Control Number: 49421

Item Number: 463

Addendum StartPage: 0

RECEIVED

2019 JUN -7 PM 3:04

PUBLIC UTILITY COMMISSION
FILING CLERK

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

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 JEFFRY POLLOCK

ON BEHALF OF
TEXAS INDUSTRIAL ENERGY CONSUMERS

June 7, 2019

418

Errata 1 to

Direct Testimony of Matthew A. Troxle

EXECUTIVE SUMMARY OF MATTHEW A. TROXLE

My testimony addresses four areas: (1) the twelve-month period ending December 31, 2018 Test Year ("Test Year") billing determinants used to design the proposed retail delivery service rates; (2) the allocation of costs among the rate classes; (3) the development of CenterPoint Energy Houston Electric, LLC's ("CenterPoint Houston" or the "Company") proposed retail and wholesale ~~delivery~~ transmission service tariff rate schedules, riders and various charges; and (4) other proposed changes to the Company's retail delivery service tariffs. Specifically, my testimony:

- explains the reasonable and necessary adjustments to the Test Year billing determinants that are necessary to make the Test Year billing and usage data more representative of conditions that are expected to exist once new rates go into effect;
- describes the two class cost of service studies used to allocate costs among the rate classes in accordance with the Federal Energy Regulatory Commission System of Accounts, the Public Utility Regulatory Act, the Public Utility Commission of Texas' rules and rate filing package instructions, and the principles of cost causation;
- explains, for both the retail delivery service tariff and the wholesale ~~delivery~~ transmission service tariff, how each rate schedule applies and how each delivery charge is calculated, and also demonstrates that these rate schedules and riders accurately recover the cost of service as described and supported in the rate filing package;
- introduces a new rider, Rider UEDIT – Unprotected Excess Deferred Income Tax, that refunds to customers the balance of unprotected excess deferred income taxes resulting from the Tax Cuts and Jobs Act of 2017 that changed the federal income tax rate in 2018;
- describes the Company's proposed additional charges and discretionary service charges and the methodology used to determine the present cost of providing these services; and
- summarizes other proposed changes to the Company's retail tariff.

WP - Acct. 366, WP - Acct. 367, and WP - Acct. 368 demonstrate how the Company proposes to allocate distribution costs in this proceeding.

Q. **WHAT IS THE FINAL STEP IN PREPARING THE CCOSS?**

A. The final step in preparing the CCOSS is applying the allocators derived in the previous step, as shown in the II-I-2 Schedules, to all of the FERC Account costs, expenses, and other revenues.

B. Demand-related Allocation Methodology

1. Transmission Cost

Q. **PLEASE DESCRIBE THE METHOD USED TO ALLOCATE CAPACITY-RELATED TRANSMISSION COST.**

A. CenterPoint Houston proposes to use the unadjusted 4CP allocation factor based on the ~~ERCOT~~ CEHE peak summer month periods to allocate capacity-related transmission costs. ~~This matches the use of the 4CP allocator the Commission uses for pricing wholesale transmission charges pursuant to PURA § 35.004(d) and is consistent with Commission rules and the Company's approved approach in Docket No. 38339.~~

2. Distribution Cost

Q. **PLEASE DESCRIBE THE METHOD USED TO ALLOCATE DEMAND-RELATED DISTRIBUTION COST.**

A. The methodology used for the demand-related distribution cost is based on the unadjusted average 4CP test year demand for electric power on CenterPoint Houston's distribution system at the time of ERCOT's peak summer month periods. This demand data is shown on Schedule II-H-1.3, sponsored by Dr. McMenamin. Furthermore, the allocation factors are determined at two points of service on the distribution system: the substation and the overhead distribution lines. Since some customers are served exclusively on the underground ("UG") line distribution system and do not use the overhead line facilities, having the allocation factors determined at the substation and the overhead distribution line level allows certain costs of the UG line facilities to be allocated exclusively to those classes which have customers served from those facilities.

Q. WHY HAVE YOU ELECTED TO USE THE 4CP DEMAND METHODOLOGY FOR DEMAND-RELATED DISTRIBUTION COST?

A. The Company's distribution system is designed to serve the maximum load requirement of each individual retail customer at the same time. The Company's distribution system is strategically constructed to have the capability to reliably deliver the maximum load when demanded by the customer. CenterPoint *Houston's customers' demand peaks are generally during the summer months of* June, July, August, and September. All cost driven by system peak loads have been allocated to the classes based upon their contribution to the summer peak loads. The 4CP component of the Company's proposed allocator accomplishes this goal by isolating class contributions to system peak load during those four months. ~~The Company uses this 4CP component to allocate cost on the basis of class energy requirements (the average demand) and class contributions to system peak demand (the excess demand).~~ A 4CP demand allocation method captures the cost causation associated with the maximum coincident load of each rate class on the Company's distribution system.

PUBLIC UTILITY COMMISSION OF TEXAS
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
II-I-2: CLASS ALLOCATION RATIOS
TEST YEAR ENDED 12/31/2018
DOCKET NUMBER PENDING ASSIGNMENT
SPONSOR: M. TROXLE

			1	2	3	4	5	6	7	8
FF #	Description	Allocation Label	Residential	Secondary <=10 KVA	Secondary > 10 KVA	Primary Voltage	Transmission Voltage	Lighting SLS	Lighting MLS	Total
	Class Allocation Factors									
			1	2	3	4	5	6	7	
1	Direct Assigned	DA								
2	Residential	RES	100%	0%	0%	0%	0%	0%	0%	100%
3	Secondary <=10 kVA	SEC<10	0%	100%	0%	0%	0%	0%	0%	100%
4	Secondary >10 kVA	SEC>10	0%	0%	100%	0%	0%	0%	0%	100%
5	Primary	Prim	0%	0%	0%	100%	0%	0%	0%	100%
6	Transmission	TRAN	0%	0%	0%	0%	100%	0%	0%	100%
7	Lighting - SLS	SLS	0%	0%	0%	0%	0%	100%	0%	100%
8	Lighting - MLS	MLS	0%	0%	0%	0%	0%	0%	100%	100%
9										
10	Generation Demand - A&E 4CP	D1	51 1328%	0.9855%	26 4231%	3 3839%	17.8653%	0 1689%	0 0405%	100%
11										
12	Transmission Demand - ERCOT 4CP	D2	46 6509%	0.8783%	34 0660%	3 4844%	14 9205%	0 0000%	0 0000%	100%
13	Dist Demand - Sub Level - 4CP	D3	54 8321%	1.0323%	40 0402%	4 0954%	0.0000%	0 0000%	0.0000%	100%
14	Dist Demand - Line Level - 4CP	D4	55 5393%	1.0484%	39 3373%	4.0750%	0 0000%	0 0000%	0.0000%	100%
15	Dist Dem-Line Level-4CP-Secondary	D5	57.8987%	1.0929%	41.0083%	0.0000%	0 0000%	0.0000%	0 0000%	100%
16										
17	Mwh - Generation Level	E1	32.6847%	1 0364%	36.5778%	4 6853%	24.7299%	0 2305%	0 0553%	100%
18										
19	Customer Count - Total	C1	87.8162%	5 9173%	5 5074%	0 0399%	0 0081%	0 2037%	0 5073%	100%
20	Customer Count - Secondary Volt	C2	88 4879%	5 9626%	5 5495%	0 0000%	0 0000%	0 0000%	0 0000%	100%
21	Customer Count - Overhead Dist	C3	78 4110%	9 4692%	12.0291%	0.0906%	0.0000%	0.0000%	0.0000%	100%
22	Customer Count - Res/Comm Dist	C4	88 4523%	5 9602%	5 5473%	0 0402%	0.0000%	0 0000%	0.0000%	100%
23										
24	Dist Land, Struct, Station Eqpt	A360-2	54 8321%	1 0323%	40.0402%	4 0954%	0 0000%	0 0000%	0.0000%	100%
25	Dist Poles, Towers, Fixtures	A364	55 8516%	1 0543%	39 5584%	3 5357%	0 0000%	0 0000%	0.0000%	100%
26	Dist OH Lines & Devices	A365	55 7487%	1 0524%	39 4856%	3 7133%	0.0000%	0 0000%	0.0000%	100%
27	O H. Poles and Conductors	A364-5	55 8157%	1 0536%	39 5330%	3 5977%	0.0000%	0.0000%	0.0000%	100%

PUBLIC UTILITY COMMISSION OF TEXAS
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
II-H-1.3 UNADJUSTED TEST YEAR LOAD DATA
TEST YEAR ENDED 12/31/2018
DOCKET NUMBER PENDING ASSIGNMENT
S. MCMENAMIN

Class Demand Coincident with CNP's System Peak Demand @ Meter

Line No	Month	Total	Residential (RS)	Secondary Voltage Small (SVS-Non IDR)	Secondary Voltage Small (SVS-IDR)	Secondary Voltage Large (SVL-Non IDR)	Secondary Voltage Large (SVL-IDR)	Primary Voltage Service (PVS-Non IDR)	Primary Voltage Service (PVS-IDR)	Transmission Voltage Service (TVS)	Miscellaneous Lighting Service (MLS)	Street Lighting Service (SLS)
1	**January**	13,399 23	6,587 66	151.95	0 01	2,456 62	1,511.82	47 16	381 94	2,198 71	12.65	50 70
2	**February**	11,532 51	3,726 59	108 18	0 01	2,865.55	1,942 43	42 68	507 25	2,339 83	-	-
3	**March**	11,576.95	3,787 90	100.29	0 02	2,523 63	1,903.47	37 75	496 17	2,727 73	-	-
4	**April**	12,880 60	4,624.60	111 13	0 01	2,819 83	2,058.31	40 50	534 54	2,691 68	-	-
5	**May**	16,535 13	7,533 32	131.37	0 01	3,324 14	2,274.94	48.71	553 65	2,668 98	-	-
6	**June**	16,834 94	7,690 04	138.66	0 01	3,520.18	2,298.91	50 24	565 55	2,571 36	-	-
7	**July**	17,113 42	8,041.67	139.65	0 01	3,507 51	2,208.73	50.48	536 60	2,628 78	-	-
8	**August**	17,747 13	8,372 79	140 84	0 01	3,586 74	2,371.83	53 55	531 90	2,689 47	-	-
9	**September**	16,309 11	7,620 25	178 09	0 01	3,409.45	2,263.08	50 20	531 01	2,257 01	-	-
10	**October**	15,080 59	6,133 93	129.93	0 01	3,231 98	2,294 24	46.61	548 76	2,695 13	-	-
11	**November**	13,627 34	4,778 57	120.88	0 01	3,142 04	2,352 85	43 96	534 87	2,654.16	-	-
12	**December**	11,376 68	3,931 16	113.93	0 01	2,384.24	1,817.60	39 53	448 67	2,641 53	-	-
13	**Annual**	174,013 64	72,828.49	1,564.90	0 13	36,771.92	25,298 21	551 37	6,170 90	30,764 36	12 65	50.70

PUBLIC UTILITY COMMISSION OF TEXAS
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
II-H-1.3 UNADJUSTED TEST YEAR LOAD DATA
TEST YEAR ENDED 12/31/2018
DOCKET NUMBER PENDING ASSIGNMENT
S. MCMENAMIN

INDEX

Coincident Peak Demand at the Time of the ERCOT Peak @ Source

Line No	Month	Total	Residential (RS)	Secondary Voltage Small (SVS-Non IDR)	Secondary Voltage Small (SVS-IDR)	Secondary Voltage Large (SVL-Non IDR)	Secondary Voltage Large (SVL-IDR)	Primary Voltage Service (PVS-Non IDR)	Primary Voltage Service (PVS-IDR)	Transmission Voltage Service (TVS)	Miscellaneous Lighting Service (MLS)	Street Lighting Service (SLS)
1	**January**	13,687 04	6,208 03	148 24	0 01	2,868 58	1,747.64	49 51	400 60	2,264 42	-	-
2	**February**	12,065.60	4,377 80	131 06	0.02	2,635.29	1,963.37	44 72	495.31	2,418 02	-	-
3	**March**	12,156 32	4,256 12	106.19	0 01	2,669 01	2,053 45	38.17	516.15	2,517.22	-	-
4	**April**	12,807 72	4,862 88	111.53	0 01	2,656.14	1,973 65	39 83	511.71	2,651 97	-	-
5	**May**	17,444 14	8,074 72	138 74	0 01	3,482 17	2,388 89	50 79	573 72	2,735 10	-	-
6	**June**	17,026 22	8,197 93	141 51	0 01	3,571 16	2,313 05	51 01	548 96	2,202 58	-	-
7	**July**	17,810 96	8,652 68	146 18	0 01	3,662 99	2,332.73	54.02	545.68	2,416 66	-	-
8	**August**	17,666.91	8,411 54	146 58	0 01	3,702 51	2,419 12	54 41	508 57	2,424 16	-	-
9	**September**	16,893.51	7,777 78	145.10	0 01	3,634 35	2,435 49	53 76	549 68	2,297 34	-	-
10	**October**	15,793 04	6,779 88	137 71	0 01	3,350 50	2,331 08	48 61	553 51	2,591 75	-	-
11	**November**	12,395 30	4,814.77	129.50	0 01	2,664 91	1,920 17	48.10	468 82	2,349 02	-	-
12	**December**	11,402 33	3,937 59	118 16	0 01	2,427.71	1,896.84	40 62	447 50	2,533 91	-	-
13	**Annual**	177,149.09	76,351 74	1,600.50	0.14	37,325.32	25,775 47	573.55	6,120 22	29,402 14	-	-

PUC DOCKET NO. 22350
SOAH DOCKET NO. 473-00-1015

APPLICATION OF TXU ELECTRIC COMPANY FOR APPROVAL OF UNBUNDLED COST OF SERVICE RATE PURSUANT TO PURA § 39.201 AND PUBLIC UTILITY COMMISSION SUBSTANTIVE RULE § 25.344	§ § § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the entrance of TXU Electric Company (TXU or the Company), including TXU SESCO, into the competitive retail electric market. More specifically, it addresses the separation of TXU's business functions, its code of conduct, the estimation and recovery of stranded costs, and the establishment of rates for transmission and distribution service, as well as other issues.

