Control Number: 39896

Item Number: 507

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BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS

SOAH DOCKET NO. 473-12-2979
PUC DOCKET NO. 39896

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES AND RECONCILE FUEL COSTS	)))))))

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DIRECT TESTIMONY OF

KEVIN C. HIGGINS

ON BEHALF OF

THE KROGER CO.

MARCH 27, 2012

507

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by The Kroger Co. ("Kroger"). Kroger is one of the largest retail grocers in the United States, and operates 15 facilities that are served by Entergy Texas, Inc. ("ETI"). Combined, Kroger facilities purchase over 40 million kWh annually from ETI.

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you previously testified as an expert witness before the Public Utility Commission of Texas ("Commission")?

A. Yes. I filed testimony in ETI's 2010 general rate proceeding, PUC Docket No. 37744, as well as in the Company's 2008 general rate proceeding, PUC Docket No. 34800. I also testified in the Oncor 2008 distribution rate proceeding, PUC Docket No. 35717.

Q. Have you testified previously before any other state utility regulatory commissions?

A. Yes. I have testified in approximately 145 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Arizona, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also filed affidavits in proceedings before the Federal Energy Regulatory Commission.

Overview and Conclusions

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses the following issues:

(1) Rate spread;

(2) Rate design for the LGS rate schedule; and

(3) ETI's proposal to include unrecovered costs from ETI's proposed Competitive Generation Service ("CGS") program;

Q. Please summarize your recommendations to the Commission.

A. I offer the following recommendations:

(1) ETI's proposal for rate spread, or class revenue allocation, demonstrates a close alignment between class cost of service and the revenue requirements allocated to customer classes in proposed rates. For this reason, I believe ETI's proposed rate spread is reasonable. At the same time, I would have no objection to rates being set even closer to cost of service. To the extent that ETI's proposed revenue requirement is reduced by the Commission, I recommend that class revenue requirement should remain closely aligned with cost of service at the lower revenue level.

(2) I recommend setting the base rate demand charge for the LGS rate schedule at 90% of demand-related costs, rather than at 72%, as proposed by ETI. At the same time, I recommend reducing the customer charge from $425.05 per month to $260 per month – which is still twice as great as ETI's cost-of-service analysis indicates it should be. Concomitant with these two changes, there should be a corresponding adjustment (reduction) in the base energy charge to achieve the target revenue requirement for the rate schedule. These changes will better align demand charges with demand-related costs, energy charges with energy-related costs, and customer charges with customer-related costs, thereby reducing the level of intra-class subsidization within this rate schedule.

(3) To the extent that CGS-related matters have implications for this rate case, I defer to (and concur with) the recommendations offered by Kroger witness Neal Townsend in Docket No. 38951.

Rate Spread

Q. What general guidelines should be employed in spreading any change in rates?

A. In determining rate spread, or revenue apportionment, it is important to align rates with cost causation, to the greatest extent practicable. Properly aligning rates with the costs caused by each customer group is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for customer groups that would experience significant rate increases from doing so by employing the ratemaking principle of gradualism. When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid practices that result in permanent cross-subsidies from other customers.

Q. What general approach has ETI used in spreading its proposed rate increase?

A. ETI is proposing base rates that are close to class costs of service. This is illustrated in Table KCH-1, below. I note that in its initial filing, ETI stripped significant costs out of its base rates in association with its request to shift a portion of cost recovery into a purchased capacity rider, Rider PPR, consideration of which has since been removed from this docket by the Commission. To represent ETI's proposed revenues by class I have aggregated the base revenues from ETI's filed case with its proposed Rider PPR revenues by class.

Table KCH-1

ETI COS Results and Proposed Rate Spread
Base Rates and Rider PPR

Class	Present Base Revenues	COS Base & PPR Revenues @ Proposed Rates	ETI Proposed Base & PPR Revenues	% Change From Present
Residential	$325,744,455	$408,500,937	$407,510,471	25.10%

SGS	$22,562,013	$22,981,264	$22,972,432	1.82%
GS	$135,404,167	$142,566,747	$142,905,765	5.54%
LGS	$42,430,160	$50,463,758	$50,517,179	19.06%
LIPS	$100,482,959	$110,949,353	$111,708,405	11.17%
LS	$7,490,488	$9,767,184	$9,689,869	29.36%
Total	**$634,114,242**	**$745,229,244**	**$745,304,121**	**17.53%**

Q. What is your general assessment of ETI's proposed rate spread?

A. I support the close alignment of class cost allocation and class revenue allocation in ETI's proposal. While I believe the Company's proposed rate spread is within the range of reasonableness, I also would have no objection to rates being set even closer to cost of service. Further, to the extent that ETI's proposed revenue requirement is reduced by the Commission, I recommend that class revenue requirement should remain closely aligned with cost of service at the lower revenue level.

