Assets in Rate Base**	II-B-12														
4																	
5		**Non-Tax Related Regulatory Assets**															
6	1823	Regulatory Assets-TEEEF Other		(9,526,573)	-	9,526,573	-	1	DA	-	-	-	-	-	-	*	*
7	1823	Regulatory Assets - TEEEF OU		9,420,810	-	(9,420,810)	-	1	DA	-	-	-	-	-	-	*	*
8	1823	Regulatory Assets-Bad Debt		8,304,940	-	(277,498)	8,027,442	3	TDCS	8,027,442	-	-	-	8,027,442	8,027,442	*	*
9	1823	Reg Asset Relief Prog Incremental Costs		8,104,805	-	-	8,104,605	71	COVID	8,104,505	1,037,645	6,344,078	484,502	238,379	8,104,805	*	*
10	1823	Regulatory Assets-Hurricane Harvey		26,498,322	-	11,440,134	37,938,456	73	HARVEY	37,938,456	482,348	37,456,108	-	-	37,938,456	*	*
11	1823	Regulatory Assets-Expedited Switch		303,943	-	-	303,943	4	MET	303,943	-	-	303,943	-	303,943	*	*
12	1823	Regulatory Assets-Rate Case Expense		2,853,364	-	(2,853,364)	-	1	DA	-	-	-	-	-	-	*	*
13	1823	Reg Assets - SMT		7,215,579	-	-	7,215,579	4	MET	7,215,579	-	-	7,215,579	-	7,215,579	*	*
14	1823	Regulatory Assets-Load Management Programs		2,984,848	-	-	2,984,848	3	DIST	2,984,848	-	2,984,848	-	-	2,984,848	*	*
15	1823	Regulatory Assets-Long Lead Time Facilities		7,593,554	-	(1,277,949)	6,315,605	65	MAT_SUP	6,315,605	3,524,019	2,731,112	60,475	-	6,315,605	*	*
16	1823	Regulatory Assets-Emergency Generation		106,061,928	-	(106,061,928)	-	1	DA	-	-	-	-	-	-	*	*
17	1823	Regulatory Assets-Emergency Generation LT		598,925,931	-	(598,925,931)	-	1	DA	-	-	-	-	-	-	*	*
18	1823	2021 Hurricane Nicholas		50,527,267	-	-	50,527,267	78	NICHOLAS	50,527,267	-	50,527,267	-	-	50,527,267	*	*
19	1823	2021 Winter Storm Uri		17,313,260	-	-	17,313,260	79	URI	17,313,260	558,486	16,754,774	-	-	17,313,260	*	*
20	1823	Regulatory Assets - Storm Costs Other		45,045,935	-	-	45,045,935	72	LAURA	45,045,935	1309,449	43,736,486	-	-	45,045,935	*	*
21	1823	Regulatory Assets-2007 Securitization		28,653	-	(28,653)	-	1	DA	-	-	-	-	-	-	*	*
22	1823	Regulatory Assets-Asset Retire Oblig		29,009,601	-	(29,009,601)	-	1	DA	-	-	-	-	-	-	*	*
23																	
24																	
25		Subtotal Non-Tax Regulatory Assets		910,665,908	-	(726,888,967)	183,776,940			183,776,940	6911,946	160,534,674	8,064,499	8,265,821	183,776,940		
26																	
27		**Tax Related Regulatory Assets**	II-B-12														
28	1823	Regulatory Assets-Docket		25,814,066	-	(25,814,066)	-	1	DA	-	-	-	-	-	-	*	*
29	1823	Reg Asset-Postretirement (RDS)		10,979,173	-	-	10,979,173	12	PAYXAG	10,979,173	2,160,017	7,043,230	1,213,500	562,425	10,979,173	*	*
30	1823	109DR-Eq AFUDC Close (Reg Tax Assets)		60,622,951	-	(60,622,951)	-	1	DA	-	-	-	-	-	-	*	*
31	1823	Amrt 109DR-Eq AFUDC (Reg Tax Assets)		(19,439,656)	-	19,439,656	-	1	DA	-	-	-	-	-	-	*	*
32	1823	109DR-Net Tx Debt AFD (Reg Tax Assets)		2,435,348	-	(2,435,348)	-	1	DA	-	-	-	-	-	-	*	*
33	1823	Amt 109DR-Net Tx AFD (Reg Tax Assets)		(2,369,696)	-	2,369,696	-	1	DA	-	-	-	-	-	-	*	*
34	1823	109CR-Post Exc DFIT (Reg Tax Assets)		(42,974,936)	-	-	(42,974,936)	21	GPLT	(42,974,936)	(15,510,164)	(25,555,640)	(1,366,885)	(542,251)	(42,974,936)	*	*
35	1823	Amt 109CR-Pst Xc DFIT (Reg Tax Assets)		42,182,030	-	-	42,182,030	21	GPLT	42,182,030	15223,995	25,084,128	1,341,661	532,246	42,182,030	*	*
36	1823	109CR- Invest Tax CR (Reg Tax Assets)		2,135,247	-	(2,135,247)	-	1	DA	-	-	-	-	-	-	*	*
37	1823	Amrt 109CR- ITC (Reg Tax Assets)		(1,821,868)	-	1,821,868	-	1	DA	-	-	-	-	-	-	*	*
38	1823	Non-Current Excess Accumm. Deferred Taxes & Other		46,696,774	-	-	46,696,774	23	GPLT	46,696,774	16853,420	27,769,882	1,485,260	589,212	46,696,774	*	*
39																	
40																	
41		Subtotal Tax Regulatory Assets		124,259,433	-	(67,376,393)	56,883,041			56,883,041	18727,267	34,340,601	2,673,540	1,141,633	56,883,041		
42																	
43		TOTAL REG II-B-12	II-B-12	1,034,925,341	-	(794,265,360)	240,659,981			240,659,981	25639,214	194,875,274	10,738,039	9,407,454	240,659,981		
44																	
45		TOTAL OTH II-B-6-12		(788,595,902)		(510,171,537)				(1,298,765,439)	(453625,644)	(764,672,339)	(56,940,811)	(23,526,646)	(1,298,765,439)		
46																	
47		TOTAL RATI II-B-1-12		13,684,055,430		(1,592,098,722)				12,091,957,708	5,048,476,010	6,653,888,818	280,853,416	108,739,464	12,091,957,708		
48																	
49		Rate of Return		7.03%	7.03%	7.03%	7.03%			7.03%	7.03%	7.03%	7.03%	7.03%	7.03%		
50																	
51																	
52		RETURN ON RATE BASE		962,210,914	-	(111,950,153)	-			850,260,761	5,048,476,010	467,876,311	19,748,551	7,646,148	850,260,761	-	-

§25.130. Advanced Metering.

(a) **Purpose.** This section addresses the deployment, operation, and cost recovery for advanced metering systems.

(b) **Applicability.** This section is applicable to all electric utilities, including transmission and distribution utilities. Any requirement applicable to an electric utility in this section that relates to retail electric providers (REPs) or REPs of record is applicable only to electric utilities operating in areas open to customer choice.

(c) **Definitions.** As used in this section, the following terms have the following meanings, unless the context indicates otherwise:

(1) Advanced meter -- Any new or appropriately retrofitted meter that functions as part of an advanced metering system and that has the minimum system features specified in this section, except to the extent the electric utility has obtained a waiver of a minimum feature from the commission.

(2) Advanced Metering System (AMS) -- A system, including advanced meters and the associated hardware, software, and communications systems, including meter information networks, that collects time-differentiated energy usage and performs the functions and has the features specified in this section.

(3) Deployment Plan -- An electric utility's plan for deploying advanced meters in accordance with this section and either filed with the commission as part of the Notice of Deployment or approved by the commission following a Request for Approval of Deployment.

(4) Enhanced advanced meter -- A meter that contains features and functions in addition to the AMS features in the deployment plan approved by the commission.

(5) Web portal --The website made available on the internet in compliance with this section by an electric utility or a group of electric utilities through which secure, read-only access to AMS usage data is made available to the customer, the customer's REP of record, and entities authorized by the customer.

(d) **Deployment and use of advanced meters.**

(1) Deployment and use of an AMS by an electric utility is voluntary unless otherwise ordered by the commission. However, deployment and use of an AMS for which an electric utility seeks a surcharge for cost recovery must be consistent with this section, except to the extent that the electric utility has obtained a waiver from the commission.

(2) Six months prior to initiating deployment of an AMS or as soon as practicable after the effective date of this section, whichever is later, an electric utility that intends to deploy an AMS must file a statement of AMS functionality, and either a notice of deployment or a request for approval of deployment. An electric utility may request a surcharge under subsection (k) of this section in combination with a notice of deployment or a request for approval of deployment, or separately. A proceeding that includes a request to establish or amend a surcharge will be a ratemaking proceeding and a proceeding involving only a request for approval of deployment will not be a ratemaking proceeding.

(3) The statement of AMS functionality must:

(A) state whether the AMS meets the requirements specified in subsection (g) of this section and what additional features, if any, it will have;

(B) describe any variances between technologies and meter functions within the electric utility's service territory; and

(C) state whether the electric utility intends to seek a waiver of any provision of this section in its request for surcharge.

(4) A deployment plan must contain the following information:

(A) Type of meter technology;

(B) Type and description of communications equipment in the AMS;

(C) Systems that will be developed during the deployment period;

(D) A timeline for the web portal development or integration into an existing web portal;
(E) A deployment schedule by specific area (geographic information); and
(F) A schedule for deployment of web portal functionalities.

(5) An electric utility must file with the deployment plan, testimony and other supporting information, including estimated costs for all AMS components, estimated net operating cost savings expected in connection with implementing the deployment plan, and the contracts for equipment and services associated with the deployment plan, that prove the reasonableness of the plan.

(6) Competitively sensitive information contained in the deployment plan and the monthly progress reports required under paragraph (9) of this subsection may be filed confidentially. An electric utility's deployment plan must be maintained and made available for review on the electric utility's website. Competitively sensitive information contained in the deployment plan must be maintained and made available at the electric utility's offices in Austin. Any REP that wishes to review competitively sensitive information contained in the electric utility's deployment plan available at its Austin office may do so during normal business hours upon reasonable advanced notice to the electric utility and after executing a non-disclosure agreement with the electric utility.

(7) If the request for approval of a deployment plan contains the information described in paragraph (4) of this subsection and the AMS features described in subsection (g)(1) of this section, then the commission will approve or disapprove the deployment plan within 150 days, but this deadline may be extended by the commission for good cause.