This Order incorporates and supercedes the decisions and orders of the Commission in the *Generic Proceeding*,[1] as well as the initial determinations of the Commission in this docket. While this Order systematically addresses final restructuring issues, parties who are interested in extensive or peripheral details are encouraged to refer to the initial decisions of the Commission, as reflected in the various interim orders entered in both the *Generic Proceeding* and in this docket. To assist in such a review, the Table of References identifies the interim orders.

The complex nature of the proceedings addressed by this Order resulted in multiple proposals for decision. Except as otherwise noted in this Order, the Commission adopts the administrative law judges' proposals for decision, including findings of fact and conclusions of law, as follows: Proposal for Interim Decision Phase I: Code of Conduct (including Business Separation Plan issues), November 27, 2000; ECOM [Excess Cost Over Market] Proposal for Interim Decision, February 7, 2001; Proposal for Decision Phases III & IV: Transmission and

[1] *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule 25.344,* Docket No. 22344, (Apr. 26, 2001) (Docket No. 22344).

151. The TLG report clearly explains the reasons for not including scrap value in the decommissioning cost estimate; that explanation reflects a reasonable treatment of this matter, and no adjustment should be made to place a value on scrap as a reduction to decommissioning expense.

152. Ratepayer funds collected in advance of decommissioning should be returned to the ratepayers in the event that the Comanche Peak nuclear site is not returned to greenfield condition and that some other, less expensive, form of decommissioning is ultimately pursued. The method for such refunding should be determined at a future date.

iv. Service Reliability

153. TXU has implemented strategies that have resulted in lower capital and maintenance expenses. TXU is prioritizing its vegetation management for the worst performing system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) feeders on a geographical basis to minimize expenses associated with crew relocations. The Company has instituted other measures to improve efficiency in vegetation management areas. Consequently, no Commission action is necessary at this time to address TXU's plant maintenance and service reliability.

5. Cost Allocation and Rate Design

i. Local Gross Receipts Taxes

154. The goal of the Commission is to institute, to the extent possible, a generic rate design that would honor the principles of cost causation, simplicity, and equity to customers within the given rate classes.

155. Local gross receipts tax (LGRT) is a tax or fee on the franchise arrangement whereby the TDU uses city streets, alleys, and rights-of-way to erect poles and run wires for delivery of electricity to the utility's customers within the municipal boundaries.

156. The LGRT legislation requires the tax be based on the number of kWh delivered within the municipal boundaries in order to maintain sufficient revenue levels for the cities. To meet this revenue requirement, LGRT should be allocated using a direct allocation and employing the energy allocator. LGRT revenues should be collected from all customers on TXU's system.

157. This franchise arrangement serves the entirety of the transmission and distribution system, benefits all customers in the system and, consequently, the costs should be shared among all customers through base rates. Therefore, using a direct allocation based on a cents per kWh allocator and collecting revenues under a spread collection from all customers honors the principle of equity for customers within rate classes.

ii. Allocation to Retail Classes

158. Transmission costs will be allocated to distribution utilities on a 4CP basis. The Distribution utility will recover those transmission costs through a facilities/delivery charge which will be billed using 4CP billing determinants for IDR-metered customers and noncoincident peak (NCP) billing determinants for non-IDR metered customers.

159. Distribution capacitors and voltage regulators (Account 368c) on the distribution system benefit all customers by providing voltage support, improved power factor, and increased efficiency to the transmission system. While the Account 368c facilities may not be necessary to provide delivery service to transmission-level customers, these facilities do support the entire transmission and distribution system. These costs should be assigned to transmission-level customers on the basis of NCP demand.

160. Redirected depreciation originated because of the potential that stranded generation would exist after deregulation. All customers are responsible for stranded costs, if they exist. Therefore, it is appropriate to include high voltage (HV) customers in the allocation of redirected depreciation.

P.U.C. DOCKET NO. 22355
SOAH DOCKET NO. 473-00-1020

APPLICATION OF RELIANT ENERGY FOR APPROVAL OF UNBUNDLED COST OF SERVICE RATE PURSUANT TO PURA § 39.201 AND PUBLIC UTILITY COMMISSION SUBSTANTIVE RULE § 25.344	§ § § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the entrance of Reliant Energy Incorporated (Reliant or the Company) into the competitive retail electric market. More specifically, it addresses the estimation and recovery of stranded costs, and the establishment of rates for transmission and distribution service, as well as other issues.

This Order incorporates and supercedes the decisions and orders of the Commission in the *Generic Proceeding*,[1] as well as the initial determinations of the Commission in this docket. While this Order systematically addresses final restructuring issues, parties who are interested in extensive or peripheral details are encouraged to refer to the initial decisions of the Commission, as reflected in the various interim orders entered in both the *Generic Proceeding* and in this docket. The Table of References identifies the interim orders to aid in cross-reference.

The complex nature of the proceedings addressed by this Order resulted in multiple proposals for decision. Except as otherwise noted in this Order, the Commission adopts the proposals for decision, including findings of fact and conclusions of law, as follows: Interim Proposal for Decision on ECOM Issues, February 7, 2001; Proposal for Decision Phase III & IV: T&D Revenue Requirement, Cost Allocation, Internal Code of Conduct, and Excess Mitigation of Stranded Costs, March 28, 2001; and revisions to the March 27, 2001 PFD, April 19, 2001.

---

[1] *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule 25.344*, Docket No. 22344, (Apr. 26, 2001) (Docket No. 22344).

d. Municipal Franchise Fees

221. Deleted.

222. Deleted.

221A. Local gross receipts tax (LGRT) is a tax or fee on the franchise arrangement whereby the TDU uses city streets, alleys, and rights-of-way to erect poles and run wires for delivery of electricity to the utility's customers within the municipal boundaries.

222A. The LGRT legislation requires the tax be based on the number of kWh delivered within the municipal boundaries in order to maintain sufficient revenue levels for the cities. To meet this revenue requirement, LGRT should be allocated using a direct allocation and employing the energy allocator. LGRT revenues should be collected from all customers on Reliant's system.

222B. This franchise arrangement serves the entirety of the transmission and distribution system, benefits all customers in the system and, consequently, the costs should be shared among all customers through base rates. Consistent with Docket No. 22350, using a direct allocation based on a cents per kWh allocator within municipalities and collecting revenues under a spread collection from all customers honors the principle of equity for customers within rate classes.

e. Scope of State University and College Discount.

223. Reliant's proposed rates apply the 20% discount for certain state institutions, required by PURA § 36.351(b), to the transmission and distribution component of the nonbypassable charge. Reliant's proposed rate design did not apply to the 20% discount to the SBF and NDF riders that may be charged to these state institutions.

224. Deleted.

PUBLIC UTILITY COMMISSION OF TEXAS
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
II - I - TOTAL
TEST YEAR ENDED 12/31/2018
CLASS MODEL - TOTAL
II-E-2 TAXES OTHER THAN FEDERAL INCOME TAXES

A	B	C	D	E	F	G	H
				1	2	3	4
Line No	FERC Account	Description	Reference Schedule	Total	Alloc #	Allocation Factor	Residential
1	**Taxes Other than Income Taxes**		II-E-2				
2							
3	**Payroll-Related**		II-E-2				
4	4081	FICA		11,295			6,803
5	4081	FUTA		310			187
6							
7		**Total Payroll**		11,605			6,990
8							
9	**Property Related**		II-E-2				
10	4081	Ad Valorem Tax		94,394			50,721
11							
12		**Total Property**		94,394			50,721
13							
14	**Other**		II-E-2				
15	4081	Sales & Use Tax		-			-
13							
14		**Total Non-Revenue Related**		105,999			57,711
15							
16	**Revenue Related**		II-E-2				
17	4081	Texas Gross Margin Tax		20,027			10,779
18	4081	Municipal Franchise Fees		153,245			51,688
19	4081	Deferred SIT/Local		(327)			(176)
20		**Total Revenue Related**		172,945			62,291
21							
22	**TOTAL TAXES OTHER THAN INCOME TAXES**		II-E-2	278,944			120,002

PUBLIC UTILITY COMMISSION OF TEXAS
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
II - I - TOTAL
TEST YEAR ENDED 12/31/2018
CLASS MODEL - TOTAL
II-E-2 TAXES OTHER THAN FEDERAL INCOME TAXES

				5	6	7	8	9	10	11	12
Line No	FERC Account	Description	Reference Schedule	Secondary <= 10 KVA	Secondary > 10 KVA	Primary Voltage	Transmission Voltage	Lighting SLS	Lighting MLS	Total	Check
1	**Taxes Other than Income Taxes**		II-E-2								
2											
3	**Payroll-Related**		II-E-2								
4	4081	FICA		159	3,483	324	339	162	25	11,295	-
5	4081	FUTA		4	96	9	9	4	1	310	-
6											
7		**Total Payroll**		164	3,578	333	349	166	25	11,605	-
8											
9	**Property Related**		II-E-2								
10	4081	Ad Valorem Tax		1,167	29,911	2,622	5,215	4,606	152	94,394	-
11											
12		**Total Property**		1,167	29,911	2,622	5,215	4,606	152	94,394	-
13											
14	**Other**		II-E-2								
15	4081	Sales & Use Tax		-	-	-	-	-	-	-	-
13											
14		**Total Non-Revenue Related**		1,331	33,489	2,955	5,564	4,772	178	105,999	-
15											
16	**Revenue Related**		II-E-2								
17	4081	Texas Gross Margin Tax		270	6,253	559	1,281	856	30	20,027	-
18	4081	Municipal Franchise Fees		1,890	73,588	7,908	17,728	326	116	153,245	-
19	4081	Deferred SIT/Local		(4)	(102)	(9)	(21)	(14)	(0)	(327)	-
20		**Total Revenue Related**		2,156	79,738	8,458	18,987	1,168	145	172,945	-
21											
22	**TOTAL TAXES OTHER THAN INCOME TAXES**		II-E-2	3,487	113,227	11,413	24,551	5,940	323	278,944	-

DOCKET NO. 22344

GENERIC ISSUES ASSOCIATED WITH APPLICATIONS FOR APPROVAL OF UNBUNDLED COST OF SERVICE RATE PURSUANT TO PURA § 39.201 AND PUBLIC UTILITY COMMISSION SUBSTANTIVE RULE § 25.344	§ § § § §	**PUBLIC UTILITY COMMISSION** **OF TEXAS**

ORDER NO. 40

INTERIM ORDER ESTABLISHING GENERIC CUSTOMER CLASSIFICATION AND RATE DESIGN

In Order No. 17, the Commission concluded that a uniform rate design and customer classification scheme is appropriate for the purpose of standardizing transmission and distribution rates in Texas.[1] This Order confirms that decision. In addition, based upon the evidence, briefs, and arguments of the parties, the Commission adopts a generic customer classification and rate design for transmission and distribution rates as more specifically described in this Order. As the Commission noted in the preliminary orders in the utility-specific unbundled-cost-of-service (UCOS) cases,[2] the resolution of an issue in this generic proceeding is to be applied in each utility's UCOS proceeding.

