NOTICE: Pursuant to the Regulatory Fairness Act, 16 U.S.C. § 824e(b), this Complaint is entitled to the same priority as that provided Section 205 filings of Entergy Services, Inc.

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

LOUISIANA PUBLIC SERVICE COMMISSION	*	
VERSUS	*	DOCKET NO. EL08-_____
ENTERGY CORPORATION, ENTERGY SERVICES, INC., ENTERGY LOUISIANA, L.L.C., ENTERGY ARKANSAS, INC., ENTERGY MISSISSIPPI, INC., ENTERGY NEW ORLEANS, INC. AND ENTERGY GULF STATES LOUISIANA, INC. ENTERGY TEXAS, INC.	*	

* *

COMPLAINT OF THE
LOUISIANA PUBLIC SERVICE COMMISSION

I. INTRODUCTION

1. This Complaint is submitted on behalf of the Louisiana Public Service Commission ("Louisiana Commission" or "LPSC") pursuant to Rules 206 and 207 of the Rules of Practice and Procedure of this Commission and Sections 205 and 206 of the Federal Power Act, 16 U.S.C. § 824d and 824e. The Complaint seeks to correct errors in the methodology of Entergy Services, Inc. ("Entergy" or "ESI") in Exhibits ETR-26 and ETR-28 in Docket EL01-88 before this Commission, as amended, which forms the basis for the rough production cost

equalization remedy adopted by the Commission in Opinion No. 480, 111 F.E.R.C. ¶ 61,311 (2005) and Opinion No. 480-A, 113 F.E.R.C. ¶ 61,282 (2005). The Louisiana Commission has submitted testimony identifying these errors in Docket ER07-956, in which Entergy filed cost calculations to implement these Orders, but under this Commission's decisions, changes to the methodology in ETR-26 and ETR-28 can only be made through an appropriate filing pursuant to Section 205 or Section 206 of the Federal Power Act. Thus, the Louisiana Commission brings this Complaint to correct the errors that have been identified.

2. Additionally, the Louisiana Commission has identified deviations from the methodology in ETR-26 and ETR-28, instances in which Entergy used incorrect data, and imprudent costs that are included in Entergy's implementation filing in Docket ER07-956. The Louisiana Commission believes that those issues properly are considered and addressed in Docket ER07-956, consistent with the Commission's Orders. Out of an abundance of caution, however, the Louisiana Commission provisionally complains of these matters to ensure the issues are preserved, in the event the Commission should rule that they were not properly raised in Docket ER07-956.

3. In the Order Accepting Compliance Filing, As Modified, 117 F.E.R.C. ¶ 61,203 (2006), the Commission required that Entergy "comply with the requirements of Opinions Nos. 480 and 480-A," and particularly, that Entergy *not* make "adjustments to the methodology reflected in Exhibits ETR-26 and ETR-28" adopted in those Orders. *Compliance Order*, ¶ 69. ETR-26 and 28 calculated the production costs of the Entergy operating companies for the purpose of determining production cost disparities on a cents-per-kilowatt-hour basis. The production cost calculation includes production plant investment cost and operation and maintenance expenses reported in various accounts under the FERC Uniform System of

Accounts. The Commission rejected Entergy's attempt to make corrections or adjustments to the methodology in Exs. ETR-26 and ETR-28, including a change to correct an error in the calculation of the income tax rate for Entergy Gulf States, Inc. ("EGSI"). The Commission ruled that *any* changes to the methodology in Exs. ETR-26 and ETR-28 must be made in a separate Section 205 or Section 206 filing with the Commission. *Id.*, ¶ 69.

4. The Commission in two Orders related to Entergy's implementation filing established that Docket No. ER07-956 will review: a) the consistency of Entergy's methodology with that adopted by the Commission; b) the justness and reasonableness of the cost inputs employed by Entergy in the production cost calculation for 2006; and c) the prudence of the costs incurred by the Entergy operating companies in 2006. In its Order Accepting and Suspending Proposed Rates and Establishing Hearing and Settlement Judge Procedures, 120 F.E.R.C. ¶ 61,094 (2007), the Commission reiterated that Entergy must comply with the methodology in Exs. ETR-26 and ETR-28 absent a separate Section 205 filing proposing a change. In reviewing its rulings, the Commission said:

> The Commission explained that Entergy must comply with the requirements of Opinion Nos. 480 and 480-A, including the requirement to follow the methodology set forth in Exhibits ETR-26 and ETR-28. The Commission also stated that Entergy should make a Section 205 filing if it desired to make any changes to the methodology in Exhibits ETR-26 and ETR-28.

Id., ¶ 4. Additionally, the Commission ruled that its decision in Docket No. ER07-956 "necessarily will be based on the underlying cost inputs and the reasonableness thereof. . . ." *Id.*, ¶ 16. Further, in *Arkansas Public Service Comm'n v. Entergy Services, Inc.*, 119 F.E.R.C. ¶ 61,223 (2007) the Commission found that the annual bandwidth filing provides "the Commission and all interested parties the opportunity to analyze all production-related costs of

each of the Entergy Operating Companies to make sure that all such costs are just and reasonable and prudently incurred." *Id.*, ¶ 47.

5. The errors in Exs. ETR-26 and ETR-28 have the effect of reducing the payments from Entergy Arkansas, Inc. ("EAI") to Entergy Gulf States-Louisiana ("EGSI"), Entergy Louisiana, LLC ("ELL") and Entergy Mississippi, Inc. ("EMI"), based on the 2006 test year. These errors make the bandwidth payments unjust and unreasonable and unduly discriminatory in violation of the Federal Power Act. The Louisiana Commission respectfully requests that this Commission summarily correct the errors, as it has done with respect to errors identified in Section 205 cases filed by Entergy. Alternatively, the Commission should set the case for hearing and establish the refund effective date be set at the earliest date allowed.

6. Additionally, Entergy in its implementation filing made changes to the methodology reflected in Exs. ETR-26 and ETR-28 approved by the Commission and included unjust, unreasonable and imprudent cost inputs in the bandwidth calculation. The Louisiana Commission believes those issues are properly before the Commission in Docket ER07-956. In the event that the Commission for some reason rules that they may not be litigated in that docket, however, the Louisiana Commission provisionally raises them in this Complaint.

II. PARTIES

7. The Louisiana Public Service Commission regulates public utilities operating in Louisiana pursuant to Article 4, Section 21 of the Louisiana Constitution of 1974. It regulates the retail rates and services of ELL and EGSI. Entergy Corporation is a public utility holding company headquartered in New Orleans, Louisiana. Its wholly owned operating company subsidiaries are ELL, Entergy New Orleans, Inc. ("ENOI"), EGSI, EMI, Entergy

Texas, Inc. ("ETI") and EAI. Entergy delivers electricity to approximately 2.7 million customers in portions of Texas, Arkansas, Louisiana and Mississippi.

8. ESI is a subsidiary of Entergy Corporation that provides various accounting, legal, regulatory and other services to the subsidiaries of the Entergy System. It acts as agent for Entergy Corporation and for the parties to the Entergy System Agreement, ELL, EGSI, ENOI, EMI, ETI and EAI, in matters related to the System Agreement before this Commission, including the dispatch, operation and planning associated with the generating units on the Entergy System.

III. THE SYSTEM AGREEMENT

9. The Entergy System Agreement is a formula tariff filed with and approved by this Commission. *Middle South Energy, Inc.*, 31 FERC ¶ 61,305 (1985). It provides the contractual basis for coordinated operations of the Entergy System, and it sets forth the terms, conditions and rates upon which the Entergy operating companies coordinate operations and install generating capacity and bulk transmission facilities for the Entergy System.

10. The System Agreement provides the contractual basis for planning and operating the generation and bulk transmission facilities of the Entergy System on a coordinated, single-system basis. The agreement requires the operating companies to plan generation and transmission facilities to meet the needs of the Entergy System as a whole, while also serving their own individual needs. This approach, along with the coordinated operations and dispatch of the System, permits the operating companies to achieve economies of scale and take advantage of other economies. The System Agreement also provides a basis for equalizing among the operating companies any imbalances of costs associated with the installation of facilities used for the mutual benefit of all the companies. [*Id.*].

11. The System Agreement is a contract between all of the Entergy operating companies and ESI. The 1982 System Agreement has been in effect since 1983, but has been amended on several occasions. Prior versions also allocated production costs among the operating companies. The 1982 Agreement replaced a System Agreement dated April 16, 1973, approved by the Federal Power Commission in Docket No. E-8130. Under the 1973 System Agreement, the System was planned and constructed on a single-system basis and capacity was shared. Prior to 1973, the System also was planned as a single system and had capacity sharing arrangements.

12. Article 3 of the System Agreement sets forth the goals and objectives of that agreement. Pursuant to Section 3.01, the System is planned to achieve economies for the System as a whole and to equalize "among the companies any imbalance of costs associated with the construction, ownership and operation of such facilities as are used for the mutual benefit of all the companies." Section 3.02 states that "economies of scale" and "integrated operations" require that the generation and transmission facilities of the System be planned, constructed and operated "on a coordinated basis."

IV. ROUGH EQUALIZATION DECISIONS

13. On June 14, 2001 the LPSC and the City of New Orleans filed a complaint with this Commission against Entergy alleging that the cost allocations among the Entergy operating companies had become unjust, unreasonable, and unduly discriminatory in violation of the Federal Power Act. *Louisiana Public Service Comm'n v. Entergy Corp., et al.*, Docket No. EL01-88-000. After hearing, the presiding administrative law judge found the Agreement was unduly discriminatory because production costs were no longer roughly equalized among the operating companies. *Initial Decision*, 106 FERC ¶ 63,012 (2004).

14. On June 1, 2005 the Commission issued Opinion No. 480. 111 FERC ¶ 61,311. In that decision the FERC found that the allocation of production costs among the operating companies in the Entergy System Agreement is no longer just and reasonable. 111 FERC ¶ 61,311, ¶ 16. It found that the production costs of the Entergy operating companies were no longer roughly equalized, as required by Commission precedent. *Id.*, ¶ 28. The Commission concluded that "the Entergy Agreement is no longer just and reasonable" and "a just and reasonable remedy is needed." *Id.* Additionally, the Commission ruled that "[f]urther production cost comparisons among the Operating Companies should follow the methodology in Exhibit ETR-26," an exhibit filed by Entergy that compared operating company production costs. *Id.*, ¶ 33. That exhibit, in turn, was built on data from Exhibit ETR-28.

15. The Commission adopted a numerical bandwidth remedy requiring that the production costs of the operating companies may deviate no more than plus or minus 11% from the average annual system production cost. The Commission ruled the remedy necessary to maintain "just and reasonable" rates and to "help keep the Entergy system in rough production cost equalization." Id., ¶ 144. This decision largely was reaffirmed by the FERC on rehearing. Opinion No. 480-A, 113 FERC ¶ 61,282.

16. On April 10, 2006, ESI made a Compliance Filing with the Commission to implement the requirements of Opinion Nos. 480 and 480-A. In that filing Entergy generally followed the methodology in Exhibits ETR-26 and ETR-28, but proposed several changes to that methodology, including a recalculation of the income tax rate for Entergy Gulf States, Inc., and a change in the factor used to allocate certain costs to the production function. *Compliance Filing* at 17-18, Docket No. EL01-88-004. This Commission on November 17, 2006 issued its *Compliance Order*. 117 FERC ¶ 61,203. In that ruling, the FERC determined that Entergy

should not make any changes to the methodology in Exhibits ETR-26 and ETR-28. The FERC rejected the changes proposed by Entergy and changes proposed by the LPSC and other parties. With respect to Entergy's proposals, the Commission stated:

> We will deny Entergy's requests to make adjustments to the methodology reflected in Exhibits ETR-26 and ETR-28. This is a compliance filing and Entergy must comply with the requirements of Opinion Nos. 480 and 480-A. Future changes, however, to the methodology set forth in Exhibits ETR-26 and ETR-28 will not be automatic. Any time Entergy seeks to make a change, *e.g.*, a change to return on equity, it must make a section 205 filing with the Commission ....

Id., ¶ 69.

V. 2007 BANDWIDTH CALCULATION

17. On May 29, 2007, Entergy Services, on behalf of the Entergy Operating Companies, made a filing seeking to calculate the bandwidth remedy required by Opinion Nos. 480 and 480-A, which was assigned Docket No. ER07-956 ("implementation filing"). The Louisiana Commission intervened and filed an "Answer and Protest" in that docket on June 19, 2007 and a "Response and Supplemental Protest" on July 18, 2007. On July 26, 2007, the FERC issued an "Order Accepting and Suspending Proposed Rates and Establishing Hearing and Settlement Judge Procedures." 120 FERC ¶ 61,094 (July 26, 2007). In that Order the FERC found that "Our preliminary analysis indicates the Entergy's proposed rate schedule has not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful." [Id. ¶ 19]. It suspended Entergy's proposed rates, and made them effective June 1, 2007, subject to refund, and it set the matter for hearing.

VI. ERRORS IN THE METHODOLOGY ADOPTED BY THE COMMISSION IN EXS. ETR-26 AND ETR-28, AS AMENDED, THAT REQUIRE CORRECTION TO MAKE THE BANDWIDTH REMEDY JUST AND REASONABLE AND NOT UNDULY DISCRIMINATORY

18. In Docket ER07-956, the Louisiana Commission identified errors in the bandwidth methodology that are also reflected in Exs. ETR-26 and ETR-28. As the LPSC understands the Commission's rulings, an error in the methodology of Exs. ETR-26 and ETR-28 can only be corrected by Entergy through a discrete Section 205 filing and by another party, here the LPSC, through a Section 206 filing. Therefore, the Louisiana Commission hereby identifies the following errors in the methodology of Exs. ETR-26 and ETR-28, which render the bandwidth calculation unjust, unreasonable and unduly discriminatory. The LPSC has also raised the issues in Docket ER07-956, because Entergy attempted to correct an asserted error in its methodology in that proceeding. The issues should be heard in that docket, however, only if the Commission reconsiders its earlier rulings requiring separate Section 205 or 206 filings to change the approved methodology.

A. Failure to Include Spindletop Storage Facility Costs in EGSI's Production Costs.

19. The Spindletop Storage Facility consists of a leeched salt storage cavern and the related natural gas pipelines and equipment located in Sabine, Texas. This natural gas storage facility is used as a physical hedge for reliability and pricing purposes and supplies the EGSI Sabine and other EGSI gas generating units. The Spindletop Storage facility capital costs are included in account 182.3 regulatory assets and the amortization expense is included in account 407.3 regulatory debits.

20. For various reasons and prior to its merger with Entergy, Gulf States Utilities, Inc. ("GSU"), the predecessor to EGSI, entered into a contract with a third party to

finance and build the Spindletop Storage cavern and related facilities. The contract required GSU to pay off the capital costs of the facility through an identifiable component of the bundled gas transportation rate over an accelerated time period compared to the useful life of the facility. Once the capital costs were fully paid, this component of the transportation rate dropped to $0 and GSU could exercise its right to purchase the facility for $1, which it has since done.

21. Due to the structure of the transaction, GSU initially expensed these amounts to account 501 fuel and commenced recovering these capital costs through its retail fuel adjustment clause. However, once it identified these costs in an EGSI rate proceeding, the Louisiana Commission directed EGSI to refund and defer these amounts and then to amortize the deferred amounts over the 40 year life of the facilities in the same manner as if EGSI had financed and built the facility itself.

22. The Louisiana Commission's decision adopted the proper ratemaking for these costs by including the capital costs in rate base and then allocating the capital costs over the expected service life of the facility, rather than allowing EGSI to expense these capital costs over a much shorter period. In this manner, the Louisiana Commission required that the ratemaking conform with the nature of the physical asset and the use of that asset over a 40-year period rather than the terms of the contract specifying the payoff of a short term loan for that physical facility.

23. The Spindletop Storage Facility Costs are production costs. In 2008, after the separation of Entergy Gulf States, Inc. into Louisiana and Texas entities, EGSI incurs its share of the Spindletop Storage facility costs pursuant to Service Schedule MSS-4 and records this cost in account 555 purchased power expense. The Spindletop capital costs were production costs in 2007 and prior years, but the methodology of Exs ETR-26 and ETR-28 did not recognize

the costs in the production cost comparison. The failure to reflect the costs was an error in the methodology. The costs in Service Schedule MSS-4 and in future cost comparisons confirms that the omission was an error. Therefore, the Commission should summarily correct the error.

B. Failure to Exclude Accumulated Deferred Income Taxes for the "Unregulated" River Bend 30% Share from EGSI's Production Costs.

24. The River Bend 30% plant in service costs are recorded on EGSI's accounting books in account 121 nonutility property and the accumulated depreciation is recorded in account 122 accumulated provision for depreciation and amortization of nonutility property. The River Bend 30% is considered to be unregulated capacity for EGSI, but is sold in its entirety by EGSI to ELL and ENOI. EGSI recovers the costs of the River Bend 30% from ELL and ENOI pursuant to the MSS-4 tariff. None of the River Bend 30% costs have been included in the production cost bandwidth comparison.

25. Unlike the River Bend 30% plant in service and accumulated depreciation, the River Bend 30% nuclear depreciation ADIT is reflected in account 282 along with the other regulated River Bend 70% and was allocated in part to the production function, along with all other ADIT amounts in that account through the nuclear production plant ratio. The River Bend 30% nuclear depreciation ADIT should not be allocated to EGSI's production costs. In retail rate filings before the Louisiana Commission, EGSI was careful to remove the River Bend 30% ADIT from the rate base computation.

26. The inclusion of ADIT for the River Bend 30% creates a mismatch. In the production cost calculations, the net plant investment to which the ADIT relates is not included, but the ADIT offset is included. This error in methodology was also present in Exs. ETR-26 and ETR-28. The methodological error renders the production cost calculation unjust, unreasonable

and unduly discriminatory. The Commission should summarily correct this error in the bandwidth calculation.

C. Inclusion of Waterford 3 Capital Lease Amounts in Functionalizing ADIT to Production.

27. In its Section 205 filing that included the Waterford 3 Capital Lease Amounts in production costs, which was approved by the Commission, ESI introduced an error into the bandwidth calculation. The capital lease amount was included in the ratio used to functionalize ADIT to production. The terms variable production rate base ("VPRB") and fixed production rate base ("FPRB") are computed in part by subtracting an allocation of ADIT amounts. The allocations to VPRB and FPRB are the nuclear production plant ratio ("NPPR"), computed by dividing nuclear production plant in service ("NPP") by electric plant in service ("PXI"), and the production plant excluding nuclear ratio ("PPRXN"), computed by dividing production plant in service less nuclear production plant in service ("PPXN") by PXI.

28. The NPP and PXI terms include the Waterford 3 capitalized lease, although none of the nuclear depreciation ADIT amounts are related to the Waterford 3 capitalized lease. The lessor, not ELL, owns the portion of the Waterford 3 unit subject to the lease. ELL does not depreciate the lease portion for income tax purposes. Thus, there are no nuclear depreciation ADIT amounts in account 282 and none of the amounts actually in account 282 should be allocated to production based on the capitalized lease.

29. This error in the computation renders the bandwidth calculation unjust, unreasonable and unduly discriminatory. The error should be corrected by removal of the Waterford 3 capitalized lease amount from the computations of NPPR and PPRXN. The Commission should summarily determine that this error be corrected in the production cost calculation.

VII. PROVISIONAL IDENTIFICATION OF POINTS ON WHICH ENTERGY DEVIATED FROM THE METHODOLOGY IN EXHIBITS ETR-26 AND ETR-28 OR EMPLOYED UNJUST AND UNREASONABLE COST INPUTS IN THE BANDWIDTH CALCULATION

30. The LPSC believes based on the Commission's Orders, that matters properly before the Commission in Docket No. ER07-956 include: a) matters on which Entergy deviated from the methodology in Exhibits ETR-26 and ETR-28 without authorization granted pursuant to a Section 205 filing; and b) issues relating to cost inputs for 2006 that are unjust and unreasonable, including costs that are imprudent. The LPSC has identified these issues in Docket ER07-956 and expects that they may properly be resolved in that docket. Out of an abundance of caution, however, the LPSC identifies issues in this Complaint to preserve the opportunity to correct the improprieties in the event of a determination that an issue or issue, could not properly be litigated in that docket.

A. Deviation from Methodology in Exhibits ETR-26 and ETR-28 for Determining Operating Company Energy Requirements.

31. Section 30.11 of Rate Schedule MSS-3 requires an allocation of variable production costs based on each Operating Company's "Energy Ratio" or "ER". In its remedy calculation, Entergy has defined "net area requirements" by using three values obtained from each Operating Company's FERC Form 1: **Page 401a line 28 <u>less</u> 401a line 18 <u>less</u> 401a line 24.** This methodology is different from the methodology used to calculate net area requirements in Exhibits ETR-26 and ETR-28 as approved by this Commission in Opinion Nos. 480 and 480-A. In Exhibits ETR-26 and ETR-28, "net area requirements" are determined directly by using values from the monthly Entergy Intrasystem Bills ("ISB"s). Exhibit ETR-28 is an analysis of operating company production costs for the 12 months ending August 31, 2002. Schedule H from Ex. ETR-28 shows the net area requirements that were used in the production cost analysis.

The net area requirements data used in exhibit ETR-28 was developed directly from the Entergy ISB data ("To Area") for the 12 months ending August 31, 2002. In the May 29, 2007 Implementation filing, Entergy used the FERC Form 1 mWh data from page 401a, not the data available from the ISBs, as was used in ETR-26 and ETR-28. In doing so, Entergy understated the Energy Ratio for EAI in a manner that deviates, without Commission authorization, from the methodology in Exhibits ETR-26 and ETR-28.

B. Reduction of Account 165 Prepayments.

32. In Exhibits ETR-26 and ETR-28, the total amount in account 165 (prepayments) for each operating company was included in the formula used to determine production costs. As detailed on the supporting Schedule B for Exhibit ETR-26 and Schedule B of Exhibit ETR-28, the account 165 amounts were the simple average of the beginning year and ending year balances as reported on the Form 1. The total account 165 amounts were functionalized to production using a production plant ratio. ESI deviated from the methodology in its Implementation filing without authorization from this Commission. ESI adjusted the account 165 amounts reported in the 2005 Form 1 for EGSI, ELL, EMI and ENOI. ESI reduced the account 165 amounts reported in the 2005 Form 1 for these operating companies to remove the effects of a tax net operating loss ("NOL") carryback. These adjustments improperly deviate from the methodology approved by the Commission.