(8) An electric utility's treatment of AMS, including technology, functionalities, services, deployment, operations, maintenance, and cost recovery must not be unreasonably discriminatory, prejudicial, preferential, or anticompetitive.

(9) Each electric utility must provide progress reports on a monthly basis following the filing of its deployment plan with the commission until deployment is complete. Upon filing of such reports, an electric utility operating in an area open to customer choice must notify all REPs of the filing through standard market notice procedures. A monthly progress report must be filed within 15 days of the end of the month to which it applies, and must include the following information:

(A) the number of advanced meters installed, listed by electric service identifier for meters in the Electric Reliability Council of Texas (ERCOT) region. Additional deployment information if available must also be provided, such as county, city, zip code, feeder numbers, and any other easily discernable geographic identification available to the electric utility about the meters that have been deployed;
(B) significant delays or deviation from the deployment plan and the reasons for the delay or deviation;
(C) a description of significant problems the electric utility has experienced with an AMS, with an explanation of how the problems are being addressed;
(D) the number of advanced meters that have been replaced as a result of problems with the AMS; and
(E) the status of deployment of features identified in the deployment plan and any changes in deployment of these features.

(10) If an electric utility has received approval of its deployment plan from the commission, the electric utility must obtain commission approval before making any changes to its AMS that would affect the ability of a customer, the customer's REP of record, or entities authorized by the customer to utilize any of the AMS features identified in the electric utility's deployment plan by filing a request for amendment to its deployment plan. In addition, an electric utility may request commission approval for other changes in its approved deployment plan. The commission will act upon the request for an amendment to the deployment plan within 45 days of submission of the request, unless good cause exists for additional time. If an electric utility filed a notice of deployment, the electric utility must file an amendment to its notice of deployment at least 45 days before making any changes to its AMS that would affect the ability of a customer, the customer's REP of record, or entities authorized by the customer to utilize any of the AMS features identified in the electric utility's notice of deployment. This paragraph does not in any way preclude the electric utility from conducting its normal operations and maintenance with respect to the electric utility's transmission and distribution system and metering systems.

(11) During and following deployment, any outage related to normal operations and maintenance that affects a REP's ability to obtain information from the system must be communicated to the REP through the outage and restoration notice process according to Applicable Legal Authorities, as defined in §25.214(d)(1) of this title (relating to Tariff for Retail Delivery Service). Notification of any planned or unplanned outage that affects access to customer usage data must be posted on the electric utility's web portal home page.

(12) An electric utility subject to §25.343 of this title (relating to Competitive Energy Services) must not provide any advanced metering equipment or service that is deemed a competitive energy service under that section. Any functionality of the AMS that is a required feature under this section or that is included in an approved deployment plan or otherwise approved by the commission does not constitute a competitive energy service under §25.343 of this title.

(13) An electric utility's deployment and provision of AMS services and features, including but not limited to the features required in subsection (g) of this section, are subject to the limitation of liability provisions found in the electric utility's tariff.

(e) **Technology requirements.** Except for pilot programs, an electric utility must not deploy AMS technology that has not been successfully installed previously with at least 500 advanced meters in North America, Australia, Japan, or Western Europe.

(f) **Pilot programs.** An electric utility may deploy AMS with up to 10,000 meters that do not meet the requirements of subsection (g) of this section in a pilot program, to gather additional information on metering technologies, pricing, and management techniques, for studies, evaluations, and other reasons. A pilot program may be used to satisfy the requirement in subsection (e) of this section. An electric utility is not required to obtain commission approval for a pilot program. Notice of the pilot program and opportunity to participate must be sent by the electric utility to all REPs and all entities authorized by a customer to have read-only access to the customer's advanced meter data.

(g) **AMS features.**

(1) An AMS must provide or support the following minimum system features:

(A) automated or remote meter reading;

(B) two-way communications between the meter and the electric utility;

(C) remote disconnection and reconnection capability for meters rated at or below 200 amps.

(D) time-stamped meter data;

(E) access to customer usage data by the customer, the customer's REP of record, and entities authorized by the customer provided that 15-minute interval or shorter data from the electric utility's AMS must be transmitted to the electric utility's or a group of electric utilities' web portal on a day-after basis;

(F) capability to provide on-demand reads of a customer's advanced meter through the graphical user interface of an electric utility's or a group of electric utilities' web portal when requested by a customer, the customer's REP of record, or entities authorized by the customer subject to network traffic such as interval data collection, market orders if applicable, and planned and unplanned outages;

(G) for an electric utility that provides access through an application programming interface, the capability to provide on-demand reads of a customer's advanced meter data, subject to network traffic such as interval data collection, market orders if applicable, and planned and unplanned outages;

(H) on-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as in American National Standards Institute (ANSI) C12.19 tables or International Electrotechnical Commission (IEC) DLMS-COSEM standards;

(I) open standards and protocols that comply with nationally recognized non-proprietary standards such as ANSI C12.22, including future revisions;

(J) for an electric utility in the ERCOT region, the capability to communicate with devices inside the premises, including, but not limited to, usage monitoring devices, load control devices, and prepayment systems through a home area network (HAN), based on open standards and protocols that comply with nationally recognized non-proprietary standards such as ZigBee, Home-Plug, or the equivalent through the electric utility's AMS. This requirement applies only to a HAN device paired to a meter and in use at the time that the version of the web portal approved in Docket Number 47472 was implemented and terminates when the HAN device is disconnected at the request of the customer or a move-out transaction occurs for the customer's premises; and

(K) the ability to upgrade these features as the need arises.

(2) A waiver from any of the requirements of paragraph (1) of this subsection may be granted by the commission if it would be uneconomic or technically infeasible to implement or there is an adequate substitute for that particular requirement. The electric utility must meet its burden of proof in its waiver request.

(3) In areas where there is not a commission-approved independent regional transmission organization, standards referred to in this section for time tolerance and data transfer and security may be approved by a regional transmission organization approved by the Federal Energy Regulatory Commission or, if there is no approved regional transmission organization, by the commission.

(4) Once an electric utility has deployed its advanced meters, it may add or enhance features provided by AMS, as technology evolves. The electric utility must notify the commission and REPs of any such additions or enhancements at least three months in advance of deployment, with a description of the features, the deployment and notification plan, and the cost of such additions or enhancements, and must follow the monthly progress report process described in subsection (d)(9) of this section until the enhancement process is complete.

(h) **Discretionary Meter Services.** An electric utility that operates in an area that offers customer choice must offer, as discretionary services in its tariff, installation of enhanced advanced meters and advanced meter features.

(1) A REP may request the electric utility to provide enhanced advanced meters, additional metering technology, or advanced meter features not specifically offered in the electric utility's tariff, that are technically feasible, generally available in the market, and compatible with the electric utility's AMS.

(2) The REP must pay the reasonable differential cost for the enhanced advanced meters or features and system changes required by the electric utility to offer those meters or features.

(3) Upon request by a REP, an electric utility must expeditiously provide a report to the REP that includes an evaluation of the cost and a schedule for providing the enhanced advanced meters or advanced meter features of interest to the REP. The REP must pay a reasonable discretionary services fee for this report. This discretionary services fee must be included in the electric utility's tariff.

(4) If an electric utility deploys enhanced advanced meters or advanced meter features not addressed in its tariff at the request of the REP, the electric utility must expeditiously apply to amend its tariff to specifically include the enhanced advanced meters or meter features that it agreed to deploy. Additional REPs may request the tariffed enhanced advanced meters or advanced meter features under the process described in this paragraph of this subsection.

(i) **Tariff.** All discretionary AMS features offered by the electric utility must be described in the electric utility's tariff.

(j) **Access to meter data.**

(1) A customer may authorize its meter data to be available to an entity other than its REP. An electric utility must provide a customer, the customer's REP of record, and other entities authorized by the customer read-only access to the customer's advanced meter data, including meter data used to calculate charges for service, historical load data, and any other proprietary customer information. The access must be convenient and secure, and the data must be made available no later than the day after it was created.

(2) The requirement to provide access to the data begins when the electric utility has installed 2,000 advanced meters for residential and non-residential customers. If an electric utility has already

installed 2,000 advanced meters by the effective date of this section, the electric utility must provide access to the data in the timeframe approved by the commission in either the deployment plan or request for surcharge proceeding. If only a notice of deployment has been filed, access to the data must begin no later than six months from the filing of the notice of deployment with the commission.

(3) An electric utility's or group of electric utilities' web portal must use appropriate and reasonable standards and methods to provide secure access for the customer, the customer's REP of record, and entities authorized by the customer to the meter data. The electric utility must have an independent security audit conducted within one year of providing that access to meter data. The electric utility must promptly report the audit results to the commission.

(4) The independent organization, regional transmission organization, or regional reliability entity must have access to information that is required for wholesale settlement, load profiling, load research, and reliability purposes.

(k) **Cost recovery for deployment of AMS.**

(1) **Recovery Method.** The commission will establish a nonbypassable surcharge for an electric utility to recover reasonable and necessary costs incurred in deploying AMS to residential customers and nonresidential customers other than those required by the independent system operator to have an interval data recorder meter. The surcharge must not be established until after a detailed deployment plan is filed under subsection (d) of this section. In addition, the surcharge must not ultimately recover more than the AMS costs that are spent, reasonable and necessary, and fully allocated, but may include estimated costs that will be reconciled pursuant to paragraph (6) of this subsection. As indicated by the definition of AMS in subsection (c)(2) of this section, the costs for facilities that do not perform the functions and have the features specified in this section must not be included in the surcharge provided for by this subsection unless an electric utility has received a waiver under subsection (g)(2) of this section. The costs of providing AMS services include those costs of AMS installed as part of a pilot program under this section. Costs of providing AMS for a particular customer class must be surcharged only to customers in that customer class.

(2) **Carrying Costs.** The annualized carrying-cost rate to be applied to the unamortized balance of the AMS capital costs must be the electric utility's authorized weighted-average cost of capital (WACC). If the commission has not approved a WACC for the electric utility within the last four years, the commission may set a new WACC to apply to the unamortized balance of the AMS capital costs. In each subsequent rate proceeding in which the commission resets the electric utility's WACC, the carrying-charge rate that is applied to the unamortized balance of the utility's AMS costs must be correspondingly adjusted to reflect the new authorized WACC.