---

[1] Order No. 17 at 10 (July 24, 2000).

[2] *Application of Sharyland Utilities, L.P. for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No. 22348 (pending); *Application of Texas-New Mexico Power Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No.22349 (pending); *Application of TXU Electric Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No. 22350 (pending); *Application of Southwestern Public Service Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No. 22351 (pending); *Application of Central Power & Light Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No. 22352 (pending); *Application of Southwestern Electric Power Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No. 22353 (pending); *Application of West Texas Utilities Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No. 22354 (pending); *Application of Reliant Energy HL&P for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No. 22355 (pending);

The Commission finds that the six customer classes as proposed in the NUA should be adopted by each of the utilities participating in this proceeding. The Commission agrees with the proponents of the generic customer classifications that cited cost causation as a significant factor in developing a uniform customer class configuration;[8] and, as a guiding principle, the need for flexibility in addressing reconciliation with the price to beat (PTB).[9] The adopted generic class design will best achieve these goals. Accordingly, the Commission adopts the six customer classes proposed in the NUA.

To recognize its unique characteristics, the Commission grants Sharyland Utilities, L.P. (Sharyland) an exemption from certain of the classifications. All of Sharyland's customers are equipped with interval data recorder (IDR) meters, obviating the need for classes to accommodate non-demand-metered customers.[10] Therefore, to the extent that such classes are unnecessary for Sharyland, a modified version of the NUA classes for Sharyland shall be addressed in its individual UCOS case.[11] This exemption does not, however, excuse Sharyland from meeting the underlying principles cited above. Additionally, Sharyland's classifications should mirror those in the NUA for demand-metered classes.

III. Generic Design of Transmission and Distribution Rates

In Order No. 17, the Commission stated that a uniform rate design was appropriate for the purposes of standardizing transmission and distribution rates in Texas.[12] As reflected in the DPL, the majority of the parties participating in this phase of the proceeding favored adoption of a generic design of transmission and distribution rates for all classes, with the exception of the lighting class. Because of the complexity of lighting rate design, as well as the variance in lighting tariffs among utilities, an attempt

[8] *See* Entergy Gulf States' (EGS) Initial Brief at 2-3; Nucor's Initial Brief at 3; Texas Industrial Electric Customers' (TIEC) Initial Brief at 5.

[9] *See* Cleco Connexus *et. al.*, Initial Brief at 1; Texas Retailers Association's (TRA) Initial Brief at 5.

[10] *See* Sharyland Statement of Position at 1.

[11] Docket No. 22348.

[12] Order No. 17 at 10.

to address lighting rate design would be impractical given the time constraints in this docket.[13]

The parties presented their positions through prefiled and live testimony as to the elements to be included in the generic transmission and distribution rate design. These elements included: (1) a customer charge; (2) a facilities/delivery charge; (3) ratchets; (4) kilovolt-ampere billing; (5) transmission cost recovery factor; (6) direct substation service; (7) a standby transmission rate; and (8) power factor correction formula. Those opposed to the generic rate design cited headroom, price signals, and intra-class variations as concerns.[14]

The Commission agrees with the proponents of a generic rate design that the primary principles to be considered in the design of transmission and distribution rates are cost causation, simplicity, and equity to customers within the given rate classes.[15] Further, uniform transmission and distribution rates help to ensure a more vibrant competitive electric market because the uniformity will facilitate entry by new competitors. The Commission finds that such a generic rate design is appropriate, and therefore, shall be adopted by transmission and distribution utilities, consistent with this Order in the individual UCOS cases.

Additionally, the Commission agrees that adoption of a generic rate design for lighting is not realistic given the complexity of the topic. Accordingly, lighting rate design shall be addressed in the individual UCOS cases.

A. Customer Charge

The testimony in this proceeding revealed that the inclusion of a customer charge was generally favored by the parties. Specifically, these parties proposed that the customer charge be comprised of costs that are incurred regardless of system usage such

---

[13] *See* Commission Staff Direct Testimony of Pevoto at 14-15.

[14] *See* Reliant HL&P's (Reliant) Initial Brief at 9-10; City of Houston's Initial Brief at 6-7.

[15] *See* Southwestern Public Service Company's (SPS) Reply Brief at 6; American Electric Power Company's (AEP) Initial Brief at 4.

as billing, metering, and customer service.[16] One party maintained that customer charges should not be applied to the residential class because a fixed charge would discriminate against low use/low income customers.[17] With the exception of TXU, the parties were not opposed to having costs related to metering, which is expected to become a competitive service in the future, recovered through a separately stated charge.[18]

The Commission finds that the adoption of a uniform rate design that includes a customer charge is appropriate. Specifically, the customer charge shall be comprised of costs that vary by customer such as metering, billing and customer service.[19] A customer charge comprised of these elements appropriately tracks cost causation. Additionally, the metering portion of such charges, at a wholesale level, should be separately stated. This will facilitate the unbundling of metering charges when they become a competitive offering.

B. Facilities/Delivery Charge

Also considered in these proceedings was whether the generic rate design should include a facilities/deliveries charge. The majority of the parties maintain that a facilities/delivery charge is appropriate and that the manner in which the charge is to be recovered will be contingent on the metering capabilities of each customer. Because the residential and small commercial[20] classes typically do not have demand meters in place, the majority of the parties agree that a facilities/delivery charge should be recovered on a monthly per-kilowatt-hour (kWh) basis for these customers.[21] Many of the parties propose that demand-metered classes should be billed based on non-coincident peak (NCP) demand. There was greater disparity among the parties as to the issue of whether IDR demand-metered locations should be given different billing treatment from non-IDR

[16] *See* Commission Staff's Initial Brief at 4-5.

[17] *See* Texas Legal Services Center's (TLS) Initial Brief at 5-7.

[18] *See* TXU Electric Company's (TXU) Initial Brief at 4-5.

[19] *See* Nucor's Initial Brief at 5; TXU's Initial Brief at 4.

[20] More properly, the secondary less than 10 kW or kVa (less than 5 kW for TNMP and Reliant) class.

[21] *See* Office of Public Utility Counsel's (OPUC) Reply Brief at 2; EGS's Initial Brief at 4.

PUC DOCKET NO. ______

APPLICATION OF AEP TEXAS INC. FOR AUTHORITY TO CHANGE RATES	**§ § §**	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

PETITION AND STATEMENT OF INTENT TO CHANGE RATES

AEP Texas Inc. (AEP Texas or the Company) files this Petition and Statement of Intent to Change Rates (Petition) in accordance with Subchapter C of Chapter 36 of the Public Utility Regulatory Act (PURA),[1] 16 Tex. Admin. Code (TAC) § 22.243(b), and 16 TAC § 25.247(c)(2)(B). AEP Texas is filing with this Petition a rate filing package (RFP) that complies in all material respects with the Commission's *Transmission & Distribution (TDU) Investor-Owned Utilities Rate Filing Package for Cost-of-Service Determination.*[2]

I. INTRODUCTION

AEP Texas is connected to and serves more than one million electric consumers in the restructured Texas marketplace. As an energy delivery (wires) company, AEP Texas delivers electricity safely and reliably to homes, businesses, and industry across its nearly 100,000 square mile service territory in south and west Texas. AEP Texas also maintains and repairs its lines, reads electric meters, and handles connections and disconnections as directed by the Retail Electric Providers (REPs) selling electricity to end-use customers. Providing safe and reliable electricity is AEP Texas' mission.

The State of Texas is fortunate to have a dynamic and diverse economy and much of the economic growth has been taking place throughout the AEP Texas service territory. New and existing businesses find an attractive environment for growth and investment. Notably, the Rio

[1] PURA is codified at Tex. Util. Code Ann. §§ 11.001–66.016.

[2] Approved November 19, 2015.

Grande Valley and Laredo have consistently been two of the fastest growing areas of the state. When oil field related activity in the well-known "Eagle Ford" shale production area began around the year 2011, AEP Texas saw tremendous growth in areas that had been stagnant for years. Similarly, the oil and gas related activity in west Texas around the Permian Basin and Cline areas also required a significantly higher level of investment to serve the increasing demand for electric service. The port areas of the state served by AEP Texas also have experienced continued growth and expansion, particularly relating to liquefied natural gas (LNG) facilities.

This expanding economy and population growth in its service territory, as well as the need to upgrade and maintain the existing transmission and distribution (T&D) infrastructure, has required AEP Texas to invest nearly six billion dollars in its T&D system since the close of the previous test year, June 30, 2006. The additional T&D investment, for which AEP Texas requests a prudency determination, supports not only the new and expanding oil and gas businesses, but also the expanding communities that create increased need for housing, schools, and commercial enterprises. This growth is a primary driver of new rates for AEP Texas. Other drivers, including the Company's request for AEP Texas-wide consolidated rates, are discussed below and in the direct testimony of AEP Texas President and Chief Operating Officer Judith Talavera.

At the time the Company's existing rates were set in Docket Nos. 33309 and 33310, AEP Texas consisted of two separate corporate entities, AEP Texas Central Company (TCC) and AEP Texas North Company (TNC). However, these companies were managed and operated as a single business under the brand name "AEP Texas." In Docket No. 46050, TCC and TNC sought and received the approval of the Commission to merge and change its name to AEP Texas Inc. (AEP

Texas).[3] After the merger, as ordered by the Commission, AEP Texas established the Central and North "divisions" within the merged utility and continued to maintain separate rates, riders, and tariff manuals for the Central and North Divisions. The then-existing TCC and TNC base rates did not change and remained in force for customers taking service within the Company's two divisions. In this case, as contemplated by the Commission in its order approving the merger, AEP Texas proposes to consolidate rates for AEP Texas' Central and North Divisions.[4]

This rate case also will allow AEP Texas to realign its rates to be consistent with the changes that have taken place in the Company's customer classes over the last 12 years. For instance, some customer classes have grown significantly while others have decreased in size, which has resulted in a mismatch of revenues collected from customer classes relative to the costs to serve those customers. Resetting rates will realign rates with the current existing customer base.

Additionally, as discussed by AEP Texas witness Jennifer Jackson, the Company proposes to: 1) terminate the Advanced Metering System Cost Recovery Factor Rider (AMSCRF); 2) reset the baseline for the Distribution Cost Recovery Factor Rider (DCRF); 3) determine the revenue requirement for the Transmission Cost Recovery Factor Rider (TCRF) and move all transmission cost recovery to the TCRF; 4) move energy efficiency costs from base rates to Rider Energy Efficiency Cost Recovery Factor (EECRF); and 5) modify or discontinue tariffs that are now outdated in light of current circumstances.

---

[3] *See Application of AEP Texas Central Company, AEP Texas North Company, and AEP Utilities, Inc. for Approval of Merger*, Docket No. 46050, Final Order at Ordering Paragraph No. 1 (Dec. 12, 2016).

[4] *Id.* at Ordering Paragraph No. 2 ("Applicants shall maintain separate TCC and TNC divisions, which will continue to charge separate rates and riders, and maintain separate tariffs, unless and until such time as the Commission may consider and approve consolidated rates and tariffs.").

Finally, the timing of this filing fits with the Commission's Rate Review Schedule rule (16 TAC § 25.247), which requires AEP Texas to file a comprehensive rate case on or before May 1, 2019, subject to extensions that AEP Texas has not sought.

Ultimately, the resolution of the issues raised in this case will facilitate AEP Texas' continued deployment of innovative technology, while simultaneously maintaining, operating, and expanding a flexible grid that provides for the safe and reliable delivery of electricity.

II. AUTHORIZED REPRESENTATIVES

AEP Texas' authorized representative for service of all pleadings and other documents is:

Jennifer J. Frederick
Regulatory Case Manager
American Electric Power Service Corporation
400 West 15th Street, Suite 1520
Austin, Texas 78701
Telephone: (512) 481-4573
Facsimile: (512) 481-4591
jjfrederick@aep.com

AEP Texas' authorized legal representatives are:

Rhonda Colbert Ryan
Jerry N. Huerta
Melissa A. Gage
American Electric Power Service Corporation
400 West 15th Street, Suite 1520
Telephone: (512) 481-3321
Facsimile: (512) 481-4591
rcryan@aep.com
jnhuerta@aep.com
magage@aep.com

John F. Williams
William Coe
Patrick Pearsall
Duggins Wren Mann & Romero, LLP
600 Congress, Suite 1900
Austin, Texas 78701
Telephone: (512) 744-9300
Facsimile: (512) 744-9399
jwilliams@dwmrlaw.com
wcoe@dwmrlaw.com
ppearsall@dwmrlaw.com

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

AEP TEXAS INC.