<u>LGS Rate Design</u>

Q. Please describe ETI's proposed rate design for Schedule LGS at the Company's proposed revenue requirement.

A. The LGS rate schedule serves customers with monthly billing demands between 300 kilowatts and 2,500 kilowatts.

In its filed case, ETI proposed a base rate design that presumed adoption of a purchased capacity rider (PPR Rider). In its Supplemental Preliminary Order, issued January 19, 2012, the Commission determined that ETI's request for a purchased-power recovery rider would not be addressed in this docket.

Anticipating a possible rejection of the Company's proposed rider, ETI witness Phillip R. May stated in his direct testimony:

> If the PPR Rider is not approved, ETI's adjusted test year purchased power capacity costs should, instead, be included in the development of ETI's generation revenue requirement used to set base rates in this docket. [p. 23, lines 4-7]

This statement notwithstanding, at the current time, I am not aware of ETI filing new proposed base rates that take into account the elimination of the PPR Rider, i.e., a filing which incorporates purchased capacity costs in base rates. However, ETI has provided a revised Schedule Q.7 in its Response to TIEC Data Request 6.5, which purports to reflect ETI's proposed rate design with all purchased power capacity costs and interruptible service costs rolled into base rates.

Accordingly, for purposes of this discussion, I will assume that ETI's proposed rate design for Rate Schedule LGS consists of the rate design as represented in this data response.

At ETI's requested revenue requirement, ETI proposes to increase the LGS demand charge from $8.56 per kW-month to $10.25 per kW-month and to increase the energy charge from $.00854 per kWh to $.01023 per kWh. The Company proposes no change in the customer charge of $425.05 per month.

Q. What is your assessment of ETI's proposed rate design for LGS?

A. As shown in Exhibit KCH-1, ETI's proposed LGS demand charge would recover only 72% of LGS demand-related costs.[1] To compensate for the resultant revenue shortfall, the LGS energy charges proposed by ETI would significantly over-recover energy-related costs. Specifically, the overall LGS energy charge is proposed to be 428% of base energy costs. In addition, although the customer charge is proposed to be unchanged, it is set at 328% of cost. If instead, the LGS customer charge were set at cost, it would only be $129.60 per month.

Q. From a customer's perspective, why should it matter if ETI proposes a demand charge that does not fully recover its demand-related costs?

A. If a utility proposes a demand charge that is below the cost of demand, it is going to seek to recover its class revenue requirement by over-recovering its costs in another area, most typically through levying an energy charge that is above unit energy costs, which is the case with ETI's proposal. For a given rate schedule such as LGS, when demand charges are set below cost, and energy charges are set above cost, those customers with relatively higher load factors are required to subsidize the costs of the lower-load-factor customers within the rate class. The subsidy is different for each higher-load-factor customer and consists of the net increase in rates paid by these customers as a result of setting energy charges above energy costs and demand charges below demand-related costs.

Q. How do you define "higher-load-factor customers"?

[1] This calculation was made using ETI's the demand-related costs identified in ETI's initial filing and adding the purchased capacity costs that ETI had segregated for recovery in Rider PPR.

A. For purposes of this discussion, I use this term to refer to customers whose load factor is greater than the average for the rate schedule.

Q. What are the implications of setting the customer charge significantly above customer-related costs?

A. When the customer charge is set significantly above customer-related costs, smaller customers on the rate schedule are over-charged and thereby subsidize the larger customers on the rate schedule.

Q. Why is it important for rate design to be representative of underlying cost causation?

A. Aligning rate design with underlying cost causation improves efficiency because it sends proper price signals. For example, setting a demand charge below the cost of demand understates the economic cost of demand-related assets, which in turn distorts consumption decisions, and calls forth a greater level of investment in fixed assets than is economically desirable.

At the same time, aligning rate design with underlying cost causation is important for ensuring equity among customers, because properly aligning with costs minimizes cross-subsidies among customers. As I stated above, if demand costs are understated in utility rates, the costs are made up elsewhere – typically in energy rates. When this happens, higher-load-factor customers (who use fixed assets relatively efficiently through relatively constant energy usage) are forced to pay the demand-related costs of lower-load-factor customers. This amounts to a cross-subsidy that is fundamentally inequitable.

