	SB7	April File	21957	21984				
Nov 16, 1999	12.70							
Nov 17 1999	14.50							
Nov 18, 1999	14.80							
Nov 19, 1999	14.60							
Nov 20, 1999	1.50							
Nov 21, 1999	3.50							
Nov 22, 1999	11.70							
Nov 23, 1999	12.80							
Nov 24, 1999	2.40							
Nov 25, 1999								
Nov 26, 1999	3.50							
Nov 27, 1999	5.0							
Nov 28, 1999	1.50							
Nov 29, 1999	9.40							
Nov 30, 1999	15.30							
Nov 31, 1999								
Dec 1, 1999	14.50							
Dec 2, 1999	11.60							
Dec 3, 1999	7.30							
Dec 4, 1999	5.60							
Dec 5, 1999	4.30							
Dec 6, 1999	14.50							
Dec 7, 1999	15.00							
Dec 8, 1999	14.70							
Dec 9, 1999	13.50							
Dec 10, 1999	16.30							
Dec 11, 1999								
Dec 12, 1999								
Dec 13, 1999								
Dec 14, 1999								
Dec 15, 1999								
Total:	240.5							

12

	SB7	April File	21957	21984				
Dec 16, 1999	16.90							
Dec 17 1999	12.80							
Dec 18, 1999	4.60							
Dec 19, 1999	7.80							
Dec 20, 1999	14.70							
Dec 21, 1999	16.00							
Dec 22, 1999	16.50							
Dec 23, 1999	6.20							
Dec 24, 1999								
Dec 25, 1999								
Dec 26, 1999	2.50							
Dec 27, 1999	16.50							
Dec 28, 1999	17.20							
Dec 29, 1999	12.00							
Dec 30, 1999	12.50							
Dec 31, 1999	5.0							
Jan 1, 2000	5.0							
Jan 2, 2000	10.							
Jan 3, 2000	16.0							
Jan 4, 2000	15.50							
Jan 5, 2000	15.80							
Jan 6, 2000	16.30							
Jan 7, 2000	11.0							
Jan 8, 2000								
Jan 9, 2000								
Jan 10, 2000								
Jan 11, 2000	4.80							
Jan 12, 2000								
Jan 13, 2000	7.50							
Jan 14, 2000	5.00							
Jan 15, 2000								
Total:	268.1							

12

Jan 16 to Feb 15, 2000

	SB7	April File	21957	21984				Daily Totals (if multiple)
Jan 16, 2000								
Jan 17 2000			9.60					
Jan 18, 2000	11.90							
Jan 19, 2000	11.50							
Jan 20, 2000		7.40						
Jan 21, 2000		4.80						
Jan 22, 2000								
Jan 23, 2000								
Jan 24, 2000			5.60					
Jan 25, 2000			9.50					
Jan 26, 2000	10.30							
Jan 27, 2000			12.80					
Jan 28, 2000			5.50					
Jan 29, 2000								
Jan 30, 2000								
Jan 31, 2000	10.30							
Feb 1, 2000		12.80						
Feb 2, 2000		11.50						
Feb 3, 2000		11.30						
Feb 4, 2000		8.30						
Feb 5, 2000								
Feb 6, 2000								
Feb 7, 2000		3.40						
Feb 8, 2000		8.50						
Feb 9, 2000		13.40						
Feb 10, 2000		11.80						
Feb 11, 2000		5.70		2.00				7.7
Feb 12, 2000								
Feb 13, 2000		2.50						
Feb 14, 2000		4.30	2.20	6.50				13
Feb 15, 2000		2.40	8.40					10.8
Column Totals:	44	108.1	53.6	8.5	214.2	**(Grand Total)**		

3 + 1 Combined

352

Feb 17 to Mar 15, 2000

	SB7	April File	21957	21984				Daily Totals (if multiple)
Jan 16, 2000		11.50						
Feb 17 2000	1.0	11.30						12.3
Feb 18, 2000		9.40						
Feb 19, 2000								
Feb 20, 2000								
Feb 21, 2000		12.60						
Feb 22, 2000		12.00	1.50					13.5
Feb 23, 2000		8.90	6.00					14.9
Feb 24, 2000		6.00	7.50					13.5
Feb 25, 2000		2.60	4.80					7.4
Feb 26, 2000								
Feb 27, 2000								
Feb 28, 2000		11.60	1.50					13.1
Feb 29, 2000		11.50	3.00					14.5
Mar 1, 2000		12.30	2.00					14.3
Mar 2, 2000		10.80	3.40					14.2
Mar 3, 2000		2.50	4.60					7.1
Mar 4, 2000		2.50	1.50					4
Mar 5, 2000		3.00	3.40					6.4
Mar 6, 2000		11.50	3.60					15.1
Mar 7, 2000		14.70						
Mar 8, 2000		15.50	1.0					16.5
Mar 9, 2000		14.20	1.2					15.4
Mar 10, 2000		13.70		.50				14.2
Mar 11, 2000								
Mar 12, 2000		4.00						
Mar 13, 2000		5.00						
Mar 14, 2000		16.30						
Mar 15, 2000		16.40	.40					16.8
Column Totals:	1.00	239.8	45.4	.50	286.7	**(Grand Total)**		

8 single

12 combined (5 also single)

15

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	SB7	April File	21957	21984				Daily Totals (if multiple)
Mar 16, 2000		14.90						
Mar 17 2000		13.30						
Mar 18, 2000		5.60						
Mar 19, 2000		6.40						
Mar 20, 2000		14.50						
Mar 21, 2000		16.20						
Mar 22, 2000		13.80						
Mar 23, 2000		15.70						
Mar 24, 2000		14.90						
Mar 25, 2000		13.90						
Mar 26, 2000		16.00						
Mar 27, 2000		16.10						
Mar 28, 2000		12.00						
Mar 29, 2000		11.80						
Mar 30, 2000		3.30						
Mar 31, 2000								
Apr 1, 2000								
Apr 2, 2000								
Apr 3, 2000								
Apr 4, 2000								
Apr 5, 2000		1.70		.70				2.4
Apr 6, 2000	1.00	2.50	4.00	1.50				9
Apr 7, 2000	3.60	2.30						5.9
Apr 8, 2000								
Apr 9, 2000								
Apr 10, 2000		2.40	1.00	3.50				6.9
Apr 11, 2000								
Apr 12, 2000								
Apr 13, 2000								
Apr 14, 2000								
Apr 15, 2000				.50				
Column Totals:	4.6	197.3	5	6.2	213.1	**(Grand Total)**		

Apr 16 to May 15, 2000

	SB7	April File	21957	21984				Daily Totals (if multiple)
Apr 16, 2000								
Apr 17 2000								
Apr 18, 2000								
Apr 19, 2000								
Apr 20, 2000								
Apr 21, 2000								
Apr 22, 2000								
Apr 23, 2000								
Apr 24, 2000		4.5	1.50					6
Apr 25, 2000	1	5.90		.50				7.4
Apr 26, 2000	2	4.90	1.00					7.9
Apr 27, 2000	3	1.50	1.30					5.8
Apr 28, 2000	.5	4.50	.50					5.5
Apr 29, 2000								
Apr 30, 2000								
Apr 31, 2000								
May 1, 2000	3.6	2.10	2.50					8.2
May 2, 2000		4.80	1.00					5.8
May 3, 2000		6.80	3.00					9.8
May 4, 2000		6.50						
May 5, 2000								
May 6, 2000								
May 7, 2000								
May 8, 2000		6.50	2.50					9
May 9, 2000		2.00		1.0				3
May 10, 2000	3.50	1.60		1.0				6.1
May 11, 2000				10.30				
May 12, 2000		1.60	1.50	5.80				8.9
May 13, 2000								
May 14, 2000								
May 15, 2000		3.10		2.50				5.6
Column Totals:	13.6	56.3	14.8	21.1	105.8	**(Grand Total)**		