FOR AUTHORITY TO CHANGE RATES

DIRECT TESTIMONY OF

JENNIFER L. JACKSON

FOR

AEP TEXAS INC.

MAY 2019

ERCOT Transmission Matrix. The proposed access fee is determined by dividing the proposed TCOS revenue requirement by the most recently approved AEP Texas system average ERCOT 4 CP demand. The resulting access fee becomes an input to the total ERCOT Matrix. The proposed AEP Texas TCOS revenue requirement, AEP Texas system ERCOT average 4 CP, and proposed access fee are shown in Schedule III-A-1. Currently, the Central and North Divisions are represented in the ERCOT Matrix individually. AEP Texas intends to request consolidation of the divisions into a single AEP Texas access fee in its next FERC filing. The ERCOT Transmission Matrix determines the overall ERCOT Transmission postage stamp rate billed to all Distribution Service Providers (DSP) in ERCOT for Transmission Service provided to REPs. It is important to understand that the TCOS does not directly set the Transmission System Charge rate billed to the REPs through the Distribution Tariffs, but the result of the TCOS is an input to the ERCOT Transmission Matrix that in turn produces the Transmission System Charge.

The Transmission System Charge contained in the distribution tariffs is a non-bypassable charge developed ***from the ERCOT Transmission Matrix*** that is billed to the REPs for Transmission Service provided to them by the Transmission Service Providers. The AEP Texas Transmission access fee developed from the TCOS is an input along with the access fees of all other ERCOT Transmission Service Providers. Docket No. 48928, *ERCOT Wholesale Transmission Matrix* (approved by the Commission at the April 4th Open Meeting) is the most recently approved ERCOT Matrix for ERCOT billings in 2019. The ERCOT average 4CP demands are based on the ERCOT peak days in each of the months of June, July, August, and September of 2018. The revenue requirement for the Transmission System Charge contained in the Distribution rates is determined by the ERCOT Matrix postage stamp rate as shown in Schedule III-A-1 in this filing. Transmission Costs can be recovered through the base Transmission System Charge and/or through the TCRF rider that authorizes a Distribution Company to charge or credit its customers for the amount of wholesale Transmission cost changes approved or allowed by the Commission, to the extent that such costs vary from the Transmission Service cost utilized to fix the base Transmission rates. Together, the Transmission and Distribution cost-of-service studies make up the AEP Texas total company revenue requirement.

The term "Transmission Voltage" is used to describe a class of retail customers in the Distribution Tariff that take wires service from the Company at a voltage of 69 kV or greater. A retail customer that takes wires service at this voltage or greater is taking service directly from the Transmission System and thus is described in the AEP Texas Tariff as a Transmission Voltage Service customer.

Q. HOW IS AEP TEXAS PROPOSING TO RECOVER THE TRANSMISSION SERVICE EXPENSE?

A. AEP Texas has two options for the recovery of the Transmission System expenses as determined by the ERCOT Wholesale Transmission Matrix. The first option is to recover the transmission system expenses as determined by the ERCOT Wholesale Transmission Matrix through the Transmission System base rate charges for each rate class and reset the TCRF to reflect only those TCOS charges that are not reflected in the base rates for Transmission Service. The second option is recovery of all Transmission expenses, including future updates to TCOS Wholesale Transmission rates through the TCRF rider. AEP Texas proposes to move recovery of all Transmission expenses to the TCRF.

Q. WHAT DETERMINANTS ARE USED IN THE DEVELOPMENT OF PROPOSED LIGHTING FACILITIES RATES FOR THE LIGHTING CLASSES?

A. In addition to the Customer Charge (if applicable) and the Transmission and Distribution System Charges, the lighting classes are subject to a monthly lighting facilities charge based on the type of lamp and fixture utilized by the lighting customer. Several determinants are needed to update the lighting facilities rates including the current rates for each Division, the current revenues associated with each fixture type, total fixture counts for each fixture type, and the total lighting class facilities revenue requirement.

The equalized class cost-of-service study provides the total Distribution function revenue requirement for the total lighting class. The total lighting class is composed of the Municipal Street Lighting (MSL) and Non-Roadway Lighting classes of customers. The lighting Distribution revenue requirement recovers the costs associated not only with Distribution Service, but also with the costs associated with the types and sizes of lighting fixtures offered by AEP Texas. Because the total Distribution Service function revenue requirement includes distribution services and fixtures costs for both Lighting classes, a process is used to separate the facilities costs from other Distribution Service costs for each class. The amount of revenue requirement attributable to each of the lighting classes must be determined. The revenue requirement is assigned to each of the two lighting classes by first determining the percent of total lighting plant attributed to each lighting class. The cost-of-service study provides the test year net plant account balances for account 371 (non-roadway lighting) and account 373 (municipal street lighting). The individual plant balances are divided by the total of both account balances to arrive at the percent of plant for each lighting class. The resulting percent of plant is then applied to the total lighting distribution revenue requirement to arrive at the total Distribution revenue requirement for each lighting class.

Once the individual lighting class Distribution revenue requirement has been determined, the individual lighting class revenue requirement must then be assigned to distribution wires service and the lighting fixture facilities. The lighting fixture facilities revenue requirement has been determined by taking the percent of total Distribution plant in service and total Distribution net revenue requirement from the cost-of-service study and applying that percentage to the total MSL and Non-Roadway Lighting net plant in service as shown in the cost-of-service study. That result is compared with the total test year revenue associated with lighting facilities and the difference provides the necessary change to the lighting fixture charges. In this case, AEP Texas is proposing to consolidate and streamline the lighting fixture offerings and charges for both the MSL and Non-Roadway lighting fixtures, except for the city or county-specific lighting fixtures highlighted earlier in this testimony.

PUC DOCKET NO. 38339
SOAH DOCKET NO. 473-10-5001

APPLICATION OF CENTERPOINT ELECTRIC DELIVERY COMPANY, LLC, FOR AUTHORITY TO CHANGE RATES	§ § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ON REHEARING

This Order addresses the application of CenterPoint Electric Delivery Company, LLC for authority to change its rates. On June 30, 2010, CenterPoint filed its application with the Public Utility Commission of Texas requesting authority to increase its transmission and distribution rates and to reconcile costs related to its advanced metering system (AMS) deployment. CenterPoint originally requested a total net increase of $110 million: $18 million represented the net increase associated with transmission service and $92 million associated with retail delivery service. CenterPoint requested a rate of return on investment of 9.0%, based on a proposed capital structure having 50-50 ratio of debt to equity; a 6.74% cost of debt; and a return on equity of 11.25%.

On December 3, 2010, the State Office of Administrative Hearings (SOAH) administrative law judges (ALJs) issued a proposal for decision in which they recommended an overall rate increase for CenterPoint of $21.483 million.[1] For the reasons discussed in this Order, the Commission adopts in part and rejects in part the proposal for decision, including findings of fact and conclusions of law, and determines that CenterPoint's appropriate system-wide adjusted rates will lead to a retail revenue increase of $14.65 million and an overall revenue requirement increase of $2.4 million for both retail and wholesale combined.[2]

[1] Proposal for Decision (PFD), Attachment ALJ-3 at 1, line 10, column 2 "Difference between ALJs' Rec. and CNP, current revenues." (Dec. 3, 2010).

[2] Revised Number Runs and Associated Workpapers, Attachment Comm-3 AFTER Postage Stamp Update, at 1, line 10, column 2 (Feb. 18, 2011).

40. PURA § 39.107(h) entitles CenterPoint to impose a surcharge to recover its reasonable and necessary costs incurred in deploying AMS.

41. Pursuant to P.U.C. SUBST. R. 25.130(k)(4) and (6) and finding of fact 34 in Docket No. 35639, CenterPoint has excluded from the surcharge calculations the reasonable and necessary costs of installed AMS equipment, placing those costs in its proposed base rates.

42. CenterPoint's treatment of the cost of removing the electro-mechanical meters being replaced by advanced meters is consistent with the Commission's rules, the Final Order in Docket No. 35639, and the FERC Uniform System of Accounts.

43. CenterPoint's rates, as approved in this proceeding, are just and reasonable in accordance with PURA § 36.003.

V. Ordering Paragraphs

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

1. The proposal for decision prepared by the SOAH ALJs is adopted to the extent consistent with this Order.

2. CenterPoint's application is granted to the extent consistent with this Order.

3. CenterPoint's implementation and administration of Rider DTA shall be consistent with this Order.

4. CenterPoint shall file tariffs consistent with this Order within 20 days of the date of this Order. No later than ten days after the date of the tariff filings, Staff shall file its comments recommending approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to the Staff's recommendation shall be filed no later than 15 days after the filing of the tariff. The Commission shall by letter approve, modify, or reject each tariff sheet. The tariff sheets shall become effective 30 days after approval by Commission letter or deemed approved pursuant to paragraph 5.

5. The tariff sheets shall be deemed approved on the expiration of 20 days from the date of filing, in the absence of written notification of modification or rejection by the Commission. If any sheets are modified or rejected, CenterPoint shall file proposed revisions of those sheets in accordance with the Commission's letter within ten days of the date of that letter, and the review procedure set out above shall apply to the revised sheets. The tariff sheets shall become effective 30 days after approval.

6. Copies of all tariff-related filings shall be served on all parties of record.

7. CenterPoint shall begin tracking its uncollectible expenses by customer class and include that result in its next base rate case.

8. CenterPoint shall make modifications to its approved AMS deployment plan to account for the accelerated deployment, and also to account for its plans to modify its pricing methodology, within 60 days of issuance of this Order. These changes shall be provided in CenterPoint's monthly compliance reporting, in Project No. 36699.

9. CenterPoint shall file a deployment plan with the Commission detailing its intelligent grid (IG) project, within 60 days of issuance of this Order.

10. When CenterPoint seeks cost recovery for the remaining costs of its IG project, it shall file a cost-benefit analysis of its IG project.

11. With regard to its IG project, CenterPoint shall file a report with the Commission on a quarterly basis with a summary of what it has deployed. This report shall include the monthly reports CenterPoint is required to file with the Department of Energy. The schedule for these reports shall commence no later than 60 days following the issuance of this Order.

12. CenterPoint shall implement a network operations center as soon as reasonably possible and report to the Commission when it is operational.

13. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted, are denied.

SIGNED AT AUSTIN, TEXAS the 23rd day of June 2011

PUBLIC UTILITY COMMISSION OF TEXAS

BARRY T. SMITHERMAN, CHAIRMAN

DONNA L. NELSON, COMMISSIONER

KENNETH W. ANDERSON, JR., COMMISSIONER

q:\cadm\orders\final\38000\38339 mfr.docx

TARIFF CONTROL NO. 39391 11 JUL 13 AM 11:10

TARIFF FILING OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC IN COMPLIANCE WITH THE ORDER ON REHEARING IN DOCKET NO. 38339	§ § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

TARIFF FILING OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC IN COMPLIANCE WITH THE ORDER ON REHEARING IN DOCKET NO. 38339

July 13, 2011

Contact: Matthew A. Troxle
CenterPoint Energy, Inc.
1111 Louisiana Street
Houston, Texas 77002
(713) 207-5287
(713) 207-0046 (fax)
Email: matthew.troxle@centerpointenergy.com

In compliance with Ordering Paragraph No. 4 of the ORDER ON REHEARING in Docket No. 38339 dated June 23, 2011, CenterPoint Energy Houston Electric, LLC (CEHE) hereby submits a clean copy of its Tariff For Retail Delivery Service and Tariff For Wholesale Transmission Service. CEHE's proposed effective date is September 1, 2011, to coincide with the effective date of the Rate Case Expense Rider in Docket No. 39127 as well as the TCRF in Docket No. 39459. As the amended TCRF filed in Docket No. 39459 on June 30, 2011, will become effective September 1, 2011, it will replace the attached TCRF at that time. The attached TCRF would become effective <u>only</u> if the effective date for the tariffs is prior to the requested September 1, 2011 date.