(3) **Surcharge Proceeding.** In the request for surcharge proceeding, the commission will set the surcharge based on a levelized amount, and an amortization period based on the useful life of the AMS. The commission may set the surcharge to reflect a deployment of advanced meters that is up to one-third of the electric utility's total meters over each calendar year, regardless of the rate of actual AMS deployment. The actual or expected net operating cost savings from AMS deployment, to the extent that the operating costs are not reflected in base rates, may be considered in setting the surcharge. If an electric utility that requests a surcharge does not have an approved deployment plan, the commission in the surcharge proceeding may reconcile the costs that the electric utility already spent on AMS in accordance with paragraph (6) of this subsection and may approve a deployment plan.

(4) **General Base Rate Proceeding while Surcharge is in Effect.** If the commission conducts a general base rate proceeding while a surcharge under this section is in effect, then the commission will include the reasonable and necessary costs of installed AMS equipment in the base rates and decrease the surcharge accordingly, and permit reasonable recovery of any non-AMS metering equipment that has not yet been fully depreciated but has been replaced by the equipment installed under an approved deployment plan.

(5) **Annual Reports.** An electric utility must file annual reports with the commission updating the cost information used in setting the surcharge. The annual reports must include the actual costs

spent to date in the deployment of AMS and the actual net operating cost savings from AMS deployment and how those numbers compare to the projections used to set the surcharge. During the annual report process, an electric utility may apply to update its surcharge, and the commission may set a schedule for such applications. For a levelized surcharge, the commission may alter the length of the surcharge collection period based on review of information concerning changes in deployment costs or operating costs savings in the annual report or changes in WACC. An annual report filed with the commission will not be a ratemaking proceeding, but an application by the electric utility to update the surcharge must be a ratemaking proceeding.

(6) **Reconciliation Proceeding.** All costs recovered through the surcharge must be reviewed in a reconciliation proceeding on a schedule to be determined by the commission. Notwithstanding the preceding sentence, the electric utility may request multiple reconciliation proceedings, but no more frequently than once every three years. There is a presumption that costs spent in accordance with a deployment plan or amended deployment plan approved by the commission are reasonable and necessary. Any costs recovered through the surcharge that are found in a reconciliation proceeding not to have been spent or properly allocated, or not to be reasonable and necessary, must be refunded to electric utility's customers. In addition, the commission will make a final determination of the net operating cost savings from AMS deployment used to reduce the amount of costs that ultimately can be recovered through the surcharge. Accrual of interest on any refunded or surcharged amounts resulting from the reconciliation must be at the electric utility's WACC and must begin at the time the under or over recovery occurred.

(7) **Cross-subsidization and fees.** The electric utility must account for its costs in a manner that ensures there is no inappropriate cost allocation, cost recovery, or cost assignment that would cause cross-subsidization between utility activities and non-utility activities. The electric utility shall not charge a disconnection or reconnection fee that was approved by the commission prior to the effective date of this rule, for a disconnection or reconnection that is effectuated using the remote disconnection or connection capability of an advanced meter.

DOCKET NO. 47364

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR THE FINAL RECONCILIATION OF ADVANCED METERING COSTS	§ § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the application by CenterPoint Energy Houston Electric, LLC to reconcile its advanced metering system (AMS) costs with revenues. A Unanimous Stipulation (agreement) was executed that resolves all issues among the parties to this proceeding. Consistent with the agreement, CenterPoint's application is approved.

The Commission adopts the following findings of fact and conclusions of law:

I. Findings of Fact

Procedural History

1. On June 29, 2017, CenterPoint filed an application for the final reconciliation of its AMS costs with revenues for the period October 1, 2013 through February 28, 2017 (final reconciliation period).

2. In support of the application, CenterPoint filed the direct testimony of R. Perrin Wall, Alberto A. Lopez, and Deryl Tumlinson.

3. On July 6, 2017, Order No. 1 was issued requiring Commission Staff to comment on the sufficiency of the application and proposed notice, and to propose a procedural schedule for processing the application.

4. On July 5, 2017, the Gulf Coast Coalition of Cities (GCCC) filed a motion to intervene.

5. On July 6, 2017, the City of Houston filed a motion to intervene.

6. On July 20, 2017, Order No. 2 was issued granting the motions to intervene of GCCC and Houston.

7. On July 25, 2017, Order No. 3 was issued finding the application and proposed notice sufficient and establishing a procedural schedule.

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8. On July 27, 2017, the Alliance for Retail Markets (ARM) filed a motion to intervene.

9. On August 8, 2017, Order No. 4 was issued granting the motion to intervene of ARM.

10. On October 27, 2017, CenterPoint filed the agreement signed by representatives of CenterPoint, Commission Staff, GCCC, Houston, and ARM, (collectively, the signatories), a motion to admit evidence and proposed order, and the testimony of R. Perrin Wall in support of the agreement.

11. Also on October 27, 2017, Commission Staff filed its final recommendation in support of the agreement.

12. On November 16, 2017, Order No. 10 was issued admitting evidence into the record.

Stipulation

13. The signatories agreed to a settlement on the following terms:

    a) The application, including the proposed refund amount and refund mechanism, should be approved consistent with the provisions in the agreement.

    b) Except for the amount referenced in subparagraph (c) below, all CenterPoint AMS costs recovered through the AMS surcharge between October 1, 2013 and February 28, 2017 and included in the application are reasonable and necessary and should be approved.

    c) Under the agreement, a reduction of $500,000 is applied to CenterPoint's actual net revenue requirement for the final reconciliation period. This results in an AMS overcollection amount of $29,227,751, as reflected in Mr. Wall's settlement testimony. CenterPoint will refund the AMS overcollection amount as an offset to its recent distribution cost recovery factor (DCRF) filing approved in Docket No. 47032.[1] In accordance with the Order in Docket No. 47032, CenterPoint's DCRF rates will be adjusted effective March 1, 2018 to reflect the final approved AMS refund amount.

    d) CenterPoint will be allowed to account for CenterPoint's and any municipal rate

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[1] *Application of CenterPoint Energy Houston Electric, LLC for Approval to Amend its Distribution Cost Recovery Factor*, Docket No. 47032, Order (Jul. 28, 2017).

case expenses associated with this proceeding and to subsequently seek recovery of such expenses in a future rate proceeding or to include these costs with other expenses in a proceeding to collect those expenses through a separate surcharge. Rate case expenses in connection with this proceeding are subject to a final determination by the Commission as to the reasonableness and necessity of those expenses.

e) It is appropriate for CenterPoint to account for its reasonable and necessary operating and maintenance costs associated with the common web portal required by 16 Texas Administrative Code (TAC) § 25.130(d), (g) and (j), authorized in CenterPoint's AMS deployment plan, developed through Project No. 34610, *Implementation Project Related to Advanced Metering,* and commonly known as Smart Meter Texas (SMT) costs. It is reasonable for CenterPoint to establish a regulatory asset in which to record SMT costs incurred after the end of the final reconciliation period and prior to the implementation date of new base rates (the rate implementation date) resulting from its next comprehensive base rate proceeding. CenterPoint will not seek recovery of such costs until such rate proceeding, at which time the reasonableness of the individual SMT costs accumulated in such regulatory asset through the end of the applicable test year (the test year end) will be subject to review. All SMT costs found reasonable will be recovered using an appropriate amortization period to be determined in that proceeding. Any SMT costs incurred after the test year end and prior to the rate implementation date will also be recorded as a regulatory asset and reviewed for reasonableness in CenterPoint's next subsequent base rate proceeding, in which CenterPoint may seek recovery of the regulatory asset in the same manner stated above.

f) To avoid a double recovery, CenterPoint shall transfer its AMS rate base to CenterPoint's base rates effective January 1, 2021, to coincide with the end of the relevant depreciation period.

g) The signatories agree to support the entry of the proposed order.

14. The evidence in the record, including the testimony of R. Perrin Wall and Commission Staff memoranda by Glenda Spence in support of the agreement, demonstrates that the agreement is just and reasonable.

Informal Disposition

15. CenterPoint, Commission Staff, GCCC, Houston, and ARM are the only parties to this proceeding.

16. There is no dispute among the parties regarding any legal issue or material fact in this proceeding; therefore, no hearing is necessary.

17. Notice of this proceeding was completed at least 15 days prior to the issuance of this Order.

II. Conclusions of Law

1. CenterPoint is a public utility as defined by PURA[2] § 11.004(1) and an electric utility as that term is defined in PURA § 31.002(6).

2. The Commission has jurisdiction over the subject matter of this proceeding under PURA § 39.107.

3. CenterPoint's provision of notice in this proceeding complies with 16 TAC § 22.55.

4. The application was processed in accordance with the requirements of PURA, the APA,[3] and the Commission's rules.

5. CenterPoint's AMS reconciliation is consistent with the requirements of 16 TAC § 25.130, the Order on Rehearing in Docket No. 38339,[4] and the Order in Docket No. 42084.[5]

6. CenterPoint has complied with the requirements of the Order in Docket No. 42084 through February 28, 2017.

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[2] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-58.302 (West 2016 & Supp. 2017), §§ 59.001-66.016 (West 2007 & Supp. 2017) (PURA).

[3] Administrative Procedure Act, Tex. Gov't Code Ann. §§ 2001.001-.902 (West 2016 & Supp. 2017) (APA).

[4] *Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates*, Docket No. 38339, Final Order (May 12, 2011); Order on Rehearing (Jun. 23, 2011).

[5] *Application of CenterPoint Energy Houston Electric, LLC for the Reconciliation of Advanced Metering Costs and to Amend the Rider AMS Surcharge*, Docket No. 42084, Order (Jun. 20, 2014).

7. The agreement is a just and reasonable resolution of all the issues it addresses, results in just and reasonable rates, terms and conditions, is supported by a preponderance of the credible evidence in the record, is consistent with relevant provisions of PURA.

8. The requirements for informal disposition under 16 TAC § 22.35 have been met in this proceeding.

III. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following orders:

1. CenterPoint's application is approved consistent with the agreement and above findings of fact and conclusions of law.

2. The stipulated AMS overcollection amount of $29,227,751 shall be applied as an offset to CenterPoint's DCRF rates consistent with the Order in Docket No. 47032, making the final adjustment effective as of March 1, 2018.

3. Consistent with the agreement and this Order, CenterPoint is authorized to create a regulatory asset to track its post-final reconciliation period SMT costs for future recovery. The reasonableness of the individual costs accumulated in such regulatory asset will be subject to review in future rate proceedings.

4. CenterPoint's AMS rate base shall be moved to CenterPoint's base rates effective January 1, 2021.

5. Entry of this Order does not indicate the Commission's endorsement or approval of any principle or methodology that may underlie the agreement. Entry of this Order shall not be regarded as a binding holding or precedent as to the appropriateness of any principle or methodology underlying the agreement.