Q. What is your recommendation with respect to the LGS rate design?

A. Ideally, the demand charge, energy charge, and customer charge should each be set at 100% of cost. However, full movement to cost-based rates in a single step is sometimes opposed on the grounds of intra-class rate impacts. Taking this potential argument into account, for purposes of this case, I recommend setting the base demand charge for LGS at 90% of demand-related costs. At the same time, I recommend reducing the customer charge to $260 per month – which is still twice as great as ETI's cost-of-service analysis indicates it should be. Concomitant with these two changes, there should be a corresponding adjustment (reduction) in the base energy charge to achieve the target revenue requirement for the rate schedule. This modification to the LGS rate design is presented in Exhibit KCH-2.

Q. How does the alignment of LGS costs and charges resulting from your proposal compare with that of ETI?

A. The cost alignment of my rate design proposal is presented in Exhibit KCH-1 and is compared to ETI's proposal in Table KCH-2, below. As shown in Table KCH-2, my proposal produces charges that are better aligned with costs than ETI's proposal.

Table KCH-2

Alignment of LGS Costs and Charges at ETI's Proposed Revenue Requirement

Functions	ETI Proposed Charge	% of Cost	Kroger Proposed Charge	% of Cost

Demand ($/kW)	$10.25	72%	$12.81	90%
Energy ($/kWh)	$0.01023	428%	$0.00513	216%
Customer ($/Mo)	$425.05	328%	$425.05	201%

Q. Have you prepared a rate impact analysis of your recommended changes to LGS rate design?

A. Yes. The rate impact analysis is presented in Exhibit KCH-3. Page 1 of the exhibit replicates the Company's rate impact analysis from ETI Schedule Q-8.9, p. 20, as presented in ETI's initial filing. Page 2 is an update of that schedule which I prepared using the ETI-proposed rates prepared by the Company in its Response to TIEC Data Request 6.5, discussed above. Page 3 shows the rate impact of my proposed rate design for LGS.

Exhibit KCH-3 demonstrates that the proposed rate impacts from my LGS proposal are reasonable. Page 3 shows that the rate impact of my proposed rate design results in a smaller rate impact on higher-load-factor customers than lower-load-factor customers, which is directionally consistent with the ETI's (updated) proposal (as shown on page 2 of Exhibit KCH-3), and is reasonable in light of the capacity-related cost drivers of this case. Moreover, the absolute difference in the rate impact on customers of differing load factors is comparable under my proposal as under ETI's initial filing as shown on page 1 of Exhibit KCH-3, but reflects a cost-based difference. (For example, for a 500-kW customer the rate impact difference between a 45% load factor customer and a 65% load factor customer is 3.66% under my overall rate design compared to a difference of 3.59% under ETI's initial rate design.)[2]

Competitive Generation Service

Q. What is ETI proposing with respect to Competitive Generation Service?

A. As explained in the direct testimony of Phillip R. May in Docket No. 38951, ETI is proposing to introduce CGS to comply with PURA § 39.452. Mr. May maintains that because the Entergy System Agreement generally precludes ETI from purchasing capacity and energy for the exclusive benefit of an individual customer, ETI is limiting its CGS offering to purchases from Qualifying Facilities ("QFs"), which are apparently exempt from this restriction. Further, ETI proposes to limit eligibility for CGS to customers taking service under the LIPS rate schedule, which are customers with billing demands of 2,500 kW or greater.

Q. Do you have any comments on ETI's CGS proposal?

A. ETI's CGS proposal is being addressed in Docket No. 38951. Kroger's position in that docket is presented by its witness Neal Townsend.

In Docket No. 38951, Mr. Townsend recommends that the Commission require that any unrecovered fixed costs resulting from the CGS program be recovered exclusively from CGS program participants. If, for some reason,

[2] Source: ETI Schedule Q-8.9, p. 20.

directly assigning these costs to participants is construed to be non-viable, then, in the alternative, Mr. Townsend recommends that the Commission reject the CGS program in its entirety, which is one of the options available to the Commission under PURA § 39.452(b).

If, as a threshold matter, the Commission elects to assign cost responsibility to non-participants, Mr. Townsend concludes that ETI's proposal to spread these costs broadly across all customers is the most equitable means to impose an otherwise inequitable cost – because it minimizes the rate impact on any group of non-participant funders. In such a case, he recommends that ETI's basic approach to cost recovery be adopted, subject to three modifications: (1) adoption of an 80-MW participation cap; (2) an adjustment that reduces unrecovered fixed cost by any increases in generation-related base revenue attributable to load growth that has occurred since the end of the test period used in setting base rates; and (3) the ETI-proposed rate design be rejected and replaced with a demand charge for all demand-billed rate schedules.