May 16 to Jun 15, 2000

	SB7	April File	21957	21984				Daily Totals (if multiple)
May 16, 2000	3	2.50		2.00				7.5
May 17 2000	1.50	6.40						7.9
May 18, 2000		6.80						
May 19, 2000		3.50						
May 20, 2000	1.00							
May 21, 2000	1.50							
May 22, 2000		2.50						
May 23, 2000	5.80							
May 24, 2000	2.00	3.90						5.9
May 25, 2000	1.50	3.00						4.5
May 26, 2000	3.90	4.50	1.50					9.9
May 27, 2000								
May 28, 2000								
May 29, 2000		2.50						
May 30, 2000	2.50	2.0						4.5
May 31, 2000	1.50		7.50					9
Jun 1, 2000	2.60		4.30					6.9
Jun 2, 2000	2.10	3.00	4.40					9.5
Jun 3, 2000								
Jun 4, 2000	1.00							
Jun 5, 2000		1.00	6.10					7.1
Jun 6, 2000	2.80		4.10					6.9
Jun 7, 2000	8.40	1.30	3.00					12.7
Jun 8, 2000	2.60		2.90					5.5
Jun 9, 2000	3.70	2.90						6.6
Jun 10, 2000								
Jun 11, 2000	1.50	1.00						2.5
Jun 12, 2000	3.60	5.80						9.4
Jun 13, 2000	5.70	4.60						10.3
Jun 14, 2000	2.50	5.70						8.2
Jun 15, 2000	3.80	4.10						7.9
Column Totals:	64.5	67	33.8	2.00	167.3	**(Grand Total)**		

1 combined

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Jun 16 to July 15, 2000

	SB7	April File	21957	Transco				Daily Totals (if multiple)
Jun 16, 2000			3.00					
Jun 17 2000								
Jun 18, 2000		3.30						
Jun 19, 2000	5.20	5.10						10.3
Jun 20, 2000		10.70						
Jun 21, 2000	5.30							
Jun 22, 2000	4.90							
Jun 23, 2000								
Jun 24, 2000								
Jun 25, 2000								
Jun 26, 2000								
Jun 27, 2000								
Jun 28, 2000								
Jun 29, 2000	2.3	2.00						4.3
Jun 30, 2000								
Jun 31, 2000								
Jul 1, 2000								
Jul 2, 2000								
Jul 3, 2000	2.50							
Jul 4, 2000	2.0	1.00						3
Jul 5, 2000	1.50	2.70						4.2
Jul 6, 2000	1.00							
Jul 7, 2000				3.50				
Jul 8, 2000								
Jul 9, 2000		4.50						
Jul 10, 2000		10.0						
Jul 11, 2000		11.30						
Jul 12, 2000		10.0	2.70					12.7
Jul 13, 2000		10.0						
Jul 14, 2000			6.40					
Jul 15, 2000		1.00	2.50					3.5
Column Total	24.7	71.6	14.6	3.50	114.4	**(Grand Total)**		

1 combined

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R-00357

Jul 16 to Aug 15, 2000

	SB7	April File	21957	21984				Daily Totals (if multiple)
Jul 16, 2000								
Jul 17 2000		11.50						
Jul 18, 2000		7.40						
Jul 19, 2000		6.90						
Jul 20, 2000		4.80						
Jul 21, 2000		7.50						
Jul 22, 2000		2.10						
Jul 23, 2000		5.90						
Jul 24, 2000		1.50						
Jul 25, 2000		8.50						
Jul 26, 2000	2	4.00						6
Jul 27, 2000	1							
Jul 28, 2000	1	14.00						15
Jul 29, 2000	2	4.50						6.5
Jul 30, 2000	2.5							
Jul 31, 2000	3.2	4.80						8
Aug 1, 2000		5.80						
Aug 2, 2000	1.30	4.60						5.9
Aug 3, 2000								
Aug 4, 2000		1.30						
Aug 5, 2000								
Aug 6, 2000		4.00						
Aug 7, 2000		10.40						
Aug 8, 2000		3.60						
Aug 9, 2000	5.3	2.00						7.3
Aug 10, 2000	7.00	4.00						11
Aug 11, 2000		4.00						
Aug 12, 2000								
Aug 13, 2000								
Aug 14, 2000								
Aug 15, 2000								
Column Totals:	25.3	123.1			148.4	**(Grand Total)**		

1 single (+combined)

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Aug 15 to Sept 16, 2000

	SB7	April File	21957	21984				
Aug 16, 2000	2.50							
Aug 17 2000	1.0							
Aug 18, 2000	1.0							
Aug 19, 2000								
Aug 20, 2000								
Aug 21, 2000								
Aug 22, 2000								
Aug 23, 2000								
Aug 24, 2000								
Aug 25, 2000								
Aug 26, 2000								
Aug 27, 2000								
Aug 28, 2000								
Aug 29, 2000								
Aug 30, 2000								
Aug 31, 2000								
Sep 1, 2000								
Sep 2, 2000								
Sep 3, 2000								
Sep 4, 2000								
Sep 5, 2000								
Sep 6, 2000								
Sep 7, 2000								
Sep 8, 2000								
Sep 9, 2000								
Sep 10, 2000								
Sep 11, 2000								
Sep 12, 2000								
Sep 13, 2000								
Sep 14, 2000								
Sep 15, 2000								
Column Total:	8.50							

-0-

Andrew Kever
Days with Multiple Time Entries Totaling Over 12 Hours

1.	Feb 14, 2000	4.30 hours for the April Filing (3943-S14) 2.20 hours for Docket 21957 (3943-S19) 6.50 hours for Docket 21984 (3943-S21) 13.00 hours total	-1.0
2.	Feb 17, 2000	1.0 hours for SB 7 (3946-S3) 11.30 hours for April Filing (3946-S7) 12.3 hours total	-0.3
3.	Feb 22, 2000	12.00 hours for SB 7 (3946-S8) 1.50 hours for Dkt. 21957 (3946-S15) 13.50 hours total	-1.5
4.	Feb 23, 2000	8.90 hours for SB 7 (3946-S8) 6.00 hours for Dkt. 21957 (3946-S15) 14.90 hours total	-2.9
5.	Feb 24, 2000	6.00 hours for SB 7 (3946-S9) 7.50 hours for Dkt. 21957 (3946-S15) 13.50 hours total	-1.5
6.	Feb 28, 2000	11.60 hours for SB 7 (3946-S9) 1.50 hours for Dkt. 21957 (3946-S16) 13.10 hours total	-1.1
7.	Feb 29, 2000	11.50 hours for SB 7 (3946-S9) 3.00 hours for Dkt. 21957 (3946-S16) 14.50 hours total	-2.5
8.	Mar 1, 2000	12.30 hours for SB 7 (3946-S10)* 2.00 hours for Dkt. 21957 (3946-S16) 14.30 hours total	-2.0
9.	Mar 2, 2000	10.80 hours for SB 7 (3946-S10) 3.40 hours for Dkt. 21957 (3946-S16) 14.20 hours total	-2.2
10.	Mar 6, 2000	11.50 hours for SB 7 (3946-S11) 3.60 hours for Dkt. 21957 (3946-S18) 15.10 hours total	-3.1

11.	Mar 8, 2000	15.50 hours for SB 7 (3946-S12)* 1.00 hours for Dkt. 21957 (3946-S18) 16.50 hours total	-1.0
12.	Mar 9, 2000	14.20 hours for SB 7 (3946-S12)* 1.20 hours for Dkt. 21957 (3946-S19) 15.40 hours total	-1.2
13.	Mar 10, 2000	13.70 hours for SB 7 (3946-S12)* .50 hours for Dkt. 21984 (3946-S21) 14.20 hours total	-0.5
14.	Mar 15, 2000	16.40 hours for SB 7 (3946-S14)* .40 hours for Dkt. 21957 (3946-S19) 16.80 hours total	-0.4
15.	June 7, 2000	8.40 hours for SB 7 (65) 1.30 hours for April Filing (73) 3.00 hours for Dkt 21957 (78) 12.70 hours total	-0.7
16.	July 12, 2000	10.00 hours for April Filing (97) 2.70 hours for Dkt 21957 (98) 12.70 hours total	-0.7
17.	July 28, 2000	1.00 hour for SB 7 (110) 14.00 hours for April Filing (115)† 15.00 hours total	-1.0
Total if all additional hours over 12.0 were disallowed			-23.6

* Hours in excess of 12.0 disallowed in Exh JKT-4 due to insufficient billing detail.
† Hours in excess of 12.0 allowed in Exh JKT-4.