In addition to the necessary changes, CEHE has, at the request of Texas Industrial Energy Consumers and with the consent of the Commission Staff, the Office of Public Utility Counsel, State of Texas' agencies and institutions of higher education, Gulf Coast Coalition of Cities, Texas Coast Utilities Coalition, and City of Houston/Houston Coalition of Cities, changed the collection of Transmission Distribution System charge from Per Billing kVA to Per 4CP kVA, and the Transmission Municipal Account Franchise Credit from Per Billing kVA to Per kWh. CEHE has made this change to avoid litigation of whether its proposal in Tariff Control No. 39458 complied with the Commission's decision in Docket No. 38339, and without prejudice to proposing its original methods of collection of these charges in future rate cases.

1

§25.193. Distribution Service Provider Transmission Cost Recovery Factor (TCRF).

(a) **Application.** The provisions of this section apply to all investor-owned distribution service providers (DSPs) providing distribution service within the Electric Reliability Council of Texas (ERCOT) region to retail electric providers and other customers of the distribution system.

(b) **TCRF authorized.**

(1) A DSP subject to this section that is billed for transmission service by a transmission service provider (TSP) pursuant to §25.192 of this title (relating to Transmission Service Rates) shall be allowed to include within its tariff a TCRF clause that authorizes the DSP to charge or credit its customers for the amount of wholesale transmission cost changes approved or allowed by the commission to the extent that such costs vary from the transmission service cost utilized to fix the base rates of the DSP. The DSP shall update its TCRF twice per year on March 1 and September 1 to pass through the wholesale transmission cost changes billed by a TSP. For the March 1 update, the DSP shall file a request to update its TCRF no later than December 1; and for the September 1 update, no later than June 1. Within 45 days after a DSP files a request to update its TCRF, the commission shall issue an order establishing the amount of the revised TCRF and suspend the effective date of the revised TCRF as necessary so that the new TCRF charges will take effect on March 1 or September 1, as applicable.

(2) A DSP shall include in its TCRF update calculation:

(A) the cost of wholesale transmission cost changes approved or allowed by the commission to the extent that such costs vary from the transmission service cost utilized to fix the rates of the DSP; and

(B) an adjustment amount, which shall equal:

(i) the actual costs paid by the DSP during the review period to TSPs as a result of increases in the TSPs' wholesale transmission rates above the wholesale transmission rates of the TSPs used to develop the retail transmission charges of the DSP in the DSP's last rate case; minus

(ii) the revenues recovered through the DSP's TCRF minus the portion of the adjustments approved by the commission in the DSP's most recent two TCRF filings that were in effect during the review period.

(iii) For a March 1 TCRF update, the adjustment shall reflect the six-month period beginning with the preceding May 1 and continuing through October 31 (review period); for a September 1 update, the adjustment shall reflect the six-month period beginning with the preceding November 1 and continuing through April 30 (review period). In no event shall a DSP's TCRF clause result in the DSP recovering more than its actual cost of wholesale transmission service included in the TCRF.

(c) **TCRF Formula.** The TCRF for each class shall be computed pursuant to the following formula:

$$\frac{\{[\sum_{i=1}^{N}(NWTR_i * NL_i) - \sum_{i=1}^{N}(BWTR_i * NL_i)] * 1/2 * ALLOC\} + ADJ}{BD}$$

Where:	$NWTR_i$ is the new wholesale transmission rate of a TSP, approved by the commission by order or pursuant to commission rules, since the DSP's last rate case;
	$BWTR_i$ is the base wholesale transmission rate of the TSP represented in the $NWTR_i$, used to develop the retail transmission charges of the DSP in the DSP's last rate case;
	NL_i is the DSP's individual 4CP load component of the total ERCOT 4CP load information used to develop the $NWTR_i$;
Where:	ADJ = $\sum_{p=1}^{6}\{EXP_p - (REV_p - ADJP1_p - ADJP2_p)\}$ ADJ = adjustment to Rate Class TCRF; EXP_p = transmission expenses not included in base rates for period p; REV_p = TCRF revenue for period p; $ADJP1_p$ = $1/6^{th}$ of ADJ calculated in the previous TCRF update for the periods 5 and 6; $ADJP2_p$ = $1/6^{th}$ of ADJ calculated in second previous TCRF update for the periods 1 through 4;
	ALLOC is the class allocator approved by the commission to allocate the transmission revenue requirement among classes in the DSP's last rate case, unless otherwise ordered by the commission; and,
	BD is each class's billing determinant (kilowatt-hour (kWh), or kilowatt (kW), or kilovolt-ampere (kVa)) for the previous March 1 through August 31 period for the March 1 TCRF update, and for the previous September 1 through February 28 period for the September 1 TCRF update.

(d) **TCRF charges**. A DSP's TCRF charge shall remain in effect until adjusted under this section or until the DSP's delivery rates change pursuant to a commission order in a rate proceeding.

(e) **Reports.** The DSP shall maintain and provide to the commission semi-annual reports containing all information required to monitor the costs recovered through the TCRF clause. This information includes, but is not limited to, the total estimated TCRF cost for each month, the actual TCRF cost on a cumulative basis, the amount of transmission costs included in base rates, total revenues resulting from the TCRF, and the calculation of the amount to be recovered under subsection (b)(2) of this section. The reports shall be filed by March 31 and September 30 of each year.

RECEIVED
2015 OCT 15 PM 3: 12
PUBLIC UTILITY COMMISSION
FILING CLERK

DOCKET NO. 44620

APPLICATION OF SHARYLAND UTILITIES, L.P. TO REVISE ITS TCRF CLASS ALLOCATION FACTORS AND REQUEST FOR GOOD CAUSE EXCEPTION FROM P.U.C. SUBST. R. 25.193(c)	§ § § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This order addresses Sharyland Utilities, L.P.'s application to revise its transmission cost recovery factor (TCRF) allocation factors before its next base rates case. According to Sharyland, the TCRF allocation factors no longer reasonably represent each class's use of the transmission system because Sharyland's primary-service class has experienced extraordinary growth compared to other rate classes since Sharyland's last base-rate case in 2012.

The Commission finds that it has authority to grant Sharyland's application under 16 TAC § 25.193(c), which states, in relevant part, that the formula for calculating the TCRF should use "the class allocator approved by the commission to allocate the transmission revenue requirement among classes in the DSP's last rate case, unless otherwise ordered by the commission." The unless-otherwise-ordered language provides ample authority to change the allocation factors outside of a base-rate proceeding.

The Commission concludes that the extraordinary circumstances of this case justify changing the allocation factors before Sharyland's next rate case in order to avoid the imposition of unjust and unreasonable rates. The Commission finds that it is appropriate to deviate from the general requirement of using the allocation factors set in the utility's last rate case when it is justified by extraordinary facts and circumstances, like in this case. Therefore, the Commission's conclusions regarding the facts and circumstances found in this case are confined only to this case.

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

98

I. Findings of Fact

Procedural History

1. On April 8, 2015, Sharyland filed an application to revise its TCRF allocation factors. The application included the direct testimony of James W. Daniel.

2. The following parties petitioned for and were granted intervenor status: Texas Industrial Energy Consumers (TIEC); the Office of Public Utility Counsel (OPUC); TXU Energy Retail Company, LLC; the Alliance for Retail Markets (ARM); Pioneer Natural Resources USA, Inc.; Targa Pipeline Mid-Continent WestTex LLC; and the St. Lawrence Cotton Growers' Association. Commission Staff also participated.

3. On April 24, 2015, in Order No. 3, the Commission ALJ found that Sharyland's application and notice were sufficient.

4. On May 12, 2015, Sharyland filed an affidavit of notice.

5. OPUC and TIEC each timely filed a request for a hearing.

6. The following parties timely filed at least one statement of position: TXU Energy and ARM (jointly, the REP Group); St. Lawrence; Targa; and Pioneer.

7. On August 7, 2015, TIEC filed the direct testimony of Jeffry Pollock and errata to Mr. Pollock's testimony, while OPUC filed the direct testimony of Clarence Johnson.

8. On August 21, 2015, Commission Staff filed the direct testimony of William Abbott.

9. On September 8, 2015, TIEC, Commission Staff, and OPUC filed respectively the cross-rebuttal testimony of Jeffry Pollock, William Abbott, and Clarence Johnson, while Sharyland filed the rebuttal testimony of James Daniel.

10. TIEC filed errata to Jeffry Pollock's direct testimony on September 10, 2015, and errata to his cross-rebuttal testimony on September 17.

11. On September 24, 2015, the Commission held a hearing on the merits and issued an order requesting briefing.

12. On September 29, 2015, the following parties filed briefs: St. Lawrence; OPUC; Commission Staff; TIEC, Targa, and Pioneer (jointly); the REP Group; and Sharyland.

13. On October 8, 2015, the Commission granted Sharyland's application at an open meeting.

Distinguishing Facts

14. Sharyland applied in this separate docket to change the TCRF allocation factors almost two months prior to filing its regular TCRF update.[1]

15. The primary-service class in Sharyland's service area has experienced significant load growth, which has caused sizeable interclass and intra-class disparities.[2] For example, from 2012 to 2014, the primary-service class's total energy usage grew from approximately 448,000 MWh to approximately 958,000 MWh.[3] During the same time period, the primary-service class's contribution to the ERCOT 4CP load grew from 56 MW to 126 MW, which is 42% of Sharyland's total contribution.[4]

16. If the Commission did not revise the allocation factors, primary-service customers without interval data recorders would likely be paid for using the transmission system.[5]

17. Sharyland entered ERCOT's competitive market in May 2014 without a price-to-beat mechanism or gradual transition; thus, customers have had less time to educate themselves regarding finding competitive rates.[6]

18. In Sharyland's first rate case after the transition to competition, a partial movement towards cost-based rates as well as the shifting of some customers between classes has magnified the resulting impact on certain customers.[7]

[1] *See* Application; *see also Petition of Sharyland for Administrative Approval of TCRF Update Pursuant to P.U.C. Subst. R. 25.193*, Docket No. 44785, Application (Jun. 1, 2015).

[2] Direct Testimony of James Daniel at 5-9.

[3] *Id.* at 5.

[4] *Id.*

[5] *Id.* at 7.

[6] *Relating to a Project Regarding Sharyland Utility Complaints*, Project No. 44592, Staff Report at 17-18, 33-35 (Sept. 17, 2015) (admitted into evidence in Docket No. 44620 as TIEC exhibit 3).

[7] *Id.* at 4, 6-7, 12-14.

19. Sharyland's predecessor utility had a favorable power contract with Southwestern Public Service Co. that expired in December 2013; without the benefit of that contract, Sharyland must purchase power at today's market rate.[8]

20. Sharyland's residential customers are facing distribution rates over three times higher than those charged by other transmission-and-distribution utilities (TDUs).[9]

21. Compared to residential customers of other TDUs in Texas, Sharyland's residential customers use on average significantly more electricity during the winter months.[10]

22. Sharyland has extremely low customer density.[11]

23. Sharyland is the smallest TDU in Texas—a fact which magnifies the impact of its out-of-date cost-of-service study.[12]

Allocation Factors

24. Under 16 TAC § 25.193(c), the class allocator approved by the Commission in the last rate case is to be used in calculating the TCRF unless otherwise ordered by the Commission.

25. The extraordinary circumstances in this case, several of which are detailed in findings of fact 13-22, justify the Commission invoking the unless-otherwise-ordered language in 16 TAC § 25.193(c) in order to change the TCRF allocation factors before Sharyland's next rate case.

26. Section 36.003(a) of the Public Utility Regulatory Act (PURA)[13] requires the Commission to ensure that each rate made by an electric utility is just and reasonable.

27. If the Commission did not change the allocation factors in this proceeding, at least some customers would likely be charged unjust and unreasonable rates under Sharyland's TCRF.

---

[8] *Id.* at 4, 6, 14.

[9] *Id.* at 3-4, 7-8.

[10] *Id.* at 3, 16.

[11] *Id.* at 3, 19-20.

[12] Direct Testimony of Clarence Johnson at 12.

[13] Texas Utilities Code §§ 11.001-66.016 (West 2007 & Supp. 2014).

II. Conclusions of Law

1. Sharyland is an electric utility as defined in PURA §§ 11.004 and 31.002(6).

2. The Commission has jurisdiction over this matter under PURA chapter 36.

3. Sharyland's application was processed in accordance with the requirements of PURA, the Administrative Procedure Act,[14] and the Commission's rules.

4. Under 16 TAC § 25.193(c), the Commission may order that allocation factors other than those approved in a utility's last rate case be used to calculate the TCRF.

5. The extraordinary circumstances in this case justify the Commission changing the TCRF allocation factors under 16 TAC § 25.193(c) before Sharyland's next rate case in order to ensure that Sharyland's TCRF rates are just and reasonable.