To the extent that these CGS-related matters have implications for this rate case, I defer to (and concur with) the recommendations offered by Mr. Townsend in Docket No. 38951.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS

Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs	§ §	PUC Docket No. 39896

AFFIDAVIT OF KEVIN C. HIGGINS

STATE OF UTAH)
)
COUNTY OF SALT LAKE)

Neal Townsend, being first duly sworn, deposes and states that:

1. He is a Principal with Energy Strategies, L.L.C., in Salt Lake City, Utah;

2. He is the witness who sponsors the accompanying testimony entitled "Direct Testimony of Kevin C. Higgins;"

3. Said testimony and exhibits were prepared by him and under his direction and supervision;

4. If inquiries were made as to the facts in said testimony and exhibits he would respond as therein set forth; and

5. The aforesaid testimony is true and correct to the best of his knowledge, information and belief.

Kevin C. Higgins

Subscribed and sworn to or affirmed before me this 22nd day of March, 2012, by Kevin C. Higgins.

Notary Public

Notary Public
KIMBERLIE ANN IGNJATOVIC
Commission #607671
My Commission Expires
April 10, 2015
State of Utah

ENTERGY PROPOSED RATE DESIGN
LARGE GENERAL SERVICE TOTAL CLASS
FUNCTIONALIZED COST RECOVERY

LINE NO.	FUNCTIONS	COSTS[1]	COLLECTED IN RATES[2]	(UNDER)/OVER COLLECTION	PERCENTAGE RECOVERED
	(a)	(b)	(c)	(d)	(e)
1	DEMAND[3]	$ 46,266,083	$ 33,116,674	$ (13,149,409)	71.6%
2	ENERGY	$ 3,635,811	$ 15,556,253	$ 11,920,442	427.9%
3	CUSTOMER	$ 561,445	$ 1,841,316	$ 1,279,871	328.0%
4	TOTAL	$ 50,463,339	$ 50,514,243	$ 50,904	

KROGER PROPOSED RATE DESIGN
AT ETI PROPOSED REVENUE REQUIREMENT

LARGE GENERAL SERVICE TOTAL CLASS
FUNCTIONALIZED COST RECOVERY

LINE NO.	FUNCTIONS	COSTS	COLLECTED IN RATES[4]	(UNDER)/OVER COLLECTION	PERCENTAGE RECOVERED
	(a)	(b)	(c)	(d)	(e)
5	DEMAND	$ 46,266,083	$ 41,539,693	$ (4,726,390)	89.8%
6	ENERGY	$ 3,635,811	$ 7,853,121	$ 4,217,310	216.0%
7	CUSTOMER	$ 561,445	$ 1,126,320	$ 564,875	200.6%
8	TOTAL	$ 50,463,339	$ 50,519,134	$ 55,795	

NOTES:
1. Data Source: ETI RFP Schedule P.6.1.2.
2. Data Source: ETI Response to Data Request TIEC 6-5.
3. Demand costs include Purchased Capacity and Interruptible Service costs. See RFP Schedule Q-8.8, p. 44.4.
4. See Higgins Exhibit KCH-2

LARGE GENERAL SERVICE
PROPOSED RATE DESIGN
AT ETI PROPOSED REVENUE REQUIREMENT

Line No	Description	Bills, kW or mWh		Present Rates		ETI Proposed Rates		Kroger Proposed Rates	
				Rate $	Revenue $	Rate $	Revenue $	Rate $	Revenue $
	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)
	Customer Charge:								
1	LGS	4,320	Bills	$425.05	$ 1,836,216	$425 05	$ 1,836,216	**$260.00**	**$1,123,200**
	Demand Charge:								
2	All kW	3,289,459	kW	$8.56	28,157,769	$10.25	33,716,955	**$12.81**	**$42,137,970**
3	Total kW	3,289,459	kW		$ 28,157,769		$ 33,716,955		**42,137,970**
	Voltage Adjustment								
4	Secondary	2,216,062	kW	$0 00	$ -	$0 00	$ -	$0 00	-
5	Primary	882,316	kW	($0.58)	$ (511,743)	($0.65)	$ (573,505)	($0 65)	($573,505)
6	Transmission	191,081	kW	($1 15)	(219,743)	($1.25)	(238,851)	($1.25)	($238,851)
7	Total Voltage Adj	3,289,459	kW		$ (731,486)		$ (812,356)		($812,356)
8	Total Demand Charges				$ 27,426,283		$ 32,904,599		**$ 41,325,614**
	Energy Charge:								
9	LGS	1,533,273	mWh	$0 00854	$ 13,094,151	$0 01023	$ 15,685,383	**$0.00513**	**$ 7,865,690**
10	Weather Adjustment	(22,855)	mWh	$0 00854	$ (195,182)	$0.01023	$ (233,807)	**$0.00513**	**$ (117,246)**
11	Sub-Total	1,510,418	mWh		$ 12,898,969		$ 15,451,576		**$ 7,748,444**
13	Non-TOD Base Rate Subtotal				$ 42,161,468		$ 50,192,391		**$50,197,258**