Proceedings Included as "SB 7" Matter on Bickerstaff Invoices

20936 Rulemaking: *Code of Conduct for Electric Utilities Pursuant to PURA Section 39.157(d).* (Code of conduct). EGIS and Shell filed comments in this proceeding.

20944 Rulemaking: *Relating to Renewable Energy Mandate under Section 39.904 of Utilities Code* (Renewable energy). EGSI and Shell filed comments in this proceeding.

20970 Implementation Project: *Plan for Implementing SB 7.* (SB7 Implementation). This project developed the general procedures and timelines for the various rulemakings and projects required by SB7. EGSI and Shell filed comments in this proceeding.

21072 Rulemaking: *Goal for natural gas generating capacity.* (Natural gas goal). Although the PUC interchange does not indicate that neither EGSI or Shell filed anything in this docket there are billing entries on Bickerstaff invoices indicating that EGSI participated in this proceeding.

21082 Rulemaking: *Certification of Retail Electric Providers (REPs) and Registration of Power Generation Companies and Aggregators; Forms.* (REP Certification) EGSI and Shell filed comments in this docket.

21083 Implementation Project: *Cost Unbundling and Separation of Utility Business Activities, Including Separation of Competitive Energy Services and Distributed Generation.* (Business separation). This project developed a rate filing package in compliance with SB7 section 39.201(a). EGSI and Shell filed comments in this docket.

21232 Rulemaking: *Rule Changes to Conform Rules to Electric Restructuring Act* (Rule Changes). EGSI filed comments in this docket. Shell did not file comments in this docket.

21251 Implementation Project: *Implementation of SB 7 Provisions Regarding Customer Education about Electric Choice.* (Customer education). This project developed the educational program to inform customers of the changes in the electric market resulting from SB7. Although there is no indication on the PUC interchange that EGSI filed anything, there are billing entries on Bickerstaff invoices indicating that EGSI participated in this proceeding.

21406 Rulemaking: *Standards for Recognition of Costs of Environmental Clean-up or Plant Retirement* (Environmental Costs). EGSI filed comments in this docket. Shell did not file comments in this docket.

22255 Rulemaking: *PUC Rulemaking Proceeding for Customer Protection Rules for Electric Restructuring Implementing SB7 and SB 86.* (Customer Protection). EGSI filed comments in this docket. Shell filed comments in this proceeding, but not signed by Chris Reeder.

22344 *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA Section 39.201 and Public Utility Commission Subst. R. 25.344* (UCOS

Generic Issues). EGSI filed pleadings in this proceeding. Shell filed pleadings in this proceeding, but not signed by Chris Reeder.

"SB 7" Activities By Month

June - July 1999

20936 (Code of conduct): EGSI filed comments.

20944 (Renewable energy): EGSI filed comments.

21083 (Business separation): Workshops[1]

July - August 1999

21072 (Natural gas goal): Workshop.

21083 (Business separation): Workshops.

Other: Securitization; renewable issues.

August - September 1999

20936 (Code of conduct): EGSI filed comments.

20944 (Renewable energy): EGSI filed comments on hypothetical scenarios, reply comments on hypothetical scenarios.

21251 (Customer education): Workshop

Other: business separation plan work; research and monitoring co-generation plant permits at the TNRCC; customer education/protection issues; energy efficiency workshop.

September - October 1999

20936 (Code of conduct): EGSI filed reply comments.

21251 (Customer education): Workshop

October - November 1999

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[1] "Workshop(s)" means that the PUC interchange includes a transcript for a workshop and the Bickerstaff invoices include a reference to a Bickerstaff attorney attending the workshop

20936 (Code of conduct): EGSI participated in the hearing.

20944 (Renewable energy): EGSI filed comments and reply comments.

21072 (Natural gas goal): Public comment hearing.

21082 (REP certification) Prepare comments.

21083 (Business separation): Workshops; EGSI filed comments and reply comments on the proposed unbundling rule; comments on the proposed business separation plan filing; a brief and a reply brief on confidentiality issues; and comments and reply on the proposed unbundled cost of service rate filing package

Other: "corporate split" issue, corporate support services, cost classification, and and the REP issue. There was also work on "January Filing."

November - December 1999

20970 (SB7 Implementation): EGSI filed comments on the interpretation of section 39.51 and a reply brief.

21083 (Business separation): prepare testimony, prepare for filing.

21232 (Rule Changes): Participate in conference calls and prepare for hearing.

Other: prepare for "January Filing." Follow TXU and CP&L securitization hearings.

December - January 2000

21082 (REP certification) Prepare joint redline, prepare draft comments.

21083 (Business separation): Workshop; PBR issues.

21406 (Environmental costs): comments.

Other: Prepare testimony and exhibits for "January Filing." Follow TXU and CP&L securitization hearings.

January - February 2000

21082 (REP certification) Prepare comments.

21083 (Business separation): PBR issues.

Other: Follow TXU, Reliant and CP&L securitization hearings, distributed generation tariff.

February - March 2000

21406 (Environmental costs): review comments.

21083 (Business separation): Workshop.

Other: securitization, GLO tariff, POLR workshop, "contract issues"

March - April 2000

21082 (REP certification) Comments on strawman.

Other: securitization, POLR workshop, "contract issues", "transco issues."

April - May 2000

21406 (Environmental costs): summarize comments.

21082 (REP certification) Prepare and file comments.

Other: "transco issues," POLR rulemaking hearing.

May - June 2000

21082 (REP certification) Prepare and file comments.

21251 (Customer education): Workshop

21406 (Environmental costs): comments.

June - July 2000

21406 (Environmental costs): Reply comments.

22255 (Customer protection): comments

Other: "market power" issues; PTB workshop.

July - August 2000

22344 (UCOS Generic) review filings, prepare presentation.

22255 (Customer protection): review rules

Other: POLR issues

DRAFT DUE TO LITIGATION SUPPORT

PREPARED AT THE REQUEST OF AN ATTORNEY FOR ENTERGY
PRIVILEGED AND CONFIDENTIAL DOCUMENT
ATTORNEY WORK PRODUCT

ENTERGY GULF STATES, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
Docket No. 31544 Transition to Competition Cost Case

Response of: Entergy Gulf States, Inc. to the Twenty-First Set of Data Requests of Requesting Party: Cities	Prepared By: Counsel Sponsoring Witnesses: Phillip R. May / J. Kay Trostle Beginning Sequence No. Ending Sequence No.

Question No.: Cities 21-5 Part No.: Addendum:

Question:

For any errors or corrections to the pre-filed or rebuttal testimony in this case, please provide the following:

a. Amount of the correction or change for each corrected item; and

b. Corrected schedules in electronic format and in hard copy.

Response:

a. In preparing its responses to various RFIs, the Company has identified the following adjustments to the TTC costs requested in this docket.

In the Company's response to State RFI 1-23 (the initial response and addendum 1), the Company noted a net undercharge of $75.50.

In the Company's response to State RFI 1-36, the Company noted a net undercharge of $1,422.00.

In the Company's response to TIEC RFI 1-7, addendum 1, the Company listed a total of $7,865.92 that should not have been included in the TTC costs requested in this docket.

In the Company's response to Cities RFI 16-9, the Company identified $445.50 that should not have been included in the TTC costs requested in this docket.

In the Company's response to Cities RFI 16-14, the Company identified $390.00 that should not have been included in the TTC costs requested in this docket.