6. All other motions and any other requests for general or specific relief, if not expressly granted, are denied.

Signed at Austin, Texas the 14th day of December 2017.

PUBLIC UTILITY COMMISSION OF TEXAS

DeAnn T. Walker

DEANN T. WALKER, CHAIRMAN

Brandy Marquez

BRANDY MARTY MARQUEZ, COMMISSIONER

Arthur C. D'Andrea

ARTHUR C. D'ANDREA, COMMISSIONER

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Commission Response

Allowing TDUs special cost recovery for the increased costs that result from performing meter reads for the purpose of standard switches is appropriate because these rule amendments will necessitate that TDUs alter their meter reading practices in a manner that will increase their costs. While noting comments by Texas ROSE/TLSC and TIEC, the commission finds that it is appropriate to allow costs incurred in shortening switching timelines to be borne by all customers because this benefit will be available to all customers and will increase market responsiveness for all customers.

The commission adopts rule language that allows TDUs at their discretion, to seek cost recovery either through a regulatory asset or under the advanced metering system (AMS) surcharge allowed under §25.130(k). Because circumstances vary among TDUs, the commission is allowing each TDU to determine which cost recovery mechanism best suits their situation. The commission recognizes that these costs will be incurred in order to provide a critical benefit of advanced metering functionality for customers: the ability to quickly read a customer's meter without cost to that customer. This will allow the TDU to flow through the cost of reading a conventional, non-advanced meter in order to expedite the switching process for customers before AMS is deployed to all customers in the service territory. The commission finds that this is an essential modification to the competitive retail market, and therefore, is applying a mechanism in §25.474(p) which allows the TDU to exercise this option.

Alternatively, a TDU may choose to create a regulatory asset for recovery of costs. This additional option is appropriate, as not all TDUs are currently deploying advanced meters, and thus have no AMS surcharge in place for this purpose.

In initial and reply comments, respectively, Reliant and REP Coalition proposed a modification of Section 4.3.4 of the TDU tariff to clarify that, unless a specific date is requested in the transaction, the TDU shall perform an expedited meter read in accordance with timelines provided in Chapter 6 of the tariff, relating to company specific rates and schedules. Reliant also proposed new Section 4.8.1.X, which would state that if no specific date is requested for a switch, the TDU will perform an expedited meter read in accordance with the timelines of Chapter 6, and provide the meter read to both the losing and gaining REP on the next business day. The date of the meter read determines the last billing date for the losing REP and first billing date for the gaining REP. In reply comments, TIEC noted that this section was noticed "no-change," and argued that the suggested revisions would constitute a violation of notice requirements in Government Code §2001.024.

In reply, Oncor took issue with Reliant's proposed new section, specifically the requirement that the meter reading data be delivered the next business day. Oncor stated that the current TDU tariff allows three business days for this, and that shortening the time would result in diminished data accuracy in that it would preclude parameter testing that currently detects and eliminates "outlier" meter reads.

237A. However, in this docket, SWEPCO sought $161,025 for other expenses associated with Docket No. 45712, including, for example, payroll for SWEPCO or AEPSC employees that is associated with Docket No. 45712.

237B. There is no basis in PURA or the Commission's rules for the term rate-case expenses not to include all expenses that are associated with Docket No. 45712.

Back-Billed SPP Z2 Costs

238. Attachment Z2 is an SPP tariff that compensates project sponsors for self-funding creditable transmission upgrades that are subsequently used by others to fulfill transmission-service requests.

239. SPP invoiced its members for back-billed Z2 costs in the fall of 2016, and gave its members the options of paying the amount either in full or in five-year installments. SWEPCO chose the pay-in-full option, and on November 15, 2016, SWEPCO paid $16.3 million in back-billed Attachment Z2 costs. SWEPCO also expects to receive $12.2 million in back-billed credits over the next five years.

240. SWEPCO requested to place the $4.1 million difference between its Attachment Z2 costs and credits in a regulatory asset for deferred accounting treatment.

241. Deferred accounting is appropriate only for costs that are legitimately recoverable from customers but cannot be otherwise recovered in rates.

242. SWEPCO has not demonstrated that deferred accounting is necessary for its back-billed Attachment Z2.

243. [Deleted.]

244. SWEPCO's Attachment Z2 costs should not be placed in a regulatory asset or recovered through an amortization established in this proceeding.

Transmission Expenses and Revenues

245. SWEPCO is both a transmission owner and a transmission customer within the SPP.

246. As a transmission owner, SWEPCO is subject to charges calculated in accordance with the SPP OATT.

production facility would place the financial integrity of a utility at risk, the Commission had the power to allow deferred accounting as necessary to comply with PURA's requirement that "a utility must be allowed a reasonable opportunity to recover its operating expenses together with a reasonable return on invested capital."[976]

Staff notes that the test to be used by the Commission in this regard is not an easy one. In assessing whether such a statutory necessity exists, the Commission may use a "financial integrity standard," which "ensure[s] that the utilities will receive an opportunity to recover the minimum rates mandated by PURA."[977] In this case, Mr. Hamlett testified that SWEPCO's financial integrity will not be threatened if the Commission does not grant the Company's request.[978]

Mr. Pollock takes a similar approach to Mr. Abbott. Mr. Pollock testified that it was SWEPCO's choice to pay the $16.3 million in a lump sum on November 15, 2016. Other SPP utilities, like SPS, who also had to make a similar payment, used the choice the SPP gave them to pay the money in five installments. SWEPCO, for whatever reason, chose to pay the $16.3 million all at one time. Mr. Pollock also testified that deferred accounting is only appropriate for costs that are legitimately recoverable from customers but cannot otherwise be recovered in rates.[979] That is not the case here because the Commission has a mechanism under which SWEPCO can recover the $4.1 million. Here, Mr. Pollock and TIEC argue that SWEPCO has not shown that the Back-Billed Attachment Z2 costs cannot be recovered in rates, such as through a TCRF case or a subsequent rate case. Therefore, TIEC and Staff recommend that SWEPCO's request to defer the $4.1 million in back-billed Z2 costs be denied.

The ALJs recommend that the Commission reject the Company's request to defer the back-billed Z2 costs into a regulatory asset. As Staff demonstrated, the creation of a regulatory

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976 *State*, 883 S.W.2d at 196-97.

977 *State*, 883 S.W.2d at 197.

978 Tr. at 1215.

979 TIEC Ex. 1 (Pollock Direct) at 46.

asset is an extraordinary remedy meant to be used only when there is no other prospect that the utility can otherwise recover legitimate costs in rates. That is not the case here. Mr. Pollock and Mr. Abbott made persuasive arguments that, in a sense, SWEPCO created this predicament by paying the $16.3 million SPP Z2 in a lump sum instead of paying the amount in the five installments SPP offered all affected utilities.

Staff is also correct that deferred accounting should only be used in very limited instances, such as to preserve a utility's financial integrity. In this case, Mr. Hamlett testified that the Company's financial integrity will not be damaged if its request is denied. Hence, there is no overriding reason why the Company should be granted deferred accounting treatment to resolve a condition that occurred post-test year. Finally, and most importantly, the Company has not shown why the Commission's TCRF mechanism or a subsequent rate case cannot allow the Company to recover the Z2 costs. At best, the Company's request for deferred accounting treatment seems premature. As a result, the ALJs recommend that the Company's request to defer the SPP Z2 costs into a regulatory asset be denied.

P. Transmission Expenses and Revenues [Germane to Preliminary Order Issue Nos. 4, 5, 6, 20, 21, 36, 37, 41, and 53]

1. SWEPCO's Position

The discussion of the law, the precedents cited, and the public policy and evidentiary issues contained in Section V.F., "Treatment of Transmission Invested Capital" is equally applicable here. That discussion will not be repeated, but is incorporated herein regarding the following discussion of SWEPCO's transmission-related revenues and expenses. In essence, SWEPCO seeks to replace the Commission's historical review of transmission-related revenues and expenses, which are then allocated to Texas retail ratepayers, with the allegedly comparable figures taken from the SPP OATT invoice sent to SWEPCO. The ALJs recommend that the Commission reject the Company's request.

PROJECT NO. 47945

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PROCEEDING TO INVESTIGATE AND ADDRESS THE EFFECTS OF TAX CUTS AND JOBS ACT OF 2017 ON THE RATES OF TEXAS INVESTOR-OWNED UTILITY COMPANIES	§ § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

AMENDED ORDER
RELATED TO CHANGES IN FEDERAL INCOME TAX RATES

After further consideration of the issues related to changes in the federal income tax rates, the Commission has determined that the Order entered on January 25, 2018 should be amended. Therefore, the Commission amends the previous order by deleting references to carrying changes on the balance of excess accumulated deferred federal income taxes (ADFIT).

This Order addresses the change in the federal income tax rates on electric, telecommunications, and water and sewer investor-owned utilities in the State of Texas. Late last year, an act was passed that, in part, amends the Internal Revenue Code[1] by, among other things, reducing the federal income tax rate to be imposed on C corporations from 35% to 21%, effective January 1, 2018, as well as reducing the federal income tax rate on certain other entities.[2]

Through this Order, the Commission takes the first steps to reflect this lower tax rate in the utility bills of Texas customers. The Commission directs the Commission Staff to review each investor-owned utility in Texas, with input from interested stakeholders, on a case-by-case basis to determine the appropriate mechanism to adjust its rates to reflect the changes under the newly enacted federal tax law.

Until a rate change may be approved to adjust charges to Texas customers, the Commission issues this accounting order under its statutory authority to preserve any changes in the federal income tax expense charged by utilities until rates can be changed.[3] The Commission requires

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[1] Internal Revenue Code, 26 U.S.C.A. § 61 (West 2011 and Supp. 2014).

[2] Act to Provide for Reconciliation Pursuant to Tiles II and V of the Concurrent Resolution on the Budget for Fiscal Year 2018, Pub. L. No. 115-97, 113 Stat. 2054 (Dec. 22, 2017).

[3] Public Utility Regulatory Act, Tex. Util. Code Ann. § 14.151 (West 2016 & Supp. 2017); Tex. Water Code Ann. § 13.131(a) (West 2008 & Supp. 2017).

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each electric, telecommunication, and class A water and sewer investor-owned utility, except as later stated in this Order, to record as a regulatory liability beginning on January 25, 2018, the following: (1) the difference between the revenues collected under existing rates and the revenues that would have been collected had the existing rates been set using the recently approved federal income tax rates; and, (2) the balance of ADFIT that now exists because of the decrease in the federal income tax rate from 35% to 21%.