LARGE GENERAL SERVICE (CONTINUED)

Line No.	Description	Bills, kW or mWh	Present Rates Rate $	Present Rates Revenue $	Proposed Rates Rate $	Proposed Rates Revenue $	Kroger Proposed Rates Rate $	Kroger Proposed Rates Revenue $
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	LGS - Time-Of-Day							
	Customer Charge:							
1	Bills - (May-Oct)	6 Bills	$425 05	$ 2,550	$425.05	$ 2,550	**$260.00**	**$ 1,560.00**
2	Bills - (Nov-Apr)	6 Bills	$425 05	$ 2,550	$425.05	$ 2,550	**$260.00**	**$ 1,560.00**
3	Total	12 Bills		$ 5,100		$ 5,100		**$ 3,120.00**
	Demand Charge:							
4	kW (May-Oct)	11,547 kW	$10 62	$ 122,629	$12 72	$ 146,878	**$12.83**	**$ 148,148**
5	kW (Nov-Apr)	12,219 kW	$5.51	$ 67,327	$6.60	$ 80,645	**$6.66**	**$ 81,379**
6	Total kW	23,766 kW		$ 189,956		$ 227,523		**$ 229,527**
	Voltage Adjustment.							
7	Secondary	0 kW	$0.00	$ -	$0 00	$ -	$0.00	$ -
8	Primary	23,766 kW	($0.58)	$ (13,784)	($0.65)	$ (15,448)	($0.65)	$ (15,448)
9	Transmission	0 kW	($1 15)	$ -	($1.25)	$ -	($1 25)	$ -
10	Total Voltage Adj	23,766 kW		$ (13,784)		$ (15,448)		$ (15,448)
11	Total Demand Charges			$ 176,172		$ 212,075		**$ 214,079**
	Energy Charge:							
12	On-peak (May-Oct)	1,098 mWh	$0 02326	$ 25,539	$0.02786	$ 30,590	$0 02786	$ 30,590
13	Weather Adjustment	0 mWh	$0.02326	$ -	$0 02786	$ -	$0.02786	$ -
14	On-peak (Nov-Apr)	1,155 mWh	$0.00834	$ 9,633	$0 00999	$ 11,538	$0 00999	$ 11,538
15	Weather Adjustment	0 mWh	$0 00834	$ -	$0 00999	$ -	$0 00999	$ -
16	Off-peak (All)	7,411 mWh	$0.00705	$ 52,248	$0 00844	$ 62,549	$0 00844	$ 62,549
17	Weather Adjustment	0 mWh	$0.00705	$ -	$0.00844	$ -	$0.00844	$ -
18	Energy Charge SubTotal	9,664 mWh		$ 87,420		$ 104,677		$ 104,677
19	TOD Base Rate Subtotal			$ 268,692		$ 321,852		$ 321,876
20	Total LGS Base Revenue			$ 42,430,160		$ 50,514,243		$ 50,519,134
21	Renewable Energy Credit Rider (1)	1,435,207 mWh			$0 000059	$ 84,677	$0.000059	$ 84,677
	Base Rev w/REC Rider					$ 50,598,920		$ 50,603,811
22	Riders TTC, HRC, EECRF, RCE, SRC & SCO (2)	1,533,273 mWh						
23	LGS		$0.004572	$ 7,010,124	$0.004572	$ 7,010,124	0.004572	$ 7,010,124
24	Weather Adjustment	(22,855) mWh	$0.004572	$ (104,493)	$0 004572	$ (104,493)	0.004572	$ (104,493)
25	LGS-TOD	9,664 mWh	$0 004572	$ 44,184	$0 004572	$ 44,184	0.004572	$ 44,184
26	Weather Adjustment	0 mWh	$0 004572	$ -	$0 004572	$ -	0 004572	$ -
	Total Riders	1,520,082 mWh		$ 6,949,815		$ 6,949,815		$ 6,949,815
27	Fuel. (3)	1,533,273 mWh						
28	LGS		$0.041221	$ 63,203,046	$0 041221	$ 63,203,046	$0 041221	$ 63,203,046
29	Weather Adjustment	(22,855) mWh	$0.041221	$ (942,106)	$0.041221	$ (942,106)	$0.041221	$ (942,106)
30	LGS-TOD	9,664 mWh	$0 040499	$ 391,382	$0.040499	$ 391,382	$0 040499	$ 391,382
31	Weather Adjustment	0 mWh	$0 040499	$ -	$0.040499	$ -	$0.040499	$ -
32	Total Fuel	1,520,082 mWh		$ 62,652,322		$ 62,652,322		$ 62,652,322
33	Total Revenue			$ 112,032,297		120,201,057		$ 120,205,948
34	Revenue Change					8,168,760		$ 8,173,651
35	Percent Change					7.29%		7.30%