In the Company's response to Cities RFI 16-30, the Company identified $480.50 that should not have been included in the TTC costs requested in this docket.

In the Company's response to Cities RFI 24-12, the Company identified $5,755.93 that should not have been included in the TTC costs requested in this docket.

The net of these adjustments is $13,440.35 of costs, exclusive of carrying costs, that should not have been included in the TTC costs requested in this docket. Assuming that during the remainder of this docket, no offsetting undercharges or calculation corrections are discovered, then the recoverable expenses requested in the Planning & Regulatory class of TTC Costs, sponsored by Company witness Phillip R. May, would be reduced by $13,440.35, excluding carrying costs.

b. Not applicable.

SOAH DOCKET NO. 473-06-0092
PUC DOCKET NO. 31544

APPLICATION OF ENTERGY	§	PUBLIC UTILITY COMMISSION
GULF STATES, INC. FOR	§	
RECOVERY OF TRANSITION	§	
TO COMPETITION COSTS	§	OF TEXAS

REBUTTAL TESTIMONY

OF

J. DAVID WRIGHT

ON BEHALF OF

ENTERGY GULF STATES, INC.

FEBRUARY 10, 2006

368

SOAH DOCKET NO. 473-06-0092

PUC DOCKET NO. 31544

APPLICATION OF

ENTERGY GULF STATES, INC.

FOR RECOVERY OF

TRANSITION TO COMPETITION COSTS

REBUTTAL TESTIMONY OF J. DAVID WRIGHT

TABLE OF CONTENTS

EXHIBITS

I. WITNESS INTRODUCTION AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is J. David Wright. My business address is Entergy Services, Inc., 425 West Capitol Avenue, Little Rock, Arkansas 72201.

Q. ARE YOU THE SAME J. DAVID WRIGHT WHO FILED DIRECT TESTIMONY IN THIS DOCKET ON AUGUST 24, 2005?

A. Yes. For both my direct and rebuttal testimony, I am testifying on behalf of Entergy Gulf States, Inc. ("EGSI" or the "Company").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I address the testimony of various Intervenor witnesses on the following topics:

1. The Commission should use the results of EGSI's Annual Reports as filed and, thus, should not use this docket to make rate case adjustments to those results.
2. Even if the Commission entertains the proposed adjustments to the Annual Reports, the Commission should reject those adjustments for lack of merit.
3. EGSI has not previously recovered the Transition to Competition ("TTC") labor costs.
4. The allowance for funds used during construction ("AFUDC") that accrued on the TTC capital projects is a legitimate cost of a capital project and, thus, EGSI should be allowed to recover the AFUDC on the TTC capital projects.
5. Capital overhead charges are a legitimate cost component of the TTC capital projects, and EGSI should be allowed to recover those charges.

6. EGSI should be allowed to recover carrying costs on its TTC expenses.

7. The carrying costs over the fifteen-year TTC cost recovery period should be EGSI's overall cost of capital approved in EGSI's last base rate case, Docket No. 20150.

In addition, as requested in the testimony of Staff witness Anna Givens, I also have determined the AFUDC associated with Staff witness Adrianne G. Brandt's proposed adjustment to various TTC costs.

II. USE OF UNADJUSTED ANNUAL REPORTS

Q. WHAT SUBJECT DO YOU DISCUSS IS THIS SECTION OF YOUR TESTIMONY?

A. I discuss the use of the Annual Reports that the Company filed with the Commission under Public Utility Regulatory Act ("PURA") section 39.257. The Annual Reports for the calendar years 1999 through 2004 were provided in my Direct Testimony as Exhibit JDW-4.

Q. WHAT DO THE INTERVENOR WITNESSES SAY ABOUT THE USE OF THE ANNUAL REPORTS?

A. Dr. Szerszen, Mr. Pous, and Mr. Pollock testify that the Commission should not use the results of the Annual Reports to determine whether the Company had excess earnings in the years 1999 through 2004 or whether the Company has previously recovered its TTC costs. They say, instead, that, in this docket, the Commission should make some of the same types of adjustments to the Annual Reports that one would make in a base rate case.[1]

Q. DO YOU AGREE WITH DR. SZERSZEN, MR. POUS, AND MR. POLLOCK THAT THE RESULTS OF THE ANNUAL REPORTS NEED TO BE ADJUSTED IN THIS PROCEEDING?

A. No. The Commission has previously stated in Docket No. 22344 that restructuring expenses are to be recovered through the Annual Report process.[2] Thus, allowing the Intervenors to adjust the Annual Reports undercuts the Commission's directive to use the Annual Reports to recover TTC Costs. Accordingly, the Commission should not make adjustments to the Annual Reports in this docket for the following four reasons.

First, the Annual Reports are different from the Earnings Monitoring Reports that some utilities—but not EGSI—were required to file during the TTC cost period under Commission Substantive Rule 25.73. Dr. Szerszen explicitly refers to EGSI's Annual Reports as Earnings Monitoring Reports.[3] Having incorrectly characterized the Annual Reports as

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[1] Direct Testimony of Carol Szerszen at page 4, line 8 through page 6, line 3; Direct Testimony of Jacob Pous at page 47, line 15 through page 48, line 6; Direct Testimony of Jeffry Pollock at page 7, line 24 through page 8, line 6, and at page 51, line 2 through page 53, line 12.

[2] *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*, Order No. 17 at 5 (July 24, 2000).

[3] Direct Testimony of Carol Szerszen at, *e.g.*, page 6, line 6; and at page 7, line 7 through page 8, line 20.

Earnings Monitoring Reports, she then assumes that whatever adjustments one would make to an Earnings Monitoring Report also are applicable to the Annual Reports. Although Messrs. Pous and Pollock do not refer to the Annual Reports as Earnings Monitoring Reports, they likewise treat the Annual Reports as if they were Earnings Monitoring Reports. All three of these witnesses fail to recognize the distinction between the two types of reports.

Second, the Commission has already established that the results of the Annual Reports, without additional adjustments, will be used to determine the level of excess earnings applicable to TTC cost recovery.

Third, the Commission has already approved the results of EGSI's Annual Reports for the calendar years 1999, 2000, and 2001. Dr. Szerszen and Messrs. Pous and Pollock are, in effect, asking the Commission to ignore or circumvent the orders approving those Annual Reports.

Fourth, the Annual Reports that the Company filed with the Commission for the calendar years 2002, 2003, and 2004 were completed using the same format and instructions used for the years 1999 through 2001.

Q. YOUR FIRST REASON FOR DISAGREEING WITH THE INTERVENOR WITNESSES IS THAT THERE IS A DIFFERENCE BETWEEN THE ANNUAL REPORTS AND THE EARNINGS MONITORING REPORTS.

PLEASE EXPLAIN THE DIFFERENCE BETWEEN THE TWO TYPES OF REPORTS.

A. An electric utility subject to a rate freeze under Senate Bill ("SB") 7—such as EGSI—is required to file an Annual Report under PURA section 39.257. The results of the Annual Reports are used, without further adjustment, for a variety of purposes such as reducing a utility's recovery of stranded costs, increasing a utility's investment in transmission and distribution plant, and, as I will discuss in my second reason, helping to determine the amount of TTC costs that a utility is allowed to recover from ratepayers.

All other electric utilities regulated by the Commission—that is, those electric utilities that are not required to file Annual Reports—file Earnings Monitoring Reports.

Prior to SB 7, the Commission required EGSI and other electric utilities to file Earnings Monitoring Reports. The Commission used those reports to make an initial assessment of whether it needed to review an electric utility's earnings in more detail in a base rate proceeding. I agree with Dr. Szerszen that the Commission does not use the Earnings Monitoring Reports to establish the final level of an electric utility's earnings. In addition, the Commission does not issue an order approving or finalizing the Earnings Monitoring Reports. Instead, the final level of an electric utility's base rates (the existence of over-earnings or under-earnings) would be determined after various adjustments were made in a base rate case.