C. Exclusion of ADIT From Accounts 190 and 282

33. In Exhibits ETR-26 and ETR-28, the ADIT amounts in these accounts were netted and then functionalized to production based on the ratio of nuclear plant in service to total plant in service, excluding intangible plant, and on the ratio of other production plant in service to total plant in service, excluding intangible plant. The ADIT amounts in these accounts

were not adjusted from the Form 1 amounts used in Exhibit ETR-26 or comparable amounts for the twelve months ending August 31, 2002 used in Exhibit ETR-28, except to exclude SFAS 109 ADIT amounts and, in some years and for some of the Companies, to remove the property insurance reserve ADIT amounts. In its implementation filing, ESI changed, without authorization, the ADIT amounts reflected in accounts 190, 281 and 282 in the 2006 Form 1 filings. It adjusted the amounts in accounts 190 and 282 to exclude numerous ADIT amounts in addition to those that it excluded in Exhibits ETR-26 and ETR-28. ESI separated the ADIT amounts into "ratemaking" balances, which it used in the computation of production costs for purposes of the compliance filing, and "other" balances, which it did not use for this purpose. Among the "other" amounts that were excluded are numerous ADIT amounts that were included on Exhibits ETR-26 and ETR-28-namely, all of the amounts except for the SFAS 109 and property insurance reserve ADIT amounts. The exclusion of these "other" ADIT amounts violated the methodology approved by this Commission.

D. Improper Recording of Property Damage Accruals

34. Account 924 expense was reflected in A&G expense in Exhibits ETR-26 and ETR-28 and was functionalized to production through the use of labor ratio using the production labor incurred directly by the operating company divided by the total labor incurred directly by the operating company, excluding the labor recorded in the A&G expense accounts. Historically, the account 924 (property insurance) expense recognized by the operating companies has been the amount allowed for recovery by its retail regulators. The account 924 expense is credited to the account 228.1 (accumulated provision for property insurance; also referred to as the "property insurance reserve"), which has a liability balance if it is over-recovered and an asset balance if it is under-recovered. Actual storm damage costs that

otherwise would have been expensed to various functional O&M expense accounts when incurred instead are debited to account 228.1 and either reduce the liability balance or increase the asset balance. Historically, the operating companies have reflected the expense amount in account 924 because this is the manner in which the asset balance in account 228.1 is reduced in accordance with the accounting requirement of the Commission's Uniform System of Accounts ("USOA"). Thus, the account 924 expense acts to amortize the asset balance in account 228.1 and thereby reduce the amounts deferred in account 228.1.

35. The Operating Companies used the "normal" accounting to record the actual costs incurred as a result of Hurricanes Katrina and Rita by deferring O&M amounts in account 228.1 and capitalizing the capital costs to plant in service, but they failed to use account 924 expense to amortize the amounts deferred in account 228.1 as they were recovered in rates. EGSI and ELL changed their accounting to record the additional expense associated with the recoveries of the Hurricanes Katrina and Rita costs deferred in account 228.1. The Companies recorded the additional expense in account 407.3 (regulatory debits) rather than in account 924, despite the fact that nearly half the recovery for each Company was due to an amortization of the large asset balances in account 228.1. The remainder of the amounts recorded in account 407.3 necessary to match the revenue recoveries was to depreciate the amounts that were capitalized into the plant accounts and should have been booked to account 403 (depreciation expense). The amounts debited to 407.3 (regulatory debits) were accumulated by the Companies as a regulatory liability in account 254 (other regulatory liabilities). This change in accounting had the effect of artificially reducing the EGSI and ELL production costs and is not consistent with the FERC USOA. The FERC USOA does not allow EGSI and ELL to create a regulatory liability in lieu of directly amortizing the asset balance in account 228.1 through the account 924 expense.

Fundamentally, this accounting fails the requirements of the USOA because there is no regulatory liability to ratepayers; instead, there is an amortization of the amounts deferred in account 228.1. The amounts deferred by EGSI and ELL in account 254 (other regulatory liabilities) do not qualify for that account.

36. The Commission should reject the ESI accounting for storm damages. The change in storm damage accounting of EGSI and ELL results in an unauthorized reduction in the EGSI and ELL production costs for equalization purposes. The change is inconsistent with the data used in Exhibits ETR-26 and ETR-28. The change is inconsistent with the historical and "normal" storm damage accounting used by EGSI and ELL, and which they continue to use for their storm damage costs other than Hurricanes Katrina and Rita. The change is inconsistent with the requirements of the FERC USOA.

E. Unjust and Unreasonable Cost Inputs for Depreciation and Decommissioning.

37. The cost inputs for depreciation and decommissioning in Exhibits ETR-26 and ETR-28 were based on the actual service lives of generating units. The methodology adopted by the Commission thus calls for reflecting actual service lives. Additionally, the FERC Uniform System of Accounts and Generally Accepted Accounting Principles require that depreciation be reflected in a "systematic and rational manner . . .the service value of depreciable property over the service life of the property." 18 C.F.R. Pt. 101, Gen.'l Instr. 22A (2007): GAAP ARB No. 43, ¶ 5. Depreciation and decommissioning expenses included in rates should reflect the costs properly attributable to the period in question using a systematic and rational method of calculation given the *expected useful life* of the property.

38. Entergy has plans to extend the service lives of all its regulated nuclear units. The Nuclear Regulatory Commission already has granted life extensions for the ANO 1

and ANO 2 units owned by EAI. Thus, the official expected service lives for ANO 1 and ANO 2 reflect 60-year rather than 40-year lives. Additionally, given Entergy's plan to life extend all the units and the NRC's announced policy to facilitate life extensions, the "expected" lives of all the units as a practical matter should be 60-year lives.

39. Despite the official license extensions for ANO 1 and ANO 2, Entergy did not reflect the correct depreciation expense for these units in the bandwidth calculation, instead employing the shorter depreciation allowances approved by the APSC. Entergy relied on tariff language calling for the inclusion of the expenses "as approved by Retail Regulators, unless the jurisdiction for determining the depreciation and/or decommissioning rate is vested in the FERC under otherwise applicable law." Serv. Sched. MSS-3 ¶ 40.05. But this provision does not authorize the inclusion of an unjust and unreasonable depreciation expense; the FERC and not the retail regulator has exclusive jurisdiction to set wholesale rates and to determine the cost components of the bandwidth production cost calculation. Additionally, the provision for establishing the accumulated provision for depreciation, which must be read consistently with ¶ 40.05, provides for accepting the amount set by the Retail Regulators, "unless the FERC determines otherwise. . . ." If the tariff were construed to permit a retail regulator to preempt the FERC's authority to establish just and unreasonable rates, the result would be illegal under he Federal Power Act. To the extent the tariff language could legally be construed in that manner, it is unjust, unreasonable and unduly discriminatory and should be amended.

40. The use of inaccurate and excessive rates of depreciation for ANO 1 and ANO 2 is unjust, unreasonable and unduly discriminatory. The correct expected service lives of all the nuclear units -- 60 years in each case -- should be used to set the depreciation and decommissioning expense in the bandwidth calculation. Alternatively, the traditional FERC

policy of using the NRC-approved license life for each unit should be applied. This policy would require the use of a 60-year lives for ANO 1 and ANO 2 and 40-year lives for Waterford 3, River Bend and Grand Gulf.

F. Double Count in the Exclusion of A&G Expense for the River Bend 30% Share in Quantifying the Production Cost of EGSI.

41. In *Entergy Services, Inc.,* Docket No. ER07-682, Entergy proposes to change the ratios used for functionalizing costs for General and Intangible Plant ("G&I Plant") and Administrative and General Expenses ("A&G Expenses") to the production function. Entergy proposes to use operating company labor ratios augmented with the labor of two affiliates, ESI and Entergy Operations, Inc. ("EOI") in the calculation.

42. In applying the proposed ratios, Entergy introduced a double count in the removal of the A&G expenses for the 30 percent share of the River Bend nuclear unit ("River Bend 30") that was acquired by EGSI in a settlement with Cajun Electric Power Cooperative, Inc. This double removal of the River Bend 30 A&G expenses is a departure from the methodology employed in Exs. ETR-26 and ETR-28. The River Bend 30 historically was treated as an "unregulated" asset in the retail jurisdictions and EGSI sold its output into the wholesale market. In 2003, however, EGSI began selling the River Bend 30 to ELL and ENO as part of the Entergy System's Strategic Supply Resource Plan. *See Entergy Services, Inc. and EWO Marketing, L.P.,* 116 F.E.R.C. ¶ 61,296 at ¶ 83 (2006). The cost of the purchase is included in the production costs of ELL and ENO, but Entergy excludes the cost of the River Bend 30 from EGSI's production costs along with the associated revenues.

43. Prior to its Section 205 filing to permit the use of augmented labor ratios to functionalize G&I plant and A&G expenses, Entergy used "direct labor" ratios to functionalize A&G expenses. In Exhibits ETR-26 and ETR-28, Entergy used all of EGSI's "direct labor" --

the payroll of the operating company itself -- to determine the labor ratio, which it then multiplied times all of EGSI's A&G expenses to functionalize these expenses to production. Thereafter, Entergy removed G&I plant costs and A&G expenses directly associated with the River Bend 30 from production costs. [*Id.*].

44. In implementing the proposed augmented labor ratio to set the rates at issue in the implementation filing, Entergy *twice* removed A&G expenses for the River Bend 30 from EGSI's production costs. The augmented labor ratios include the labor of ESI, which provides multifunctional services to the operating companies, and EOI, which operates the System's nuclear plants. EOI operates River Bend for EGSI. Entergy removes 30 percent of the EOI labor from the augmented labor ratio for EGSI, which it then multiplies times the total EGSI A&G expenses to functionalize these costs to production. This adjustment to the labor ratio removes the 30 percent share in functionalizing costs to production. But *after* adjusting the labor ratio to remove these costs, Entergy *again* removes them through a specific adjustment to subtract 30 percent of River Bend's A&G expenses, similar to the adjustment in ETR-26 and ETR-28. This double removal of A&G expenses incorrectly decreases EGSI's production costs. The double removal of A&G for the River Bend 30 is unjust, unreasonable and unduly discriminatory to EGSI and its customers.

G. Imprudent Cost Consequences of Failure to Buy Back ISES 2.

45. In 1996 and 1997, EAI was provided opportunities to "buy back" up to 180 megawatts of the Independence 2 Steam Electric Station ("ISES 2"), then owned by Entergy Power, Inc. Although ISES 2 would have provided EAI and Entergy with a source of low-cost base load capacity and energy and contribute to fuel diversity, Entergy directed EAI to decline the offer. Entergy did not conduct a complete analysis of the economics of buying back the

capacity in connection with that decision. The only analysis it provided that was conducted contemporaneous with the decision was deficient for: a) its failure to consider fuel cost impacts of the buyback; b) its failure to evaluate System economics related to the decision; and c) its failure to consider impacts beyond 10 years. Entergy's decisionmaking process was flawed, just as it was flawed when Entergy decided that EAI should spin off ISES 2. *City of New Orleans v. Entergy Corp.,* 65 F.E.R.C. ¶ 61,333 at p. 62,564 (1993). Had Entergy performed a reasonable analysis, it would have determined that the buyback was economic and in the interests of its customers. EAI's failure to exercise its Right of First Refusal was imprudent. The effects of the imprudence should be excluded from the bandwidth calculation. Additionally, the FERC should require that the bandwidth impacts be assessed to Entergy's shareholders and should not be part of FERC-mandated costs that must flow through in retail rates. Shareholders should pay the costs of imprudence.

VIII. EVIDENCE

46. The issues raised in this Complaint have been identified and addressed in Pre-Filed Testimony filed by the LPSC in Docket ER07-956. The LPSC attaches the relevant testimony to establish the evidentiary basis for this Complaint. This evidence includes the Direct Testimony of Stephen Baron, Lane Kollen, the Cross-Answering Testimony of Stephen Baron and Lane Kollen, and the Supplemental Direct Testimony of Randy A. Futral. [Attachs. 1 - 3].

IX. PRAYER FOR RELIEF

The LPSC prays that the Commission summarily grant relief on the issues identified in Part VI of this Complaint or, alternatively, establish a refund effective date at the earliest date allowed by law and hearing procedures to determine whether Entergy's methodology is unjust, unreasonable or unduly discriminatory. The LPSC requests no action on the other issues identified in the Complaint, unless the Commission determines that a matter or matters are not properly before the Commission in Docket No. ER07-956 and that a Complaint must be filed to correct the unjust and unreasonable cost inputs. If the Commission so finds, the LPSC prays that the Commission summarily correct the deficiency in Entergy's calculation or, alternatively, establish a refund effective date at the earliest time allowed by law and establish hearing procedures to resolve the issue or issues. The LPSC also prays for any other relief that is equitable in the circumstances.

Respectfully submitted,

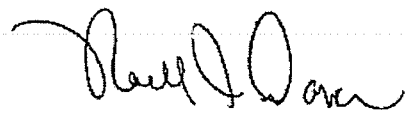
Eve Kahao Gonzalez
General Counsel
Ann Hill
Staff Attorney
Louisiana Public Service Commission
Galvez Building – 12th Floor
602 N. Fifth Street
Baton Rouge, Louisiana 70802
Telephone: (225) 342-9888

Michael R. Fontham
Paul L. Zimmering
Noel J. Darce
Dana M. Shelton
Of
STONE, PIGMAN, WALTHER, WITTMANN, LLC
546 Carondelet Street
New Orleans, Louisiana 70130
Telephone: (504) 581-3200

Attorneys for the Louisiana Public Service Commission

CERTIFICATE

I hereby certify that a copy of the above and foregoing Complaint of the Louisiana Public Service Commission has been served upon Entergy and upon the Entergy Regulators' counsel on the attached list, this 31st day of March, 2008.



Noel J. Darce

Attachment

Entergy Services, Inc. On Behalf of System Energy Resources, Inc.

Walter C. Ferguson
Vice President, System Regulatory Affairs
Entergy Services, Inc.
639 Loyola Avenue
New Orleans, LA 70113
Telephone: 504-576-4867
Fax: 504-576-7300
E-Mail: wfergus@entergy.com
(Via FedEx)

Kimberly H. Despeaux
Associate General Counsel
Entergy Legal Services
639 Loyola Avenue
New Orleans, LA 70113
Telephone: 504-576-4867
Fax: 504-576-3989
E-Mail: kdespea@entergy.com
(Via FedEx)

Texas Public Utilities Commission
1701 N. Congress Avenue
Austin, TX 78711-3326
E-Mail: brennan.foley@puc.state.tx.us
(Via FedEx)

Arkansas Public Service Commission
1000 Center Street
Little Rock, AR 72201
E-Mail: rhightower@psc.state.ar.us
mcochran@psc.state.ar.us
(Via FedEx)

Mississippi Public Service Commission
P.O. Box 1174
Jackson, MS 39215-1174
E-Mail: george.fleming@psc.state.ms.us
(Via U. S. Mail)

New Orleans City Council
Utilities Regulatory Office
Room 6E07
1300 Perdido Street
New Orleans, LA 70112
E-Mail: kpmeehan@cityofno.com
cvince@sonnenschein.com
ehand@sonnenschein.com
(Via U. S. Mail)

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.	)	DOCKET NO. ER07-956-000

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

THE LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.

ROSWELL, GEORGIA

FEBRUARY 2008

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.	)	DOCKET NO. ER07-956-000

Table of Contents

I. QUALIFICATIONS AND SUMMARY 1

II. IMPRUDENT COSTS ASSOCIATED WITH THE FAILURE OF EAI TO REPURCHASE ISES 2 CAPACITY 13

III. ENERGY RATIO ("ER") AND NET AREA REQUIREMENTS ISSUES 24

IV. INTERRUPTIBLE LOAD ISSUES 39

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

DIRECT TESTIMONY OF STEPHEN J. BARON

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by who are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this

capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Virginia, West Virginia, Wisconsin, Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ___(LC-2).

Q. Have you previously testified in Entergy regulatory proceedings before the Federal Energy Regulatory Commission ("FERC" or "Commission") and state regulatory commissions?

A. Yes. I have significant experience in addressing issues associated with the Entergy System, its Operating Companies, the Entergy System Agreement, and proceedings involving the Entergy Open Access Transmission Tariff at the FERC. I filed an affidavit in the original Complaint case filed by the Louisiana Public Service Commission and the City of New Orleans in Docket No. EL01-88 and presented testimony in that supported the LPSC's contention that production costs among the Entergy Operating Companies were no longer in rough production cost equalization and that the Entergy System Agreement was not just and reasonable. In its decisions in that case (Opinion Nos. 480 and 480A), the Commission found

that production costs among the Entergy Operating Companies were no longer in rough production cost equalization.

I have been involved in numerous regulatory proceedings before the Louisiana Public Service Commission and the Federal Energy Regulatory Commission regarding other Entergy system issues concerning the Entergy System Agreement, its rate schedules and on economic analyses related to Entergy wholesale and retail ratemaking. Before the FERC, I have also participated in the Entergy merger proceeding with Gulf States Utilities, Inc. (FERC Docket No. EC92-21); the Extended Reserve Shutdown ("ERS") proceeding involving the Entergy System Agreement (FERC Docket No. EL94-13); a System Entergy Resources, Inc. ("SERI") rate proceeding (FERC Docket No. ER95-1042); an Entergy proceeding concerning interruptible load and its impact on Operating Company load responsibility (FERC Docket No. EL00-66), an Entergy System Agreement proceeding involving the attempted withdrawal of Operating Companies facing retail access (FERC Docket No. ER00-2854); and a proceeding involving Entergy Operating Company purchased power agreements (FERC Docket No. ER03-583).

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

1 A. I am testifying on behalf of the Louisiana Public Service Commission ("LPSC").

2

3 **Q. What is the purpose of your testimony?**

4

5 A. I am presenting testimony on a number of issues related to the reasonableness of the
6 2006 Entergy Operating Company ("EOC") production costs that Entergy Services
7 ("Entergy") used to develop the payments and receipts pursuant to Sections 30.11
8 through 30.13 of System Agreement Rate Schedule MSS-3.

9

10 I and other witnesses for the LPSC have identified a number of unreasonable costs or
11 calculations that Entergy has made in its May 2007 compliance filing in this case.
12 The July 26, 2007 Commission Order establishing this proceeding specifically set
13 the prudence and reasonableness of the "underlying cost inputs" of the bandwidth
14 payments and receipts (hereinafter also referred to as the "bandwidth calculation")
15 for hearing. In so doing, the Commission rejected the request of certain retail
16 regulators to limit the proceeding to the reasonableness of the bandwidth calculation
17 itself.[1]

[1] These other retail regulators are collectively, the Arkansas PSC, the Mississippi PSC and the Council of the City of New Orleans.

The Commission also incorporated prudence issues raised in a complaint filed by the Arkansas Public Service Commission ("APSC"). Though the Commission denied the APSC complaint in its June 1, 2007 Order in Docket No. EL06-76, the Commission stated that the section 205 compliance filings to set the bandwidth calculations will "provide the Commission and all interested parties the opportunity to analyze *all production-related costs* of each of the Entergy Operating Companies to make sure that all such costs are just and reasonable and prudently incurred." (Order at paragraph 47, emphasis added). Based on the scope of prudence issues to be addressed in this case set forth in these two Commission Orders, the LPSC has identified a number of costs that have been included as inputs in the bandwidth calculation that are imprudent and/or not just and reasonable.

In my testimony, I will discuss three issues associated with Entergy's calculation of the bandwidth in this case. The first issue concerns the inclusion by Entergy of excessive 2006 production costs for Entergy Arkansas, Inc. ("EAI") that arise because EAI failed to repurchase a portion of the Independence II coal unit ("ISES 2") from Entergy Power, Inc. ("EPI") in 1996, pursuant to a right of first refusal. As I will discuss, in 1990, EAI transferred 265 mW of ISES 2 capacity to EPI, with a right of first refusal to repurchase the capacity at net book value if EPI elected to sell the capacity to a third party. EAI imprudently waived its right of first refusal in

1996, resulting in excess production costs in 2006. These excess production costs have flowed through the calculation of the bandwidth payments and receipts. As will be discussed subsequently in my testimony and that of LPSC witness Philip Hayet, a reasonable analysis performed by EAI in 1996 would have shown that purchasing additional ISES 2 coal capacity was economic for the Entergy System. As I will show, the presence of additional ISES 2 coal capacity would have reduced EAI's 2006 production costs, resulting in higher bandwidth payments to Entergy Louisiana, Inc. ("ELI") and Entergy Gulf States, Inc., ("EGS").

The next issue that I will address concerns Entergy's calculation of Net Area Load in its determination of the energy ratio ("ER") in the bandwidth calculation.[2] As I will discuss, Entergy did not properly follow the Commission approved MSS-3 tariff in the calculation of the ER factor because it substituted FERC Form 1 data for the Commission approved Intra-System Bill ("ISB") data. In Opinion Nos. 480 and 480-A, as well as the Commission's November 17, 2006 Order on Entergy's compliance filing, the Commission repeatedly relied on the methodologies contained in Entergy exhibits ETR-26 and ETR-28 as the basis for the calculation of bandwidth payments and receipts.[3] In Opinion No. 480, the Commission stated at paragraph 33, "Future production cost comparisons among the Operating Companies should follow the methodology in Exhibit ETR-26, which accounts for Vidalia by re-pricing the energy

[2] Pursuant to Section 30.13 of Schedule MSS-3.

at the annual MSS-3 rate."[4] Entergy's May 29, 2007 compliance filing did not conform to this requirement and is thus improper, with regard to the calculation of factor ER.