(1) Excludes Transmission Level mWh.
(2) Summary rider factor (Source WP/Q-7/RD-5) applied for both present and proposed rider revenue.
(3) Composite fuel factor (Source: WP/Q-7/RD-2) applied for both present and proposed fuel revenue.

RATE IMPACT ANALYSIS
ENTERGY PROPOSED RATE DESIGN - AS FILED
LARGE GENERAL SERVICE TYPICAL BILLS
(SECONDARY)

LOAD FACTOR **45%**

LINE NO.	FUEL FACTOR AND RIDERS	KW BILLING DEMAND	PRESENT MONTHLY BILLING	PROPOSED MONTHLY BILLING	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
	(a)	(b)	(c)	(d)	(e)	(f)
1		300	$8,507.97	$8,804.17	$296.20	3.48%
2		500	$13,896.58	$14,390.24	$493.66	3.55%
3		1,000	$27,368.11	$28,355.43	$987.32	3.61%
4		1,500	$40,839.64	$42,320.63	$1,480.99	3.63%
5		2,000	$54,311.16	$56,285.82	$1,974.66	3.64%

LOAD FACTOR **55%**

LINE NO.	FUEL FACTOR AND RIDERS	KW BILLING DEMAND	PRESENT MONTHLY BILLING	PROPOSED MONTHLY BILLING	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
	(a)	(b)	(c)	(d)	(e)	(f)
6		300	$9,733.50	$10,266.86	$533.36	5.48%
7		500	$15,939.14 *	$16,828.06	$888.92	5.58%
8		1,000	$31,453.23	$33,231.07	$1,777.84	5.65%
9		1,500	$46,967.32	$49,634.09	$2,666.77	5.68%
10		2,000	$62,481.41	$66,037.10	$3,555.69	5.69%

LOAD FACTOR **65%**

LINE NO.	FUEL FACTOR AND RIDERS	KW BILLING DEMAND	PRESENT MONTHLY BILLING	PROPOSED MONTHLY BILLING	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
	(a)	(b)	(c)	(d)	(e)	(f)
11		300	$10,959.04	$11,729.55	$770.51	7.03%
12		500	$17,981.70	$19,265.88	$1,284.18	7.14%
13		1,000	$35,538.35	$38,106.72	$2,568.37	7.23%
14		1,500	$53,095.01	$56,947.55	$3,852.54	7.26%
15		2,000	$70,651.66	$75,788.38	$5,136.72	7.27%
16	FUEL FACTOR		$0.041695	$0.041695		
17	RIDERS: TTC, HRC, EECRF, RCE, SRC, SCO, REC AND PPR (1)		$0.004572	$0.017951		
18	FRANCHISE FEE RIDER		$0.0011536	$0.0011536		
19	TOTAL NON-FUEL RIDERS		$0.005726	$0.019105		

* Average Customer
(1) Summary rider factor (Source: WP/Q-7/RD-5) applied for both present and proposed rider revenue.
Data Source: Schedules O and Q Support Documents, Q-8.9 Typical Bill With Franchise Fee

RATE IMPACT ANALYSIS
ENTERGY PROPOSED RATE DESIGN - REVISED TO REFLECT ELIMINATION OF PPR RIDER PROPOSAL
LARGE GENERAL SERVICE TYPICAL BILLS
(SECONDARY)