The requirement in the Order to create a regulatory liability does not apply to Oncor Electric Delivery Company LLC, El Paso Electric Company, or Southwestern Electric Power Company, except as provided in this paragraph. These three utilities have previously been ordered by the Commission to establish a regulatory liability tracking the difference in the amount of federal income tax collected in current rates, and the amount of federal income tax calculated under the new federal income tax rates. Accordingly, these three utilities shall record the balance of excess ADFIT as a regulatory liability.

In addition, in reviewing the rates of water and sewer utilities, the Commission Staff should first focus on class A and the larger class B utilities. The Commission Staff should then take a sample of the class C and smaller class B utilities to determine the effect of the new tax law, and report the findings back to the Commission.

In accordance with the discussion in the Order, the Commission orders the following:

1. Each investor-owned electric, telecommunications, and class A water and sewer utility in the State of Texas, for which the Commission has jurisdiction, shall, starting the date this Order is signed, record as a regulatory liability the following: (1) the difference between the revenues collected under existing rates and the revenues that would have been collected had the existing rates been set using the recently approved federal income tax rates; and, (2) the balance of excess accumulated deferred federal income taxes (ADFIT) that now exists because of the decrease in the federal income tax rate from 35% to 21%.

2. The Commission Staff shall investigate each investor-owned utility in Texas, with input from interested stakeholders, on a case-by-case basis, as discussed in this Order, to determine the appropriate mechanism to adjust its rates to reflect the changes under the newly enacted federal tax law.

3. The Commission Staff shall report its findings regarding class C and smaller class B water and sewer utilities within six months of the signing of this Order.

Signed at Austin, Texas the 15th day of February 2018.

PUBLIC UTILITY COMMISSION OF TEXAS

DeAnn T. Walker

DEANN T. WALKER, CHAIRMAN

Brandy M. Marquez

BRANDY MARTY MARQUEZ, COMMISSIONER

Arthur C. D'Andrea

ARTHUR C. D'ANDREA, COMMISSIONER

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GSU operates its electric system as an integrated pool. Power generated in Louisiana is sold in Texas and vise versa. It is a member of the Southwest Power Pool and operates as an integral portion of that regional utility network. GSU purchases a large portion of its energy requirements from other members of that power pool, all of whom operate in the interstate power market. It does not have any operational interconnections or ties with members of the Energy Reliability Council of Texas or any other strictly intra-state Texas utility.

B. Prior GSU Rate Cases

Docket No. 3871 is the fourth in a series of almost annual GSU rate applications. The prior GSU rate cases are Docket No. 1528 (1977), Docket No. 2677 (1979) and Docket No. 3298 (1980). Docket No. 1528 is the only other GSU rate case which went to a full contested hearing. The other two were settled by stipulations of the parties which were subsequently adopted by the Commission.

[1] Several of the parties herein presented arguments that various material issues must be resolved in particular manners because they were resolved in the same manner in Dockets Numbers 2677 and 3298. The Examiner would note that those cases were settled by stipulation. The issues in question were not exposed to the close scrutiny of cross-examination and rebuttal. The Commission has consistently held that cases resolved by stipulation are not precedent of the proper resolution of issues stipulated to. See: Application of Sunbelt Utilities, Docket No. 3083, 6 P.U.C. BULL. 75 (September 12, 1980). Furthermore, the stipulations themselves state that they do not propose to adopt or support any theories or resolutions of underlying issues but merely approve bottomline dollar amounts. For these reasons, the Examiner finds that any arguments presented herein that various issues must be resolved in a particular manner because of the orders in Dockets Numbers 2677 and 3298 are incorrect and are without merit. These decisions are advisory only and are not precedent for purposes of this docket.

C. Purpose of Establishing A Cost of Service

P.U.C. SUBST. R. 052.02.03.032(a) states, "Cost of service is equal to the amount of revenue required to (1) cover all reasonable and necessary expenses properly incurred by a utility in rendering service to the public and (2) provide a fair and reasonable return on the adjusted value of invested capital used and useful in rendering such service." Throughout this case, GSU has interpretted this rule to mean that if the Company incurred any expense in the past that was reasonable at the time it was made, the Commission must allow the complete recovery of that expense in cost of service or amortize it and include the unamortized portion in rate base. In effect GSU seeks future recovery of past expenses. The Company repeatedly objected to recommendations of the Staff and the Cities to disallow various expenses as non-recurring. GSU claims that such treatment is consfiscatory.

[2] The Examiner finds that GSU is incorrect in its interpretation of the rate making process and that this issue must be discussed as a predicate for the following ratemaking recommendations. Rates are set prospectively only. Railroad Commission v. Houston Natural Gas Corp., 289 SW 2d 559 (Tex. 1956); Railroad Commission v. City of Fort Worth, 576 SW 2d 899 (Tex.Civ.App. - Austin, 1979, writ ref'd n.r.e.) A historic test year is used to approximate the utility's anticipated cost of operation during the period when rates will be in effect. When necessary to reflect changes in conditions since the test year, adjustments can be made to those historical costs for known and measurable costs which are certain to be incurred. Still there is a matching of expenses and revenues.

[3,4] In many cases, a utility will incur an expense which is not representative of expenses that can be expected on an annual basis. However, expenses of this type or general amount can often be expected to occur on a two or three year cycle. Since rates are traditionally set on a one year cost of service basis, it is reasonable to allow a portion of that nonannual recurring expense proportionate with the anticipated period of reoccurance in that single year's cost of service. Thus, one third of an expense anticipated to occur once every three years is included. This is still an attempt to match future expenses with future revenues. If the actual incurred expense in question or a similar expense cannot be anticipated to reoccur with any reasonable certainity within a given period, no allowance for that expense shall be made in the cost of service. It is not a question of not allowing the utility to recover the expense with future revenues. The expense should have been recovered by revenues collected at the time the expense was incurred. Since ratemaking is not an exact science, often the expense is not recovered. This is not confiscation; it is a risk of doing business. The utility is compensated for this risk when the regulatory authority establishes a return on the utility's adjusted value of invested capital.

The Examiner would note that this theory of the principle of establishing a cost of service has never been expressly set forth in any Commission's opinion. It has not been deemed necessary in the past since it is inherent in the traditional use of a historical test year to set rates. It has been alluded to in Commission's opinions. See the discussion of rotor repairs in Application of Texas Power and Light Co., Docket No. 3780, 7 P.U.C. BULL. ____ (August 5, 1981). The Examiner would recommend, however, that the Commission adopt the preceding discussion in this opinion as a statement of policy to give guidance to GSU and other utilities in future rate cases thus simplifying those proceedings.

II. Determination of Rate Base

A. Adjusted Value of Invested Capital

Section 41(a) of the Act defines adjusted value of invested capital as, "...a reasonable balance between original cost less depreciation and current cost less an adjustment for both present age and condition." GSU, the Cities, and the Staff all

DOCKET NO. 3871

PPLICATION OF GULF STATES UTILITIES COMPANY FOR A RATE INCREASE	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

In public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that, after statutory notice was provided to the public and interested parties, the application in this case was processed by an Examiner who prepared a report containing Findings of Fact and Conclusions of Law, which report, with the following changes, is adopted and made a part of this Order.

1. The Commission finds that GSU's proposal to allocate demand costs by the average and excess (A&E) methodology is the most appropriate recommendation in the record. Accordingly, the Examiner's proposal to allocate demand costs by the four coincident peak (4CP) methodology is rejected and GSU's A&E proposal adopted.

2. The Commission finds that GSU has not met its burden of proof as to the reasonableness of its proposed curtailment plan; therefore, this proposal is rejected and GSU shall continue to operate under the curtailment plan currently on file at the Commission in GSU's existing tariff.

3. The Commission finds that GSU and ETLSG entered into stipulations on the record regarding customer information pamphlets entitled "Customer Rights and Responsibilities" and the calculating of customer deposits found in the hearing Transcript at 1451-1454 which the Commission find reasonable. It is therefore ordered that those stipulations are incorporated into this Order by reference, the terms of which shall be met by the parties under Order of the Commission.

4. The first sentence of Finding of Fact Number 21 is amended to read, "The cost allocations and rate structures proposed by the Examiner, as modified herein, will be based on sound ratemaking principles and should be adopted.

5. Finding of Fact Number 26 shall be deleted.

6. Conclusion of Law Number 5 is amended to read, "The Examiner's recommendations herein, as expressly modified by this Order, will allow GSU to recover its reasonable and proper operating expenses together with a reasonable return on its invested capital pursuant to PURA, §39."

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7. Conclusion of Law Number 6 is amended to read, "Rates designed according to the guidelines recommended by the Examiner, as modified herein, if properly implemented, are reasonable and non-discriminatory and should be approved by the Commission for complying with the ratemaking criteria of Article VI of the Act."

The Commission further issues the following Order:

1. The petition of Gulf States Utilities Company (GSU) is hereby granted in part and denied in part, as set out in the Examiner's Report.

2. GSU is hereby ordered to rerun its cost of service study, as modified to reflect the cost of service and cost allocation changes recommended by the Examiner, except as modified herein, and using the revenue adjustments approved herein. GSU shall within twenty (20) days from the date hereof submit the results of this study to the Commission for its review, showing how revenues will be allocated among rate classes. The cost of service study, when rerun, shall incorporate all changes in rates, schedules, and service rules ordered herein. A copy of the study shall be served upon each of the parties hereto at the time it is filed with the Commission.

3. GSU shall file five (5) copies of its tariff, revised in accordance with the Examiner's Report and the terms of this Order, and sufficient to generate revenues no greater than those prescribed in that Report and this Order, with the Commission Secretary and one copy with each of the Intervenors within twenty (20) days of the date hereof. The Commission Staff shall have twenty (20) days from the date of the filing to review and to approve or reject the tariff. All parties to this docket shall have ten (10) days from the date of that filing to file their objections, if any, to the revised tariff. The tariff shall be deemed approved and shall become effective upon the expiration of twenty (20) days after filing, or sooner upon notification of approval by the Commission Secretary. In the event of rejection, GSU shall have fifteen (15) additional days to file an amended tariff, with the same review procedures to again apply.

4. The revised and approved rates shall be charged only for service rendered in areas over which this Commission is exercising its original and appellate jurisdiction as of the adjournment of the hearing on the merits herein, and said rates may be charged only for service rendered after the tariff approval date. If the tariff approval date falls within GSU's normal customer billing cycle, the Company is hereby authorized to prorate customer bills according to the number of days service was provided under the applicable rate schedules.