The final issue that I will address concerns the inclusion of interruptible loads in the calculation of the bandwidth payments and receipts. Pursuant to the Commission's Opinion Nos. 468 and 468-A, interruptible load is excluded in the calculation of load responsibility in Entergy System Agreement Schedule MSS-1. Interruptible load is excluded in the allocation of Joint Account Purchases among the EOCs.[5] Interruptible load is also excluded from the allocation of off-system sales margins via Rate Schedule MSS-5. Because of the interruptible load adjustments in the allocation of Joint Account Purchases, the amounts of energy purchased and sold to the "exchange" pursuant to Rate Schedule MSS-3 is directly impacted by interruptible load.

The LPSC opposed Entergy's compliance tariff (April 10, 2006 filing) because Entergy did not adjust the 12 coincident peak demand allocation factor to remove interruptible load, pursuant to the Commission finding in Opinion Nos. 468 and 468-A. In its November 17, 2006 Order on Entergy's April 10th filing, the Commission

[3] These exhibits were produced in Docket No. EL01-88.
[4] Exhibit ETR-28 provides detailed production cost calculations for one of the years presented in ETR-26.

rejected the LPSC's protest on this issue (excluding interruptible load from the 12 CP demands used to calculate the demand ratio ("DR"), pursuant to Section 30.13 of Schedule MSS-3).[6] However, the Commission's July 26, 2007 Order setting this proceeding for hearing suggests that all prudence issues are to be considered. As such, to the extent that the Commission finds that it is unreasonable to include interruptible demands in the 12 CP allocation factor in this case, I will present a revised calculation of the bandwidth payments and receipts that excludes such interruptible loads.

Q. Would you summarize your testimony?

A. Yes.

- **The LPSC has identified that EAI's 2006 production costs include imprudent cost inputs because EAI failed to reacquire a portion of the Independence Steam Electric Station Unit 2 ("ISES 2") generating unit. In 1990, EAI transferred its 265 mW share of the 842 mW coal unit to an unregulated subsidiary of Entergy Corporation, to be known as Entergy Power, Inc. ("EPI"). If EAI had repurchased 164 mW of ISES 2 capacity in 1996, its 2006 production costs would have been reduced. All else being equal, in this event (increased ownership of ISES 2 in 2006), EAI bandwidth payments to ELI, EGS and EMI would have increased (compared to the actual payments calculated in Entergy's compliance filing). The 2006 bandwidth payments and receipts should be revised to reflect the adjustment calculated by**

[5] An EOC with interruptible load will receive a smaller allocation of system purchases for the accounts of all Companies.
[6] The Commission stated that no such adjustment was made in exhibit ETR-26.

the LPSC to reflect the inclusion of ISES 2 capacity in EAI's 2006 production costs.

- **The methodology used in Entergy's May 29, 2007 compliance filing (based on FERC Form 1 data) to calculate net area requirements is not the method approved by the Commission in Opinion Nos. 480 and 480-A, which used "To Area" mWh data from the monthly Intra-System Bills ("ISB").**

- **The current MSS-3 bandwidth calculation compares actual costs that include an interruptible load adjustment to allocated costs that ignore interruptible load. As a result, the bandwidth payments and receipts partially reverse the effect of the Commission's decision in Opinion Nos. 468 and 468-A. In the event that the Commission finds that such an issue is appropriate in this docket, the demand allocation factor, "DR" in the bandwidth calculation, should be revised to reflect the removal of interruptible load from each EOC's load responsibility. The "DR" factor is an "input" into the bandwidth calculation. The LPSC's contention in this case is that the Company used an incorrect input factor.**

II. IMPRUDENT COSTS ASSOCIATED WITH THE FAILURE OF EAI TO REPURCHASE ISES 2 CAPACITY

Q. Would you please explain this issue and discuss the general approach that the LPSC is using to address ISES 2 imprudence?

A. The Commission's July 26, 2007 Order setting this case for hearing specifically stated (paragraph number 16) that "all parties will have the opportunity to raise prudence issues." The Commission went on to state that this includes the reasonableness of the underlying input costs. The LPSC has identified that EAI's 2006 production costs include imprudent cost inputs because EAI failed to reacquire a portion of the Independence Steam Electric Station Unit 2 ("ISES 2") generating unit. In 1990, EAI transferred its 265 mW share of the 842 mW coal unit to an unregulated subsidiary of Entergy Corporation, to be known as Entergy Power, Inc. ("EPI").[7] This followed the approval of the Arkansas Public Service Commission ("APSC") for the transfer of EAI's ISES 2 capacity to EPI in an order issued on April 2, 1990 in APSC Docket No. 89-128-U. In granting approval for the transfer, the APSC required EPI to provide EAI an offer of a right of first refusal to repurchase the capacity (or a portion thereof) in the event that EPI subsequently decided to sell ISES 2 to another utility.

Q. Has the Commission previously evaluated the economics of the ISES 2 capacity to the Entergy System?

A. Yes. As more fully discussed in LPSC witness Hayet's testimony in this case, the Commission evaluated the economics of the original transfer of the ISES 2 and Ritchie 2 capacity from EAI to EPI in Docket Nos. EL90-48-000 and EL90-48-003. Among other findings, the Commission found that Entergy did not perform a proper economic analysis to evaluate the original transfer of the capacity from EAI to EPI. In its Opinion No. 386, the Commission found that Entergy's "decisionmaking process was flawed." The Commission stated as follows:

> **Though ultimately finding the spin-off prudent, the judge also noted that Entergy's decisionmaking process was flawed. On exceptions, Entergy argues that because the ruling is not necessary to reach a conclusion on the prudence issue, the Commission should vacate the judge's finding on this matter. 51/**
>
> **The evidence demonstrates that, rather than performing any detailed, formalized, and recorded study supporting a spin-off involving millions of dollars and potential long-term system effects, there was little more than a "back-of-the-envelope" look at the decision (Tr. 3756) and even this was in part not retained. The record also shows that the Operating Committee abdicated its role under the System Agreement by not performing any analysis of the effects of the spin-off. Entergy acknowledged that apart from a study which pertained only to AP&L, "there was no study over a**

[7] EAI also transferred its ownership of the Ritchie 2 steam unit to EPI; though the LPSC is not addressing this capacity in this case.

> **twenty-year time frame as to any of the other companies or the system until after the transaction occurred" (Tr. 4969). The judge ruled that the after-the-fact studies produced by Entergy in support of the spin-off are no substitute for comprehensive pre-transfer studies.**
>
> **Entergy has offered no credible defense in response to the evidence or the resulting ruling by the judge. The unrebutted record evidence indicates that Entergy did not conduct or record a detailed analytical study of comprehensive system impacts until after management decided to go forward with the spin-off. Consequently, we affirm the judge's ruling that the Entergy decisionmaking process was flawed.** (Opinion No. 386 at page 18).

Q. Did the Commission find that Entergy was imprudent, with regard to the capacity transfer?

A. The Commission specifically deferred any decision on the prudence of the transfer. In so doing, the Commission vacated the portion of the Initial Decision in which the ALJ found that the Company was prudent. The Commission stated as follows in this portion of Opinion No. 386:

> **However, we make no finding as to the prudence of costs incurred if capacity additions are made. Hence, we vacate that portion of the Initial Decision which addresses such capacity additions. n68/ Thus, it follows that Entergy stockholders are not absolved from any potential disallowance in a future proceeding involving the assignment of replacement capacity costs.** (Opinion No. 386 at page 22).

1 **Q. Are you relying on this finding to support your finding of imprudence in this**
2 **case?**
3
4 A. Not specifically. However, the Commission's decision in Opinion No. 386
5 establishes that a full economic study of System impacts is necessary when the
6 System considers a transfer of significant and potentially valuable capacity.
7
8 **Q. Did Entergy conduct such a full economic study of System impacts in its**
9 **evaluation of the offer of ISES 2 capacity in 1996?**
10
11 A. No. In response to a data request in this case (LPSC 6-9), Entergy provided an
12 analysis that was developed in 1996 to evaluate the economics of repurchasing the
13 offered ISES 2 capacity from EPI. As Mr. Hayet discusses in his testimony, this
14 analysis suffers from the same flaws that the FERC noted in Entergy's analysis
15 supporting the original transfer of ISES 2 and Ritchie 2 capacity from EAI to EPI
16 in 1989.
17
18 First, the analysis only evaluates the impact of the repurchase of ISES 2 capacity
19 on fixed revenue requirements; there is no analysis of the impact of the additional
20 coal capacity on Entergy fuel and purchased power expenses. This is a significant

1 failure in a power supply economic analysis. Base load coal capacity is more
2 expensive than gas fired peaking capacity on a fixed cost basis, but produces lower
3 operating costs because of the lower cost of coal, compared to natural gas. The
4 same is true for nuclear capacity, compared to gas fired peaking capacity. This
5 creates a classic screening curve tradeoff that generation system planners,
6 including Entergy's planners, have considered for more than half a century. If only
7 the fixed revenue requirements are considered, as Entergy did in its evaluation of
8 the ISES 2 repurchase, no utility would ever have invested in coal or nuclear
9 capacity.
10
11 The second two, serious flaws in the Entergy analysis are that it only considered
12 the 10 year period 1996 through 2006 and it only evaluated the impact on EAI, not
13 the Entergy System as a whole. Both of these flaws were noted by the FERC in its
14 criticism of the analysis used by Entergy to evaluate the original ISES 2/Ritchie 2
15 spin-off from EAI in Opinion No. 386.
16
17 **Q. With regard to EAI's right of first refusal for a repurchase of ISES 2 capacity,**
18 **did EPI decide to make such a sale to a third party utility that would trigger the**
19 **right?**
20

A. Yes. As more fully discussed in LPSC witness Hayet's testimony, EPI offered to sell up to 180 mW of its ISES 2 capacity in 1996 and, pursuant to its agreement, first offered it to EAI, which declined the offer to purchase any amount of ISES 2.

Q. What were the pricing terms being offered to EAI for a repurchase of ISES 2 capacity?

A. EPI offered to sell up to 180 mW of ISES 2 at depreciated book value, which EPI estimated was about $450 per kW at year end 1996.

Q. Was EAI's decision to waive its right of first refusal reasonable?

A. No. Based on the economic analyses presented by LPSC witness Hayet, it was imprudent for EAI to have waived its right to purchase the offered ISES 2 capacity. This retrospective economic study, using data, models and assumptions from a 1996 perspective, shows that a reasonable 1996 analysis would have concluded that the purchase of 164 mW of ISES 2 capacity by EAI at that time would have produced a 20 year net present value benefit of $23 million for the Entergy System as a whole.

1 **Q. What is the basis for evaluating the economics of a 164 mW purchase of ISES 2**
2 **capacity from EPI?**
3
4 A. Though EPI offered up to 180 mW of ISES 2 capacity out of their ownership share
5 of 265 mW, EPI eventually sold 101 mW to ENO and ELI in 2003 for 10 years.
6 Given that, in the 2006 bandwidth calculation the System EOCs were purchasing
7 101 mW of the unit, our prudence evaluation is based only on the remaining 164
8 mW owned by EPI (about 91% of the mW actually offered to EAI in 1996).
9
10 **Q. Based on your conclusion that EAI was imprudent in not repurchasing 164 mW**
11 **of ISES 2 capacity in 1996, what are the implications in this bandwidth**
12 **calculation case?**
13
14 A. As I discussed, the reasonableness of the cost inputs into each EOC's production
15 costs is an issue in this case. If EAI had repurchased 164 mW of ISES 2 capacity in
16 1996, its 2006 production costs would have been reduced. All else being equal, in
17 this event (increased ownership of ISES 2 in 2006), EAI's bandwidth payments to
18 ELI, EGS and EMI would have increased (compared to the actual payments
19 calculated in Entergy's compliance filing).
20

1 **Q. What standard have you used to evaluate the reasonableness of EAI's 2006**
2 **production costs, with regard to its failure to repurchase ISES 2 coal capacity**
3 **from EPI?**
4
5 A. I have evaluated EAI's decision to forgo the repurchase of ISES 2 capacity in 1996
6 by developing analyses that a reasonable utility management would have made, in
7 good faith, under the same circumstances, and at the relevant point in time. LPSC
8 witness Hayet's 1996 economic analysis provides such a basis to evaluate EAI's
9 decision making on this issue, using information available to EAI at that time. Our
10 conclusion is that a reasonable utility management, under the circumstances
11 existing in 1996, would have repurchased the ISES 2 capacity.
12
13 **Q. Have you developed an analysis of the impact on the 2006 bandwidth payments**
14 **and receipts of EAI owning 164 mW of ISES 2 capacity in 2006?**
15
16 A. Yes. Based on Mr. Hayet's 1996 economic analysis, EAI should have repurchased
17 164 mW of ISES 2 capacity in 1997. Had EAI done this, its 2006 production costs
18 (as well as the production costs of each of the other EOCs) would have been lower.
19

To calculate this impact on EOC production costs, the LPSC developed an analysis of the impact of an EAI ownership of 164 mW on: 1) EAI and the other EOC's fuel and purchased power expenses, 2) EAI's fixed production revenue requirements and 3) MSS-1 reserve equalization payments.

Q. Would you describe the specific analyses that you made to estimate the impact on 2006 EOC production costs?

A. The first analysis, which calculates the impact on EOC fuel and purchased power expenses in 2006, relies on the PROMOD production cost model. Mr. Hayet discusses this analysis in his testimony. He has calculated the impact on each EOC in 2006 from an addition to EAI of 164 mW of ISES 2 coal capacity.

The second analysis involved the development of the fixed revenue requirements associated with a 164 mW ownership share of ISES 2 by EAI. These revenue requirements, which consist of a return on rate base, depreciation and O&M expenses, were developed by using 2006 FERC Form 1 data for EPI and EMI (which co-owns ISES 2). In addition, I relied on EAI data to develop the annual depreciation expense for the unit (using EAI's ISES 1 depreciation rate) and EAI's cost of capital rate.

The third analysis calculates the impact on each EOC's MSS-1 payments and receipts from the addition of 164 mW of capacity on EAI for 2006. This analysis used actual 2006 Rate Schedule MSS-1 charge rates for each EOC and computed the incremental payments and receipts associated with the changed "capability" for EAI in 2006.

Baron Exhibit__(LC-3) summarizes the 2006 production cost changes for each EOC as a result of the ownership of an additional 164 mW of ISES 2 capacity by EAI. These changes, for both variable and fixed production costs, are then made directly to the inputs into the bandwidth calculation.[8]

Q. Have you calculated the impact of these production cost changes on the bandwidth payments and receipts for 2006?

A. Yes. Baron Exhibit__(LC-4) contains the calculations of bandwidth payments and receipts for each EOC, reflecting the production cost changes due to the additional ISES 2 capacity on EAI that is presented in Exhibit__(LC-3). Table 1 below summarizes these results for each EOC.

[8] Line number references are shown for each input change to the bandwidth calculation.

Table 1
Impact of Additional ISES 2 Coal Capacity for EAI in 2006

	EAI	EGS	ELL	EMI	ENOI	System
EAI with ISES 2 Capacity						
Actual Production Cost	1,038,407	2,492,223	1,850,747	963,022	233,746	6,578,145
Bandwidth (Payment)/Receipt	(273,471)	129,111	99,360	45,000	0	0
Per ETR Filing						
Actual Production Cost	1,067,133	2,496,827	1,852,571	963,584	233,550	6,613,665
Bandwidth (Payment)/Receipt	(251,731)	120,103	91,051	40,577	0	0
Difference						
Actual Production Cost	(28,726)	(4,604)	(1,824)	(562)	196	(35,520)
Bandwidth (Payment)/Receipt	**(21,740)**	**9,008**	**8,309**	**4,423**	**0**	**0**

The 2006 bandwidth payments and receipts should be revised to reflect the results of this analysis (Table 1). Specifically, EAI's payment should be increased by $21.74 million, while the receipts for EGS, ELL and EMI should be increased by the amounts shown in Table 1.

III. ENERGY RATIO ("ER") AND NET AREA REQUIREMENTS ISSUES

Q. Would you please discuss the problem that you have identified with the Company's compliance filing on the development of the energy ratio?

A. Yes. The energy ratio ("ER") is an allocation factor used to allocate System variable costs in the bandwidth calculation. It is defined in Section 30.13 of Schedule MSS-3 as "net area requirements" less non-requirements sales for resale. Its origin in the bandwidth calculation, like all of the elements of the formula, is supposed to be the methodology used in the development of busbar production costs in exhibits ETR-26 and ETR-28 in Docket EL01-88. The Commission has relied on the methodology used in these two exhibits in its Opinion Nos. 480 and 480-A and has specifically required Entergy to utilize this methodology in the bandwidth calculation, absent a Section 205 filing that seeks a change in the methodology.[9] Conceptually, the ER allocation factor is designed to assign variable costs to each EOC on the basis of each EOC's relative share of "requirements" energy.

The problem that I have identified in reviewing the Company's compliance filing is that Entergy has used a series of computations developed from FERC Form 1

data in developing the ER allocation factor, rather than data from the Intra-System Bills ("ISB"), as used in ETR-26 and ETR-28. The methodology used in Entergy's May 29, 2007 compliance filing (based on FERC Form 1 data) to calculate net area requirements is not the method approved by the Commission in Opinion Nos. 480 and 480-A, which used "To Area" mWh data from the monthly Intra-System Bills ("ISB").

Q. Does the Commission approved MSS-3 compliance tariff state that the energy allocation factor ("ER") will be based on FERC Form 1 data for this calculation, instead of the ISB data used in ETR-26 and ETR-28?

A. No. The approved tariff makes no reference to the use of FERC Form 1 data to calculate the ER factor. The use of this FERC Form 1 data appears for the first time in the May 29, 2007 bandwidth calculations.

Q. Would you please explain the manner in which the compliance filing specifically differed from the methodology in Exhibits ETR-26 and ETR-28, regarding the calculation of the energy allocation factor?

[9] In fact, the Company has made a number of Section 205 filings to seeking approval for such changes (for example, Docket ER07-682 that is currently before the Commission).

A. This issue concerns the allocation of the System's total variable production costs to each Operating Company based on the Operating Company's Energy Ratio ("ER"), pursuant to Section 30.11 of Rate Schedule MSS-3. The energy ratio is defined in section 30.13 of the tariff as:

> ER= Each Company's Annual Energy (Net Area Requirements less Non-Requirements Sales for Resale) Divided by the Sum of all Companies Annual Energy (Energy Ratio).

In its May 29, 2007 Compliance Filing, in which the bandwidth payments and receipts are calculated, Entergy has computed annual energy using three values from each Operating Company's FERC Form 1, as follows:

Page 401a line 28 less 401a line 18 less 401a line 24

This methodology to calculate the energy ratio is different from the methodology used in exhibits ETR-26 and ETR-28, which the Commission has directed Entergy to use as the basis for the calculation of payments and receipts required in Order Nos. 480 and 480-A.

In Exhibits ETR-26 and ETR-28, the energy values for each EOC are determined directly by using values from the monthly Entergy ISBs. Exhibit ETR-28 is an analysis of Operating Company production costs for the 12 months ending August

31, 2002. Baron Exhibit__(LC-5) contains a copy of Schedule H from exhibit ETR-28. Schedule H shows the "net area requirements" that were used in the production cost analysis to implicitly allocate variable costs.[10] The energy requirements data used in exhibit ETR-28 were developed directly from the Entergy ISB data ("To Area") for the 12 months ending August 31, 2002. Baron Exhibit__(LC-6) shows the monthly ISB data for each Operating Company and compares this information to the net area requirements data from Schedule H of exhibit ETR-28. The data are identical; establishing that the methodology used in ETR-28 for net area requirements was based on the ISB "To Area" data.

Q. Was ISB data also used in exhibit ETR-26 to develop the energy allocation factor?

A. Yes. First, exhibit ETR-26 included the production cost analysis detailed in exhibit ETR-28; thus, ETR-26 also relies on the ISB "to Area" load data. This is confirmed by Entergy witness Louiselle in his Direct Testimony at page 37, beginning at line 3. Mr. Louiselle also confirms that ISB data (and not FERC

[10] Though in ETR-26 and ETR-28 there are no explicit allocations of costs because these exhibits represent busbar production cost comparisons, there is an implicit allocation of costs in each of the exhibits. In these two exhibits, production costs are unitized by dividing variable costs by annual EOC energy (net area requirements) and dividing fixed costs by load factor adjusted energy. These unitized production costs are then compared to the average System unitized costs. The bandwidth calculation, while explicitly allocating costs, similarly compares EOC production costs to System average production costs.

Form 1 load data) was used for the other years in developing the production cost analyses reported in exhibit ETR-26.

Baron Exhibit__(LC-7) contains a workpaper supporting the 2001 production costs calculations in exhibit ETR-26. These annual GWH values for each Operating Company are used to calculate the busbar production costs shown for the year 2001 in exhibit ETR-26. Baron Exhibit__(LC-8) shows the summary calculations of the 2001 production costs that appear in ETR-26. Line 4 of this exhibit, "Sales" contains the GWH values for net area requirements shown in Exhibit__(LC-7). Baron Exhibit__(LC-9) contains page 1 of ETR-26, which matches the detailed production cost calculations for 2001 (adjusted for load factor) in Exhibit__(LC-8). The net area requirements data in Exhibit__(LC-7) and Exhibit__(LC-8) (supporting ETR-26) is identical to the monthly "To Area" data from the Entergy 2001 ISBs. The only exception to this is a correction to the EAI entry to reflect an error in the mWh data included in the ISB data for the first six months of 2001. This error was addressed by LPSC witness Lane Kollen in his direct testimony in Docket No. EL01-88 [LPSC Exhibit LC-8 at page 49, lines 3 through 9.] The error was due to the inadvertent inclusion of co-owner energy in the EAI "To Area" entry in the ISB).