LOAD FACTOR **45%**

LINE NO.	FUEL FACTOR AND RIDERS	KW BILLING DEMAND	PRESENT MONTHLY BILLING	PROPOSED MONTHLY BILLING	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
	(a)	(b)	(c)	(d)	(e)	(f)
1		300	$8,507.97	$9,187.33	$679.36	7.98%
2		500	$13,896.58	$15,028.85	$1,132.27	8.15%
3		1,000	$27,368.11	$29,632.65	$2,264.54	8.27%
4		1,500	$40,839.64	$44,236.46	$3,396.82	8.32%
5		2,000	$54,311.16	$58,840.26	$4,529.10	8.34%

LOAD FACTOR **55%**

LINE NO.	FUEL FACTOR AND RIDERS	KW BILLING DEMAND	PRESENT MONTHLY BILLING	PROPOSED MONTHLY BILLING	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
	(a)	(b)	(c)	(d)	(e)	(f)
6		300	$9,733.50	$10,451.17	$717.67	7.37%
7		500	$15,939.14 *	$17,135.25	$1,196.11	7.50%
8		1,000	$31,453.23	$33,845.45	$2,392.22	7.61%
9		1,500	$46,967.32	$50,555.66	$3,588.34	7.64%
10		2,000	$62,481.41	$67,265.86	$4,784.45	7.66%

LOAD FACTOR **65%**

LINE NO.	FUEL FACTOR AND RIDERS	KW BILLING DEMAND	PRESENT MONTHLY BILLING	PROPOSED MONTHLY BILLING	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
	(a)	(b)	(c)	(d)	(e)	(f)
11		300	$10,959.04	$11,715.01	$755.97	6.90%
12		500	$17,981.70	$19,241.65	$1,259.95	7.01%
13		1,000	$35,538.35	$38,058.26	$2,519.91	7.09%
14		1,500	$53,095.01	$56,874.86	$3,779.85	7.12%
15		2,000	$70,651.66	$75,691.46	$5,039.80	7.13%
16	FUEL FACTOR		$0.041695	$0.041695		
17	RIDERS: TTC, HRC, EECRF, RCE, SRC, SCO, REC AND PPR (1)		$0.004572	$0.004631		
18	FRANCHISE FEE RIDER		$0.0011536	$0.0011536		
19	TOTAL NON-FUEL RIDERS		$0.005726	$0.005785		

* AVERAGE CUSTOMER
(1) Summary rider factor (Source: WP/Q-7/RD-5) applied for both present and proposed rider revenue.
Data Source: Entergy's Response to TIEC 6-5

RATE IMPACT ANALYSIS
KROGER RECOMMENDED RATE DESIGN
LARGE GENERAL SERVICE TYPICAL BILLS
(SECONDARY)

LOAD FACTOR 45%

LINE NO.	FUEL FACTOR AND RIDERS	KW BILLING DEMAND	PRESENT MONTHLY BILLING	PROPOSED MONTHLY BILLING	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
	(a)	(b)	(c)	(d)	(e)	(f)
1		300	$8,507.97	$9,287.68	$779.71	9.16%
2		500	$13,896.58	$15,306.13	$1,409.55	10.14%
3		1,000	$27,368.11	$30,352.25	$2,984.14	10.90%
4		1,500	$40,839.64	$45,398.38	$4,558.74	11.16%
5		2,000	$54,311.16	$60,444.51	$6,133.35	11.29%

LOAD FACTOR 55%

LINE NO.	FUEL FACTOR AND RIDERS	KW BILLING DEMAND	PRESENT MONTHLY BILLING	PROPOSED MONTHLY BILLING	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
	(a)	(b)	(c)	(d)	(e)	(f)
6		300	$9,733.50	$10,439.83	$706.33	7.26%
7		500	$15,939.14 *	$17,226.38	$1,287.24	8.08%
8		1,000	$31,453.23	$34,192.75	$2,739.52	8.71%
9		1,500	$46,967.32	$51,159.13	$4,191.81	8.92%
10		2,000	$62,481.41	$68,125.51	$5,644.10	9.03%

LOAD FACTOR 65%

LINE NO.	FUEL FACTOR AND RIDERS	KW BILLING DEMAND	PRESENT MONTHLY BILLING	PROPOSED MONTHLY BILLING	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
	(a)	(b)	(c)	(d)	(e)	(f)
11		300	$10,959.04	$11,591.98	$632.94	5.78%
12		500	$17,981.70	$19,146.63	$1,164.93	6.48%
13		1,000	$35,538.35	$38,033.26	$2,494.91	7.02%
14		1,500	$53,095.01	$56,919.88	$3,824.87	7.20%
15		2,000	$70,651.66	$75,806.51	$5,154.85	7.30%
16	FUEL FACTOR		$0.041695	$0.041695		
17	RIDERS: TTC, HRC, EECRF, RCE, SRC, SCO, REC AND PPR (1)		$0.004572	$0.004631		
18	FRANCHISE FEE RIDER		$0.0011536	$0.0011536		
19	TOTAL NON-FUEL RIDERS		$0.005726	$0.005785		