After SB 7 took effect, however, the Commission changed its rule on Earnings Monitoring Reports to state that those utilities that are required to file an Annual Report under PURA section 39.257 because they are in a rate freeze—such as EGSI—do not have to file Earnings Monitoring Reports.

> (b) **Annual earnings report.** Each electric utility not required to file an Annual Report pursuant to the Public Utility Regulatory Act (PURA) §39.257 shall file with the commission, on commission-prescribed forms, an earnings report ....[4]

Therefore, as an electric utility subject to the rate freeze established under SB 7, EGSI has been required to file an Annual Report starting with calendar year 1999. The Annual Reports showed the differences between adjusted annual revenues and annual costs. The difference in any year showed whether EGSI had excess earnings in that year. In completing the Annual Reports, the Company reflected and adjusted its various expenses and components of invested capital based upon the instructions in PURA sections 39.258 through 39.260 and the Commission's further instructions. The Commission opened a project for each year's Annual Report (each year's project was for all of the electric utility's Annual

[4] P.U.C. SUBST. R. 25.73(b). The complete Rule is provided in my workpapers to this testimony.

Reports—not just for EGSI's Annual Report). In contrast to the Commission's treatment of the Earnings Monitoring Reports, the Commission has issued Orders approving and finalizing EGSI's Annual Reports for the years 1999 through 2001 (I will discuss these Orders in more detail in my third reason).

Consequently, an Earnings Monitoring Reports is a preliminary review of an electric utility's earnings and is not used for any purpose other than to help the Commission determine whether a base rate case may be warranted. In contrast, the results of the Annual Report (that is, the level of earnings) are used for a variety of purpose in later proceedings, but the level of earnings are not subject to change in those later proceedings.

Q. WHY IS IT IMPORTANT TO DISTINGUISH THE ANNUAL REPORTS FROM THE EARNINGS MONITORING REPORTS?

A. When Dr. Szerszen and Messrs. Pous and Pollock discuss various proposed adjustments to EGSI's Annual Reports, they are presenting the types of adjustments that might be applied to an Earnings Monitoring Report to determine whether a base rate case is warranted or that might be proposed in the base rate case itself. They have failed to recognize that the two types of reports are different and serve different purposes.

Q. TURNING NOW TO YOUR SECOND REASON, PLEASE EXPLAIN HOW THE COMMISSION HAS USED AN ANNUAL REPORT, WITHOUT ADDITIONAL ADJUSTMENTS, TO DETERMINE THE LEVEL OF EXCESS EARNINGS APPLICABLE TO TTC COST RECOVERY.

A. Southwestern Public Service Company ("SPS") was one of the electric utilities that filed an Annual Report under PURA section 39.257 for calendar year 1999. After reviewing SPS's 1999 Annual Report and resolving an appeal involving that Annual Report, the Commission determined that SPS had excess earnings for 1999 (in the amount of $7,279,138) and ordered SPS to use that level of excess earnings to offset the dollar amount of TTC costs that SPS was requesting in its TTC cost recovery proceeding.[5] In SPS's TTC cost recovery proceeding (Docket No. 25088), the level of excess earnings was used, without further adjustment, to reduce the amount of TTC costs recovered from ratepayers.[6] SPS's TTC cost recovery docket was resolved through a unanimous settlement, but the Commission issued its order (in Docket No. 25434) directing the use of the 1999 excess earnings to offset TTC costs before the parties reached that settlement.[7]

[5] *Remand of Southwestern Public Service Company 1999 Annual Report (Project No. 22276)*, Docket No. 25434, Order on Remand at FoF 11 and Ordering Paragraph 2 (March 21, 2002). This Order is provided in my workpapers to this testimony.

[6] *Application of Southwestern Public Service Company to Recover Transition to Competition Costs Pursuant to Section 39.409 of PURA*, Docket No. 25088, Order at FoF 10 (May 30, 2002). This Order is provided in my workpapers to this testimony.

[7] *Id.*, at FoFs 6 and 7.

Therefore, the Commission has used the results of an approved and finalized Annual Report, without further adjustment, in a TTC cost recovery proceeding. Likewise, here in this docket, the Commission should use the results of EGSI's Annual reports without further adjustments.

Q. YOUR THIRD REASON FOR DISAGREEING WITH THE INTERVENOR WITNESSES IS THAT THE COMMISSION HAS ALREADY ISSUED ORDERS APPROVING AND FINALIZING THE RESULTS IN THE COMPANY'S 1999, 2000, AND 2001 ANNUAL REPORTS. PLEASE EXPLAIN HOW THE COMMISSION HAS HANDLED THE ANNUAL REPORTS FOR THOSE YEARS.

A. As I have already mentioned, the Commission opened projects for the electric utilities to file their 1999,[8] 2000,[9] and 2001[10] Annual Reports. After EGSI filed its Annual Reports, the Staff and OPC had the opportunity to review those reports and to file any disagreements they had with those reports, and the Commission resolved any disagreements. As a result of the Commission's resolution of those disagreements, EGSI filed revised

[8] *1999 Electric Utilities' Annual Report Filed Pursuant to § 39.257 of PURA*, Project No. 22276.

[9] *2000 Electric Utilities Annual Report Filed Pursuant to § 39.257 of PURA*, Project No. 23806.

[10] *2001 Electric Utilities Annual Report Filed Pursuant to § 39.257 of PURA*, Project No. 23806.

Annual Reports for 1999 and 2000 (the 2001 Annual Report did not need to be revised because it was filed after the Commission resolved the issues arising from the 1999 and 2000 Annual Reports and, thus, reflects the Commission's resolution of those issues). (The 1999 and 2000 Annual Reports provided in my Exhibit JDW-4 are the revised Annual Reports.) The Commission then issued Orders approving and finalizing the results, reflecting any revisions, of EGSI's Annual Reports for those three years. The three Orders are provided in my Exhibit JDW-R-1.

Given that the Commission has approved and finalized the results of EGSI's Annual Reports for 1999, 2000, and 2001, the Commission should reject the Intervenors' proposals to use this docket to revisit those results.

Q. AND TURNING NOW TO YOUR FOURTH REASON, PLEASE EXPLAIN HOW THE COMPANY'S 2002, 2003, AND 2004 ANNUAL REPORTS WERE COMPLETED USING THE SAME FORMAT AND INSTRUCTIONS APPLICABLE TO THE THREE EARLIER ANNUAL REPORTS.

A. Starting in 2002, when the electric utilities in the Electric Reliability Counsel of Texas implemented retail open access, the Commission did not open a separate project solely for EGSI to file its 2002 Annual Report. Instead, the 2002 Annual Report was filed in Project No. 27312, which was where the other electric utilities filed their Earnings Monitoring

Reports. Likewise, EGSI filed its 2003 Annual Report in Project No. 29343 and its 2004 Annual Report in Project No. 30805. (The Annual Reports for all three of these years were provided in my Exhibit JDW-4.)

The Commission has not issued an order regarding the Annual Reports in any of these projects. These three Annual Reports, however, have been completed using the same instructions and Commission guidelines as used for EGSI's 2001 Annual Report. EGSI's 2001 Annual Report was uncontested and approved and finalized by the Commission without change.[11] Thus, the 2002, 2003, and 2004 Annual Reports present an accurate result of EGSI's excess earning for those years as calculated according to the instructions applicable to Annual Reports. In light of their accuracy, the Commission should not allow the Intervenors to propose adjustments to those results that are at odds with the instructions to the Annual Reports.

[11] *2001 Electric Utilities Annual Report Filed Pursuant to § 39.257 of PURA*, Project No. 23806, Order at ordering paragraph 1 (Dec. 20, 2002).

III. PROPOSED ADJUSTMENTS TO THE ANNUAL REPORTS

Q. WHAT SUBJECT DO YOU DISCUSS IS THIS SECTION OF YOUR TESTIMONY?

A. I discuss the adjustments that the Intervenor witnesses propose to make to the results of the Annual Reports. As I discussed in Section II of my testimony, the Commission should not make adjustments to the results of the Annual Reports. If, however, the Commission entertains the Intervenors' proposed adjustments, then I explain in this section of my testimony that the Commission should reject the proposed adjustments because they lack merit.