1 Baron Exhibit__(LC-10) shows the monthly ISB "To Area" values for each
2 Operating Company and the correction for the EAI entry. As can be seen, the
3 values for net area requirements used to calculate ETR-26 match the ISB data for
4 each Company, except EAI, which has the correction. Also shown in Baron
5 Exhibit__(LC-10) are 2001 FERC Form 1 data for annual energy using Entergy's
6 new methodology, presented in the May 29, 2007 bandwidth calculations. As can
7 be seen, none of the values developed using Entergy's new methodology match the
8 data used in ETR-26 for 2001. The methodology used to calculate "net area
9 requirements" in exhibits ETR-26 and ETR-28 is indisputably the "To Area" mWh
10 data from the monthly ISBs, not the data from FERC Form 1, page 401a.
11
12 **Q. What is the impact of using the ISB data versus the FERC Form 1 data relied**
13 **on in the Company's bandwidth calculations?**
14
15 A. Entergy witness Louiselle, in his Direct Testimony in this case (Exhibit ESI-6)
16 provides a calculation in his Table 5 on page 48.
17
18 **Q. Mr. Louiselle, in his November 16, 2007 testimony in this case, states that the**
19 **2006 ISB "to Area" mWh amounts contain some non-RQ sales. He further**
20 **argues that, if the ISB data are to be used to calculate the energy allocation**
21 **factor ("ER"), then either these sales must be removed from the ISB data or**

that the revenue from these sales should not be included as a revenue credit in the bandwidth calculation. Do you agree with his position on this issue?

A. No. First, as I will discuss subsequently, the Company has previously stated in Docket No. ER03-583 that mWh sales to third parties that are included in an Operating Company's load responsibility are "requirements" sales. As Mr. Louiselle explains in his testimony in this case, an EOC's load responsibility is derived from the "To area" data in the monthly ISBs. Therefore, all of the sales included in the "To Area" mWh data from the ISBs are requirements sales and should be included in the calculation of the energy allocation factor ("ER") used to allocate variable production costs. This is consistent with the methodology used in ETR-26 and ETR-28.

While conceptually, if non-RQ mWh energy is included in the mWh amounts used to allocate variable production costs, then the revenues from these sales would not be credited in the bandwidth calculation via variable RC (Revenue Credits) in Section 30.12 of Schedule MSS-3, the tariff does not permit the Company to unilaterally adjust off-system sales revenues. The Commission requires the Company to use the methodology of ETR-26 and ETR-28 to perform the bandwidth calculations. The Commission has previously stated this position in its

November 2006 Order on the Company's compliance tariff in this case. In paragraph number 62 of the Commission's November 17, 2006 Order in Docket EL01-88-004, the Commission reiterated that:

> **"In Opinion No. 480, the Commission found that "[f]uture production cost comparisons among the Operating Companies should follow the methodology in Exhibit ETR-26."**

In paragraph number 69 of the November 17, 2006 Order, the Commission stated:

> **"We will deny Entergy's request to make adjustments to the methodology reflected in Exhibits ETR-26 and ETR-28. This is a compliance filing and Entergy must comply with the requirements of Opinion Nos. 480 and 480-A. Future changes, however, to the methodology set forth in Exhibits ETR-26 and ETR-28 will not be automatic. Any time Entergy seeks to make a change, e.g., a change to return on equity, it must make a section 205 filing with the Commission."**

Q. On page 49 of Mr. Louiselle's Direct Testimony (ESI Exhibit ETR-6), he presents a bandwidth calculation (his Table 6) that incorporates ISB data for the ER factor, but also makes an offsetting adjustment to reduce off-system revenue credits ("RC") to remove revenues associated with the sales included in the ISB data. Is this a proper bandwidth calculation?

A. No. It is improper because it is inconsistent with the methodology used in Exhibits ETR-26 and ETR-28. Entergy cannot unilaterally make changes to this methodology without making a Section 205 filing with the Commission.

1 **Q. What if there is a "mismatch," as argued by Mr. Louiselle?**

2

3 A. If, there is a problem with the application of the methodology used in ETR-26 and
4 ETR-28 with regard to the calculation of the ER factor in the bandwidth
5 calculation, Entergy is required to make a Section 205 filing to correct this
6 problem, and can only do so prospectively (i.e., the Company cannot now correct
7 this problem for 2006).

8

9 **Q. Did Entergy include off-system sales made directly by EAI in the ISB "To**
10 **Area" data used to develop the energy allocation factor ("net area**
11 **requirements") in Exhibit ETR-28?**

12

13 A. Yes. In response to a Commission Staff data request in this case (Staff 1-1) asking
14 whether there was a mismatch in the bandwidth calculation between net area load
15 and revenue credits, Mr. Louiselle states (in part (a) of the response) that "there
16 may have been such sales by EAI reflected in Exhibit ETR-28." In fact, there were
17 such sales included in the 12 month ending August 31, 2002 test period used to
18 calculate busbar production costs in Exhibit ETR-28. During this period, EAI
19 directly made numerous opportunity sales that were included in its load

responsibility and in the EAI "To Area" mWh energy used to develop net area requirements.

In response to LPSC 9-1, submitted in Docket No. ER03-583, Entergy provided a listing of sales, by date, made directly by EAI using the capacity made available by the expiration of a wholesale power contract with the City of North Little Rock. These sales, which began on July 1, 2002, were included in EAI's "load shape for System Agreement purposes," according to the data response.[11] This means that the sales, which are off-system opportunity sales, are included in the net area requirements energy calculation used in the development of ETR-28. I have attached the non-confidential portion of the data response as Baron Exhibit__(LC-11).

Q. Were there any adjustments to remove FERC account 447 off-system sales revenues associated with these sales from the revenue credit in the ETR-28 production cost analyses?

A. No. This was confirmed by Mr. Louiselle in his January 22, 2007 deposition in this case (at transcript page 128 lines 7 to 22 and page 129, lines 1 to 2). Mr. Louiselle testified as follows:

Q. Have you made an inquiry as to whether any of the companies were making sales to so-called nonrequirements customers in any of the years covered by your two-exhibits?

A. Well, I have personal knowledge that ELL and ENO were not, and I don't believe EGS, Entergy Gulf States, was making any such sales either. They had requirements sales, but I do not believe they had any opportunity sales.

Q. I take it there was no correction or adjustment – let me restate. I take it there was no specific adjustment in ETR-26 or 28 to remove revenues from off-system sales, is that right, from operating company off-system sales?

A. ETR-26 and 28 credited all nonrequirements sales revenue in the calculation of the bus bar production costs, and that information was taken directly from the Form 1.

Q. Okay. Now, the question was, there's no adjustments to not credit it; is that right?

A. That's correct.

The methodology used in Exhibit ETR-28 did include off-system sales in the net area requirements (energy allocation factor) and at the same time included the revenues from those sales as a revenue credit to EOC production costs.

Q. Mr. Louiselle argues in his testimony in this case that opportunity or non-requirements sales made directly by an EOC and included in its load responsibility (and "To Area" mWh energy) should be removed from the

[11] This is consistent with the standard practice of Entergy, according to Mr. Louiselle, in his direct testimony of November 16, 2007 in this case on page 40, beginning at line 15.

calculation of the "ER" energy allocation factor because they are not "requirements" sales. Is this consistent with the position that the Company took in Docket ER03-583 for these types of direct EOC opportunity sales?

A. No. In that case, the Company consistently argued that these opportunity sales were, in fact, requirement sales of the EOC making the sale. Entergy argued that if such opportunity sales to third parties were included in the EOC's hourly load shape (the basis for the ISB "To Area" mWh data at issue in this case), then these sales constituted "requirements" sales of the EOC for "System Agreement" purposes.[12] These "purposes," included the System Agreement Section 3.05 "right of first refusal" and the calculation of load responsibility for Rate Schedules MSS-1 and MSS-2.

This issue was also addressed by Mr. Louiselle in his testimony in Docket No. ER03-583. In his rebuttal testimony in that case [(excerpt attached as Baron Exhibit__(LC-12)], Mr. Louiselle testified as follows, regarding the issue of individual Operating Company off-system sales:

> **The fallacy in Mr. Baron's position is that as long as the sale to a customer, whether retail or wholesale, is included in the Operating Company's load shape, that load is part of that Company's "requirements." A load is included in the Company's load shape and its "requirements" under Section 3.05 if that load is counted in**

[12] Including mWh energy from these sales in the hourly load shape of the EOC means that they are included in the "To Area" energy (net area requirements) and also used to calculate load responsibility.

calculating a Company's load responsibility ratio. Thus, any sale by EAI would be included in its load shape and would not involve excess generating capacity. (Rebuttal Testimony at pages 20 and 21).

Q. IS A WHOLESALE SALE BY AN OPERATING COMPANY SUCH AS EAI AN "OFF-SYSTEM" SALE?

A. No. As long as the sale is reflected in the selling Company's load shape for responsibility ratio calculation purposes, it is by definition not an "off-system" sale. (Rebuttal Testimony at page 22).

The specific sales that were at issue in that case were opportunity sales that were made by EAI. As I have shown, these sales were made by EAI in the 12 months ending August 2002 test period used in the development of busbar production costs in Exhibit ETR-28. The revenues from these sales were also reflected in the revenue credits included in the busbar production cost calculation.

Q. Did EAI make such sales in 2001, the period covered by the busbar analysis used in Exhibit ETR-26?

A. Based on my review of transcripts in Docket No. ER03-583, it appears that such sales were made in 2001 and as early as 1999. Baron Exhibit__(LC-13) contains hearing transcript pages 6054 to 6057 in Docket No. ER03-583. These pages are transcripts of a direct examination of Mr. Louiselle on the issue of the inclusion of

1 off-system sales in the load shape (and thus the "To Area" mWh data) of EAI in
2 2001 and earlier years. On page 6056 at lines 8 and 9, Mr. Louiselle testifies that
3 this practice "had been going on for years. It's just normal practice." At any rate,
4 the last entry in ETR-26 is a calculation of EOC busbar production costs for the 12
5 months ending August 31, 2000 (the period covered by ETR-28).
6
7 Therefore, this methodology was used in the development of Exhibit ETR-26 for
8 2002 and most likely during 2001 and prior years as well.
9
10 **Q. Is the Company taking a different position on the character of these EOC**
11 **Company specific opportunity sales in this case?**
12
13 A. Yes. In this case, Mr. Louiselle is taking the position that these opportunity sales
14 are not "requirements," at least for Rate Schedule MSS-3 purposes. He does
15 continue to argue that these opportunity sales are "requirements" sales for System
16 Agreement Rate Schedules MSS-1, MSS-2, MSS-6 and Section 3.05 of the
17 Agreement; just not for System Agreement Rate Schedule MSS-3, where he says
18 they should be considered non-requirements sales. It makes no sense, and there is
19 no basis to argue, as the Company does, that there opportunity sales are both
20 "requirements" and "non-requirements" sales, depending on the System

1 Agreement rate schedule. The Company's inconsistent position on the
2 characterization of these sales is clearly not reasonable.
3
4 **Q. Should the bandwidth calculation for 2006 be revised to incorporate the ISB**
5 **"To Area" mWh data that was used in the development of ETR-26 and ETR-**
6 **28?**
7
8 A. Yes. The bandwidth calculation for 2006 should be revised to be consistent with
9 ETR-26 and ETR-28, which requires the use of ISB "To Area" load data for the
10 development of the "ER" factor.
11
12

IV. INTERRUPTIBLE LOAD ISSUES

Q. Would you discuss the adjustment that you have developed to adjust the bandwidth calculation to be consistent with the results of Commission Order Nos. 468 and 468-A?

A. Yes. In Order Nos. 468 and 468-A, the Commission found that the 12 CP load responsibility used in the calculation of System Agreement Rate Schedules MSS-1, MSS-5 and Joint Account Purchases should be adjusted to remove each Operating Company's interruptible load. As noted in paragraph 62 of the Commission's March 8, 2004 Opinion (No. 468),

> **The Commission thus traditionally has not 'allocated' the cost of facilities to interruptible load.**

In Opinion No. 468-A, at footnote 7, the Commission explains that "If the Commission were to require utilities to allocate costs it interruptible customers in the same manner that utilities allocate costs to firm customers, then the Commission effectively would be allowing interruptible and firm customers to be charged the same rate, notwithstanding the differences in the service each takes (i.e., the differences in the firmness of the service each takes). In the bandwidth calculation, a

12 CP allocation factor is used to allocate fixed production costs (except for nuclear costs) to Operating Companies. The bandwidth calculation is based on a traditional cost allocation framework, wherein all of the System's production costs are allocated to Operating Companies using traditional cost of service methodologies. This is true except for the recognition of the fact that Operating Companies have difference amounts of interruptible load. The Commission found in Opinions 468 and 468-A, as noted above, that interruptible load is not the same as firm load, consistent with longstanding cost allocation principles.

Q. Do the actual costs for each Operating Company reflect the amount of interruptible load on their respective Systems?

A. Yes. In 2006, the year on which the bandwidth calculations are based, each Operating Company paid MSS-1, MSS-5 (off-system sales margin credits) and Joint Account Purchases based on each EOC's respective load responsibility, adjusted to remove interruptible load. Because Joint Account Purchases were allocated on the basis of load responsibility, adjusted for interruptible load, the 2006 actual amounts of sales and purchases to the exchange, pursuant to MSS-3 are also affected by interruptible load.

As a result, the current MSS-3 bandwidth calculation compares actual costs that include an interruptible load adjustment to allocated costs that ignore interruptible load. As a result, the bandwidth payments and receipts partially reverse the effect of the Commission's decision in Opinion Nos. 468 and 468-A.[13]

Q. In its decision in Opinion Nos. 468 and 468-A, the Commission ordered that interruptible load be removed from the calculation of load responsibility used to allocate costs in Rate Schedule MSS-1, which only equalizes reserves and is priced using only the cost of oil and gas units on the System. Is it reasonable to remove interruptible load from the 12 CP allocation factor used in the bandwidth calculation, which also allocates the cost of coal units, as well as oil and gas units on the System?

A. Yes. In Docket No. EL00-66, *et al.* in which the Commission issued Opinion Nos. 468 and 468-A, the issue before the Commission was the allocation of fixed, demand related costs associated with Rate Schedule MSS-1, which allocates costs associated with reserves on the System. Though this case concerned Rate Schedule MSS-1, which prices the reserve deficits or excesses for each EOC based on the average cost of oil and gas capacity, the principle that the Commission relied on in its decision

[13] Effectively, through the operation of the bandwidth calculation, the lower actual costs that an EOC incurs due to interruptible load (via MSS-1, MSS-5 and Joint Account Purchases) are compared to allocated System costs, which ignore an EOC's interruptible load.

case is that interruptible load is not responsible for capacity costs and should not be reflected in the allocation of fixed demand related production costs.[14] In Opinion Nos. 468 and 468-A, the Commission only applied this principle via Rate Schedules MSS-1, MSS-5 and Joint Account Purchases; however, the principle continues to be applicable in any Entergy cost allocation analysis, including the bandwidth calculation at issue in this case. As noted in Opinion No. 468, "Because the utility incurs the cost of these facilities to meet the peak demand of its firm customers, those customers should pay for the facilities." (emphasis added). The application of this principle in this bandwidth calculation case is to compute the "DR" allocation factor based on 12 CP demands without interruptible load.

Q. Hasn't the Commission previously rejected the LPSC's request to adjust the 12 CP demand allocation factor to remove interruptible load?

A. Yes, even though, as the presiding judge found, all the parties in the case agreed that "the issue of whether interruptible loads should be included in calculating load responsibility ratios will be decided in another proceeding now on appeal before the Commission."[15]

[14] Though the deficit reserves are priced on the basis of oil and gas capacity, all capacity (gas, oil, coal, nuclear, hydro, purchases) are being "allocated" in the reserve equalization calculation.
[15] See Initial Decision, Docket No. EL 01-88, 106 F.E.R.C. P 63,012 at fn. 15. This appeal ultimately led to Opinion Nos. 468 and 468-A.

1 I have been advised by LPSC counsel, however, that the wording of the order
2 establishing this docket and the order dismissing the Arkansas Public Service
3 Commission complaint may require the LPSC to raise the issue in this docket so as
4 not to waive its rights with respect to an interruptible load adjustment.
5
6 The inputs that include interruptible load are inconsistent with the inputs that
7 exclude interruptible load, which are part of the cost allocations for MSS-1, MSS-
8 5 and Joint Account Purchases. Additionally, because the Commission has held
9 that interruptible loads do not cause Entergy to incur capacity costs, including
10 interruptible loads in the capacity cost allocation portion of the formula is not just
11 and reasonable. Therefore, the LPSC determined that it would be appropriate to
12 raise the issue, even though the Commission rejected it as inconsistent with ETR-
13 26 and ETR-28.
14
15 In the event that the Commission finds that such an issue is appropriate in this
16 docket, I am presenting an adjustment to the demand allocation factor, "DR" to
17 reflect the removal of interruptible load from each EOC's load responsibility. The
18 "DR" factor is an "input" into the bandwidth calculation. The LPSC's contention in
19 this case is that the Company used an incorrect input factor. In fact, the 12 CP
20 allocation factor that Entergy used in the bandwidth calculations is the transmission

allocator used for Rate Schedule MSS-2 (transmission equalization). It is not used for production costs, except in the bandwidth calculations. All other System Agreement rate schedules that allocate production costs use 12 CP demands without interruptible loads.

Q. Would you please explain the methodology that you have used to adjust the 2006 12 CP demand data to remove interruptible load?

A. Yes. I have used the 12 CP demands, without interruptible load, for each Operating Company that is shown for the 12 months ended December 31, 2006 contained in the Entergy Intra-System Bill for the month of January 2007. This is the same source as used by Entergy in computing the bandwidth calculations. I have attached a copy of this page from the January 2007 ISB as Exhibit__(LC-14). Table 2 shows the results of the bandwidth calculation used a "DR" allocation factor that excludes interruptible load. Also shown is a comparison to the payments and receipts for each EOC calculated by Entergy in its compliance filing. Baron Exhibit__(LC-15) contains the bandwidth calculation using the DR factor, excluding interruptible load.

1

Table 2
Impact of Removing Interruptible Load from the 12 CP Allocation Factor
(Bandwidth payments and receipts)

	As Filed	Interuptible Load Removed	Difference
EAI	(251,731)	(255,108)	(3,377)
EGS	120,103	114,022	(6,081)
ELL	91,051	102,598	11,547
EMI	40,577	38,488	(2,089)
ENO	0	0	0

2

3

4 **Q. Does that complete your testimony?**

5

6 A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Stephen J. Baron

Sworn to and subscribed before me on this
4th day of February 2008.

Jessica K. Inman

Notary Public

JESSICA K. INMAN
MY COMMISSION EXPIRES
NOTARY PUBLIC
JULY 31ST, 2011
CHEROKEE COUNTY, GA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.	)	DOCKET NO. ER07-956-000

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

EXHIBIT__(LC-2)

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	Clara WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
			Millennium Inorganic Chemicals Inc.		unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric, gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2008

Date	Case	Jurisdict.	Party	Utility	Subject
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Revenue Incr, Off-System Sales margin rate treatment
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

EXHIBIT__(LC-3)

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Adjustments required to impute 164 mW ISES 2 Capacity to EAI
(adjustments to specified lines of Op Co Input tab of the RCPE "Bandwidth" model)

	Adjustment Line	EAI	EGS	ELL	EMI	ENO
Adjustments to Add ISES 2 Costs & Impacts						
Plant in Service	Line 10	105,723	-	-	-	-
Accumulated Depreciation	Line 60	53,620	-	-	-	-
Average Fuel Inventory	Line 82	4,740	-	-	-	-
ADIT	Line 89	17,329	-	-	-	-
M&S - Beg Balance	Line 92	1,593	-	-	-	-
M&S - End Balance	Line 93	1,720	-	-	-	-
Total Steam O&M	Line 115	3,528	-	-	-	-
PROMOD Results w/ISES		363,539	2,649,877	1,732,970	850,489	116,908
PROMOD Results Base Case		402,998	2,656,274	1,735,957	851,800	116,948
Net Adjustment - Include in Fuel	Line 126	(39,460)	(6,397)	(2,987)	(1,311)	(40)
Calculated MSS-1 w/ISES		23,526	20,792	(23,637)	(8,295)	(12,387)
Calculated MSS-1 Base Case		27,467	18,999	(24,799)	(9,044)	(12,623)
Net Adjustment - Include in PP	Line 143	(3,941)	1,793	1,163	749	236
Depreciation Expense	Line 162	4,017	-	-	-	-
A&G Expense	Line 177	302	-	-	-	-
Production Labor	Line 181	1,598	-	-	-	-
Total Labor	Line 187	1,598	-	-	-	-
Taxes other than Income	Line 195	14	-	-	-	-

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

EXHIBIT__(LC-4)

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

ENTERGY SERVICES, INC.
ENTERGY SYSTEM AGREEMENT SERVICE SCHEDULE MSS-3 2007 FILING IN COMPLIANCE WITH FERC OPINION NOS. 480 AND 480-A
FOR THE YEAR ENDED DECEMBER 31, 2006
(000's)