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5. This Order is deemed to be final upon the date of rendition. Approval of the revised tariff in compliance with this Order shall be deemed to be final on the date of its effectiveness either by operation of this Order or by notification from the Commission Secretary, whichever shall occur first.

6. GSU shall immediately initiate actions to conduct the generation plant cost study recommended by Mr. Saathoff under the conditions recommended by the Examiner. GSU is encouraged to complete that study before it files its next rate change application.

7. GSU is expressly ordered to make all future rate change applications on a system-wide basis pursuant to the recommendations of Messrs. Winkelmann and Lee.

8. The Examiner's discussion of the purpose for establishing a cost of service for ratemaking purposes found in §I(C) of the Examiner's Report is concurred with by the Commission and shall be adopted as a policy statement of the Commission. The Commission's Director of Public Utilities shall take such steps as are necessary to carry out this directive.

9. All motions, requests, applications and proposed Findings of Fact or Conclusions of Law not expressly granted herein are denied for want of merit and for being unsupported by the preponderance of the credible evidence in the record of this docket.

RENDERED AT AUSTIN, TEXAS, on this the 17th day of September 1981.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: ______________________
GEORGE M. COWDEN

SIGNED: ______________________
GARRETT MORRIS

SIGNED: ______________________
H. M. ROLLINS

ATTEST:

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PHILIP F. RICKETTS
SECRETARY OF THE COMMISSION

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PUC DOCKET NO. 49421
SOAH DOCKET NO. 473-19-3864

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR AUTHORITY TO CHANGE RATES	§ § §	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

STIPULATION AND SETTLEMENT AGREEMENT

The parties to this stipulation and settlement agreement (Agreement) are CenterPoint Energy Houston Electric, LLC (CenterPoint Houston); the Staff of the Public Utility Commission of Texas (Staff); Office of Public Utility Counsel (OPUC); City of Houston/Houston Coalition of Cities (COH/HCOC); Gulf Coast Coalition of Cities (GCCC); H-E-B LP; Texas Coast Utilities Coalition of cities (TCUC); Texas Industrial Energy Consumers (TIEC); Alliance for Retail Markets; Texas Energy Association for Marketers; and Walmart Inc. Texas Competitive Power Advocates; Calpine Corporation; Olin Corporation; Solar Energy Industries Association; Enel X North America, Inc.; Generation Park Management District and McCord Development, Inc. are unopposed to the Agreement. The parties who are signing as signatories to the Agreement shall be referred to individually either as a Signatory or by the respective acronyms assigned above, and collectively as the Signatories. The Signatories agree to support the Commission's implementation of the Agreement. The Agreement provides for the resolution of all base rate, rate rider, tariff, and rate case expense issues in connection with this proceeding and Commission Docket No. 49595.

RECITALS

WHEREAS, on April 5, 2019, CenterPoint Houston filed an application for authority to change rates (Application), as amended by its errata, to be effective May 10, 2019; and

WHEREAS, the Signatories wish to avoid the uncertainty, time, inconvenience and expense of further litigation of this proceeding by compromising and resolving this proceeding;

NOW, THEREFORE, the Signatories, through their undersigned representatives, hereby enter into this Agreement on the following terms:

ARTICLE I

A. **Overall Revenues.** CenterPoint Houston's total base rate revenue requirement should be increased by a "black box" amount of $13 million, as detailed in the schedule attached hereto and incorporated by reference as Exhibit A. If the Commission issues a Final Order on or before February 5, 2020, then the approved rates should be effective on March 1, 2020. If the Commission issues a Final Order on or after February 6, 2020, then the approved rates will be effective 45 days after the date of the Order.

B. **Cost of Capital.** Beginning with the effective date of the new rates authorized in this proceeding CenterPoint Houston's Weighted Average Cost of Capital (WACC) shall be 6.51% based upon an as filed 4.38% Cost of Debt, an agreed Return on Equity (ROE) of 9.4%, and an agreed regulatory capital structure of 57.5% long-term debt and 42.5% equity. The foregoing WACC, Cost of Debt, ROE and Capital Structure are in accord with Public Utility Regulatory Act (PURA) §§ 36.051 and 36.052,[1] and will apply, in accordance with the PURA and Commission rules, in all Commission proceedings or Commission filings requiring the application of the WACC, Cost of Debt, ROE, or Capital Structure established in this case.

C. **Future Base Rate Proceeding.** CenterPoint Houston will file a base rate case no later than four years from the date of the Commission's final order in this docket and will not request a delay of the filing of its next base rate case using the provisions of 16 Texas Administrative Code (TAC) § 25.247(b)(2). Nothing in this paragraph shall prohibit

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[1] Public Utility Regulatory Act, Tex. Util. Code §§ 11.001-66.016 (PURA).

CenterPoint Houston from filing, or any regulatory authority from requiring pursuant to applicable law, a base rate case earlier than four years from the date of the Commission's final order in this docket.

D. **Distribution Cost Recovery Factor (DCRF) Proceeding.** CenterPoint Houston will not file a DCRF proceeding during the 2020 calendar year. When updating its distribution rate base through future DCRF proceedings, CenterPoint Houston will update its distribution rate base to account for the effects of changed accumulated deferred federal income tax (ADFIT) and excess deferred income tax (EDIT) regulatory liability balances, in each proceeding requesting an update of its distribution rates.

E. **Transmission Cost of Service (TCOS) Proceedings.** Between the date of the final order in this proceeding and the date of the final order in CenterPoint Houston's next base rate proceeding, when updating its transmission rate base through TCOS proceedings, CenterPoint Houston will update its transmission rate base to account for the effects of changed ADFIT and EDIT regulatory liability balances, in each proceeding requesting an update of its wholesale transmission rates.

F. **Revenue Allocation.** The revenue requirement, including the revenue increase authorized under Paragraph I.A. above, shall be distributed among customer classes per the allocation set forth in Staff's number run filed on December 5, 2019, as set forth in Exhibit B attached to and incorporated into this Agreement. In accordance with this Agreement, CenterPoint Houston will recover all existing and future transmission-related costs through its transmission cost recovery factor (TCRF) instead of through base rates.

G. **Rate Design and Tariff Approval.** The tariff sheets in Exhibit C attached to and incorporated by reference set out the rate design agreed to by the Signatories and incorporate the total base revenue increase provided for in paragraph I.A above.

CenterPoint Houston's proposed tariff text changes and rates for the various classes are consistent with this Agreement, as set out in Exhibit C, and should be approved by the Commission.

H. **Ring-Fencing.** The following ring-fencing measures, which are a product of compromise between the Signatories and subject to Paragraph II.C below, are adopted for CenterPoint Houston:

a. CenterPoint Houston's credit agreements and indentures shall not contain cross-default provisions by which a default by CNP or its other affiliates would cause a default at CenterPoint Houston;

b. The financial covenant in CenterPoint Houston's credit agreement shall not be related to any entity other than CenterPoint Houston. CenterPoint Houston shall not include in its debt or credit agreements any financial covenants or rating agency triggers related to any entity other than CenterPoint Houston.

c. CenterPoint Houston shall not pledge its assets in respect of or guaranty any debt or obligation of any of its affiliates. CenterPoint Houston shall not pledge, mortgage, hypothecate, or grant a lien upon the property of CenterPoint Houston except pursuant to an exception in effect in CenterPoint Houston's current credit agreement, such as the first mortgage and general mortgage.

d. CenterPoint Houston shall maintain its own stand-alone credit facility, and CenterPoint Houston shall not share its credit facility with any regulated or unregulated affiliate.

e. CenterPoint Houston shall maintain registrations with all three ratings agencies.

f. CenterPoint Houston shall maintain a stand-alone credit rating.

g. CenterPoint Houston's first mortgage bonds and general mortgage bonds shall be secured only with CenterPoint Houston's assets.

h. No CenterPoint Houston assets may be used to secure the debt of CNP or its non-CenterPoint Houston affiliates.

i. CenterPoint Houston shall not hold out its credit as being available to pay the debt of any affiliates (provided that, for the avoidance of doubt, CenterPoint Houston is not considered to be holding its credit out to pay the debt of affiliates, or in breach of any other ring-fencing measure, with respect to the $68 million of CenterPoint Houston general mortgage bonds that currently serve as collateral for certain outstanding CNP pollution control bonds).

j. Without prior approval of the Commission, neither CNP nor any affiliate of CNP (excluding CenterPoint Houston) may incur, guaranty, or pledge assets in respect of any incremental new debt that is dependent on: (1) the revenues of CenterPoint Houston in more than a proportionate degree than the other revenues of CenterPoint Houston; or (2) the stock of CenterPoint Houston.

k. CenterPoint Houston shall not transfer any material assets or facilities to any affiliates, other than a transfer that is on an arm's length basis consistent with the Commission's affiliate standards applicable to CenterPoint Houston.

l. Except for its participation in an affiliate money pool, CenterPoint Houston shall not commingle its assets with those of other CNP affiliates.

m. Except for its participation in an affiliate money pool, CenterPoint Houston shall not lend money to or borrow money from CNP affiliates.

n. CenterPoint Houston shall notify the Commission if its credit issuer rating or corporate rating as rated by any of the three major rating agencies falls below investment grade level.

The Signatories further agree that the Commission will decide whether to adopt dividend restriction ringfencing provisions for CenterPoint Houston based on the record and the parties' briefing currently on file with the Commission, unless the Commission requests additional briefing. If CenterPoint Houston appeals any Commission decision related to dividend restrictions, CenterPoint Houston will reimburse, on a monthly basis, the expenses of other parties incurred to litigate that appeal and not seek recovery of those expenses in rates.

I. **Invested Capital.** CenterPoint Houston's invested capital, including its plant in service through the end of the test year (December 31, 2018), as reflected on Exhibit D attached to this Agreement and incorporated by reference, is used and useful in providing service, and prudent and properly included in rate base. This includes approximately $41.2 million in Underground Cable Life Extension Program investment placed in service from January 1, 2013 through December 31, 2017. For purposes of CenterPoint Houston's Earnings Monitoring Reports for reporting years beginning in 2020, CenterPoint Houston's total Company Cash Working Capital is $24,269,000, as shown on Exhibit D.