A. Merger Savings Tracker

Q. MR. POUS EXCLUDES THE O&M MERGER SAVINGS TRACKER ESTABLISHED IN DOCKET NO. 11292.[12] DO YOU AGREE WITH HIS ADJUSTMENT?

A. No. Mr. Pous terms these costs fictitious and phantom. Yet, both Public Utility Regulatory Act ("PURA") § 39.258(8) and the instructions for Schedule III of the Annual Reports state that the costs calculated under the merger savings tracker are to be included in the Annual Reports. Consequently, these are legitimate costs to be reflected in the Annual

[12] Direct Testimony of Jacob Pous at page 54, line 13 through page 55, line 18.

Reports. The Commission should reject Mr. Pous's proposed adjustment.

Q. WHAT IS THE MERGER SAVINGS TRACKER?

A. In the Commission's Order approving the merger between Entergy Corporation and Gulf States Utilities Company (Docket No. 11292), the Commission established a cost tracker mechanism to determine the amount of merger-related O&M expense savings for the first eight years after the merger was completed (1994 – 2001). In any base rate proceeding during that time period, the ratepayers and EGSI would split the merger savings (as measured by the tracker) 50-50. EGSI would receive its half of the merger savings by including its 50% of the merger savings as an expense in its cost of service. The language from the Commission's Order establishing the 50-50 split of merger-related expenses savings is as follows (Docket No. 11292, Ordering Paragraph 9(e)):

> The sharing of non-fuel operations and maintenance expense savings will be implemented in cases which are brought before any Texas regulatory authority during the eight year term of the regulatory plan, including but not limited to cases contemplated by sub-paragraphs b-d above, for the purpose of reviewing the reasonableness of Gulf States' base rates. In any such case, savings to be shared shall be the test year non-fuel operations and maintenance expense merger-related savings as measured by the mechanism defined by paragraphs 6, 7 and 8 and Appendices 1 and 2 and as illustrated in Appendix 3 to this agreement. In any such case, Gulf States shall be permitted to include Applicants' share of the non-fuel savings as a reasonable operations and maintenance expense which shall be treated as a reasonable and necessary cost of service adjustment for purposes of establishing Gulf States' revenue requirement.

Q. ARE THE MERGER SAVINGS COSTS INCLUDED IN THE ANNUAL REPORTS FOR THE YEARS AFTER 2001?

A. No. These costs are included in only the 1999, 2000, and 2001 Annual Reports. Under the Commission's Order in Docket No. 11292, the merger tracker provision expired at the end of 2001. Thus, the Company has not included 50% of the merger savings in the 2002 through 2004 Annual Reports.

B. Inconsistent Rate Base and Expenses

Q. IN MAKING HIS ADJUSTMENTS TO EGSI'S ANNUAL REPORTS, HAS MR. POUS TREATED RATE BASE AND EXPENSES CONSISTENTLY?

A. No. The instructions to the Annual Report direct the Company to use a year-end level of invested capital for determining the Company's excess return. The Company has followed that instruction. Thus, the Annual Report matches the growth in rate base with the growth in costs and revenue. Mr. Pous, however, takes the growth in costs and revenues and then applies it to an earlier rate base, which has the effect, in his analysis, of over-stating the Company's excess return. Revenues from new customers require additions to plant in service for distribution lines, substations and other plant necessary to provide electric service and produce additional revenues. Mr. Pous's analysis ignores that relationship.

C. Consolidated Tax Savings

Q. MS. BLUMENTAL AND DR. SZERZSEN PROPOSE AN ADJUSTMENT TO REFLECT CONSOLIDATED TAX SAVINGS. DO YOU AGREE WITH THIS ADJUSTMENT?

A. No. Dr. Szerszen testifies that the results in the Annual Reports need to be adjusted to reflect consolidate tax savings, and she relied upon Ms. Blumenthal to calculate the adjustment.[13] The instructions for the Annual Report, however, state that federal income taxes are to be calculated on a stand-alone basis. Therefore, the Commission should reject this proposed adjustment.

Moreover, Ms. Blumenthal's calculation of the consolidated tax savings is incorrect.

Q. PLEASE EXPLAIN HOW THE CALCULATION IS INCORRECT?

A. Ms. Blumental calculated a consolidated tax adjustment of $21.7 million. Of that amount, $6.5 million was for 2003. EGSI has a loss in 2003. Under the Commission's method for calculating consolidated tax savings, no consolidated tax savings is supposed to be assigned to a loss Company.[14] Yet, Ms. Blumenthal attributes a $6.5 million consolidated tax savings to 2003. Because the Company has not yet filed its 2004 tax

[13] Direct Testimony of Carol Szerszen at page 6, lines 4-13.

[14] Direct Testimony of Ellen Blumental at page 9, lines 19 – 20.

return, Ms. Blumental used her 2003 consolidated tax savings ($6.5 million) for 2004 as well. Consequently, $13 million ($6.5 million x 2) of her $21.7 million adjustment is for a year in which EGSI has a loss and for a year in which EGSI has not yet filed a federal income tax return.

D. Decommissioning Expense Accrual

Q. MR. POLLOCK PRESENTS A PROPOSED ADJUSTMENT TO CHANGE THE DECOMMISSIONING EXPENSE ACCRUAL.[15] DO YOU AGREE WITH HIS ADJUSTMENT?

A. No. Mr. Pollock eliminates EGSI's nuclear decommissioning expense from the 2003 and 2004 Annual Reports. He argues that, as the result of a settlement of a series of rate proceedings before the Louisiana Public Service Commission ("LPSC"), EGSI has agreed to reduce its annual decommissioning expense in Louisiana.

Q. DO THE COMMISSION AND THE LPSC ESTABLISH THE SAME NUCLEAR DECOMMISSIONING FUNDING LEVELS IN RATE CASES?

A. No. The two Commissions determine different funding levels. The Company's nuclear decommission expense in Texas retail jurisdiction is different from its expense in the Louisiana retail jurisdiction.

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[15] Direct Testimony of Jeffry Pollock at page 53, line 9 through page 54, line 18.

Q. HAS THE COMMISSION ESTABLISHED A DECOMMISSIONING FUNDING LEVEL FOR TEXAS?

A. Yes. In the Company's last base rate case, Docket No. 20150, the Commission ordered EGSI to maintain the decommissioning funding established in the prior base rate case, Docket No. 16705.[16] The decommissioning funding levels are based upon a detailed decommissioning funding study, supported by several witnesses, which is fully litigated in a base rate case. Mr. Pollock has presented no such study in this case.

Q. DOES THE COMPANY HAVE USE OF THESE REVENUES ASSOCIATED WITH DECOMMISSIONING EXPENSE?

A. No. The Company deposits the revenues it collects equal to its decommissioning expense in an external decommissioning trust fund. Thus, Mr. Pollock is proposing to remove the expense that the Company incurred to fund the decommissioning trust fund for 2003 and 2004. It is totally without merit to remove these expenses to artificially increase earnings when the Company has to deposit the revenues it receives in a trust fund.

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[16] *Application of Entergy Gulf States, Inc. for Authority to Change Rates*, Docket No. 20150, Order at ordering paragraph 12 (June 30, 1999). An excerpt from this Order is provided in the workpapers to this testimony.

E. Rate of Return and Excess Return

Q. DO YOU AGREE WITH DR. SZERSZEN THAT THE ANNUAL REPORTS SHOULD UTILIZE THE COMPANY'S ACTUAL YEAR-END RATE OF RETURN IN CALCULATING THE ALLOWED RATE OF RETURN?

A. No. The instructions to the Annual Report specifically state the Company is to use the cost of capital approved in the utility's most recent rate proceeding. In the case of EGSI, this is 9.67%. If we did not have a rate order which met the criteria of being issued after January 1, 1992, the rate prescribed by the Commission was 9.6%. The Commission apparently believed this to be a reasonable percentage to use as a return amount.