Section 30.11: Rough Production Cost Equalization

Line No.		Formula / Reference	System	EAI	EGS	ELL	EMI	ENOI
1	D = Disparity							
2	D = [(PC / APC) - 1] * 100%							
	where:							
3	PC = Actual Production Cost	A.2 Ln 26 =	6,578,145	1,038,407	2,492,223	1,850,747	963,022	233,746
4	APC = Average Production Cost	A.5 Ln 137 =	6,578,145	1,474,044	2,284,898	1,693,420	887,622	238,161
5	$DD = Dollar Deviation from Average ($)	Ln 3 - Ln 4 =	0	(435,637)	207,325	157,327	75,400	(4,415)
	Determination of Average Production Cost outside the 11% Band							
6	D = Disparity	[(Ln 3 / Ln 4) - 1] * 100% =		-29.55%	9.07%	9.29%	8.49%	-1.85%
	where:							
7	PCBB = Production Cost Below Band							
8	PCBB = If %DD < -11%, then PCBB equals [(%DD + 11%) / %DD] * $DD, otherwise zero.	If Ln 6 < -11%, Then (Ln 6 + 11%) / Ln 6 * Ln 5), Otherwise 0 =		(273,471)	0	0	0	0
	or,							
9	PCAB = Production Cost Above Band							
10	PCAB = If %DD > 11%, then PCAB equals [(%DD - 11%) / %DD] * $DD, otherwise zero.	If Ln 6 > 11%, Then (Ln 6 - 11%) / Ln 6 * Ln 5), Otherwise 0 =		0	0	0	0	0
11	% DD = Percent Dollar Deviation at the Band	(Ln 5 - Ln 8) / Ln 5 =		-11.00%	9.07%	9.29%	8.49%	-1.85%
	Equalization							
	Step 1							
12	Receipts of the company with the highest disparity up to the level of the sum of the payments or until the receiving company's adjusted disparity matches the disparity of the next highest company.			(3,734)	0	3,734	0	0
13	D^1 = Disparity after Step 1	(Ln 5 - Ln 12) / Ln 4 =		-29.30%	9.07%	9.07%	8.49%	-1.85%
	Step 2							
14	Remaining (payments), if any, become the receipts of the two companies equally as a percent deviation up to the level of the distribution of the remaining (payments) or until these two companies' adjusted disparity matches the disparity of the third highest company.			(23,159)	13,337	9,822	0	0
15	D^2 = Disparity after Steps 1 and 2	(Ln 5 - Ln 12 - Ln 14) / Ln 4 =		-27.73%	8.49%	8.49%	8.49%	-1.85%
	Step 3							
16	Remaining (payments), if any, become the receipts of the three companies equally as a percent deviation up to the level of the distribution of the remaining (payments) or until the disparity of these three companies matches the disparity of the fourth highest company.			(246,578)	115,774	85,804	45,000	0
17	D^3 = Disparity after Steps 1, 2 and 3	(Ln 5 - Ln 12 - Ln 14 - Ln 16) / Ln 4 =		-11.00%	3.42%	3.42%	3.42%	-1.85%
	Step 4							
18	Remaining (payments), if any, become the receipts of the four companies equally as a percent deviation up to the level of the distribution of the remaining (payments) or until the disparity of the four companies matches.			0	0	0	0	0
19	D^4 = Final Disparity	(Ln 5 - Ln 12 - Ln 14 - Ln 16 - Ln 18) / Ln 4 =		-11.00%	3.42%	3.42%	3.42%	-1.85%
	Step 5				(Payments) / Receipts			
20	**Annual Rough Production Cost Equalization**	Ln 12 + Ln 14 + Ln 16 + Ln 18 =	0	(273,471)	129,111	99,360	45,000	0
21								

ENTERGY SERVICES, INC.
ENTERGY SYSTEM AGREEMENT SERVICE SCHEDULE MSS-3 2007 FILING IN COMPLIANCE WITH FERC OPINION NOS. 480 AND 480-A
FOR THE YEAR ENDED DECEMBER 31, 2006
(000's)

Line No.		Formula / Reference	System	EAI	EGS	ELL	EMI	ENO
	Section 30.12: Actual Production Cost [1]							
22	**PC = Actual Production Cost**							
23	PC = VPC + FPC							
	where:							
24	VPC = Variable Production Cost	A.3 Ln 67 =	5,468,496	760,143	2,131,334	1,562,174	819,514	195,331
25	FPC = Fixed Production Cost	A.4 Ln 121 =	1,109,649	278,264	360,890	288,572	143,508	38,415
26	**PC = Actual Production Cost**	Ln 24 + Ln 25 =	6,578,145	1,038,407	2,492,223	1,850,747	963,022	233,746
27	**VPC = Variable Production Cost**							
28	VPC = VPRB * (CM + F) + VPX							
	where:							
29	**VPRB = Variable Production Rate Base [2]**							
30	VPRB = NPP - NAD - (ADIT * NPPR)							
	where:							
31	NPP = Nuclear Production Plant in Service as recorded in FERC Plant Accounts 320 through 325 and FERC Account 101.1 excluding Asset Retirement Obligations (ARO) recorded in FERC Plant Account 326, if any	B.1 Ln 7 =		2,104,624	3,224,822	2,925,277	-	-
32	NAD = Nuclear Accumulated Provisions for Depreciation and Amortization excluding ARO associated with NPP above, as recorded in FERC Account 108 and 111, (consistent with the accounting relating to SFAS 143 approved by the retail regulator having jurisdiction over the Company, unless the FERC determines otherwise)	B.2 Ln 57 =		932,073	1,998,248	1,421,799	-	-
33	ADIT = Net Accumulated Deferred Income Taxes (ADIT) recorded in FERC Accounts 190, 281 and 282 (as reduced by amounts not generally and properly includable for FERC cost of service purposes, including but not limited to, SFAS 109 ADIT amounts and ADIT amounts arising from retail ratemaking decisions plus Accumulated Deferred Investment Tax Credit - 3% portion only recorded in FERC Account 255	B.2 Ln 89 =		703,209	912,136	847,888	330,402	103,103
34	NPPR = Ratio of Nuclear Production Plant to Total Plant excluding Intangible Plant [3]							
35	NPPR = NPP / PXI							
	where:							
36	NPP = Nuclear Production Plant in Service	Ln 31 =		2,104,624	3,224,822	2,925,277	-	-
37	PXI = Electric Plant in Service which includes the sum of the Company's Production, Transmission, Distribution and General Plant in Service recorded in FERC Plant Accounts 310 through 399, Property under Capital Lease as recorded in FERC Account 101.1 and Completed Construction not yet Classified as recorded in FERC Account 106 excluding ARO, if any	B.1 Ln 37 =		6,357,608	8,615,502	6,630,507	2,575,669	638,065
38	NPPR = Ratio of Nuclear Production Plant to Total Plant excluding Intangible Plant	Ln 36 / Ln 37 =		33.10%	37.43%	44.12%	0.00%	0.00%
39	**VPRB = Variable Production Rate Base**	Ln 31 - Ln 32 - (Ln 33 * Ln 38) =		939,789	885,161	1,129,390	-	-
40	**CM = The weighed average cost of capital determined as follows:**							
41	CM = (DR * i) + (PR * p) + (ER * c)							
	where:							
42	DR = Ratio of Debt Capital and Preferred Stock with tax deductible dividends (QUIPS) at Dec. 31 of the previous year	B.3 Ln 103 =		41.10%	50.18%	48.92%	53.58%	56.02%
43	PR = Ratio of Preferred Stock without tax deductible dividends at Dec. 31 of the previous year	B.3 Ln 105 =		4.36%	1.10%	3.26%	3.45%	5.06%
44	ER = Ratio of Common Stock at Dec. 31 of the previous year	B.3 Ln 106 =		54.54%	48.72%	47.82%	42.97%	38.92%
45	i = Average embedded cost of debt capital and preferred stock with tax deductible dividends (QUIPS) outstanding at Dec. 31 of the previous year	B.3 Ln 102 =		6.36%	6.02%	7.08%	5.95%	5.86%
46	p = Average embedded cost of preferred stock outstanding at Dec. 31 of the previous year	B.3 Ln 104 =		5.99%	9.63%	7.50%	5.69%	4.82%
47	c = Simple average of the Companies' approved retail return on common equity rates at Dec. 31 of the previous year	B.3 Ln 109 =		10.75%	10.75%	10.75%	10.75%	10.75%
48	**CM = Weighed avg. cost of capital**	(Ln 42 * Ln 45)+(Ln 43 * Ln 46)+(Ln 44 * Ln 47) =		8.74%	8.36%	8.85%	8.00%	7.71%

[1] All Rate Base, Revenue and Expense items shall be based on the actual amounts on the Company's books on the Company's books for the twelve months ended December 31 of the previous year as reported in FERC Form 1 or such other supporting data as may be appropriate for each Company; and shall include certain retail regulatory adjustments pursuant to the production cost methodology set forth in Exhibit ETR-26/ETR-28 filed in Docket No. EL01-88-001, including but not limited to: (1) the Deregulated Asset Plan adjustment for EGS, (2) the regulated portion (70%) of River Bend for EGS, (3) repricing of energy associated with the Vidalia purchase power contract for ELL based on the average annual Service Schedule MSS-3 rate paid by ELL, including the exclusion of the income tax savings of the Vidalia purchase power contract from ADIT and reflecting the reversal of the Vidalia capital transaction, and the debt rate associated with the Waterford 3 Sale/Leaseback for ELL, and (4) exclusion of the EAI and EMI retail approved Grand Gulf Accelerated Recovery Tariff effects on purchased power on EAI's and EMI's production cost.

[2] Rate Base values shall be based on the actual balances on the Company's books as of December 31 of the previous year except for Fuel Inventory, Materials & Supplies and Prepayments which shall be based on the average of the beginning and ending actual balances on the Company's books.

[3] Plant ratios shall be determined based on plant in service balances exclusive of associated ARO as of December 31 of the previous year.

ENTERGY SERVICES, INC.
ENTERGY SYSTEM AGREEMENT SERVICE SCHEDULE MSS-3 2007 FILING IN COMPLIANCE WITH FERC OPINION NOS. 480 AND 480-A
FOR THE YEAR ENDED DECEMBER 31, 2006
(000's)

Line No.		Formula / Reference	EAI	EGS	ELL	EMI	ENO
49	**F = Federal & State Income Taxes determined from the following:**						
50	F = T / (1 - T) * (CM - (DR * i)						
	where:						
51	T = f + s - fs when federal tax is not deductible in computing state tax, and						
52	T = (f + s - 2fs) / (1 - (fs)) when federal tax is deductible in computing state tax, and						
53	f = Federal Income Tax Rate	B.3 Ln 111 =	35.00%	35.00%	35.00%	35.00%	35.00%
54	s = State Income Tax Rate [4]	B.3 Ln 112 =	6.50%	4.00%	8.00%	5.00%	8.00%
55	T = EAI and EMI	(Ln 53 + Ln 54 - (Ln 53 * Ln 54) =	39.23%			38.25%	
56	T = EGS, ELI & ENO	(Ln 53 + Ln 54) - 2 * (Ln 53 * Ln 54)) / [1 - (Ln 53 * Ln 54)] =		36.71%	38.48%		38.48%
57	**F = Federal & State Income Tax**	(Ln 55 / (1 - Ln 55) * (Ln 48 - (Ln 42 * Ln 45)) =	3.95%			2.98%	
58	**F = Federal & State Income Tax**	(Ln 56 / (1 - Ln 56) * (Ln 48 - (Ln 42 * Ln 45)) =		3.10%	3.37%		2.77%
59	**VPX = Variable Production Expense**						
60	VPX = NPOMNF + FE + PURP - RC + NDE						
	where:						
61	NPOMNF = Nuclear Production O&M Non-Fuel Expense, recorded in FERC Accounts 517 through 532 excluding Nuclear Fuel in FERC Account 518	B.3 Ln 140 =	154,963	39,227	103,588	0	0
62	FE = Production O&M Fuel Expense recorded in Accounts 501, 518 & 547 and Net Hedging Costs as recorded in Account	B.3 Ln 133 =	180,456	737,049	732,786	376,110	69,125
63	PURP = Purchased Power Expense recorded in FERC Account 555, but excluding payments made pursuant to Section 30.09(d) of this Service Schedule	B.3 Ln 146 =	616,415	1,289,930	755,033	491,088	217,448
64	RC = Revenue Credits resulting from revenue received from customers outside the Company's Net Area for Production Service recorded in FERC Account 447, but excluding payments made pursuant to Section 30.09(d) of this Service Schedule	B.4 Ln 158 =	381,834	92,036	222,520	47,684	91,242
65	NDE = Nuclear Depreciation and Amortization Expense associated with (NPP) as recorded in Accounts 403 and 404 Decommissioning Expense, as approved by Retail Regulators, unless the jurisdiction for determining the depreciation and/or decommissioining rate is vested in the FERC under otherwise applicable law	B.4 Ln 171 =	70,884	55,724	55,276	0	0
66	**VPX = Variable Production Expense**	(Sum of Lines 61 thru 63) - Ln 64 + Ln 65 =	640,884	2,029,894	1,424,163	819,514	195,331
67	**VPC = Variable Production Cost**	Ln 39 * (Ln 48+ [Ln 57 or Ln 58]) + Ln 66 =	760,143	2,131,334	1,562,174	819,514	195,331
68	**FPC = Fixed Production Cost**						
69	FPC = FPRB * (CM + F) + FPX - [(ITC / TX) * PPR]						
	where:						
70	**FPRB = Fixed Production Rate Base**						
71	FPRB = PPXN + CME - ADXN + FI - (ADIT * PPRXN) + [(GP - GAD + IP - IAA) * PLR] + (MS + P) * PPREG						
	where:						
72	PPXN = Production Plant in Service excluding Nuclear Plant recorded in FERC Plant Accounts 310 through 317, Accounts 330 through 346, and FERC Account 101.1 excluding ARO recorded in FERC Plant Accounts 317 and 337, if any	B.1 Ln 18 =	941,649	1,740,884	850,392	769,236	170,516
73	CME = Coal Mining Equipment in FERC Plant Account 399 owned by the Company	B.1 Ln 35 =	11,183	-	-	15,461	-
74	ADXN = Accumulated Provision for Depreciation and Amortization associated with PPXN and CME above, as recorded in FERC Account 108 and 111, excluding ARO associated with PPXN and CME, if any (consistent with the accounting relating to SFAS 143 approved by the retail regulator having jurisdiction over the Company, unless the FERC determines otherwise)	B.2 Ln 71 =	660,267	1,265,759	515,755	468,210	169,298
75	FI = Fuel Inventory recorded in FERC Account 151	B.2 Ln 82 =	19,213	64,692	-	5,365	-
76	ADIT = Net Accumulated Deferred Income Taxes plus Accumulated Deferred Investment Tax Credit	B.2 Ln 89 =	703,209	912,136	847,888	330,402	103,103
77	PPRXN = Ratio of Production Plant in Service excluding Nuclear Plant to Total Plant excluding Intangible Plant						
78	PPRXN = PPXN / PXI						
	where:						
79	PPXN = Production Plant in Service excluding Nuclear Plant	Ln 72 =	941,649	1,740,884	850,392	769,236	170,516
80	PXI = Electric Plant in Service excluding Intangible Plant	Ln 37 =	6,357,608	8,615,502	6,630,507	2,575,669	638,065
81	PPRXN = Ratio of Production Plant ex. Nuclear to Total ex. Intangible	(Ln 79 / Ln 80) =	14.81%	20.21%	12.83%	29.87%	26.72%
82	GP = General Plant in Service recorded in FERC Plant Accounts 389 through 398 excluding ARO, if any	B.1 Ln 32 =	118,227	185,762	122,311	118,066	24,374
83	GAD = General Plant Accumulated Provision for Depreciation, as recorded in FERC Account 108 excluding ARO associated with GP above, if any, (consistent with the accounting relating to SFAS 143 approved by the retail regulator having jurisdiction over the Company, unless the FERC determines otherwise)	B.2 Ln 75 =	46,905	69,836	(24,109)	1,966	(2,728)
84	IP = Intangible Plant in Service recorded in FERC Plant Accounts 301 through 303	B.1 Ln 40 =	283,146	200,694	265,053	116,484	59,748
85	IAA = Intangible Plant Accumulated Provision for Amortization associated with IP above recorded in FERC Account 111	B.2 Ln 77 =	156,036	86,408	99,022	49,725	25,915

[4] The State Income Tax rate for EGS is the average of the rates for Louisiana and Texas.

ENTERGY SERVICES, INC.

ENTERGY SYSTEM AGREEMENT SERVICE SCHEDULE MSS-3 2007 FILING IN COMPLIANCE WITH FERC OPINION NOS. 480 AND 480-A

FOR THE YEAR ENDED DECEMBER 31, 2006

(000's)

Line No.		Formula / Reference	EAI	EGS	ELL	EMI	ENO
86	PLR = Ratio of Production Labor to Total Labor excluding A&G Labor [5]						
87	PLR = PL / LXAG						
	where:						
88	PL = Production Labor charged to O&M expense	B.4 Ln 184 =	96,877	65,028	74,502	15,118	3,349
89	LXAG = Total Labor charged to O&M Expense excluding A&G Labor	B.4 Ln 193 =	142,237	118,681	113,022	45,847	11,521
90	PLR = Ratio of Production Labor to Total Labor excluding A&G Labor	(Ln 88 / Ln 89) =	68.11%	54.79%	65.92%	32.98%	29.07%
91	MS = Materials and Supplies recorded in FERC Account 154	B.2 Ln 94 =	87,442	106,410	90,305	23,288	7,495
92	P = Prepayments as recorded in FERC Account 165	B.2 Ln 99 =	4,427	13,155	3,320	1,824	3,468
93	PPREG = Ratio of Production Plant in Service to Electric and Gas Plant in Service excluding Intangible Plant						
94	PPREG = PP / EGPXI						
	where:						
95	PP = Production Plant in Service as recorded in FERC Plant Accounts 310 through 346 and FERC Account 101.1 excluding ARO recorded in FERC Plant Accounts 317, 326 and 337, if any	B.1 Ln 19 =	3,046,273	4,965,706	3,775,669	769,236	170,516
96	EGPXI = Electric and Gas Plant in Service defined as PXI above plus Gas Plant as recorded in FERC Account 118 excluding ARO, if any	B.1 Ln 39 =	6,357,608	8,707,870	6,630,507	2,575,669	828,775
97	PPREG = Ratio of Prod. Plant to Electric & Gas Plant ex Intangible	(Ln 95 / Ln 96) =	47.92%	57.03%	56.94%	29.87%	20.57%
98	**FPRB = Fixed Production Rate Base**	Ln 72 + Ln 73 - Ln 74 + Ln 75 - (Ln 78 * Ln 81) + (Ln 82 - Ln 83 + Ln 84 - Ln 85) * Ln 90 + (Ln 91 + Ln 92) * Ln 97 =	386,808	549,795	485,131	290,969	(6,362)
99	**CM = Weighed average cost of capital**	Ln 48 =	8.74%	8.36%	8.85%	8.00%	7.71%
100	**F = Federal & State Income Tax**	Ln 57 or Ln 58 =	3.95%	3.10%	3.37%	2.98%	2.77%
101	**FPX = Fixed Production Expense**						
102	FPX = NFPOMXN + DEXN + [(AG + GDX + IAX) * PLR] + (OT * PPR)						
	where:						
103	NFPOMXN = Non-Fuel Production O&M Expense excluding Nuclear; i.e. costs recorded in FERC Accounts 500 through 514 plus Accounts 535 through 554 plus Account 556 less Accounts 501 and 547	B.3 Ln 123 =	47,439	69,660	58,972	49,910	7,614
104	DEXN = Depreciation and Amortization Expense associated with the plant investment in PPXN as recorded in FERC Account 403 and 404, as approved by Retail Regulators unless the jurisdiction for determining the depreciation rate is vested in the FERC under otherwise applicable law	B.4 Ln 165 =	31,386	42,017	26,787	13,949	6,188
105	AG = Administrative and General (A&G) O&M Expense recorded in FERC Accounts 920 through 935	B.4 Ln 177 =	141,874	178,153	146,604	75,062	56,442
106	GDX = General Plant Depreciation Expense recorded in FERC Account 403	B.4 Ln 173 =	10,420	12,187	6,252	4,799	1,312
107	IAX = Intangible Plant Amortization Expense recorded in FERC Account 404	B.4 Ln 175 =	20,121	20,615	16,210	9,547	4,705
108	PLR = Ratio of Production Labor to Total Labor excluding A&G Labor	Ln 90 =	68.11%	54.79%	65.92%	32.98%	29.07%
109	OT = Other Tax Expense recorded in FERC Account 408	B.4 Ln 195 =	75,599	131,249	61,168	63,126	27,232
110	PPR = Ratio of Production Plant to Total Plant excluding Intangible Plant						
111	PPR = PP / PXI						
	where:						
112	PP = Production Plant in Service	Ln 95 =	3,046,273	4,965,706	3,775,669	769,236	170,516
113	PXI = Electric Plant in Service excluding Intangible Plant	Ln 37 =	6,357,608	8,615,502	6,630,507	2,575,669	638,065
114	PPR = Ratio of Production Plant to Total ex. Intangible	(Ln 112 / Ln 113) =	47.92%	57.64%	56.94%	29.87%	26.72%
115	**FPX = Fixed Production Expense**	Ln 103 + Ln 104 + [(Ln 105 + Ln 106 + Ln 107) * Ln 108] + (Ln 109 * Ln 114) =	232,484	302,911	232,036	112,201	39,235
116	**ITC = Investment Tax Credit Amortization** recorded in FERC Account 411	B.4 Ln 197 =	4,192	5,521	2,968	1,326	354
117	TX = Composite Corporate After Tax Income Tax Rate						
118	TX = 1-T						
119	TX = Composite Corporate After Tax Income Tax Rate	(1 - Ln 55) or (1 - Ln 56) =	60.77%	63.29%	61.52%	61.75%	61.52%
120	PPR = Ratio Production Plant to Total ex. Intangible	Ln 114 =	47.92%	57.64%	56.94%	29.87%	26.72%
121	**FPC = Fixed Production Cost**	Ln 98 * (Ln 99 + Ln 100) + Ln 115 - [(Ln 116 / Ln 119) * Ln 120] =	278,264	360,890	288,572	143,508	38,415

[5] Labor ratios shall be determined based on the payroll expense for each Operating Company, including those payroll expenses billed to it by EOI and ESI, for the twelve months ended December 31 of the previous year.