III. Ordering Paragraphs

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

1. The Commission grants Sharyland's application.

2. Effective December 1, 2015, Sharyland's allocation factors shall be revised in accordance with Sharyland's application. Such revisions shall be implemented from December 1, 2015 forward and shall be used in Sharyland's December 1, 2015 TCRF update filing.

3. The entry of this Order represents the Commission's conclusions and holdings regarding the facts underlying this case and shall not be regarded as precedent in any future Commission proceeding.

4. All other motions, requests for entry of specific findings of fact and conclusions of law, and other requests for general or specific relief, if not expressly granted herein, are denied.

[14] Tex. Gov't Code §§ 2001.001-.902 (West 2008 & Supp. 2014).

SIGNED AT AUSTIN, TEXAS the 15th day of October, 2015.

PUBLIC UTILITY COMMISSION OF TEXAS

Donna L. Nelson

DONNA L. NELSON, CHAIRMAN

KENNETH W. ANDERSON, JR., COMMISSIONER

Brandy M. Marquez

BRANDY MARTY MARQUEZ, COMMISSIONER

Q:\CADM\ORDERS\FINAL\44000\44620 FO.docx

PUC DOCKET NO. 48401
SOAH DOCKET NO. 473-18-3981

RECEIVED
2018 DEC 20 PM 3:24
PUBLIC UTILITY COMMISSION
FILING CLERK

APPLICATION OF TEXAS-NEW MEXICO POWER COMPANY TO CHANGE RATES	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the application of Texas-New Mexico Power Company (TNMP) for authority to change its rates. TNMP filed a settlement agreement that resolves certain issues among the parties in this proceeding. The Commission approves TNMP's application, as modified by the settlement agreement, to the extent provided in this Order.

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

I. Findings of Fact

Applicant

1. TNMP is a Texas corporation and a wholly owned subsidiary of PNM Resources, Inc.
2. TNMP provides electric transmission and distribution services in Texas.

Application

3. On May 30, 2018, TNMP filed an application and statement of intent to change its transmission and distribution rates effective July 5, 2018.
4. No party objected to the sufficiency of the application.
5. Concurrent with filing its application with the Commission, TNMP filed a similar petition and statement of intent with each incorporated municipality in its Texas service area that has original jurisdiction over its rates.
6. In its application, TNMP used a test year of January 1, 2017 through December 31, 2017.
7. TNMP initially sought Commission approval to adjust its transmission and distribution rates for approval of a $31.3 million increase in base rates and other revenues with respect to its retail Texas jurisdiction. TNMP also sought changes to the structure and terms of its tariffs.

368

00001

82. TNMP's catastrophe reserve results in savings, and ratepayers will receive the benefit of those savings.

Baseline Values for Interim Updates of Transmission Rates

83. The signatories agreed that, when TNMP files an application to update its transmission rates on an interim basis under 16 Texas Administrative Code (TAC) § 25.192(h), the baseline values to be used in that application are as provided in exhibit D to the settlement agreement.

84. It is appropriate for TNMP to use the baseline values set forth in exhibit D to the settlement agreement for interim updates of transmission rates.

Baseline Values for Transmission Cost Recovery Factor (TCRF) Filings

85. The signatories agreed that, when TNMP files an application for approval of a transmission cost recovery factor under 16 TAC § 25.193, the baseline allocators to be used in that application are those set forth in exhibit E to the settlement agreement.

86. The signatories agreed that the TCRF class allocation factors set forth in exhibit E to the settlement agreement would continue to be used to set TNMP's TCRF rates until the September 2020 TCRF takes effect.

87. TNMP agreed to file an informational filing in March 2020 providing the 2019 four-coincident-peak (4CP) data and to implement the September 2020 TCRF using the 2019 4CP data. TNMP agreed that, if (as a result of using the 2019 4CP data) the residential class's allocation increases above the percentage provided for that class in exhibit E to the settlement agreement, the first \$250,000 in increased allocated cost will instead be allocated to the secondary > 5 kilowatts (kW) class, and the next \$50,000 will be borne by TNMP, with any excess above these amounts being allocated to the residential class. The signatories also agreed that the \$250,000 and \$50,000 reallocations, if any, may be used in any subsequent TCRF proceeding using the 2019 4CP data to the extent that they have not already been applied.

88. The signatories agreed that TCRFs filed after the September 2020 TCRF would be implemented using the 2019 4CP data until TNMP files its next base-rate case, unless the Commission provides otherwise by rule or order.

89. The settlement agreement's treatment of the baseline values for TCRF filings is appropriate.

Baseline Values for Distribution Cost Recovery Factor (DCRF) Filings

90. The parties agreed that, when TNMP files an application for approval of a distribution cost recovery factor (DCRF) under 16 TAC § 25.243, the baseline values to be used in that application are those set forth in exhibit F to the settlement agreement.

91. It is appropriate for TNMP to use the baseline values set forth in exhibit F to the settlement agreement in DCRF applications.

Allocation of Revenue Increase

92. The signatories agreed that the retail revenue increase would be distributed among the rate classes as set forth in exhibit G to the settlement agreement.

93. The allocation of the retail revenue increase set forth in exhibit G to the settlement agreement is just and reasonable.

Rate Design and Tariff Approval

94. The signatories agreed for TNMP to use the tariffs and rate design set forth in exhibit H to the settlement agreement.

95. The rate design in exhibit H to the settlement agreement waives the application of demand ratchet provisions for each nonresidential secondary service customer that has a maximum load factor equal to or below 25%.

96. The tariffs in exhibit H to the settlement agreement include a wholesale tariff for transmission service.

97. The tariffs and rate design in exhibit H to the settlement agreement are just and reasonable.

Postemployment benefits tracker

98. The signatories agreed that TNMP could establish one or more reserve accounts for expenses for pension and other postemployment benefits.

Interim Rates

99. On November 5, 2018, TNMP filed an agreed motion for interim rates.

RECEIVED

10 MAY 17 PM 1:36

PROJECT NO. 37909

RULEMAKING PROCEEDING TO AMEND PUC SUBST. R. 25.193, RELATING TO DISTRIBUTION SERVICE PROVIDER TRANSMISSION COST RECOVERY FACTORS (TCRF)	§ § § § §	PUBLIC UTILITY COMMISSION FILING CLERK OF TEXAS

TEXAS INDUSTRIAL ENERGY CONSUMERS' COMMENTS ON THE PROPOSAL FOR PUBLICATION

Texas Industrial Energy Consumers (TIEC) appreciates the opportunity to submit the following comments on the proposed amendments to P.U.C. Subst. R. 25.193.

I. INTRODUCTION

The transmission cost recovery factor (TCRF) available to distribution service providers (DSPs) under existing P.U.C. Subst. R. 25.193 is a generous cost recovery mechanism that is more than sufficient to allow "timely" recovery of wholesale transmission costs, as envisioned by PURA § 35.004(d). Like any cost of a regulated utility, transmission costs are subject to change. When one cost increases for a utility, that increase is often offset by load growth or decreases in other costs. These types of relationships are the reason for the general policy against piecemeal ratemaking, since a utility's cost increases and offsetting decreases can only be properly explored through a comprehensive rate proceeding. Unlike other costs, however, existing Rule 25.193 allows DSPs to account for increases in wholesale transmission costs without undergoing a full rate case. This interim TCRF adjustment mechanism greatly reduces DSPs' regulatory lag and shifts risk to consumers by allowing DSPs to change an isolated component of their rates without a thorough vetting of their entire cost of service. The bi-annual interim update process is more than sufficient to provide timely recovery of wholesale transmission costs, and no additional measures are necessary or appropriate.

Yet, in addition to allowing DSPs to periodically adjust their rates outside of a rate case, the proposal for publication would also allow DSPs to defer the costs associated with transmission cost of service (TCOS) increases that occurred after the DSP's last TCRF update, and true-up any under- or over-recoveries in their next TCRF update. As a result, the proposal for publication would *completely* eliminate DSPs' risk and regulatory lag with respect to wholesale transmission costs. These proposed changes are overreaching, unnecessary, and

10

problem because the rule could be read to leave open the possibility that DSPs would continue in a state of over-recovery until they decided to submit an interim TCRF filing, which might not happen for some time. This would shift substantial risk to customers, and could result in intergenerational inequities if the DSPs' customers change between the over-collection and refund periods. Although the proposal for publication references truing-up costs and revenues over a six month period, it is not clear that this provision requires DSPs to update their TCRFs every six months. Rather, this provision could be interpreted to mean that only the last six months prior to the TCRF would be trued-up in the subsequent TCRF update, or that DSPs that fail to file for another TCRF update after six months are relieved of the obligation to true-up costs and revenues for that period. These potential interpretations of the proposed rule create significant cost exposure for customers. To correct this problem, TIEC has added language to clarify that that DSPs must file for an interim TCRF update at the next available opportunity if they begin to over-recover their transmission costs.

Consistent with the above discussion, TIEC submits the following to replace subsection (b)(2) of the proposal for publication:

> <u>(2) A DSP may accrue the net impact of Commission-approved changes to wholesale transmission rates placed in effect after its most recent TCRF update. The accrual shall be taken into account in the DSP's next TCRF update; however, in no event shall this result in the DSP recovering more than its actual cost of wholesale transmission services. A DSP that has over-collected must file a TCRF update at the next available opportunity. The over-collection shall be credited to the TCRF with interest at the DSP's weighted average cost of capital as approved in the DSP's most recent rate case.</u>

<u>Subsection (b)(3).</u>

Several changes to the TCRF formula are necessary to ensure that it properly accounts for load growth and class changes since the last adjustment. These modifications should be made regardless of whether the Commission makes any other changes to the existing rule. First, the class allocator used for the TCRF formula should be amended to reflect the appropriate class allocations at the time of the TCRF update. This is necessary because some classes may grow much faster than others, which may result in classes paying more than their share of transmission charges if the class allocators are not updated. TIEC recommends amending the class allocator as follows:

> ALLOC is each class's percentage of the DSP's 4CP demand for the previous calendar year. The DSP may estimate the 4CP demands for non-IDR metered classes; ~~the class allocator approved by the commission to allocate the transmission revenue requirement among classes in the distribution service provider's last rate case, unless otherwise ordered by the commission;~~and

Additionally, the billing determinants should be updated for the November TCRF updates to better account for load growth. TIEC recommends the following changes to the definition of BD for the TCRF formula:

> BD is each class' annual billing determinant (kWh, or kW, or kVa). For the March update, the DSP shall use billing determinants for the previous calendar year. For the September update, the DSP shall use the billing determinants for the twelve months ended June 30.

III. CONCLUSION

TIEC appreciates the opportunity to submit comments on the proposal for publication and respectfully requests that the Commission adopt the foregoing recommendations.

Respectfully submitted,

ANDREWS KURTH LLP

Katie Coleman

Phillip Oldham
State Bar No. 00794392
Tammy Cooper
State Bar No. 00796401
Katherine Coleman
State Bar No. 24059596
111 Congress Avenue, Suite 1700
Austin, Texas 78701
(512) 320-9200
(512) 320-9292 FAX

ATTORNEYS FOR TEXAS INDUSTRIAL
ENERGY CONSUMERS

PROJECT NO. 37909

RULEMAKING PROCEEDING TO	§	**PUBLIC UTILITY COMMISSION**
AMEND PUC SUBST. R. 25.193,	§	
RELATING TO DISTRIBUTION	§	**OF TEXAS**
SERVICE PROVIDER TRANSMISSION	§	
COST RECOVERY FACTOR (TCRF)	§	

ORDER ADOPTING AMENDMENT TO §25.193
AS APPROVED AT THE SEPTEMBER 29, 2010 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts an amendment to §25.193, relating to Distribution Service Provider Transmission Cost Recovery Factor (TCRF), with changes to the proposed text as published in the April 16, 2010 *Texas Register* (35 TexReg 2909). The amendment requires a distribution service provider (DSP) to include in its rates an adjustment that reflects the difference between (1) the amount of transmission service providers' (TSPs) commission-approved wholesale transmission costs that are paid by the DSP and not included in the base rates of the DSP, and (2) the revenues recovered through the DSP's TCRF. Project Number 37909 is assigned to this proceeding.