Q. DR. SZERSZEN COMMENTS THAT THE COMPANY'S NET INCOME HAS INCREASED FROM $46.363 MILLION IN 1998 TO $192.264 MILLION IN 2004. IS HER ANALYSIS CORRECT?

A. The dollar amount is correct, but her interpretation of the dollar amount is wrong. The Company's net income has increased by that amount. However, this is "net" income, and includes non-utility operating income. The Company's net utility operating income in 1998 was $203.978 Million. In 2004, this figure was $267.498 Million. This is a 31% increase over a six-year period. The Company has certainly not experienced the phenomenal growth that she indicates. These are total Company figures, which include Louisiana and Wholesale operations.

Q. DR. SZERSZEN ALSO STATES THAT THE LOW EQUITY RETURN THE COMPANY EXPERIENCED IN 2003 WAS PRIMARILY DUE TO A $470 MILLION INCREASE IN THE COMPANY'S PURCHASE POWER EXPENSES. IS THIS A CORRECT STATEMENT?

A. No. Fuel and purchase power expenses are recoverable in the Company's fuel recovery mechanisms for the most part and, as such, an increase in fuel and purchase power expense would not have a material impact on earnings.

Q. DR. SZERSZEN STATES THAT THE COMPANY HAS EXPERIENCED EITHER NO UNDER-EARNINGS OR POSSIBLY ONLY $64.644 MILLION IN UNDER-EARNINGS. DO YOU AGREE WITH EITHER OF THESE AMOUNTS?

A. No. Dr. Szerszen bases the possible $64.644 million of under-earnings figure on her usage of a year-end cost of capital calculation to determine the allowed return and a consolidated tax calculation amount. Rather than follow the guidelines developed for the Annual Report, she has developed her own guidelines. Then, she states that even the $64.644 million is probably not a correct indicator of the under-earnings since it would probably need to be adjusted for typical revenue, cost, and base adjustments that are made to a company's cost of service. She does not enumerate these "typical" adjustments, but simply concludes they would be enough to eliminate any under-earnings EGSI may have experienced.

Dr. Szerszen has not only developed her own instructions for the Annual Report, but she has managed to manufacture whatever adjustment is needed to bring the under-earnings to zero.

Q. DO YOU AGREE WITH DR. SZERSZEN THAT ONLY $25.5 MILLION OF TTC O&M COSTS REMAIN TO BE RECOVERED?

A. No. Dr. Szerszen makes this statement based on the incorrect assumption that the Company has experienced no under-earnings. She states that since EGSI has already included $37 million in the Annual Reports, which, she says, reflect no under-earnings, and EGSI's total TTC O&M costs were $62.5 million, there remains only $25.5 million to be recovered. As I stated previously, her original premise in calculating the Company's under-earnings is incorrect. She then decides that since the $37 million was included in the Annual Reports and she has decided that EGSI probably had no under-earnings, then all that is left is $25.5 million of expense. EGSI has followed the instructions and guidelines as set out by the Commission to determine what its return/(deficit) was. Dr. Szerszen has not.

Q. MR. POLLOCK STATES THAT ALL BUT $50.7 MILLION OF TTC COSTS HAVE BEEN RECOVERED. HOW DID HE REACH THAT NUMBER?

A. EGSI is asking to recover $189.4 million of TTC cost, including AFUDC and carrying costs. The tax gross-up on the AFUDC and the carrying costs amount to $15.6 million for a total through February 28, 2006 of $205 million. Mr. Pollock has recommended a disallowance of $42 million in capital costs for systems that the Company was required to develop. He disallows the Company's AFUDC costs because he states AFUDC is not applicable to capital projects that have been abandoned or cancelled. (The Company, however, has not abandoned its TTC projects.) This amounts to another $42.5 million. He excluded $6.3 million of our expenses which he deems unreasonable and another $25 million for carrying costs that the Company has incurred. This leaves a remainder of $88.9 million, which he deems reasonable. Of this amount, he states the Company has already recovered $38.2 million by virtue of its returns for the years since 1999 having been a positive number. This leaves, according to Mr. Pollock, an amount still to be recovered of $50.7 million.

Q. DO YOU AGREE WITH MR. POLLOCK'S ANALYSIS?

A. No. As I explain throughout this testimony, I disagree with Mr. Pollock's proposed adjustments to the Annual Reports and to the Company's TTC costs. His $50.7 million amount is based on the assumption that the Commission accepts all of his adjustments.

IV. <u>TTC LABOR COSTS</u>

Q. WHAT SUBJECT DO YOU DISCUSS IS THIS SECTION OF YOUR TESTIMONY?

A. Several Intervenor witnesses (Dr. Szerszen, Mr. Norwood, Mr. Arndt, Mr. Pous, and Mr. Higgins) recommend disallowing TTC labor expenses. In this section of my testimony, I explain that the Commission should reject their recommendation.

Q. THE INTERVENOR WITNESSES TESTIFY THAT THE TTC LABOR EXPENSES ARE NOT INCREMENTAL BUT INSTEAD ARE BEING RECOVERED THROUGH EGSI'S CURRENT BASE RATES. DO YOU AGREE WITH THEIR ASSESSMENT?

A. No. The Intervenor witnesses are incorrect. Over $8 million ($7,903,379 ESI and $339,945 EGSI) of these payroll costs are for capital expenditures. These capital costs are one time expenditures of the Company's funds for these TTC projects. These costs are not included in the Company's current base rates and have not been recovered by the Company and will not be recovered unless they are recovered as part of this request. The remaining $15,718,041 of ESI labor costs were also specifically incurred for TTC projects and are in fact incremental costs to EGSI. Absent the Company's efforts to move to competition, these ESI labor costs would not have been charged to EGSI. ESI employees charge their time to specific project codes based on the work being performed by that employee.

Q. CITIES WITNESS ARNDT CLAIMS THAT THE ESI EMPLOYEE COUNT HAS GONE DOWN SINCE THE COMPANY'S LAST BASE RATE CASE. DOES A REDUCTION IN THE ESI EMPLOYEE COUNT AFFECT WHETHER THE TTC LABOR EXPENSES ARE INCREMENTAL COSTS TO EGSI?

A. No. Mr. Arndt is correct is his statement that the total ESI employee count has gone down since the test year in Docket No. 20150, but that reduction does not necessarily imply that the ESI labor costs are incremental to EGSI. The Company supplied total ESI payroll costs and total ESI payroll costs billed to EGSI in response to various Cities data requests. As is shown on Exhibit JDW-R-3 since the Company's last base rate case in Docket No. 20150, the percentage of total ESI payroll costs billed to EGSI has increased. And not only has the percentage increased, but also the actual payroll dollar amounts billed to EGSI has increased.

Q. DR. SZERSZEN TESTIFIES THAT EGSI HAS NOT PROVIDED ANY EVIDENCE THAT THE ESI LABOR CHARGES ARE INCREMENTAL EXPENSES THAT CAN BE SPECIFICALLY ASSOCIATED WITH TRANSITION TO COMPETITION ACTIVITIES. HAS THE COMPANY PROVIDED ANY EVIDENCE THAT WOULD INDICATE THAT THESE LABOR CHARGES ARE SPECIFICALLY FOR TTC ACTIVITIES?

A. Yes. As I have previously stated, employees charge specific project codes based on the work being performed. Only work being performed on

TTC projects are included in this request. Also, as I already mentioned, the percentage of total ESI payroll costs billed to EGSI has increased and the ESI payroll dollars billed to EGSI have increased to above what was included in the Company's last base rate case.

V. AFUDC ON TTC CAPITAL COSTS

Q. WHAT SUBJECT DO YOU DISCUSS IS THIS SECTION OF YOUR TESTIMONY?

A. The Company has accrued AFUDC on the TTC capital projects. Messrs. Arndt, Pous, and Pollock testify that the Commission should disallow that AFUDC. In this section of my testimony, I explain that the AFUDC that has accrued on the TTC capital projects is part of the cost of those capital projects and, thus, is recoverable as a TTC cost.