ENTERGY SERVICES, INC.
ENTERGY SYSTEM AGREEMENT SERVICE SCHEDULE MSS-3 2007 FILING IN COMPLIANCE WITH FERC OPINION NOS. 480 AND 480-A
FOR THE YEAR ENDED DECEMBER 31, 2006
(000's)

Section 30.13: Average Production Cost

Line No.		Formula / Reference	System	EAI	EGS	ELL	EMI	ENOI
122	**APC = Average Production Cost**							
123	**APC = AVPC + AFPC**							
124	where:							
125	AVPC = Company's Allocation of the System's Variable Production Cost							
126	AVPC = SVPC * ER							
	where:							
127	SVPC = Sum of the Companies' Actual Variable Production Cost	Ln 24 =	5,468,496					
128	ER = Energy Ratio							
129	ER = Each Company's Annual Energy (Net Area Requirements less Non-Requirments Sales for Resale) divided by the sum of all Companies Annual Energy	B.4 Ln 204 =		22.28%	34.90%	25.90%	13.34%	3.58%
130	AVPC = Company's Allocation of the System's Variable Production Cost	Ln 127 * Ln 129 =	5,468,496	1,218,381	1,908,505	1,416,341	729,497	195,772
131	AFPC = Company's Allocation of the System's Fixed Production Cost							
132	AFPC = SFPC * DR							
	where:							
133	SFPC = Sum of the Companies' Actual Fixed Production Cost	Ln 25 =	1,109,649					
134	DR = Demand Ratio							
135	DR = The ratio for each Company of its 12 CP loads divided by the sum of all Companies' 12 CP loads as defined in Section 2.16 (a)	B.4 Ln 208 =		23.04%	33.92%	24.97%	14.25%	3.82%
136	AFPC = Company's Allocation of the System's Fixed Production Cost	Ln 133 * Ln 135 =	1,109,649	255,663	376,393	277,079	158,125	42,389
137	**APC = Average Production Cost**	Ln 130 + Ln 136 =	6,578,145	1,474,044	2,284,898	1,693,420	887,622	238,161

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

EXHIBIT__(LC-5)

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

SCHEDULE H - NET AREA REQUIREMENTS (GWH) 2002

	EAI	ELI	EMI	EGS	ENO	ENTERGY
NET AREA REQUIREMENTS	25,671	30,372	13,652	36,748	6,070	112,513

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

EXHIBIT__(LC-6)

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

COMPARISON OF ETR 28 "NET AREA RESPONSIBILITY TO ISB "TO AREA" MWH
For the Twelve Months Ending August 31, 2002

ISB - To Area Mwh

		EAI	ELI	EMI	ENOI	EGSI	ETR
2001	**Sep**	2,135,376	2,631,535	1,177,827	557,051	3,158,585	9,660,374
2001	**Oct**	1,924,039	2,329,954	1,015,666	451,350	2,753,234	8,474,243
2001	**Nov**	1,830,008	2,121,957	931,111	400,480	2,656,102	7,939,658
2001	**Dec**	2,010,754	2,191,643	990,565	412,658	2,688,208	8,293,828
2002	**Jan**	2,127,502	2,429,704	1,062,579	445,684	2,844,715	8,910,184
2002	**Feb**	1,805,760	2,182,551	950,786	383,347	2,659,654	7,982,098
2002	**Mar**	2,041,459	2,411,106	1,008,544	431,163	2,863,778	8,756,050
2002	**Apr**	1,863,853	2,438,780	1,016,421	481,906	3,066,881	8,867,841
2002	**May**	2,013,196	2,714,469	1,160,538	558,557	3,314,257	9,761,017
2002	**Jun**	2,424,377	2,833,339	1,334,884	609,943	3,421,322	10,623,865
2002	**Jul**	2,745,437	3,053,567	1,499,922	678,481	3,629,809	11,607,216
2002	**Aug**	2,748,792	3,032,985	1,502,772	659,565	3,691,353	11,635,467
Totals		25,670,553	30,371,590	13,651,615	6,070,185	36,747,898	112,511,841
Rounded and divided by 1000		25,671	30,372	13,652	6,070	36,748	112,512
Aug 2002 ETR-28		25,671	30,372	13,652	6,070	36,748	112,513
Variance		-	-	-	-	-	(1)

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

EXHIBIT__(LC-7)

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

SCHEDULE H - TOTAL SALES TO ULTIMATE CONSUMERS (GWH) 2001

	EAI	ELI	EMI	EGS	ENO	ENTERGY
NET AREA REQUIREMENTS	25,405	29,404	13,516	36,791	5,920	111,036

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

EXHIBIT__(LC-8)

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

No Dap
With Vidalia Adjustment

TOTAL PRODUCTION COSTS PER KWH
ADJUSTED FOR LOAD FACTOR
2001

LINE NO.	ITEM	EAI	ELI	EMI	ENO	EGS	ENTERGY
1	CAPITAL COSTS	259,674	309,863	35,975	8,286	327,890	941,688
1A	NUCLEAR CAPITAL COSTS	177,925	247,897	-	-	200,680	425,822
1B	NON-NUCLEAR CAPITAL COSTS	81,749	61,966	35,975	8,286	127,210	515,866
2	FUEL AND PURCHASED POWER	527,518	939,289	505,867	310,031	1,173,526	3,456,231
3	NON-FUEL O&M	249,360	206,102	78,501	33,782	195,071	195,071
3A	NUCLEAR NON-FUEL O&M	141,412	90,189	-	-	50,413	282,014
3B	NON-NUCLEAR NON-FUEL O&M	107,948	115,913	78,501	33,782	160,978	497,122
4	SALES (1,000s of MWh)	25,405	29,404	13,516	5,920	36,791	111,036
5	LOAD FACTOR	76.21851%	80.96047%	69.03456%	74.83932%	78.47320%	77.09593%
6	PEAK-12 MONTH AVERAGE	3,805	4,146	2,235	903	5,352	16,441
7	SALES AT CONSTANT LOAD FACTOR	25,697	28,000	15,094	6,099	36,145	111,036
8	CAPITAL COSTS	1.7898	1.3235	1.5672	1.6989	0.8974	1.3383
9	FUEL AND PURCHASED POWER	1.3052	2.9353	2.4138	3.6740	3.1897	2.6225
10	NON-FUEL O&M	0.9767	0.7207	0.5201	0.5539	0.5824	0.7017
11	TOTAL PROD COST (CENTS/KWH)	4.07	4.98	4.50	5.93	4.67	4.66
12	% DEVIATION FROM SYSTEM AVERAGE	-12.67%	6.80%	-3.46%	27.12%	0.15%	0.00%

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

EXHIBIT__(LC-9)

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Official FERC-Generated PDF of 20040308-0267 Received by FERC OSEC 08/18/2003 in Docket#: EL01-88-001

REVISED VERSION

Exhibit-ETR-36
Page 1

HISTORICAL PRODUCTION COST ANALYSIS-ELI ADJUSTED FOR VIDALIA

BUS BAR PRODUCTION COSTS-CENTS PER KILOWATT HOUR

UNADJUSTED AND ADJUSTED FOR LOAD FACTOR

1983-2002

Year	Entergy Arkansas		Entergy Louisiana		Entergy Mississippi		Entergy New Orleans		Entergy Gulf States		Entergy, Inc	
	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted	Unadjusted	Adjusted
1983	3.10	3.21	3.70	3.69	4.05	3.88	4.52	4.48	0.00	0.00	3.61	3.61
1984	3.29	3.41	3.62	3.61	3.99	3.78	4.38	4.32	0.00	0.00	3.62	3.62
1985	3.97	4.12	5.56	5.55	4.20	3.98	5.24	5.19	0.00	0.00	4.78	4.78
1986	6.04	5.98	5.49	5.55	6.60	6.43	6.00	6.01	0.00	0.00	5.88	5.88
1987	5.57	5.53	4.91	4.95	6.25	6.14	5.52	5.52	0.00	0.00	5.37	5.37
1988	5.55	5.51	4.57	4.60	5.78	5.70	4.91	4.92	0.00	0.00	5.09	5.09
1989	5.30	5.25	4.43	4.46	5.30	5.20	4.83	4.85	0.00	0.00	4.86	4.86
1990	5.13	5.11	4.11	4.13	4.91	4.83	4.66	4.68	0.00	0.00	4.59	4.59
1991	4.29	4.25	3.99	4.01	4.61	4.52	4.22	4.23	0.00	0.00	4.20	4.20
1992	4.92	4.89	4.11	4.13	4.96	4.87	4.43	4.45	0.00	0.00	4.52	4.52
1993	4.53	4.50	4.12	4.13	4.39	4.31	4.41	4.42	0.00	0.00	4.31	4.31
1994	4.13	4.10	3.98	4.02	4.07	3.97	3.99	3.98	4.38	4.40	4.15	4.15
1995	4.00	3.97	3.67	3.69	3.77	3.68	3.82	3.82	3.78	3.81	3.79	3.79
1996	3.93	3.91	4.05	4.07	3.97	3.91	4.39	4.38	4.10	4.11	4.05	4.05
1997	3.90	3.89	4.23	4.25	3.88	3.82	4.23	4.21	4.03	4.05	4.06	4.06
1998	3.87	3.84	3.90	3.92	4.73	4.60	4.18	4.18	3.61	3.63	3.91	3.91
1999	3.95	3.93	4.12	4.14	4.01	3.96	4.37	4.37	3.86	3.88	4.00	4.00
2000	4.05	4.02	5.26	5.29	4.72	4.64	5.62	5.62	4.85	4.87	4.81	4.81
2001	4.08	4.07	4.95	4.98	4.59	4.50	5.95	5.93	4.66	4.67	4.66	4.66
2002 [1]	3.38	3.37	4.12	4.16	3.96	3.87	4.46	4.45	3.97	3.97	3.90	3.90
Average (1986-2002)	4.51	4.48	4.35	4.38	4.74	4.64	4.71	4.71	4.14	4.16	4.48	4.48

Note: [1] Twelve months ending August 31, 2002

FEDERAL ENERGY REGULATORY COMMISSION

Docket No. EL01-88-001
Hearing Ex. No. ETR-36
Date Identified 8/18/03
Date Admitted 8/18/03

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

EXHIBIT__(LC-10)

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

COMPARISON OF ISB "TO AREA" MWH DATA TO FERC FORM 1, PAGE 401a DATA
12 MONTHS ENDING DECEMBER 2001

ISB - To Area

		EAI	ELI	EMI	ENOI	EGSI	ETR
2001	**Jan**	3,144,740	2,491,966	1,151,934	444,582	3,115,760	10,348,982
2001	**Feb**	2,546,914	2,087,148	920,511	376,757	2,617,860	8,549,190
2001	**Mar**	2,701,332	2,065,439	988,400	396,519	2,788,582	8,940,272
2001	**Apr**	2,587,200	2,330,188	1,003,684	458,378	3,045,324	9,424,774
2001	**May**	2,785,315	2,614,911	1,170,738	539,667	3,407,123	10,517,754
2001	**Jun**	3,261,743	2,618,239	1,258,138	583,083	3,322,153	11,043,356
2001	**Jul**	2,770,075	2,950,214	1,466,089	653,821	3,575,647	11,415,846
2001	**Aug**	2,687,175	2,970,499	1,441,778	645,752	3,662,129	11,407,333
2001	**Sep**	2,135,376	2,631,535	1,177,827	557,051	3,158,585	9,660,374
2001	**Oct**	1,924,039	2,329,954	1,015,666	451,350	2,753,234	8,474,243
2001	**Nov**	1,830,008	2,121,957	931,111	400,480	2,656,102	7,939,658
2001	**Dec**	2,010,754	2,191,643	990,565	412,658	2,688,208	8,293,828
Totals		30,384,671	29,403,693	13,516,441	5,920,098	36,790,707	116,015,610
GWH		30,385	29,404	13,516	5,920	36,791	116,016
EAI Correction		(4,980)					
ISB Net Area Load		25,405	29,404	13,516	5,920	36,791	111,036
Dec 2001 ETR-26		25,405	29,404	13,516	5,920	36,791	111,036

2001 Form 1 Page 401a MWH Data, Using Entergy Methodology in Compliance Filing

P.401a Line 28	33,493,422	29,629,060	16,254,314	6,295,873	39,784,524	125,457,193
P.401a Line 18	(173,256)	(190,690)	(100,590)	(40,152)	(246,769)	(751,457)
P.401a Line 24	(7,752,909)	(714,779)	(2,016,743)	(174,236)	(3,056,777)	(13,715,444)
FERC Form 1 Net Area Load	25,567,257	28,723,591	14,136,981	6,081,485	36,480,978	110,990,292
FERC Form 1 Net Area Load (GWH)	25,567	28,724	14,137	6,081	36,481	110,990
Dec 2001 ETR-26	25,405	29,404	13,516	5,920	36,791	111,036

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

EXHIBIT__(LC-11)

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

response provided on July 12

EXHIBIT LC-60C

ENTERGY SERVICES, INC.
FEDERAL ENERGY REGULATORY COMMISSION
Docket No. ER03-583-000 And Other Dockets Consolidated

Response of: Entergy Services, Inc.
to the Ninth Set of Data Requests
of Requesting Party: Louisiana Public Service Commission

Question No.: LPSC 9-1 Part No.: Addendum:

Question:

For the period beginning with the termination of the North Little Rock contract to the present, please identify each sale of EAI capacity that was made possible by the NLR contract termination (the EAI WBL capacity) to a third party (a party other than an EOC). For each such sale, provide the following:

a. buyers name;

b. date and duration of sale;

c. mw capacity sold;

d. mwh sold;

e. the adjustment to the EAI load shape to reflect the sale;

f. if no load shape adjustment was made, please so state, and explain why no load shape adjustment was made;

g. any notification (in writing) to the Operating Committee, the other EOC's or the EMO that the load from these sales was being included in EAI's load shape for system agreement purposes.

Response:

a-d. Please see the attached material, which material is a type of Highly Sensitive Protected Material of a type only being provided to State and Local Regulators and Outside Counsel.

e. The EAI load shape was adjusted hourly by the hourly MW of capacity sold in accordance with Article II, ¶ 2.16 of the Entergy System Agreement.

f. N/A

g. No written notification was provided to the Operating Committee, the other Operating Companies, or the EMO that the loads from these sales were to be included in EAI's load shape for System Agreement purposes. Notice of the sales was provided to the EMO, but such notice did not, and was not required to, notify that the load from the sales was to be included in the load shape.

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

EXHIBIT__(LC-12)

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Exhibit ETR-110

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Entergy Services, Inc. and EWO Marketing, L.P.	Docket Nos. ER03-583-000, ER03-583-001 and ER03-583-002
Entergy Services, Inc. and Entergy Power, Inc.	Docket Nos. ER03-681-000 and ER03-681-001
Entergy Services, Inc. and Entergy Power, Inc.	Docket Nos. ER03-682-000, ER03-682-001 and ER03-682-002
Entergy Services, Inc. and Entergy Louisiana, Inc.	Docket Nos. ER03-744-000 and ER03-744-001 (Consolidated)

REBUTTAL TESTIMONY

OF

BRUCE M. LOUISELLE

ON BEHALF OF

ENTERGY SERVICES, INC.

MAY 11, 2004

capacity used to serve such wholesale load would not be 'excess' under Section 3.05 of the System Agreement."[16] However, Mr. Baron also contends that

> an EOC cannot sell its excess capacity to a new third party wholesale customer without offering a right-of-first refusal. Any other interpretation of an EOC to sell its excess capacity to a wholesale customer (for example, a market-based sale to a third party electric utility) would effectively moot the provision of Section 3.05 for a right-of-first refusal.[17]

In other words, under Mr. Baron's theory, if an Operating Company had a wholesale customer whose contract expired, it would not be allowed to enter into a rollover or a new wholesale sale without first offering an equivalent amount of capacity to other Operating Companies on a unit-by-unit basis. In fact, if Mr. Baron's interpretation of Section 3.05 were correct, and in my opinion, it is not, it would require an Operating Company to make such an offer to other Operating Companies when it lost a retail customer before it could contract with a new retail customer. Section 3.05 does not distinguish between retail and wholesale loads when it refers to capacity "above its requirements."

The fallacy in Mr. Baron's position is that as long as the sale to a customer, whether retail or wholesale, is included in the Operating Company's load shape, that load is part of that Company's "requirements." A load is included in the Company's load shape and its "requirements" under Section 3.05 if that load is

---

16 Response of Mr. Baron to Data Request ESI-LPSC-1-30 attached as Exhibit ETR-117.

17 *Id.*

counted in calculating a Company's load responsibility ratio. Thus, any wholesale sale by EAI would be included in its load shape and would not involve excess generating capacity.

EAI has the right to sell this capacity to a new wholesale customer without first offering it to the other Operating Companies pursuant to Section 3.05. Therefore, EAI also has the right to sell this capacity to ELI and ENO without first offering it to all Operating Companies on a responsibility ratio basis. Once this transaction occurs, the capability is reflected by ELI and ENO in determining its capability responsibility. The load that is served by this capability is part of the load shape of the Company ~~owing~~ owning this capability.

Q. DOES MR. BARON ASSERT A DISTINCTION BETWEEN THE OBLIGATION TO SERVE NEW RETAIL CUSTOMERS AND NEW WHOLESALE CUSTOMERS?

A. Yes, he does. However, while I understand that distinction, such a distinction is not set forth in Section 3.05. Mr. Baron seemingly would establish a right for retail customers of one public utility to choose certain resources to serve their needs that would override the right of another public utility to engage in wholesale transactions for the benefit of its retail customers.

Q. IS A WHOLESALE SALE BY AN OPERATING COMPANY SUCH AS EAI TO ANOTHER ENTERGY OPERATING COMPANY AN "OFF-SYSTEM" SALE?

A. No. As long as the sale is reflected in the selling Company's load shape for responsibility ratio calculation purposes, it is by definition not an "off-system" sale.

Q. IF AN OPERATING COMPANY ENGAGES IN A WHOLESALE SALE, DOES THAT AFFECT THE ECONOMIC DISPATCH OF THE SYSTEM'S RESOURCES?

A. No, it does not. Under economic dispatch, as required by the System Agreement and as practiced by the Entergy System, the System's resources are dispatched on an economic basis regardless of whether the System's resources are used to meet wholesale obligations of an Operating Company. In other words, if the wholesale transaction does not remove resources from economic dispatch, the resources cannot, by definition, be "excess" to the System.

Q. DOES YOUR INTERPRETATION OF SECTION 3.05 MAKE THE RIGHT OF FIRST REFUSAL PROVISION MOOT AS ALLEGED BY MR. BARON?

A. No, it does not. If EAI were to offer to sell the capacity and energy from a particular unit via a Unit Power Sales Agreement or an undivided interest in one of

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

EXHIBIT__(LC-13)

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Changes

1 whether load is properly included in an operating
2 company's load shape, how does that relate to some issue
3 in this case, and if so, what issue is it?
4 A The question in this case, at least one of the
5 issues in this case, seems to be that whether Entergy
6 Arkansas has capacity in excess of its needs, and if so,
7 whether that capacity, then, is in excess of its needs,
8 triggers a Section 3.05 right of first refusal if it were
9 to sell that capacity to presumably someone else, and the
10 issue is whether an offeror -- it seems like there is a
11 contention that an offer by Entergy Arkansas to sell the
12 North Little Rock -- what had been capacity used to meet
13 North Little Rock's load, rather to replace that load to
14 sales to other wholesale customers, constitutes capacity
15 that is excess to Entergy Arkansas's needs. And the
16 issue, then, is if it's included in its load, is that
17 excess.
18 Q If it's included in whose load?
19 A Entergy Arkansas's load, is it excess to
20 Entergy Arkansas? My opinion is it is not.
21 Q Do you recall Mr. Fontham asking you whether
22 you could or had -- whether you could go back to see or
23 you had gone back to see whether such sales such as sales
24 of the type depicted in LC-60, whether such sales were
25 included in the EAI load shape prior to the April 2001

1 operating committee meeting that was appended to your
2 exhibit in this case regarding that matter?
3 A Yes, I could, and I did.
4 Q What did you find out?
5 A I went back to 1999, specifically again looking
6 at an hour, and the hour that I looked at was June 28,
7 hour 1700, which was the peak hour for Entergy Arkansas's
8 load in that hour, 4072 megawatts and I basically went
9 through the same exercise I described in connection with
10 the North Little Rock transaction. In that case, there's
11 a transaction again on the same kind of sheet. It's the
12 AR special transactions. The calculation is done the same
13 way, by the way, in building up the load.
14 In the Arkansas special transaction appears
15 165-megawatt sale to Ameren. Ameren was the name
16 became the name of Union Electric. Union Electric had
17 purchased the Missouri facilities of what had been known,
18 I believe, as Arkansas Missouri Power, which was part of
19 Arkansas Power & Light at the time.
20 In connection with that transaction, a sale to
21 Ameren of 165 megawatts was entered into and that is
22 included as part of Entergy Arkansas's load shape for
23 purposes of MSS-1, and that was back in 1969 -- I'm sorry,
24 1999.
25 Q In that's the case, what was the relevance of

1 the April 2001 operating committee minutes?
2 A Those were attached because they were
3 referenced in the e-mail between Mr. Turner and
4 Mr. Benedetto, and since there was a reference to minutes,
5 I thought it best to put the reference to the minutes even
6 though the reference to the minutes is not in my view to
7 permission or authorization or instructions to include
8 them in the load shape. That had been going on for years.
9 It's just normal practice.
10 Q Why would it be appropriate, in your view, to
11 include the load represented by such sales in the load
12 shape of the operating company?
13 A I think -- not "I think" -- if you do not do
14 that, then what you are doing is committing resources for
15 the benefit of the seller. You're committing those
16 resources to a third party sale, but you're not assigning
17 the reserve cost of reserve responsibility to that company
18 incident to those sales. I do not think that would be
19 fair to the other operating companies.
20 Q Do you have a copy of LC-99 at the witness
21 stand?
22 MR. FONTHAM: Your Honor, may I ask, if counsel
23 is leaving this subject, I notice Mr. Louiselle was
24 referring to documents as he answered the last question,
25 and I would like to request that we be provided a chance

1 to look at those.
2 MR. ANDERSON: I'm not leaving the subject,
3 your Honor, but I have a copy -- in fact, I have many
4 copies of what Mr. Louiselle was referring to, and I can
5 mark it for identification.
6 BY MR. ANDERSON:
7 Q Mr. Louiselle, before we go to LC-99, what is
8 the title on the first page of the document to which you
9 just referred when I asked you about the prior -- whether
10 you had been able to determine prior instances of this
11 load being added to EAI's load shape?
12 A EAI peak reconciliation date of June 28, 1999,
13 hour 17.
14 MR. ANDERSON: Your Honor, I'd like to mark for
15 identification what I make out to be 15 or 16 sheets.
16 I'll mark it as ETR --
17 PRESIDING JUDGE: 190, I believe.
18 MR. ANDERSON: Thank you very much, ETR-190.
19 It's a packet of papers that relate to prescheduled sale
20 to Ameren by EAI, the first page of which has the title
21 EAI peak load reconciliation.
22 PRESIDING JUDGE: As you've identified it, it
23 will be ETR-190 for identification.
24 (Exhibit ETR-190 identified.)
25 BY MR. ANDERSON:

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

EXHIBIT__(LC-14)

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Full Load (including interruptible customers)

Year	Month	Day	Hour	EES	EAI	ELI	EMI	ENOI	EGSI
2006	1	18	7	14,614,261	3,530,959	3,581,512	1,908,606	562,347	5,030,837
2006	2	13	8	15,515,907	3,739,328	3,902,354	2,081,553	610,204	5,182,468
2006	3	12	20	13,522,641	3,024,129	3,426,889	1,686,933	600,479	4,784,211
2006	4	18	17	17,594,797	3,888,528	4,281,105	2,565,076	731,187	6,128,901
2006	5	25	17	18,506,073	4,369,269	4,477,048	2,685,818	621,940	6,351,998
2006	6	22	16	19,606,321	4,564,823	4,871,180	2,928,312	895,045	6,346,961
2006	7	18	16	20,707,383	5,142,209	4,950,236	3,195,753	672,844	6,746,341
2006	8	15	17	20,886,869	4,547,542	5,257,485	3,267,286	780,195	7,034,361
2006	9	22	16	18,265,899	3,806,797	4,758,048	2,618,549	717,074	6,365,431
2006	10	3	17	17,647,921	3,867,026	4,568,803	2,667,100	683,239	5,861,753
2006	11	21	8	14,506,333	3,380,490	3,692,987	1,860,734	501,820	5,070,302
2006	12	8	8	16,877,818	4,129,093	4,221,885	2,219,952	581,098	5,725,790
Total				208,252,223	47,990,193	51,989,532	29,685,672	7,957,472	70,629,354
12-Month Average					3,999,182	4,332,461	2,473,806	663,122	5,885,779
Responsibility Ratio					0.2304	0.2497	0.1425	0.0382	0.3392

Interruptible Load (excluding interruptible customers)

Year	Month	Day	Hour	EES	EAI	ELI	EMI	ENOI	EGSI
2006	1	18	7	14,321,426	3,529,046	3,330,406	1,907,965	542,985	5,011,024
2006	2	13	8	15,184,310	3,736,848	3,660,732	2,045,318	586,164	5,155,248
2006	3	12	20	13,248,324	3,024,129	3,254,170	1,655,542	570,633	4,743,850
2006	4	18	17	17,151,855	3,864,713	3,958,836	2,529,672	724,810	6,073,824
2006	5	25	17	18,105,981	4,366,718	4,184,012	2,672,460	589,446	6,293,345
2006	6	22	16	19,203,955	4,561,678	4,563,759	2,893,438	861,398	6,323,682
2006	7	17	16	20,287,314	5,046,115	4,671,632	3,165,244	630,724	6,773,599
2006	8	15	17	20,425,385	4,478,804	4,991,295	3,229,501	743,804	6,981,981
2006	9	22	16	17,787,696	3,713,781	4,445,392	2,611,880	684,752	6,331,891
2006	10	3	17	17,207,810	3,851,236	4,243,265	2,664,705	648,205	5,800,399
2006	11	21	8	14,181,368	3,364,724	3,458,128	1,846,737	472,330	5,039,449
2006	12	8	8	16,612,182	4,115,504	4,050,332	2,192,117	559,577	5,694,652
Total				203,717,606	47,653,296	48,811,959	29,414,579	7,614,828	70,222,944
12-Month Average					3,971,108	4,067,663	2,451,214	634,569	5,851,912
Responsibility Ratio					0.2339	0.2396	0.1444	0.0374	0.3447

Interruptible Load (excluding interruptible customers and ENOI)

Year	Month	Day	Hour	EES	EAI	ELI	EMI	ENOI	EGSI
2006	1	18	7	13,778,441	3,529,046	3,330,406	1,907,965	0	5,011,024
2006	2	13	8	14,598,146	3,736,848	3,660,732	2,045,318	0	5,155,248
2006	3	12	20	12,677,691	3,024,129	3,254,170	1,655,542	0	4,743,850
2006	4	18	17	16,427,045	3,864,713	3,958,836	2,529,672	0	6,073,824
2006	5	25	17	17,516,535	4,366,718	4,184,012	2,672,460	0	6,293,345
2006	6	22	16	18,342,557	4,561,678	4,563,759	2,893,438	0	6,323,682
2006	7	17	16	19,656,590	5,046,115	4,671,632	3,165,244	0	6,773,599
2006	8	15	17	19,681,581	4,478,804	4,991,295	3,229,501	0	6,981,981
2006	9	22	16	17,102,944	3,713,781	4,445,392	2,611,880	0	6,331,891
2006	10	3	17	16,559,605	3,851,236	4,243,265	2,664,705	0	5,800,399
2006	11	21	8	13,709,038	3,364,724	3,458,128	1,846,737	0	5,039,449
2006	12	8	8	16,052,605	4,115,504	4,050,332	2,192,117	0	5,694,652
Total				196,102,778	47,653,296	48,811,959	29,414,579	0	70,222,944
12-Month Average					3,971,108	4,067,663	2,451,214	0	5,851,912
Responsibility Ratio					0.2430	0.2489	0.1500	0.0000	0.3581

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.) DOCKET NO. ER07-956-000

EXHIBIT__(LC-15)

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

ENTERGY SERVICES, INC.
ENTERGY SYSTEM AGREEMENT SERVICE SCHEDULE MSS-3 2007 FILING IN COMPLIANCE WITH FERC OPINION NOS. 480 AND 480-A
FOR THE YEAR ENDED DECEMBER 31, 2006
(000's)

Section 30.11: Rough Production Cost Equalization

Line No.		Formula / Reference	System	EAI	EGS	ELL	EMI	ENOI
1	D = Disparity							
2	D = [(PC / APC) - 1] * 100%							
	where:							
3	PC = Actual Production Cost	A.2 Ln 26 =	6,613,665	1,067,133	2,496,827	1,852,571	963,584	233,550
4	APC = Average Production Cost	A.5 Ln 137 =	6,613,665	1,485,676	2,303,462	1,691,701	894,305	238,521
5	$DD = Dollar Deviation from Average ($)	Ln 3 - Ln 4 =	(1)	(418,543)	193,365	160,869	69,279	(4,971)
	Determination of Average Production Cost outside the 11% Band							
6	D = Disparity	[(Ln 3 / Ln 4) - 1] * 100% =		-28.17%	8.39%	9.51%	7.75%	-2.08%
	where:							
7	PCBB = Production Cost Below Band							
8	PCBB = If %DD < -11%, then PCBB equals [(%DD + 11%) / %DD] * $DD, otherwise zero.	If Ln 6 < -11%, Then (Ln 6 + 11%) / Ln 6 * Ln 5), Otherwise 0 =		(255,108)	0	0	0	0
	or,							
9	PCAB = Production Cost Above Band							
10	PCAB = If %DD > 11%, then PCAB equals [(%DD - 11%) / %DD] * $DD, otherwise zero.	If Ln 6 > 11%, Then (Ln 6 - 11%) / Ln 6 * Ln 5), Otherwise 0 =		0	0	0	0	0
11	% DD = Percent Dollar Deviation at the Band	(Ln 5 - Ln 8) / Ln 5 =		-11.00%	8.39%	9.51%	7.75%	-2.08%
	Equalization							
	Step 1							
12	Receipts of the company with the highest disparity up to the level of the sum of the payments or until the receiving company's adjusted disparity matches the disparity of the next highest company.			(18,935)	0	18,935	0	0
13	D^1 = Disparity after Step 1	(Ln 5 - Ln 12) / Ln 4 =		-26.90%	8.39%	8.39%	7.75%	-2.08%
	Step 2							
14	Remaining (payments), if any, become the receipts of the two companies equally as a percent deviation up to the level of the distribution of the remaining (payments) or until these two companies' adjusted disparity matches the disparity of the third highest company.			(25,674)	14,847	10,827	0	0
15	D^2 = Disparity after Steps 1 and 2	(Ln 5 - Ln 12 - Ln 14) / Ln 4 =		-25.17%	7.75%	7.75%	7.75%	-2.08%
	Step 3							
16	Remaining (payments), if any, become the receipts of the three companies equally as a percent deviation up to the level of the distribution of the remaining (payments) or until the disparity of these three companies matches the disparity of the fourth highest company.			(210,499)	99,175	72,836	38,488	0
17	D^3 = Disparity after Steps 1, 2 and 3	(Ln 5 - Ln 12 - Ln 14 - Ln 16) / Ln 4 =		-11.00%	3.44%	3.44%	3.44%	-2.08%
	Step 4							
18	Remaining (payments), if any, become the receipts of the four companies equally as a percent deviation up to the level of the distribution of the remaining (payments) or until the disparity of the four companies matches.			0	0	0	0	0
19	D^4 = Final Disparity	(Ln 5 - Ln 12 - Ln 14 - Ln 16 - Ln 18) / Ln 4 =		-11.00%	3.44%	3.44%	3.44%	-2.08%
	Step 5				(Payments) / Receipts			
20	**Annual Rough Production Cost Equalization**	Ln 12 + Ln 14 + Ln 16 + Ln 18 =	0	(255,108)	114,022	102,598	38,488	0
21								

ENTERGY SERVICES, INC.
ENTERGY SYSTEM AGREEMENT SERVICE SCHEDULE MSS-3 2007 FILING IN COMPLIANCE WITH FERC OPINION NOS. 480 AND 480-A
FOR THE YEAR ENDED DECEMBER 31, 2006
(000's)

Line No.		Formula / Reference	System	EAI	EGS	ELL	EMI	ENO
	Section 30.12: Actual Production Cost [1]							
22	**PC = Actual Production Cost**							
23	PC = VPC + FPC							
	where:							
24	VPC = Variable Production Cost	A.3 Ln 67 =	5,518,932	803,785	2,135,938	1,563,998	820,076	195,135
25	FPC = Fixed Production Cost	A.4 Ln 121 =	1,094,733	263,348	360,890	288,572	143,508	38,415
26	**PC = Actual Production Cost**	Ln 24 + Ln 25 =	6,613,665	1,067,133	2,496,827	1,852,571	963,584	233,550
27	**VPC = Variable Production Cost**							
28	VPC = VPRB * (CM + F) + VPX							
	where:							
29	**VPRB = Variable Production Rate Base [2]**							
30	VPRB = NPP - NAD - (ADIT * NPPR)							
	where:							
31	NPP = Nuclear Production Plant in Service as recorded in FERC Plant Accounts 320 through 325 and FERC Account 101.1 excluding Asset Retirement Obligations (ARO) recorded in FERC Plant Account 326, if any	B.1 Ln 7 =		2,104,624	3,224,822	2,925,277	-	-
32	NAD = Nuclear Accumulated Provisions for Depreciation and Amortization excluding ARO associated with NPP above, as recorded in FERC Account 108 and 111, (consistent with the accounting relating to SFAS 143 approved by the retail regulator having jurisdiction over the Company, unless the FERC determines otherwise)	B.2 Ln 57 =		932,073	1,998,248	1,421,799	-	-
33	ADIT = Net Accumulated Deferred Income Taxes (ADIT) recorded in FERC Accounts 190, 281 and 282 (as reduced by amounts not generally and properly includable for FERC cost of service purposes, including but not limited to, SFAS 109 ADIT amounts and ADIT amounts arising from retail ratemaking decisions plus Accumulated Deferred Investment Tax Credit - 3% portion only recorded in FERC Account 255	B.2 Ln 89 =		685,880	912,136	847,888	330,402	103,103
34	NPPR = Ratio of Nuclear Production Plant to Total Plant excluding Intangible Plant [3]							
35	NPPR = NPP / PXI							
	where:							
36	NPP = Nuclear Production Plant in Service	Ln 31 =		2,104,624	3,224,822	2,925,277	-	-
37	PXI = Electric Plant in Service which includes the sum of the Company's Production, Transmission, Distribution and General Plant in Service recorded in FERC Plant Accounts 310 through 399, Property under Capital Lease as recorded in FERC Account 101.1 and Completed Construction not yet Classified as recorded in FERC Account 106 excluding ARO, if any	B.1 Ln 37 =		6,251,885	8,615,502	6,630,507	2,575,669	638,065
38	NPPR = Ratio of Nuclear Production Plant to Total Plant excluding Intangible Plant	Ln 36 / Ln 37 =		33.66%	37.43%	44.12%	0.00%	0.00%
39	**VPRB = Variable Production Rate Base**	Ln 31 - Ln 32 - (Ln 33 * Ln 38) =		941,684	885,161	1,129,390	-	-
40	**CM = The weighed average cost of capital determined as follows:**							
41	CM = (DR * i) + (PR * p) + (ER * c)							
	where:							
42	DR = Ratio of Debt Capital and Preferred Stock with tax deductible dividends (QUIPS) at Dec. 31 of the previous year	B.3 Ln 103 =		41.10%	50.18%	48.92%	53.58%	56.02%
43	PR = Ratio of Preferred Stock without tax deductible dividends at Dec. 31 of the previous year	B.3 Ln 105 =		4.36%	1.10%	3.26%	3.45%	5.06%
44	ER = Ratio of Common Stock at Dec. 31 of the previous year	B.3 Ln 106 =		54.54%	48.72%	47.82%	42.97%	38.92%
45	i = Average embedded cost of debt capital and preferred stock with tax deductible dividends (QUIPS) outstanding at Dec. 31 of the previous year	B.3 Ln 102 =		6.36%	6.02%	7.08%	5.95%	5.86%
46	p = Average embedded cost of preferred stock outstanding at Dec. 31 of the previous year	B.3 Ln 104 =		5.99%	9.63%	7.50%	5.69%	4.82%
47	c = Simple average of the Companies' approved retail return on common equity rates at Dec. 31 of the previous year	B.3 Ln 109 =		10.75%	10.75%	10.75%	10.75%	10.75%
48	**CM = Weighed avg. cost of capital**	(Ln 42 * Ln 45)+(Ln 43 * Ln 46)+(Ln 44 * Ln 47) =		8.74%	8.36%	8.85%	8.00%	7.71%

[1] All Rate Base, Revenue and Expense items shall be based on the actual amounts on the Company's books on the Company's books for the twelve months ended December 31 of the previous year as reported in FERC Form 1 or such other supporting data as may be appropriate for each Company; and shall include certain retail regulatory adjustments pursuant to the production cost methodology set forth in Exhibit ETR-26/ETR-28 filed in Docket No. EL01-88-001, including but not limited to: (1) the Deregulated Asset Plan adjustment for EGS, (2) the regulated portion (70%) of River Bend for EGS, (3) repricing of energy associated with the Vidalia purchase power contract for ELL based on the average annual Service Schedule MSS-3 rate paid by ELL, including the exclusion of the income tax savings of the Vidalia purchase power contract from ADIT and reflecting the reversal of the Vidalia capital transaction, and the debt rate associated with the Waterford 3 Sale/Leaseback for ELL, and (4) exclusion of the EAI and EMI retail approved Grand Gulf Accelerated Recovery Tariff effects on purchased power on EAI's and EMI's production cost.

[2] Rate Base values shall be based on the actual balances on the Company's books as of December 31 of the previous year except for Fuel Inventory, Materials & Supplies and Prepayments which shall be based on the average of the beginning and ending actual balances on the Company's books.

[3] Plant ratios shall be determined based on plant in service balances exclusive of associated ARO as of December 31 of the previous year.

ENTERGY SERVICES, INC.

ENTERGY SYSTEM AGREEMENT SERVICE SCHEDULE MSS-3 2007 FILING IN COMPLIANCE WITH FERC OPINION NOS. 480 AND 480-A

FOR THE YEAR ENDED DECEMBER 31, 2006

(000's)

Line No.		Formula / Reference	EAI	EGS	ELL	EMI	ENO
49	**F = Federal & State Income Taxes determined from the following:**						
50	F = T / (1 - T) * (CM - (DR * I)						
	where:						
51	T = f + s - fs when federal tax is not deductible in computing state tax, and						
52	T = (f + s - 2fs) / (1 - (fs)) when federal tax is deductible in computing state tax, and						
53	f = Federal Income Tax Rate	B.3 Ln 111 =	35.00%	35.00%	35.00%	35.00%	35.00%
54	s = State Income Tax Rate [4]	B.3 Ln 112 =	6.50%	4.00%	8.00%	5.00%	8.00%
55	T = EAI and EMI	(Ln 53 + Ln 54 - (Ln 53 * Ln 54) =	39.23%			38.25%	
56	T = EGS, ELI & ENO	(Ln 53 + Ln 54) - 2 * (Ln 53 * Ln 54)) / (1 - (Ln 53 * Ln 54)) =		36.71%	38.48%		38.48%
57	**F = Federal & State Income Tax**	(Ln 55 / (1 - Ln 55) * (Ln 48 - (Ln 42 * Ln 45)) =	3.95%			2.98%	
58	**F = Federal & State Income Tax**	(Ln 56 / (1 - Ln 56) * (Ln 48 - (Ln 42 * Ln 45)) =		3.10%	3.37%		2.77%
59	**VPX = Variable Production Expense**						
60	VPX = NPOMNF + FE + PURP - RC + NDE						
	where:						
61	NPOMNF = Nuclear Production O&M Non-Fuel Expense, recorded in FERC Accounts 517 through 532 excluding Nuclear Fuel in FERC Account 518	B.3 Ln 140 =	154,963	39,227	103,588	0	0
62	FE = Production O&M Fuel Expense recorded in Accounts 501, 518 & 547 and Net Hedging Costs as recorded in Account	B.3 Ln 133 =	219,916	743,446	735,773	377,421	69,165
63	PURP = Purchased Power Expense recorded in FERC Account 555, but excluding payments made pursuant to Section 30.09(d) of this Service Schedule	B.3 Ln 146 =	620,356	1,288,137	753,870	490,339	217,212
64	RC = Revenue Credits resulting from revenue received from customers outside the Company's Net Area for Production Service recorded in FERC Account 447, but excluding payments made pursuant to Section 30.09(d) of this Service Schedule	B.4 Ln 158 =	381,834	92,036	222,520	47,684	91,242
65	NDE = Nuclear Depreciation and Amortization Expense associated with (NPP) as recorded in Accounts 403 and 404 Decommissioning Expense, as approved by Retail Regulators, unless the jurisdiction for determining the depreciation and/or decommissioning rate is vested in the FERC under otherwise applicable law	B.4 Ln 171 =	70,884	55,724	55,276	0	0
66	**VPX = Variable Production Expense**	(Sum of Lines 61 thru 63) - Ln 64 + Ln 65 =	684,285	2,034,498	1,425,987	820,076	195,135
67	**VPC = Variable Production Cost**	Ln 39 * (Ln 46+ [Ln 57 or Ln 58]) + Ln 66 =	803,785	2,135,938	1,563,998	820,076	195,135
68	**FPC = Fixed Production Cost**						
69	FPC = FPRB * (CM + F) + FPX - [(ITC / TX) * PPR]						
	where:						
70	**FPRB = Fixed Production Rate Base**						
71	FPRB = PPXN + CME - ADXN + FI - (ADIT * PPRXN) + [(GP - GAD + IP - IAA) * PLR] + (MS + P) * PPREG						
	where:						
72	PPXN = Production Plant in Service excluding Nuclear Plant recorded in FERC Plant Accounts 310 through 317, Accounts 330 through 346, and FERC Account 101.1 excluding ARO recorded in FERC Plant Accounts 317 and 337, if any	B.1 Ln 18 =	835,926	1,740,884	850,392	769,236	170,516
73	CME = Coal Mining Equipment in FERC Plant Account 399 owned by the Company	B.1 Ln 35 =	11,183	-	-	15,461	-
74	ADXN = Accumulated Provision for Depreciation and Amortization associated with PPXN and CME above, as recorded in FERC Account 108 and 111, excluding ARO associated with PPXN and CME, if any (consistent with the accounting relating to SFAS 143 approved by the retail regulator having jurisdiction over the Company, unless the FERC determines otherwise)	B.2 Ln 71 =	606,647	1,265,759	515,755	468,210	169,298
75	FI = Fuel Inventory recorded in FERC Account 151	B.2 Ln 82 =	14,473	64,692	-	5,365	-
76	ADIT = Net Accumulated Deferred Income Taxes plus Accumulated Deferred Investment Tax Credit	B.2 Ln 89 =	685,880	912,136	847,888	330,402	103,103
77	PPRXN = Ratio of Production Plant in Service excluding Nuclear Plant to Total Plant excluding Intangible Plant						
78	PPRXN = PPXN / PXI						
	where:						
79	PPXN = Production Plant in Service excluding Nuclear Plant	Ln 72 =	835,926	1,740,884	850,392	769,236	170,516
80	PXI = Electric Plant in Service excluding Intangible Plant	Ln 37 =	6,251,885	8,615,502	6,630,507	2,575,669	638,065
81	PPRXN = Ratio of Production Plant ex. Nuclear to Total ex. Intangible	(Ln 79 / Ln 80) =	13.37%	20.21%	12.83%	29.87%	26.72%
82	GP = General Plant in Service recorded in FERC Plant Accounts 389 through 398 excluding ARO, if any	B.1 Ln 32 =	118,227	185,762	122,311	118,066	24,374
83	GAD = General Plant Accumulated Provision for Depreciation, as recorded in FERC Account 108 excluding ARO associated with GP above, if any, (consistent with the accounting relating to SFAS 143 approved by the retail regulator having jurisdiction over the Company, unless the FERC determines otherwise)	B.2 Ln 75 =	46,905	69,836	(24,109)	1,966	(2,728)
84	IP = Intangible Plant in Service recorded in FERC Plant Accounts 301 through 303	B.1 Ln 40 =	283,146	200,694	265,053	116,484	59,748
85	IAA = Intangible Plant Accumulated Provision for Amortization associated with IP above recorded in FERC Account 111	B.2 Ln 77 =	156,036	86,408	99,022	49,725	25,915

[4] The State Income Tax rate for EGS is the average of the rates for Louisiana and Texas.