* AVERAGE CUSTOMER
(1) Summary rider factor (Source: WP/Q-7/RD-5) applied for both present and proposed rider revenue.
Data Source: Entergy's Response to TIEC 6-5 and Exhibit KCH-2

CERTIFICATE OF SERVICE

I hereby certify that true copy of the foregoing was served by regular U.S. mail, postage prepaid, unless otherwise noted, on the attached this 26th day of March, 2012 to the parties listed below.

K Boehm ka

Kurt J. Boehm, Esq.
Jody M. Kyler, Esq

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TEXAS INDUSTRIAL ENERGY CONSUMERS **Filed MTI 11/29/11 rdh**	MEGHAN GRIFFITHS ANDREWS KURTH LLP 111 CONGRESS AVE STE 1700 AUSTIN TX 78701 512-320-9200 512-320-9292 FAX
STATE AGENCIES **Filed MTI 12/2/11 rdh**	SUSAN M KELLEY OFFICE OF THE ATTORNEY GENERAL P O BOX 12548 AUSTIN TX 78711-2548 512-475-4173 512-477-4544 FAX Email: susan.kelley@oag.state.tx.us bryan.baker@oag.state.tx.us
OFFICE OF PUBLIC UTILITY COUNSEL **Filed MTI 12/6/11 rdh**	SARA J FERRIS OFFICE OF PUBLIC UTILITY COUNSEL 1701 N CONGRESS AVE STE 9-180 AUSTIN TX 78711-2397 512-936-7500 512-936-7525 FAX

CITIES **(Bridge City, Groves, Orange, Pine Forest, and West Orange)** **Filed MTI 12/8/11 rdh**	STEPHEN MACK LAWTON LAW FIRM PC 701 BRAZOS STE 500 AUSTIN TX 78701 512-322-0019 512-716-8917 FAX
THE KROGER CO. **Filed MTI 12/14/11 rdh** **Filed Motion for Admission Pro Hac Vice – 12/22/11 rdh; SOAH Order No. 4 – Granting Motions for Admission Pro Hac Vice 1/17/12 as**	KURT J BOEHM ESQ BOEHM KURTZ & LOWRY 36 EAST SEVENTH ST STE 1510 CINCINNATI OH 45202 513-421-2255 513-421-2764 FAX Email: kboehm@BKLlawfirm.com GRANT CLIFTON ESQ 5700 JIM HOGG AVE AUSTIN TX 78756 512-934-1228 NO FAX Email: grantclifton@gmail.com
WALMART **(Wal-Mart Stores Texas, LLC and Sam's East, Inc.,)** **Filed MTI 12/27/11 rdh; SOAH Order NO. 3 – Granting MTI 1/17/12 as**	RICK D CHAMBERLAIN BEHRENS TAYLOR WHEELER & CHAMBERLAIN 6 N E 63RD ST STE 400 OKLAHOMA CITY OK 73105-1401 405-848-1014 405-848-3155 FAX Email: rdc_law@swbell.net
EAST TEXAS ELECTRIC COOPERATIVE, INC. **Filed MTI 1/5/12 rdh; SOAH Order No. 7 – Granting MTI 1/26/12 as**	MARK C DAVIS BRICKFIELD BURCHETTE RITTS & STONE PC 1005 CONGRESS AVE STE 950 ~~400~~ AUSTIN TX 78701 512-472-1081 512-472-7473 FAX Email: mdavis@bbraustin.com
THE UNITED STATES DEPARTMENT OF ENERGY **Filed MTI 1/13/12 rdh; SOAH Order No. 7 – Granting MTI 1/26/12 as**	STEVEN A PORTER THE UNITED STATES DEPARTMENT OF ENERGY 1000 INDEPENDENCE AVE SW WASHINGTON DC 20585 202-586-4219 NO FAX Email: Steven.Porter@hq.doe.gov

KAREN BERMUDEZ **Filed MTI per S.H. – AIS Item # 185 – 1/20/12 rdh**	KAREN BERMUDEZ NO ADDRESS NO FAX 832-445-9192