Q. WHAT REASONS DO THE INTERVENOR WITNESSES GIVE FOR EXCLUDING AFUDC FROM THE TTC CAPITAL PROJECTS?

A. The Interveners raise a variety of arguments to support their contention that EGSI should not be allowed to recover the AFUDC costs incurred for TTC projects. The arguments can be summarized as follows:

- AFUDC is not to be recognized on abandoned capital projects (18 CFR Chapter 1, Electric Plant Instruction 3.A.(17)).
- The assets are not used and useful.

- The Arkansas Public Service Commission ("APSC") did not allow Entergy Arkansas, Inc. ("EAI") recovery of AFUDC associated with its Market Mechanics Project.
- Recovery of AFUDC and the carrying costs on unamortized TTC costs would be a double recovery.
- PURA § 39.454 allows recovery of reasonable and necessary expenditures only and, therefore, does not allow recovery of AFUDC on TTC Capital Projects.

Q. TURNING TO THE FIRST BULLET POINT, MESSRS. ARNDT, POUS, AND POLLOCK TESTIFY THAT THE TTC CAPITAL EXPENDITURES ARE ABANDONED OR CANCELLED PLANT AND THAT THE UNIFORM SYSTEM OF ACCOUNTS CALLS FOR THE REMOVAL OF AFUDC ON ABANDONED PLANT. ASSUMING FOR THE SAKE OF ARGUMENT THAT THE TTC CAPITAL EXPENDITURES ARE ABANDONED OR CANCELLED PLANT, DO YOU AGREE WITH MESSRS. ARNDT'S, POUS'S, AND POLLOCK'S READING OF THE ACCOUNTING RULES?

A. No. The language in the Uniform System of Accounts does not necessarily say that the AFUDC that has accrued on a construction project must be removed when that construction project is abandoned or cancelled. Instead, the language says only that the utility should not continue to accrue AFUDC on the project from the time of abandonment going forward.

> No allowance for funds used during construction shall be included in these [construction] accounts upon expenditures for construction projects which have been abandoned.[[17]]

Thus, assuming that the TTC capital projects in this docket are abandoned or cancelled plant, then this language does not require EGSI to remove the AFUDC that has accrued on the TTC capital projects prior to the time that the construction are cancelled or abandoned.

Q. HAS THE COMMISSION PREVIOUSLY RULED ON THE RECOVERY OF AFUDC ASSOCIATED WITH CANCELLED OR ABANDONED PLANT?

A. Yes. At least twice, the Commission has allowed a utility to recover the AFUDC that accrued on a construction project prior to the time of cancellation, provided that the timing of the cancellation was prudent. In ruling on the recovery of cancellation costs associated with Gulf State Utilities Company's[18] River Bend Nuclear Plant, Unit II, the Commission stated that "AFUDC is a legitimate financing cost" on a construction project that was later cancelled and the utility should be allowed to recover the AFUDC that accrued prior to cancellation. The Commission also noted that it had made the same decision regarding the cancellation costs for Houston Lighting and Power Company's Allen's Creek Nuclear Project.

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[17] Federal Energy Regulatory Commission, Uniform System of Accounts, 18 C.F.R. Part 101, Electric Plant Instruction 3.A.(17). The complete instruction regarding AFUDC is provided in my workpapers to this testimony.

[18] Gulf States Utilities Company is the former name of EGSI.

> Having found the timing of the cancellation of the [River Bend Unit II] project to have been prudent, the examiner recommends against disallowing AFUDC, or any component of AFUDC, which has accrued on the project prior to its cancellation. AFUDC represents a legitimate financing cost incurred by the Company to Keep River Bend II as a viable option. Moreover, the Commission has previously included AFUDC in recoverable nuclear plant cancellation losses. <u>Application of Houston Lighting and Power [for a Rate Increase</u>, Docket No. 4540], supra.[[19]]

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE ACCOUNTING RULES AND THE COMMISSION'S PREVIOUS DECISIONS ALLOWING THE RECOVERY OF AFUDC ON CANCELLED OR ABANDONED PLANT?

A. Assuming for discussion purposes that the TTC capital projects in this docket are cancelled or abandoned plant, then EGSI should be allowed to recover the AFUDC that has accrued on the capital projects prior to the time of cancellation or abandonment. To the extent that the Commission disallows a portion of the capital costs, then the AFUDC that has accrued on that disallowed portion will be disallowed as well. But for those capital expenditures that the Commission determines to be reasonable and necessary and, thus, recoverable, EGSI should recover the AFUDC that has accrued as well.

[19] *Application of Gulf States Utilities Company for Authority to Change Rates*, Docket No. 5560, Revised Examiner's Report, 10 P.U.C. BULL. 405, 432 (July 13, 1984). The relevant pages from the Revised Examiner's Report and the Order are provided in my workpapers to this testimony. *See also Application of Houston Lighting and Power Company for a Rate Increase*, Docket No. 4540, Examiner's Report, 8 P.U.C. BULL. 75, 126 (Dec. 6, 1982). The relevant pages from the Revised Examiner's Report and the Order are provided in my workpapers to this testimony.

Q. ARE THE INDIVIDUAL TTC CAPITAL PROJECTS AT ISSUE IN THIS DOCKET CANCELLED OR ABANDONED PLANT?

A. No. The overall project is the implementation of retail open access ("ROA") in the Entergy Settlement Area in Texas ("ESAT"). EGSI has not cancelled or abandoned that project. Instead, I am advised that this project has been on hold since the Commission issued its order on July 12, 2004 in Docket No. 28818 directing EGSI to cease work on an interim solution and to terminate the pilot project,[20] but the effort to implement ROA in ESAT has not been cancelled or abandoned. (In their direct testimony, Company witnesses Joseph F. Domino and Phillip R. May addressed the status of the ROA effort.) The individual capital projects that are at issue in this docket are components that have provided support for the overall ROA project. Given that the overall ROA project has not been cancelled or abandoned, these individual capital projects are not abandoned or cancelled plant.

Q. SHOULD THE COMMISSION ALLOW EGSI TO RECOVER THE AFUDC THAT HAS ACCRUED ON THE TTC CAPITAL EXPENDITURES UNDER REVIEW IN THIS DOCKET?

[20] *Application of Entergy Gulf States, Inc. for Certification of an Independent Organization for the Entergy Settlement Area in Texas*, Docket No. 28818, Order at ordering paragraph 1 (July 12, 2004). The relevant pages from the Order are provided in my workpapers to this testimony.

A. Yes. Under the Uniform System of Account, AFUDC is a routine and integral component of capital costs. In addition, PURA section 39.454 allows EGSI to recover appropriate carrying costs on its TTC costs. Finally, the TTC capital projects are not abandoned or cancelled plant. Even if one were to consider the individual TTC capital projects to be abandoned or cancelled plant, the time of abandonment or cancellation would be July 12, 2004 (the date of the Order in Docket No. 28818). Thus, under the accounting rules and the Commission previous decisions, EGSI would be allowed to recover the AFUDC that accrued through that date.

Q. TURNING TO THE INTERVENORS' SECOND ARGUMENT, ARE THE TTC CAPITAL PROJECTS CURRENTLY USED AND USEFUL?

A. No. EGSI acknowledged that fact in its direct testimony. If the projects were used and useful, EGSI would not be seeking to recover those costs in this TTC filing. But AFUDC is a legitimate part of the cost of a capital project, including TTC capital projects. Thus, it is proper accounting for EGSI to accrue AFUDC on the TTC capital projects.

Q. IN REGARD TO THE INTERVENOR WITNESSES' THIRD POINT, WHAT IMPORT DO YOU GIVE TO THE APSC'S TREATMENT OF AFUDC ON EAI'S MARKET MECHANICS PROJECT?