J. **Certain Tax Matters.**

a. **UEDIT.** CenterPoint Houston shall refund through Rider UEDIT and its Wholesale Transmission Service tariff an unprotected excess deferred income tax (UEDIT) amount of $64,903,763, protected excess deferred income tax amount of $18,659,227, and gross up of $21,886,079 for a total UEDIT refund of $105,449,069 plus carrying costs. The refund and amortization period for UEDIT for Residential Service, Secondary Service Less Than or Equal to 10 KVA, Street Lighting Service, and Miscellaneous Lighting Service shall be approximately 30 months beginning with the effective date of the rates authorized in this proceeding, as shown in the rate schedules on Exhibit E to the Agreement. The refund and amortization period for UEDIT for Secondary Service Greater Than 10 KVA, Primary Service, and Transmission Service shall be approximately 36 months beginning with the effective date of the rates authorized in this proceeding, as shown in the rate schedules on Exhibit E to the Agreement. The refund and amortization period for the amount included in the Wholesale Transmission Service (WTS) tariff is approximately 36 months, as shown in the WTS rate schedule on Exhibit C to the Agreement.

b. **Proceeding Related to Securitized EDIT.** The Signatories agree that no proceeding should be initiated to review CenterPoint Houston's or its affiliate's ADFIT balances on CenterPoint Houston's or its affiliate's transition and restoration bonds and that no Signatory will raise issues related to the appropriate treatment of EDIT amounts associated with those bonds in future Commission proceedings related to CenterPoint Houston or its affiliates.

K. **Accounting Matters.** CenterPoint Houston shall be permitted, for purposes of future DCRF, TCOS and general rate case proceedings, to reflect Texas Margin Tax (TMT) expense based on the current TMT rate applicable in the period that rates are recovered. Except with respect to EDIT regulatory assets and liabilities, regulatory assets and liabilities maintained on the Company's books and records and at issue in this proceeding may be amortized over five years. The Texas Margin Tax regulatory asset included in CenterPoint Houston's rate filing package is not considered in the regulatory assets and the amount of the amortization expense referenced in this Agreement. CenterPoint Houston's total Prepaid Pension Asset will be reduced by the capital component identified as Construction Work in Progress (CWIP) and CenterPoint Houston is authorized to apply and recover an amount for AFUDC. With exception of rate case expenses as described below, nothing in this "black box" Agreement shall be construed in such a way as to require CenterPoint Houston to write off any investment, assets or liabilities currently maintained on its books and records.

L. **Rate Case Expenses.** CenterPoint Houston agrees to reimburse cities participating in this docket for rate case expenses incurred in all dockets subject to Docket No. 49595. CenterPoint Houston agrees not to seek recovery of rate case expenses requested in Docket No. 49595, including expenses associated with this proceeding, Docket No. 49421, and any appeals of this proceeding. Cities shall provide CenterPoint Houston with invoices for all rate case expenses incurred within 10 days of a final order in this proceeding. CenterPoint Houston shall reimburse Cities for rate case expenses included on invoices submitted in accordance with this timeline within 30 days of a final order in this proceeding. CenterPoint Houston shall not be required to reimburse Cities for rate case expenses not included on invoices provided in accordance with this timeline. CenterPoint Houston shall withdraw or move to dismiss Docket No. 49595 within 30 days of a final order in this proceeding.

M. **Statutory Requirements and Baseline Values.**

a. **Affiliate Expenses.** The affiliate amounts included in the rates developed through this Agreement, are reasonable and necessary, are allowable, and are charged to

CenterPoint Houston at a price no higher than was charged by the supplying affiliate to other affiliates. Each Signatory reserves the right, in a future CenterPoint Houston proceeding and for prospective application, to dispute whether and in what amount, CenterPoint Houston may include in rate base or expense, amounts related to affiliate services.

b. **Self-Insurance Reserve.** CenterPoint Houston's request for an annual self-insurance reserve accrual of $7.685 million and a new target property insurance reserve of $6.55 million is reasonable and should be approved by the Commission. The accrual is comprised of: (1) $3.575 million to provide for average annual expected operations and maintenance (O&M) expense losses from events where losses are greater than $100,000; and (2) $4.11 million accrued annually for three years to achieve a target reserve of $6.55 million from the current reserve deficit level of ($5.79 million).

c. **Depreciation.** Beginning with the effective date of the new rates authorized in this proceeding, CenterPoint Houston will use the depreciation rates as proposed in the direct testimony of CenterPoint Houston witness Dane Watson (CEHE Ex. 25). These rates are shown on Exhibit F, which is a copy of Exhibit DAW-1 from Mr. Watson's direct testimony.

d. **Pension and Other Postemployment Benefit Baselines.** Consistent with PURA § 36.065, CenterPoint Houston's Pension and Other Postemployment Benefits (OPEB) Baselines are $23,853,739 for pension and $2,671,274 for OPEB expense. The combined total of $26,525,013 is comprised of the amount for CenterPoint Houston of $19,627,483 and Service Company of $6,897,530.

e. **Interim Update of Transmission Rates.** When CenterPoint Houston files an application to update its transmission rates on an interim basis pursuant to 16 TAC

§ 25.192(h), the baseline values to be used in that application are as provided in Exhibit G attached to and incorporated into this Agreement. The baseline values are a product of compromise between the Signatories. The fact that the Signatories have agreed to the use of these baseline values as specified in this section does not reflect an agreement on any methodology that may or may not have been used to derive those baselines.

f. **Transmission Cost Recovery Factor (TCRF).** The rates set following this proceeding will reflect CenterPoint Houston's updated TCRF, as approved in Commission Docket No. 50294. When CenterPoint Houston files an application to update its TCRF under 16 TAC § 25.193, the baseline values to be used in that application are as provided in Exhibit H attached to and incorporated into this Agreement. The baseline values are a product of compromise between the Signatories. The fact that the Signatories have agreed to the use of these baseline values as specified in this section does not reflect an agreement on any methodology that may or may not have been used to derive those baselines.

g. **Distribution Cost Recovery Factor (DCRF).** When CenterPoint Houston files an application for a DCRF pursuant to 16 TAC § 25.243, the baseline values to be used in that application are as provided in Exhibit I attached to and incorporated into this Agreement. The baseline values are a product of compromise between the Signatories. The fact that the Signatories have agreed to the use of these baseline values as specified in this section does not reflect an agreement on any methodology that may or may not have been used to derive those baselines.

ARTICLE II

A. Proposed Order

The terms of this Agreement are fair, reasonable, and in the public interest, and the Commission should enter the proposed order attached to Exhibit J to this Agreement, which is consistent with the terms of this Agreement, or an order consistent with all terms of this Agreement. The Signatories agree to fully support this Agreement in all respects and to use all reasonable efforts to request prompt entry of the proposed order attached as Exhibit J.

B. Effect of Modification of Agreement

If the Commission issues a final order that is inconsistent with the terms of the Agreement, each Signatory has the right to withdraw from the Agreement, to submit testimony, and to obtain a hearing and advocate any position it deems appropriate with respect to any issue in this Agreement. The Signatories further agree that the terms and conditions in this Agreement are interdependent and that the various provisions of this Agreement are not severable.

C. No Precedent

Because the matters resolved herein are resolved on the basis of compromise and settlement, nothing in this Agreement should be considered precedent. No Signatory shall be deemed to have agreed to the propriety of any theory or principle that may be said to underlie any of the issues resolved by this Agreement. Because this is a settlement, the Signatories recognize that no Signatory is under any obligation to take the same position in any other docket, except as specifically required by this Agreement, whether or not the docket presents the same or similar circumstances. This Agreement is binding on each of the Signatories only for the purpose of settling the issues herein and for no other purpose. Oral and written statements made during the course of settlement negotiations shall not be used as an admission or concession of any sort or as evidence in this or any other proceeding.

D. Entire Agreement

This Agreement is the entire understanding and agreement of the Signatories to this Agreement, and it supersedes prior understandings and agreements, if any, among the Signatories with respect to the subject matter of the Agreement. There are no representations, agreements, arrangements, or understandings, oral or written, concerning the subject matter hereof between and among the Signatories to this Agreement which are not fully expressed herein.

E. Authorization to Sign

Each person executing this Agreement represents that he or she is authorized to sign the Agreement on behalf of the Signatory represented.

F. Countersigned Originals

This document may be countersigned by each Signatory on separate originals. Each signature shall be treated as if it is an original signature.

This Agreement has been executed, approved, and agreed to by the Signatories hereto in multiple counterparts, each of which shall be deemed an original, on the date indicated below by the Signatories hereto, by and through their undersigned duly authorized representatives. This Agreement shall be effective and binding when it is signed by all Signatories.

195. SWEPCO's annual incentive plan includes both financially-based and performance-based goals.

196. Compensation to employees under the annual incentive plan is based in part on an earnings-per-share trigger.

197. A certain amount of incentives to achieve operational measures is reasonable and necessary to the provision of electric service. However, SWEPCO failed to prove that its proposal removed all of the costs associated with the financially-based components of the annual incentive plan.

198. Staff's recommended adjustment to eliminate $2,277,726 associated with the annual incentive plan, plus corresponding flow through reductions, results in allowable expense for the plan that is reasonable and necessary to the provision of electric service, and should be included in the cost of service.

Long-Term Incentive Compensation

199. SWEPCO removed the entirety of its financially based long-term incentive compensation in the amount of $2,140,880. However, the $359,705 of restricted stock units are not based on financial measures as are other SWEPCO or AEP incentive plans and are appropriate to include in SWEPCO's rates.

Financial Counseling Expense

200. The $4,071 related to executive perquisites should not be included in rates because they provide no benefit to ratepayers and are not reasonable or necessary for the provision of electric service.

Supplemental Executive Retirement

201. SWEPCO requests recovery of $99,654 in directly incurred non-qualified pension expense and an additional $310,422 that was allocated from AEP Services Company (AEPSC) ($410,076 total).

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.

Pensions and Other Post-Retirement Benefits

205. The amount requested by the company for pension and OPEB (including post-retirement benefits and post-employment benefits) was determined by actuarial or other similar studies in accordance with generally accepted accounting principles. With the exception of SERP, SWEPCO's pension and OPEB costs were not challenged.

Distribution Plant Maintenance

206. SWEPCO's proposal to recover distribution O&M base-rate expenses of $9.3 million total, consisting of the test-year amount of $7.3 million and an additional amount of $2 million, is reasonable.

207. The additional amount of distribution O&M expense in the amount of $2 million is reasonable and necessary to carry forward SWEPCO's vegetation-management program to improve overall reliability on targeted circuits and decrease outages caused by trees.

208. SWEPCO commits to spending the entirety of the increased amounts of $2 million for distribution O&M expense solely on vegetation management.