ENTERGY SERVICES, INC.
ENTERGY SYSTEM AGREEMENT SERVICE SCHEDULE MSS-3 2007 FILING IN COMPLIANCE WITH FERC OPINION NOS. 480 AND 480-A
FOR THE YEAR ENDED DECEMBER 31, 2006
(000's)

Line No.		Formula / Reference	EAI	EGS	ELL	EMI	ENO
86	PLR = Ratio of Production Labor to Total Labor excluding A&G Labor [5]						
87	PLR = PL / LXAG						
	where:						
88	PL = Production Labor charged to O&M expense	B.4 Ln 184 =	95,279	65,028	74,502	15,118	3,349
89	LXAG = Total Labor charged to O&M Expense excluding A&G Labor	B.4 Ln 193 =	140,639	118,681	113,022	45,847	11,521
90	PLR = Ratio of Production Labor to Total Labor excluding A&G Labor	(Ln 88 / Ln 89) =	67.75%	54.79%	65.92%	32.98%	29.07%
91	MS = Materials and Supplies recorded in FERC Account 154	B.2 Ln 94 =	85,786	106,410	90,305	23,288	7,495
92	P = Prepayments as recorded in FERC Account 165	B.2 Ln 99 =	4,427	13,155	3,320	1,824	3,468
93	PPREG = Ratio of Production Plant in Service to Electric and Gas Plant in Service excluding Intangible Plant						
94	PPREG = PP / EGPXI						
	where:						
95	PP = Production Plant in Service as recorded in FERC Plant Accounts 310 through 346 and FERC Account 101.1 excluding ARO recorded in FERC Plant Accounts 317, 326 and 337, if any	B.1 Ln 19 =	2,940,550	4,965,706	3,775,669	769,236	170,516
96	EGPXI = Electric and Gas Plant in Service defined as PXI above plus Gas Plant as recorded in FERC Account 118 excluding ARO, if any	B.1 Ln 39 =	6,251,885	8,707,870	6,630,507	2,575,669	828,775
97	PPREG = Ratio of Prod. Plant to Electric & Gas Plant ex Intangible	(Ln 95 / Ln 96) =	47.03%	57.03%	56.94%	29.87%	20.57%
98	**FPRB = Fixed Production Rate Base**	Ln 72 + Ln 73 - Ln 74 + Ln 75 - (Ln 76 * Ln 81) + (Ln 82 - Ln 83 + Ln 84 - Ln 85) * Ln 90 + (Ln 91 + Ln 92) * Ln 97 =	340,098	549,795	485,131	290,969	(6,362)
99	**CM = Weighed average cost of capital**	Ln 48 =	8.74%	8.36%	8.85%	8.00%	7.71%
100	**F = Federal & State Income Tax**	Ln 57 or Ln 58 =	3.95%	3.10%	3.37%	2.98%	2.77%
101	**FPX = Fixed Production Expense**						
102	FPX = NFPOMXN + DEXN + [(AG + GDX + IAX) * PLR] + (OT * PPR)						
	where:						
103	NFPOMXN = Non-Fuel Production O&M Expense excluding Nuclear; i.e. costs recorded in FERC Accounts 500 through 514 plus Accounts 535 through 554 plus Account 556 less Accounts 501 and 547	B.3 Ln 123 =	43,911	69,660	58,972	49,910	7,614
104	DEXN = Depreciation and Amortization Expense associated with the plant investment in PPXN as recorded in FERC Account 403 and 404, as approved by Retail Regulators unless the jurisdiction for determining the depreciation rate is vested in the FERC under otherwise applicable law	B.4 Ln 165 =	27,369	42,017	26,787	13,949	6,188
105	AG = Administrative and General (A&G) O&M Expense recorded in FERC Accounts 920 through 935	B.4 Ln 177 =	141,572	178,153	146,604	75,062	56,442
106	GDX = General Plant Depreciation Expense recorded in FERC Account 403	B.4 Ln 173 =	10,420	12,187	6,252	4,799	1,312
107	IAX = Intangible Plant Amortization Expense recorded in FERC Account 404	B.4 Ln 175 =	20,121	20,615	16,210	9,547	4,705
108	PLR = Ratio of Production Labor to Total Labor excluding A&G Labor	Ln 90 =	67.75%	54.79%	65.92%	32.98%	29.07%
109	OT = Other Tax Expense recorded in FERC Account 408	B.4 Ln 195 =	75,585	131,249	61,168	63,126	27,232
110	PPR = Ratio of Production Plant to Total Plant excluding Intangible Plant						
111	PPR = PP / PXI						
	where:						
112	PP = Production Plant in Service	Ln 95 =	2,940,550	4,965,706	3,775,669	769,236	170,516
113	PXI = Electric Plant in Service excluding Intangible Plant	Ln 37 =	6,251,885	8,615,502	6,630,507	2,575,669	638,065
114	PPR = Ratio of Production Plant to Total ex. Intangible	(Ln 112 / Ln 113) =	47.03%	57.64%	56.94%	29.87%	26.72%
115	**FPX = Fixed Production Expense**	Ln 103 + Ln 104 + [(Ln 105 + Ln 106 + Ln 107) * Ln 108] + (Ln 109 * Ln 114) =	223,434	302,911	232,036	112,201	39,235
116	**ITC = Investment Tax Credit Amortization** recorded in FERC Account 411	B.4 Ln 197 =	4,192	5,521	2,968	1,326	354
117	TX = Composite Corporate After Tax Income Tax Rate						
118	TX = 1-T						
119	TX = Composite Corporate After Tax Income Tax Rate	(1 - Ln 55) or (1 - Ln 56) =	60.77%	63.29%	61.52%	61.75%	61.52%
120	PPR = Ratio Production Plant to Total ex. Intangible	Ln 114 =	47.03%	57.64%	56.94%	29.87%	26.72%
121	**FPC = Fixed Production Cost**	Ln 98 * (Ln 99 + Ln 100) + Ln 115 - [(Ln 116 / Ln 119) * Ln 120] =	263,348	360,890	288,572	143,508	38,415

[5] Labor ratios shall be determined based on the payroll expense for each Operating Company, including those payroll expenses billed to it by EOI and ESI, for the twelve months ended December 31 of the previous year.

ENTERGY SERVICES, INC.
ENTERGY SYSTEM AGREEMENT SERVICE SCHEDULE MSS-3 2007 FILING IN COMPLIANCE WITH FERC OPINION NOS. 480 AND 480-A
FOR THE YEAR ENDED DECEMBER 31, 2006
(000's)

Section 30.13: Average Production Cost

Line No.		Formula / Reference	System	EAI	EGS	ELL	EMI	ENOI
122	**APC = Average Production Cost**							
123	**APC = AVPC + AFPC**							
124	where:							
125	AVPC = Company's Allocation of the System's Variable Production Cost							
126	AVPC = SVPC * ER							
	where:							
127	SVPC = Sum of the Companies' Actual Variable Production Cost	Ln 24 =	5,518,932					
128	ER = Energy Ratio							
129	ER = Each Company's Annual Energy (Net Area Requirements less Non-Requirments Sales for Resale) divided by the sum of all Companies Annual Energy	B.4 Ln 204 =		22.28%	34.90%	25.90%	13.34%	3.58%
130	AVPC = Company's Allocation of the System's Variable Production Cost	Ln 127 * Ln 129 =	5,518,932	1,229,618	1,926,107	1,429,403	736,225	197,578
131	AFPC = Company's Allocation of the System's Fixed Production Cost							
132	AFPC = SFPC * DR							
	where:							
133	SFPC = Sum of the Companies' Actual Fixed Production Cost	Ln 25 =	1,094,733					
134	DR = Demand Ratio							
135	DR = The ratio for each Company of its 12 CP loads divided by the sum of all Companies' 12 CP loads as defined in Section 2.16 (a)	B.4 Ln 208 =		23.39%	34.47%	23.96%	14.44%	3.74%
136	AFPC = Company's Allocation of the System's Fixed Production Cost	Ln 133 * Ln 135 =	1,094,733	256,058	377,355	262,298	158,080	40,943
137	**APC = Average Production Cost**	Ln 130 + Ln 136 =	6,613,665	1,485,676	2,303,462	1,691,701	894,305	238,521

Exhibit LC-36

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.	)	DOCKET NO. ER07-956-000

CROSS-ANSWERING TESTIMONY

OF

STEPHEN J. BARON

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

March 2008

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ENTERGY SERVICES, INC., et al.	)	DOCKET NO. ER07-956-000

CROSS-ANSWERING TESTIMONY OF STEPHEN J. BARON

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. Have you previously filed testimony in this proceeding?

A. Yes. I submitted Direct Testimony.

Q. What is the purpose of your Cross-Answering Testimony?

A. I am responding to the Direct and Answering Testimony of FERC Staff witness John K. Sammon. I will address issues raised in Mr. Sammon's testimony associated with Entergy's failure to use an energy allocation factor in its bandwidth calculations that is consistent with the methodology used in the development of exhibits ETR-26 and

1 ETR-28 that the Commission relied on as the basis for all future production cost
2 calculations. Mr. Sammon concludes that Entergy's compliance bandwidth
3 calculation does not conform to the methodology in ETR-26 and ETR-28 and that
4 Entergy did not file the requisite Section 205 filing to seek a change. Nevertheless,
5 he appears to conclude that the Company's bandwidth calculation filing is acceptable
6 because the "Commission apparently inadvertently accepted this particular change to
7 the ETR-28 methodology."[1] I disagree with Mr. Sammon's conclusions and findings
8 on this issue.
9
10 **Q. Before responding to Mr. Sammon's testimony, would you briefly summarize**
11 **this net area requirements issue and its significance in the bandwidth**
12 **calculation?**
13
14 A. As I discussed in my Direct Testimony, this issue concerns the Company's failure to
15 apply the methodology used in Exhibits ETR-26 and ETR-28 for the development of
16 the energy allocation factor ("ER") employed in the bandwidth calculation to allocate
17 variable production costs to each Operating Company. The bandwidth calculation
18 involves a comparison between 1) each Entergy Operating Company's ("EOC")
19 actual 2006 production costs and 2) the EOC's allocated share of the Entergy

[1] Sammon Direct and Answering Testimony at page 25, lines 11 to 12.

System's total production costs.[2] Of the total $6.6 billion in 2006 Entergy System production costs, $5.5 billion are variable production costs that are allocated to EOCs on the basis of the energy allocation factor "ER." Given the magnitude of the costs being allocation ($5.5 billion), even very small changes in the computation of the ER factor can have multi-million dollar impacts on the payments and receipts that are determined in the bandwidth calculation.

The issue before the Commission in this case is the propriety of Entergy's calculation of this ER factor. In Exhibit ETR-26 and ETR-28, the energy allocation factor was developed using Intra-System Bill ("ISB") "To Area" mWh data. As I discuss in my Direct Testimony, the ISB data has always been recognized by Entergy as reflecting "requirements" energy and thus it was reasonable to rely on this ISB data to develop the energy allocation factor. Because the "To Area" mWh data for each EOC represented "requirements" mWh energy, it explicitly did not include "non-requirements" energy. Section 30.13 of the Company's MSS-3 tariff defines the ER allocation factor as:

> ER= Each Company's Annual Energy (Net Area Requirements less Non-Requirements Sales for Resale) Divided by the Sum of all Companies Annual Energy (Energy Ratio).

[2] The Entergy System total production costs are simply the summation of the actual production costs for all EOCs.

1 Based on Entergy's prior position categorizing the ISB load data as "requirements"
2 energy and the undisputed fact that Entergy had used this ISB "To Area" data to
3 develop Exhibits ETR-26 and ETR-28, there was no reason to believe that Entergy
4 was implicitly modifying its bandwidth calculations in MSS-3 to incorporate an
5 alternative methodology for the development of the "ER" allocation factor.
6 Furthermore, Entergy's position has been that "non-requirements sales" consisted of
7 "System Sales" that are made jointly by all Operating Companies. Based on
8 Entergy's prior positions, it was reasonable to interpret its MSS-3 tariff language to
9 be consistent with the use of ISB load data for the calculation of the "ER" factor.
10 Now, in its compliance filing, Entergy uses FERC Form 1 data to calculate the ER
11 factor, resulting in a significant change the in payments and receipts for each EOC.
12
13 **Q. Does Mr. Sammon agree with your basic position on this issue?**
14
15 A. In part. With regard to the factual issues, Mr. Sammon agrees that the Company
16 utilized ISB data to develop the energy allocation factor in ETR-28 and "potentially
17 in ETR-26" (Sammon Testimony at page 17, lines 4 to 5).[3] He also acknowledges
18 that the Company is now using FERC Form 1 data to develop the ER allocation
19 factor and that Entergy did not make a Section 205 filing to request approval for the
20 change in methodology, despite the Commission's stated requirement that any

[3] In my Direct Testimony, I established that ISB data was also used in the development of Exhibit ETR-26.

1 changes to the methodology adopted by the Commission would require such a
2 Section 205 filing. As I discussed in my Direct Testimony, and confirmed by Mr.
3 Sammon on page 20 at lines 12 through 19 of his Testimony, the Commission
4 explicitly requires a Section 205 filing for changes to the methodology in Exhibits
5 ETR-26 and ETR-28. This requirement was enforced by the Commission even in the
6 case where errors were identified in those exhibits.[4]
7
8 Mr. Sammon, however, fails to acknowledge Entergy's position that energy included
9 in an EOC's "load shape" is, by definition, "requirements" load. Either Mr. Sammon
10 believes that this is not important, or he was not aware of the Company's position on
11 this important issue. As I discussed in my Direct Testimony (LC-1, pages 35 to 38),
12 in Docket ER03-583 Entergy took the position that all sales made individually by an
13 Operating Company (including retail and wholesale requirements sales, as well as
14 opportunity sales to third parties) were "requirements" sales for System Agreement
15 purposes and were reflected in the ISB "To Area" data. This is a material and
16 significant factual predicate for understanding the problem with the Company's
17 change to the FERC Form 1 data for calculating the ER factor in the bandwidth
18 computations. The Company's compliance tariff (MSS-3, Section 30.13) did not

[4] Exhibits ETR-26 and ETR-28 used an incorrect state income tax rate for the Texas jurisdiction of Entergy Gulf States. Even though it was not disputed by any party that the tax rate was incorrect, the Commission required Entergy to make a Section 205 filing to fix the error because it was a change in methodology.

1 provide any notice that the Company intended to revise it's interpretation of
2 "requirements" and "non-requirements" sales.
3
4 **Q. Are there other points or conclusions in Mr. Sammon's testimony on which you**
5 **disagree?**
6
7 A. Yes. The most significant disagreement that I have with Mr. Sammon is his
8 conclusion that the Company's use of FERC Form 1 data is permissible (even though
9 it changed the methodology from ETR-26 and ETR-28 without the requisite Section
10 205 filing) because "The Bandwidth formulas in Service Schedule MSS-3 are the
11 filed rates accepted and approved by the Commission. Only if there is an ambiguity
12 in a formula would I look to the methodology in ETR-28."[5] Mr. Sammon appears to
13 be arguing that if the FERC accepts a change in methodology without realizing that it
14 is a different methodology from the approved ETR-26 and ETR-28 method then the
15 "approved" tariff is appropriate. In his Testimony Summary attached to his
16 testimony, Mr. Sammon is even more direct on his position when he states that the
17 Company did not "explicitly inform the Commission of the change" in methodology
18 and then states:
19 **Mr. Sammon testifies that because the Commission accepted Entergy's**
20 **proposed definition of "ER" that Entergy's definition of "ER" is now the**

[5] Sammon Direct Testimony at page 22, lines 15 to 17. Mr. Sammon goes on to conclude that there is such an ambiguity in the formula on page 23 at line 1 of his testimony.

filed lawful rate and it takes precedence over any "methodology" conflict in ETR-26/28. (Sammon Testimony Summary)

I disagree with Mr. Sammon's position for a number of reasons. I am advised by LPSC counsel that there is no provision in the Federal Power Act that would support Mr. Sammon's conclusion that if a utility makes a Section 205 filing that incorporates a methodology in strict violation of a Commission directive (in this case the directive that the bandwidth methodology must conform with ETR-26 and ETR-28) and the Commission subsequently approves the filing because the Commission is unaware of the violation, the tariff is lawful and should now be accepted. Section 205(d) of the Federal Power Act requires a "notice" of any change in a rate or rate schedule that states "plainly the change or changes to be made in the schedule or schedules then in force ..." Counsel advises that the notice fails in this case because Entergy did not provide any such notice of a change and did not explain that it was using FERC Form 1 data in lieu of ISB load data and did not provide notice that it was changing its interpretation of the meaning of "non-requirements." This change is apparently only for Section 30.13 of Rate Schedule MSS-3, but not for Rate Schedules MSS-1, MSS-2 or Sections 30.03, 30.04 or 30.05 of Rate Schedule MSS-3. These sections of MSS-3 (30.03, 30.04 and 30.5) provide for the allocation of the cost of energy among EOCs via the MSS-3 exchange (Entergy System Pool). In these sections of MSS-3, third party opportunity sales made individually by an EOC are included in "requirements" for the purposes of allocating the lowest cost energy the EOC "having such sources."

1

2 Whether or not Mr. Sammon's position is consistent with the law, I do not believe
3 that it is consistent with the public interest. The assertion that the Commission
4 unwittingly approved a provision of the MSS-3 tariff that violated the Commission's
5 stated policy in its November 17, 2006 order does not provide a reasonable basis to
6 now accept the provision. This is especially true given the fact that the Company did
7 not reveal the new meaning of the approved provision until after the Commission
8 accepted it. As I stated in my Direct Testimony, if the Company desires to "fix" the
9 problem with the definition of the energy allocation factor in MSS-3, it is required to
10 make a Section 205 filing to do so. Entergy cannot, as Mr. Sammon concludes
11 "resort to self-help" to fix this problem.

12

13 Mr. Sammon agrees that the Company could easily have made a Section 205 filing to
14 fix the synchronization problem associated with the use of ISB data discussed by Mr.
15 Sammon, yet chose not to do so. Whether or not a synchronization problem occurs
16 with the use of the ETR-26/28 methodology is not the issue; the Commission has
17 already ruled that even to fix obvious errors requires a Section 205 or Section 206
18 filing if the fix represents a change in the ETR-26/28 methodology.

19

20 **Q. Are there additional reasons why you disagree with Mr. Sammon's position that**
21 **Entergy's switch in methodologies is permissible?**

1

2 A. Yes. Mr. Sammon's position endorsing Entergy's use of FERC Form 1 data, in lieu
3 of the ISB data required by ETR-26/28 is not supported based on the specific
4 language in the definition of the "ER" factor. Specifically, Mr. Sammon states that
5 MSS-3 requires the "ER" factor to exclude non-requirements sales, which in turn,
6 requires the use of FERC Form 1 data instead of the ISB "To Area" data. As I
7 previously discussed in my Direct Testimony (see Exhibit LC-1 at pages 35 to 38),
8 Entergy has consistently argued that the ISB data is "requirements" energy.
9 Therefore, there is no inconsistency between the definition of the "ER" factor and the
10 use of ISB mWh data.

11

12 **Q. On page 23 of Mr. Sammon's testimony, beginning on line 11, he discusses this**
13 **last issue, whether the ISB data should be characterized as "requirements" data.**
14 **Would you respond to his testimony on this issue?**

15

16 A. Mr. Sammon testifies that the formula for developing the "ER" factor in MSS-3
17 (Section 30.13) is "net area requirements" less "non-requirements." He then argues
18 that the ISB data represents the "net area requirements" portion of the equation but
19 that it does not subtract out the "non-requirements" data as called for in the ER
20 formula. His conclusion is that the use of the ISB data alone (as was done in ETR-

26/28 and approved by the Commission for the bandwidth calculation) is "unreasonable."[6]

Q. Is Mr. Sammon correct on this point?

A. No. Mr. Sammon is incorrect for a number of reasons. First, he admits that the Company unilaterally changed the formula for the energy allocator in MSS-3 from the Commission mandated methodology employed in ETR-26/28, without the benefit of a Section 205 filing to seek approval for such a change. Second, Entergy has consistently argued that the ISB data represents "requirements" load. Entergy's witness in this case testified in a previous case (ER03-583) that "A load is included in the Company's load shape and its 'requirements' under Section 3.05 if that load is counted in calculating a Company's load responsibility ratio."[7] The "load responsibility data that Mr. Louiselle referred to is calculated directly from the same ISB "To Area" mWh that was used in ETR-26/28 to develop the energy allocator. It follows then, that this mWh energy data represents "requirements" data. As such, contrary to Mr. Sammon's position, there would be no basis to further subtract out so-called non-requirements load from the ISB data.

[6] Sammon Direct, page 23 at line 20.
[7] Rebuttal Testimony of Bruce Louiselle in Docket ER03-583 (excerpted in Exhibit LC-12 of my Direct Testimony)

1 **Q. Do you agree with Mr. Sammon's conclusion that Entergy should have made a**
2 **Section 205 filing to correct this problem?**
3
4
5 A. Yes. The only reasonable conclusion on this issue is the one discussed by Mr.
6 Sammon on page 26 of his testimony when he states "If Entergy wished to make a
7 change in an ETR-28 data source or if it discovered an error in ETR-28 it should not
8 resort to self-help. It should have made a timely Section 205 filing to correct the data
9 source error."
10
11 I agree completely with this portion of Mr. Sammon's testimony. If there is a so-
12 called "synchronization error," in ETR-26/28, it should be corrected through a
13 Section 205 filing, not be a unilateral revision to the methodology.
14
15 **Q. Does this complete your testimony?**
16
17 A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Stephen J. Baron

Sworn to and subscribed before me on this
26th day of March 2008.

Jessica K. Inman

Notary Public

JESSICA K. INMAN
MY COMMISSION EXPIRES
NOTARY PUBLIC
JULY 31ST, 2011
CHEROKEE COUNTY, GA

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Stephen J. Baron

Sworn to and subscribed before me on this
27th day of March 2008.

Jessica K. Inman

Notary Public

JESSICA K. INMAN
MY COMMISSION EXPIRES
NOTARY PUBLIC
JULY 31ST, 2011
CHEROKEE COUNTY, GA