The commission received written comments on the amendment from AEP Texas Central Company, AEP Texas North Company, CenterPoint Energy Houston Electric LLC, Oncor Electric Delivery Company LLC, and Texas-New Mexico Power Company (collectively, Joint DSPs); City of Houston (COH); the Steering Committee of Cities Served by Oncor (Cities); the Coalition of Regulatory Entities (CORE); Electric Transmission Texas LLC, Lone Star Transmission LLC, and Wind Energy Transmission Texas LLC (collectively, Interested TSPs); Office of Public Utility Counsel (OPUC); the Retail Electric Provider Coalition (REP Coalition); Sharyland Utilities, L.P. (Sharyland); and Texas Industrial Energy Consumers (TIEC).

Adjustments to TCRF Formula to Account for Load Growth and Class Allocation Factors

TIEC stated that if the commission makes any amendments to its rules in this proceeding, it should adjust the TCRF formula to properly account for load growth and changes in the appropriate class allocations. TIEC opined that several changes to the TCRF formula are necessary to ensure that it properly accounts for load growth and class changes since the last adjustment. First of all, TIEC argued, the class allocator used for the TCRF formula should be amended to take into account the appropriate class allocations at the time of the TCRF update, to reflect the fact that some classes may grow much faster than others and result in classes paying more than their share of transmission charges if the class allocators are not updated. Additionally, TIEC commented that the billing determinants should be updated to better account for load growth. TIEC recommended changes to the rule language to achieve these objectives, and TIEC submitted that these modifications should be made regardless of whether the commission makes any other changes to the existing rule. CORE, Cities, and OPUC similarly commented that the published proposal does not appear to consider the possible increase in a DSP's base revenues that offset increases to wholesale transmission costs. Cities, CORE, and OPUC disagreed, however, with TIEC's proposal that class allocation factors should be changed outside of a base-rate case, observing that TIEC proposes to update allocation factors for customer classes with IDR meters, and estimate allocation factors for other classes. Cities, CORE, and OPUC opined that while it is possible that IDR meters will allow more accurate measures of four coincident peak (4CP) loads for those classes, that does not necessarily translate into more accurate allocation factors, as each class's allocation factor, which is a ratio, is dependent on the 4CP loads of other classes, and because the class allocation factors must sum to 100%, a change in the load of one class will simply shift costs to other classes. Cities, CORE, and OPUC commented that any estimates that update non-IDR class loads are likely to be based on simplistic assumptions that are inaccurate and may be unreliable. Cities and OPUC argued that the complexities of TIEC's suggested updating of class allocation factors are more suitable for litigation in a general rate case, not a TCRF proceeding.

Joint DSPs stated that TIEC's proposal to amend the class allocators to reflect the appropriate class allocations at the time of the TCRF update should be rejected. Joint DSPs commented that updating the class allocators has nothing to do with removing regulatory lag, and Joint DSPs observed that TIEC itself noted that the number and timing of TCRF updates will not be changing; rather, only the amounts to be charged will be impacted. Moreover, Joint DSPs stated that the allocation factors are related to the 4CPs occurring in the DSP's last base rate case, and TIEC's proposal would thus have the effect of having the base rate transmission costs allocated using one set of allocation factors while the transmission costs recovered through the TCRF would be recovered using a different set of allocation factors. Joint DSPs submitted that a single set of allocation factors should apply to all wholesale transmission costs, whether recovered through base rates or the TCRF. Joint DSPs additionally noted that TIEC's proposal would require DSPs to calculate new allocation factors that, for rate classes that are not 100% metered with interval data recorder meters, would require the use of load research data that has not previously been reviewed by the commission. Joint DSP's pointed out that this would result in a contentious and time-consuming proceeding, in direct conflict with the purpose of the published proposal. Joint DSPs submitted that, in sum, the administrative burden that would be imposed on these semi-annual filings would greatly outweigh any possible benefit to having updated class allocation information.

Joint DSPs also replied that the impact of various changes (weather, economic conditions, increased taxes, etc.) on base rate costs and revenues is reviewed by the commission in the utilities' annual (quarterly for Oncor) Earnings Monitoring Reports. Joint DSPs asserted that rather than assuming that base rate revenues will be higher than anticipated, the better course of action is for the commission to ensure that DSPs recover the level of transmission costs in excess of that included in rates, continue to monitor the utilities' earnings and, should one of them significantly over-earn, begin a commission inquiry into that utility's rates. Joint DSPs argued that to purposefully maintain a regulatory system that has resulted in inadequate TCRF revenues over time is not reasonable.

Commission Response

As stated by the commission previously, DSPs essentially serve as billing and collection agents for passed-through TCRF costs and, under the commission's current rules, have no ability to avoid such costs or address and manage the regulatory lag that exists with respect to these costs. Therefore, the load growth adjustment advocated by TIEC would be inappropriate. In addition, changes to the class allocations would be inappropriate in a TCRF proceeding. As stated by the Joint DSPs, TIEC's proposal would require DSPs to calculate new allocation factors that would require the use of load research data that has not previously been reviewed by the commission, and consideration of these issues in a TCRF update could result in a contentious and time-consuming proceeding.

Adjustments to Rate of Return

The REP Coalition commented that when the commission adopted the TCRF rule during the development of rate design for the unbundled cost of service (UCOS) cases prior to the start of competition, the commission recognized that the adopted TCRF did not address the risk to DSPs of under- and over-collection of transmission service charges. According to the REP Coalition, the commission stated at that time that the risk would be considered when the utility's rate of return was determined. The REP Coalition cited an example of the commission doing this in Docket Number 22350, which was the UCOS proceeding case for TXU Electric Company (now Oncor Electric Delivery). The order in that case states:

> The Commission concludes, however, that an upward adjustment to the ROE of 0.5% is appropriate. This adjustment accounts for the following: (1) the Commission decision in the rate design phase of this proceeding; (2) potential rating uncertainty due to higher debt, based on the adoption of 60% debt and 40% equity ratio for capital structure in this proceeding; and (3) a risk premium recalculation as recommended by Commission Staff witness Martha Hinkle.

The REP Coalition stated that the changes proposed in this rulemaking would eliminate the risk associated with the under- and over-collection of the transmission service charges for the first time since the inception of the TCRF. The REP Coalition argued that it must therefore be assumed that in subsequent rate cases the commission considered this risk premium in setting the return on equity. The REP Coalition stated that, consequently, a proper reduction to a DSP's return on equity should occur in future rate proceedings if the commission approves in this rulemaking the proposed changes that would eliminate the risk of regulatory lag.

Cities similarly held that the current authorized returns on equity for DSPs are based on the regulatory lag that existed prior to this rulemaking, and that by providing for total elimination of and findings in the Construction Study to execute a Construction Services Agreement with Company for the Project.

4. Incorporation of Tariff. The Tariff is incorporated into this agreement, including without limitation Sections 5.2.1 (limitation of liability), 5.2.4 (force majeure), and 5.2.6 (disclaimer of warranties) thereof. In the event of any conflict between the terms of this agreement and the terms of the Tariff, the terms of the Tariff shall prevail. T

5. Final Agreement. This agreement contains the final and complete agreement of the parties hereto regarding the subject matter hereof and supersedes all prior understandings and agreements between them with respect thereto.

IN WITNESS WHEREOF, this agreement is executed as of the date first written above by the parties' duly authorized personnel.

CenterPoint Energy Houston Electric, LLC	**[Insert Customer's Name]**
By: ______________________ (Signature)	By: ______________________ (Signature)
______________________ (Print Name)	______________________ (Print Name)
______________________ (Title)	______________________ (Title)

CenterPoint Energy Houston Electric, LLC
Applicable: Entire Service Area

CNP 8044

Utility Construction Services Agreement

This Utility Construction Services Agreement (this "Agreement") is entered into as of the ___ day of May, 2017 between CenterPoint Energy Houston Electric, LLC ("CenterPoint Energy") and ____________________ ("Customer"). T

Customer has requested the Construction Services described below by CenterPoint Energy, and CenterPoint Energy is willing to provide such Construction Services upon its receipt of funds from Customer sufficient to cover the estimated costs for providing the Construction Services. Customer and CenterPoint Energy therefore agree as follows:

1. Defined Terms. All capitalized terms used but not otherwise defined in this Agreement have the respective meanings set forth in CenterPoint Energy's Tariff for Retail Delivery Service (the "Tariff") approved by the Commission.

2. Description of Construction Services. Subject to its receipt of the Estimated Amount described in Section 3 hereof, CenterPoint Energy will provide the following Construction Services as requested by Customer (*check as applicable*):

- ☐ Relocation of any part of the Delivery System
- ☐ Installation or extension of non-standard Delivery System facilities
- ☐ Repair, maintenance or replacement work on the Delivery System outside of CenterPoint Energy's normal hours of operation as specified in the Tariff
- ☐ Other

The Construction Services to be provided under this Agreement (a) will be performed by CenterPoint Energy in accordance with Good Utility Practice and (b) may be further described in an attachment to this Agreement labeled Exhibit A. An Exhibit A ☐ is or ☐ is not attached to this Agreement as of the date hereof (*check one*).

3. Customer Upfront Payment. Customer agrees to pay the cost of the Construction Services described in this Agreement. CenterPoint Energy estimates the cost of the Construction Services to be $______________ (the "Estimated Amount"). Customer shall pay the Estimated Amount to CenterPoint Energy prior to CenterPoint Energy's commencement of the Construction Services. CenterPoint Energy may revise the Estimated Amount at any time after receiving payment thereof based on Good Utility Practice, and Customer shall pay the revised Estimated Amount prior to CenterPoint Energy's commencement or continued performance of the Construction Services. Customer's payment of the Estimated Amount is non-refundable.

4. Ownership of Equipment. Title to all equipment and facilities installed, constructed or relocated by CenterPoint Energy pursuant to this Agreement shall remain with CenterPoint Energy.

5. Incorporation of Tariff. The provisions of the Tariff governing Construction Services are incorporated into this Agreement, in particular Sections 5.2.1 (limitation of liability), 5.2.4 (force majeure), and 5.2.6 (disclaimer of warranties) of the Tariff. In the event of any conflict between the terms of this Agreement and the terms of the Tariff, the terms of the Tariff shall prevail. T

6. Governing Law; No Third Party Beneficiaries; Interpretation. This Agreement is to be interpreted under the laws of the State of Texas, excluding its choice of law principles, and such laws shall govern all disputes under this Agreement. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the parties hereto, and the obligations herein assumed are solely for the use and benefit of the parties hereto, their successors in interest and, where permitted, their assigns. The descriptive headings of the various sections of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the parties hereto or to impose any partnership obligation or liability upon either party.

7. Execution and Amendment. This Agreement may be executed in two or more counterparts which may be in portable document format (PDF) or other electronic form, each of which is deemed an original but all constitute one and the same instrument. This Agreement may be amended only upon mutual written agreement of the parties.

8. No Agency. Neither party hereto has any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other party.

9. Final Agreement. This Agreement contains the final and complete agreement of the parties hereto regarding the subject matter hereof and supersedes all prior understandings and agreements between them with respect thereto.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement to be effective as of the date first written above.

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	**[INSERT CUSTOMER'S NAME]**
By: ______________________	By: ______________________
(Signature)	*(Signature)*
______________________	______________________
(Name)	(Name)

ENTERGY TEXAS, INC. Electric Service EXTENSION POLICY	Sheet No.: 18 Effective Date: Service on and after 10-17-18 Revision: 6 Supersedes: Revision Effective 4-1-14 Schedule Consists of: Three Sheets

ELECTRIC EXTENSION POLICY

This Electric Extension Policy shall apply only to those facilities that Company will construct and maintain in order to provide electric service to its Customer.

I. NEW LOAD OF LESS THAN 2500 KW

For (a) residential Customers with any new and additional load and (b) Customers which, unless otherwise agreed to by Company, are Customers with a Contract Demand of new and additional load ("New Load") of less than 2500 kW, the Company will extend and/or modify its overhead facilities, including infrastructure improvements required to provide electric service to the Customer but excluding Customer-specific substation(s) and System Improvements as defined below ("New Facilities"), necessary to serve new and permanent Customers, or additional load of an existing Customer to Customer's Point of Delivery, as agreed upon by the Company and the Customer, under the following terms:[1]

(A) (1) The Customer will not be required to reimburse the Company for New Facilities when Anticipated Revenues for the first four years of the contract term (if a contract is entered), or for the first four years after electric service associated with the New Load is provided (if no contract is entered) is equal to or exceeds the Company's Projected Investment in New Facilities necessary to serve the New Load. Anticipated Revenues are defined as projected annual non-fuel firm rate schedule revenues, plus base rate cost recovery mechanisms. Existing and future non-base rate cost recovery mechanisms applicable to the firm rate schedules under which the Customer receives service are not to be included in Anticipated Revenue.