209. It is reasonable to open a compliance docket where SWEPCO will file regular reports indicating how it is spending the additional amount of vegetation-management expense allowed in its cost of service, and will also report on the effect such additional spending is having on its distribution outage rates.

Affiliate Charges

210. SWEPCO adjusted the lead-lag study to include an increase of $73,188 to the interest expense based on a change in the date on which AEPSC pays invoices.

211. SWEPCO agreed to reverse the $73,188 adjustment to the lead-lag study.

PUBLIC UTILITY COMMISSION OF TEXAS
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
II-B-7 ACCUMULATED PROVISIONS
TEST YEAR ENDING 12/31/2023
DOCKET NO. 56211
SPONSOR: K. COLVIN / J. STORY

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	FERC Account	Description	Reference Schedule	Total Company	Non-Regulated or Non-Electric	Known and Measurable Changes	Company Total Electric	FF #	Functionalization Factor Name	Allocation to Texas	TRAN	DIST	MET	TDCS	Total
1															
2	**Other Rate Base Items**														
3															
4	**Other Accumulated Provisions**		II-B-7												
5	1823	Regulatory Assets-Storm Reserve		42,017,815	-	(199,056)	41,818,759	3	DIST	41,818,759	-	41,818,759	-	-	41,818,759
6	2281	Regulatory Assets-Other		-	-	-	-	3	DIST	-	-	-	-	-	-
7	2282	Injuries & Damages-Auto Liability		(3,046,306)	-	-	(3,046,306)	21	GPLT	(3,046,306)	(1,099,448)	(1,811,528)	(96,892)	(38,438)	(3,046,306)
8	2282	Injuries & Damages-Gen Liability		(16,290,423)	-	11,161,631	(5,128,792)	15	PLTSVC-N	(5,128,792)	(2,107,365)	(2,841,389)	(129,379)	(50,659)	(5,128,792)
9	2282	Injuries & Damages-Workers' Comp		(4,130,595)	-	-	(4,130,595)	12	PAYXAG	(4,130,595)	(812,644)	(2,649,811)	(456,544)	(211,596)	(4,130,595)
10	2283	Benefit Restoration		-	-	(5,278,000)	(5,278,000)	12	PAYXAG	(5,278,000)	(1,038,381)	(3,385,881)	(583,364)	(270,374)	(5,278,000)
11		**Subtotal**		**18,550,490**	**-**	**5,684,575**	**24,235,065**			**24,235,065**	**(5,057,838)**	**31,130,150**	**(1,266,179)**	**(571,067)**	**24,235,065**
12	**Accumulated Deferred Income Taxes**														
13															
14	1900	Deferred Income Tax		300,848,302	-	482,723	301,331,025	62	DIT_190	301,331,025	105,869,092	178,854,921	11,889,610	4,717,402	301,331,025
15	2820	Def Inc Taxes-Fed-Accel Depr		(1,484,359,106)	-	20,897,115	(1,463,461,991)	63	DIT_282	(1,463,461,991)	(543,710,812)	(851,856,774)	(49,289,348)	(18,605,057)	(1,463,461,991)
16	2830	Def Inc Taxes-Federal-Other		(245,420,561)	-	136,572,727	(108,847,834)	64	DIT_283	(108,847,834)	(10,599,437)	(78,022,127)	(10,211,195)	(10,015,055)	(108,847,834)
17															
18		Subtotal		(1,428,931,365)	-	157,952,565	(1,270,978,800)			(1,270,978,800)	(448,441,177)	(751,023,980)	(47,610,933)	(23,902,710)	(1,270,978,800)
19															
20	**TOTAL ACCUMULATED PROVISIONS**		II-B-7	(1,410,380,875)	-	163,637,140	(1,246,743,735)			(1,246,743,735)	(455,499,015)	(719,893,830)	(48,877,113)	(24,473,777)	(1,246,743,735)

125. Two other projects were also erroneously classified as distribution plant and should be reclassified to transmission plant: Pittsburg ($14,712) and Bryan Mills ($9,213).

126. The total amount of capital investment misclassified as distribution plant should be re-classified as and included in transmission plant. This transmission capital investment incurred during the period January 1, 2012, through June 30, 2016, is used and useful in providing service to the public and reasonable and necessary.

127. Apart from the reclassifications to transmission plant discussed immediately above, the entirety of the distribution investment is used and useful in providing service to the public and reasonable and necessary.

Capitalized Supplemental Executive Retirement Plan

128. Since the end of 2011, the test year for SWEPCO's last base-rate case, SWEPCO identified $1,363,305 of non-qualified pension expense capitalized to construction work in progress (CWIP) and $8,721 capitalized to removal work in progress.

129. The capitalized portion of SWEPCO's supplemental-executive-retirement-plan (SERP) payments that are financially based are properly excluded from SWEPCO's rate base because they 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.

130. SWEPCO's accounting system cannot provide the exact amount of capitalized financial incentives closed to plant in service or the amount remaining in CWIP as of the end of the test year. An appropriate approximation for the amount of capitalized financial incentives included in SWEPCO's requested plant in service balance is the same proportion as the test-year-end balance of completed construction not classified to CWIP, which is 83.17%.

131. $1,141,151, which is 83.17% of the total SERP invested-capital request, is removed from invested capital.

Capitalized Incentive Compensation

132. Since the end of 2011, the test year for SWEPCO's last base-rate case, the amount of incentive compensation based on financial measures that SWEPCO capitalized to rate base

215. The PUC permits a utility to recover in its base rate incentives that are designed to achieve "operational measures" and that are necessary and reasonable to provide utility services, but not incentive programs that are designed to achieve "financial measures."

216. Operational measures are those designed to encourage a utility's employees to meet goals and standards relating to the efficient operation of the utility, a benefit to shareholders and ratepayers alike.

217. Financial measures are those designed to encourage employees to achieve financial targets, a benefit primarily to shareholders.

218. SWEPCO's "Regulatory," "Strategic," and "Margin Generating" annual incentive goals relate to financial measures.

219. SWEPCO's long term incentive awards in the form of performance units relate to financial measures.

220. Of SWEPCO's annual incentive compensation of $10,728,117, $3,523,732 should be disallowed as financial goals. Of SWEPCO's long-term compensation, all but $2,045,072 of the total should be disallowed as financial goals.

Executive Perquisites

221. The $16,350 related to executive perquisites should not be included in rates because they provide no benefit to ratepayers and are not reasonable or necessary for the provision of electric service.

Relocation

222. SWEPCO's proposed relocation expense, in the amount of $574,588, is reasonable and necessary.

Pensions

223. It is reasonable to base pension expense in SWEPCO's cost of service upon the cost of $8,306,420 on a total Company basis calculated in the 2012 actuarial report prepared in accordance with FAS 87.

195. SWEPCO's annual incentive plan includes both financially-based and performance-based goals.

196. Compensation to employees under the annual incentive plan is based in part on an earnings-per-share trigger.

197. A certain amount of incentives to achieve operational measures is reasonable and necessary to the provision of electric service. However, SWEPCO failed to prove that its proposal removed all of the costs associated with the financially-based components of the annual incentive plan.

198. Staff's recommended adjustment to eliminate $2,277,726 associated with the annual incentive plan, plus corresponding flow through reductions, results in allowable expense for the plan that is reasonable and necessary to the provision of electric service, and should be included in the cost of service.

Long-Term Incentive Compensation

199. SWEPCO removed the entirety of its financially based long-term incentive compensation in the amount of $2,140,880. However, the $359,705 of restricted stock units are not based on financial measures as are other SWEPCO or AEP incentive plans and are appropriate to include in SWEPCO's rates.

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Supplemental Executive Retirement

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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.

136A. Affiliate charges totaling $203,474 (total company) were made to SPS using multiple six-digit work orders that contained "New Mexico" or locations within New Mexico in their titles. Six-digit work orders are used to directly charge costs to specific Xcel Energy operating companies, but not to specific retail jurisdictions.

136B. SPS met its burden to prove the managerial-level work associated with these work orders benefitted Texas retail customers.

136C. It would be inconsistent and inequitable to include only a portion of the costs of work orders with Texas in the titles while also wholly excluding the costs of work orders with New Mexico in the title.

136D. The affiliate charges, totaling $203,474 (total company), associated with these work orders are reasonable and necessary expenses and are properly included in setting SPS's base rates.

137. A component of the shared facilities charges SPS incurred from affiliates included the carrying costs associated with those facilities. Because these carrying costs are unnecessary and unreasonable, $1,564,659 should be removed from SPS's affiliate expense. SPS should also make a corresponding decrease to FERC account 922 of $1,187,726 in revenue SPS has received related to carrying costs. This results in a net reduction of $376,933 (total company).

138. SPS agreed to remove $2,475 in Life Event costs, which were contained in multiple affiliate classes, from its application.

139. SPS agreed to remove a $104 charge that was due to a timekeeping entry error from its application.

140. All remaining affiliate transactions for which recovery was sought were reasonable and necessary, were allowable, and were charged to SPS at a price no higher than was charged by the supplying affiliate to other affiliates, and the rate charged was a reasonable approximation of the cost of providing the service.

212. A component of the shared-facilities charges SWEPCO incurred from affiliates included the carrying costs associated with those facilities. Because these carrying costs are unnecessary and unreasonable, \$795,480 should be removed from SWEPCO's affiliate expense. SWEPCO should also make a corresponding decrease to FERC Account 922 of \$509,723 in revenue that SWEPCO has received related to carrying costs. This results in a net reduction of \$285,757, on a total-company basis.

213. All remaining affiliate transactions for which recovery was sought were reasonable and necessary, were allowable, and were charged to SWEPCO at a price no higher than was charged by the supplying affiliate to other affiliates, and the rate charged was a reasonable approximation of the cost of providing the service.

Injuries and Damages

214. In the test year, SWEPCO incurred \$5,327,950 as injuries and damages expense.

215. In the test year, SWEPCO incurred \$1,255,000 as litigation expense.

216. The test-year amount for litigation was substantially in excess of the litigation expenses incurred by SWEPCO in the three preceding years.

217. It is reasonable to adjust the test-year amount by a \$837,667 reduction, which is the amount the test-year litigation expense exceeds the average litigation expense in the three previous years.

Directors'/Officers' Liability Insurance

218. The existence of directors' and officers' (D&O) liability insurance improves the utility's ability to attract and retain qualified directors and officers and enables them to make decisions without fear of personal liability.

219. The Commission has already found D&O liability insurance to be an element of SWEPCO's reasonable and necessary operating expenses. *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Order on Rehearing, Finding of Fact Nos. 236, 237 (Mar. 6, 2014).