(2) If a minimum bill is required by Company, the Customer and Company will enter either a minimum bill agreement or an Agreement for Electric Service which shall contain provisions for a monthly minimum bill for New Load at the greater of, as applicable, (a) 1/48th of the Anticipated Revenues for the first four years of the contract term for New Load, or (b) the Net Monthly Bill provision of the Customer's firm rate schedule plus base rate cost recovery mechanisms, less the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules under which the Customer receives service for the New Load, or (c) the contracted monthly minimum bill for the New Load, to include all base rate cost recovery mechanisms, and such other terms as agreed to by the Company and the Customer that provide for an adequate assurance of revenue to pay for the New Facilities. In all cases, the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules for which the Customer receives service shall be applied to the resulting bill.

(3) The Company may require the Customer to provide and maintain financial security, including at the sole discretion of the Company a parental guarantee, in a form that is mutually acceptable to the Customer and the Company, on revenue justified New Facilities until all Anticipated Revenues have been collected.

[1] Some pre-construction costs may be handled separately based on the scope of the project.

(Continued on reverse side)

(4) If the Customer's reimbursement obligation is based on an estimate of the cost of New Facilities that is equal to or greater than $100,000 or the Company elects to apply the true-up option at its sole discretion, the Company will true-up the estimated New Facilities costs to actual costs, and the Company or the Customer, as may be applicable, will pay to the other, the true-up amount[2] within 60 days of notice to the Customer of the true-up amount (including all applicable tax gross-up costs).

(B) (1) The Customer will be required to reimburse the Company for the cost of New Facilities when the Anticipated Revenues for the first four years of the contract term (if a contract for New Load is entered) or for the first four years after electric service associated with the New Load is provided (if no contract is entered) are less than the Company's Projected Investment in New Facilities necessary to serve the New Load. The Customer will, prior to the start of construction, reimburse the Company for any cost for New Facilities (including all applicable tax gross-up costs) that exceeds the Anticipated Revenues for the first four years of the contract term.

(2) If a minimum bill is required by the Company, the Customer's monthly minimum bill for the New Load shall be the greater of, as applicable, (a) 1/48th of the Anticipated Revenues for the first four years of the contract term for the New Load, or (b) the Net Monthly Bill provision of the Customer's firm rate schedule plus base rate cost recovery mechanisms, less the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules under which the Customer receives service for the New Load, or (c) the contracted monthly minimum bill for the New Load, to include all base rate cost recovery mechanisms, and such other terms as agreed to by the Company and the Customer that provide for an adequate assurance of revenue to pay for the New Facilities. In all cases, the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules for which the Customer receives service shall be applied to the resulting bill.

(3) The Company may require the Customer to provide and maintain financial security, including at the sole discretion of the Company a parental guarantee, in a form that is mutually acceptable to the Customer and the Company, on revenue justified New Facilities until all Anticipated Revenues have been collected. The Company may also require the Customer to provide and maintain financial security, acceptable to the Company, equal to the amount of any cost for New Facilities subject to reimbursement.

(4) If the Customer's reimbursement obligation is based on an estimate of the cost of New Facilities that is equal to or greater than $100,000 or the Company elects to apply the true-up option at its sole discretion, the Company will true-up the estimated facility costs to actual costs, and the Company or the Customer, as may be applicable, will pay to the other, the true-up amount[3] within 60 days of notice to the Customer of the true-up amount (including all applicable tax gross-up costs).

(5) The reimbursement obligation for the cost of New Facilities (and the minimum bill, financial security, and true up provisions applicable thereto) shall extend to the entire cost of New Facilities (including all applicable tax gross-up costs) that are no longer revenue justified under Section I Paragraph (A) above due to an increase in the actual or estimated cost of New Facilities and a decrease in the actual or expected Anticipated Revenues, or either of them.

[2] Customer refund not to exceed the amount of total reimbursement (including all applicable tax gross-up costs) paid by the Customer.
[3] Customer refund not to exceed the amount of total reimbursement (including all applicable tax gross-up costs) paid by the Customer.

 (Continued on next page)

ENTERGY TEXAS, INC. Electric Service EXTENSION POLICY	Sheet No.: 18A Effective Date: Service on and after 10-17-18 Revision: 6 Supersedes: Revision Effective 4-1-14 Schedule Consists of: Three Sheets

ELECTRIC EXTENSION POLICY

(C) (1) When the required ratio is not satisfied by original Customers applying for service, but the Project Investment is to be made in a growing area and the Company feels that the development therein will produce a ratio of 4 to 1 or less in three (3) years, such facilities will be built without cost to Customers.

(2) The Company's Projected Investment will include the total investment in the New Facilities including, but not limited to, material costs, labor costs, labor cost adders, costs associated with third party vendors and consultants, costs associated with the procurement of real property rights, costs associated with securing all necessary approvals, taxes, capital suspense charges, overheads and associated tax gross-up charges, less any investment included in the total investment which should be charged to " System Improvements" and less any nonrefundable lump sum payments covered under the Policy on Service to Small Three-phase Loads. System Improvements are defined as those Entergy transmission projects (A) included in (1) Appendix A of MISO's Transmission Expansion Plan, or (2) Target Appendix A of MISO's Transmission Expansion Plan (subject to MISO's timely approval) (said (1) or (2) being referred to as "Entergy System Improvement Projects") and (B) whose construction has commenced or is scheduled to commence within five (5) years of Customer's execution of Company's required document(s) relating to this Policy. However, System Improvements shall not include those Entergy System Improvement Projects to be constructed solely due to Customer's New Load. In the event MISO's Transmission Expansion Plan is no longer applicable to Company, System Improvements shall be defined as those transmission upgrades in Company's five-year transmission plan that are expected to be owned by Company.

II. NEW LOAD EQUAL TO OR GREATER THAN 2500 KW

For large commercial and industrial customers, which, unless otherwise agreed to by Company, are customers with a Contract Demand of at least 2500 kW, the Company will extend and/or modify its overhead facilities, including infrastructure improvements required to provide electric service to the Customer but excluding customer-specific substation(s) and System Improvements as defined above ("New Facilities"), necessary to serve new and permanent customers, or additional load of an existing customer to customer's Point of Delivery (the new and additional load being collectively referred to as "New Load"), as agreed upon by the Company and the Customer, under the following terms:[4]

(A) (1) The Customer will not be required to reimburse the Company for New Facilities when projected Contract Revenues for the first four years of the contract term for New Load is equal to or exceeds the Company's Projected Investment (as defined in Section I) in New Facilities necessary to serve the New Load. Contract Revenues are defined as projected annual non-fuel firm rate schedule revenues, plus base rate cost recovery mechanisms. Existing and future non-base rate cost recovery mechanisms

[4] Some pre-construction costs may be handled separately based on the scope of the project.

(Continued on reverse side)

applicable to the firm rate schedules under which the Customer receives service are not to be included.

(2) If a minimum bill is required by Company, the Customer and Company will enter an Agreement for Electric Service which shall contain provisions for a monthly minimum bill for New Load at the greater of (a) 1/48th of the Contract Revenues for the first four years of the contract term for New Load, or (b) the Net Monthly Bill provision of the Customer's firm rate schedule plus base rate cost recovery mechanisms, less the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules under which the Customer receives service for the New Load, or (c) the contracted monthly minimum bill for the New Load, to include all base rate cost recovery mechanisms, and such other terms as agreed to by the Company and the Customer that provide for an adequate assurance of revenue to pay for the New Facilities. In all cases, the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules for which the Customer receives service shall be applied to the resulting bill.

(3) The Company may require the Customer to provide and maintain financial security, including at the sole discretion of the Company a parental guarantee, in a form that is mutually acceptable to the Customer and the Company, on revenue justified New Facilities until all projected Contract Revenues have been collected.

(4) If the Customer's reimbursement obligation is based on an estimate of the cost of New Facilities, the Company will true-up the estimated facility costs to actual costs, and the Company or the Customer, as may be applicable, will pay to the other, the true-up amount[5] within 60 days of notice to the Customer of the true-up amount (including all applicable tax gross-up costs).

(B) (1) The Customer will be required to reimburse the Company for the cost of New Facilities when the projected Contract Revenues for the first four years of the contract term for New Load are less than the Company's Projected Investment in New Facilities necessary to serve the New Load. The Customer will, prior to the start of construction, reimburse the Company for any cost for New Facilities (including all applicable tax gross-up costs) that exceeds the projected Contract Revenues for the first four years of the contract term. Construction shall be deemed to start when any equipment for the New Facilities is ordered by the Company.

(2) If a minimum bill is required by Company, the Customer and Company will enter an Agreement for Electric Service which shall contain provisions for a monthly minimum bill for the New Load at the greater of (a) 1/48th of the Contract Revenues for the first four years of the contract term for the New Load, or (b) the Net Monthly Bill provision of the Customer's firm rate schedule plus base rate cost recovery mechanisms, less the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules under which the Customer receives service for the New Load, or (c) the contracted monthly minimum bill for the New Load, to include all base rate cost recovery mechanisms, and such other terms as agreed to by the Company and the Customer that provide for an adequate assurance of revenue to pay for the New Facilities. In all cases, the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules for which the Customer receives service shall be applied to the resulting bill.

[5] Customer refund not to exceed the amount of total reimbursement (including all applicable tax gross-up costs) paid by the Customer.

 (Continued on next page)

ENTERGY TEXAS, INC. Electric Service EXTENSION POLICY	Sheet No.: 18B Effective Date: Service on and after 10-17-18 Revision: 6 Supersedes: Revision Effective 4-1-14 Schedule Consists of: Three Sheets

ELECTRIC EXTENSION POLICY

(3) The Company may require the Customer to provide and maintain financial security, including at the sole discretion of the Company a parental guarantee, in a form that is mutually acceptable to the Customer and the Company, on revenue justified New Facilities until all projected Contract Revenues have been collected. The Company may also require the Customer to provide and maintain financial security, acceptable to the Company, equal to the amount of any cost for New Facilities subject to reimbursement.

(4) If the Customer's reimbursement obligation is based on an estimate of the cost of New Facilities, the Company will true-up the estimated facility costs to actual costs, and the Company or the Customer, as may be applicable, will pay to the other, the true-up amount[6] within 60 days of notice to the Customer of the true-up amount (including all applicable tax gross-up costs).

(5) The reimbursement obligation for the cost of New Facilities (and the minimum bill, financial security, and true up provisions applicable thereto) shall extend to the entire cost of New Facilities (including all applicable tax gross-up costs) that are no longer revenue justified under Section II Paragraph (A) above due to an increase in the actual or estimated cost of New Facilities and a decrease in the actual or expected Contract Revenues, or either of them.

(6) If the Company is reimbursed more than $10,000,000 (including all applicable tax gross-up costs) by a Customer per Section II Paragraph (B)(1) above, and more large commercial or industrial customers are served by the New Facilities within a four-year period following Construction as defined in Section II Paragraph (B)(1) above, then the initial Customer that reimbursed the Company shall be entitled to receive a prorated refund of the reimbursement for common facilities (a) when additional large commercial or industrial customers execute an agreement for electric service within the four-year period following Construction as defined in Section II Paragraph (B)(1), and, (b) upon fulfillment of the refund process described in Section II Paragraph (B)(7) below. The Company will collect the full amount identified in Section II Paragraph (B)(1) above from the initial Customer.

(7) When requested by the initial Customer and after payment from the additional large commercial or industrial customer(s), a refund of reimbursement for common facilities to the initial Customer will be made on a pro-rata share of the amount initially paid by the initial Customer from each additional large commercial or industrial customer to be served by the New Facilities within the four-year period following Construction as defined in Section II Paragraph (B)(1), or until the capacity of the New Facilities is fully utilized, whichever comes first.[7] The additional large commercial or industrial customer(s) shall be obligated to make a payment to the Company for its pro rata share of New Facilities within 60 days of demand for such payment.

[6] Customer refund not to exceed the amount of total reimbursement (including all applicable tax gross-up costs) paid by the Customer.
[7] Customer refund not to exceed the amount collected by Company from additional customer(s).

(Continued on reverse side)

(8) When Customer is required to reimburse Company for New Facilities, Company shall provide reasonably detailed information setting forth the cost of the New Facilities as soon as practicable after receiving a request from Customer.

NATIVE FILES ON THE ATTACHED CD