Entergy

Entergy Operations, Inc
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John F. McCann
Vice President – Nuclear Safety,
Emergency Planning and Licensing

CNRO-2012-00007
October 15, 2012

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
11555 Rockville Pike
Rockville, MD 20852-2738

SUBJECT: **Status of Decommissioning Funding - Entergy Operations, Inc**

Arkansas Nuclear One, Units 1 & 2
Docket Nos. 50-313 & 50-368

River Bend Station
Docket No. 50-458

Grand Gulf Nuclear Station
Docket No. 50-416

Waterford 3 Steam Electric Station
Docket No. 50-382

References:

1. Entergy letter CNRO-2012-00005, "Application for Order Approving Transfers of Licenses and Conforming License and ESP Amendments," September 27, 2012.
2. Entergy letter CNRO-2011-00001, "Status of Decommissioning Funding for Plants Operated by Entergy Operations, Inc," March 31, 2011.
3. NUREG-1307, "Report on Waste Burial Charges," Revision 14, November 2010.
4. NRC Regulatory Issue Summary 2001-07, "10 CFR 50.75(f)(1) Reports on the Status of Decommissioning Funds," Revision 1 dated January 8, 2009.

Dear Sir or Madam:

NRC regulations regarding the reporting of decommissioning funding status requires that for plants involved in mergers or acquisitions, the status report shall be submitted annually instead of at the usual biennial frequency. On September 27, 2012 Entergy Operations, Inc (Entergy) submitted a license application (Reference 1) to NRC regarding an indirect license transfer involving the subject plants. Entergy has determined that these proposed transactions satisfy the 'mergers or acquisitions' clause of 10 CFR 50.75(f)(1).

Therefore, on behalf of Entergy Arkansas, Inc. for Arkansas Nuclear One (ANO), System Entergy Resources, Inc. (SERI) and South Mississippi Electric Power Association (SMEPA) for

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Grand Gulf Nuclear Station (GGNS), Entergy Gulf States, L.L.C. for River Bend Station (RBS) and Entergy Louisiana, LLC for Waterford 3 Steam Electric Station (WF3), Entergy Operations, Inc. hereby submits the information requested in 10 CFR 50.75(f)(1) for power reactors operated by Entergy for the year ending December 31, 2011. The previous biennial status report (Reference 2) provided the funding status for the year ending December 31, 2010.

The estimated minimum decommissioning fund values were determined using the methodology described in NUREG-1307, Revision 14 (Reference 3) and the information provided in Attachments 1 through 4 is based on RIS 2001-07, Revision 1 (Reference 4).

Included with this submittal to supplement Attachments 1 through 4 is information consistent with NRC letter dated March 11, 2011 (ML110280410). This information includes certain agreements providing for nuclear plant power sales (that may, from time to time, include decommissioning collections) between Entergy operating companies that invoke Federal Energy Regulatory Commission (FERC) Service Schedule MSS-4 in the FERC-approved Entergy System Agreement or other FERC tariffs. Entergy respectfully asserts that these rate-making tariffs should not be viewed as "contractual obligations" as used in 10 CFR 50.75(e)(1)(v). These arrangements describe exchanges among regulated utilities that operate within the confines of a FERC-approved tariff, under the ratemaking jurisdiction of the FERC. As such, the various agreements are simply extensions of the FERC tariff and not the type of "contractual obligations" contemplated by 10 CFR 50.75(e)(1)(v), and Entergy's decommissioning funding is still provided by the external sinking fund method in accordance with 10 CFR 50.75(e)(1)(ii). In an abundance of caution and in a spirit of cooperation, however, Entergy is providing the various tariff agreements for each affected plant. Footnotes associated with Line Item 5 in Attachments1 through 4 (regarding contracts) further explain the relationships between the current ratepayer decommissioning funding assurance mechanisms and these system instruments.

Although not required by NRC regulations, Entergy is also providing the Minimum Funding Assurance calculation worksheets (Attachment 5) for the subject plants. These worksheets are derived from NRC Office Instruction LIC-205, Revision 4 and are provided to assist the reviewer in understanding the basis for figures reported elsewhere in this filing.

This submittal contains no new commitments. Please address any comments or questions to Mr. Bryan Ford, Senior Manager, Licensing at 601-368-5516.

Sincerely,

JFM / bsf / ljs / krk

cc: next page

cc:

NRC PM (ANO)
NRC PM (GGNS)
NRC PM (RBS)
NRC PM (WF3)
NRC Region IV (w/o att)
Arkansas Department of Health
Mississippi Department of Health
Louisiana Department of Environmental Quality

Mr. J. A. Aluise (ENT)
Ms. W. C. Curry (ECH)
Mr. L. J. Smith (ECH)
Mr. B. F. Ford (ECH)

Attachments:

1 Entergy Arkansas, Inc. – ANO 1 & 2 Status Reports (2 pages)

1-A Entergy Arkansas, Inc. – Calculation of Minimum Amount (1 page)

1-B Changes to Trust Agreements, APSC Order in Docket No. 87-166-TF, Order Nos. 50 (19 pages)

1-C APSC Order in Docket No. 87-166-TF, Order Nos. 55 (6 pages)

1-D ANO Decommissioning Cost Rider NDCR Update and Rate Sch.37 Workpapers (64 pages)

1-E Entergy Arkansas, Inc. Unit Power Purchase Agreements under Service Sch MSS-4 (53 pages)

2 SERI & SMEPA - GGNS Status Report (1 page)

2-A SERI & SMEPA – Calculation of Minimum Amount (1 page)

2-B Schedule of Remaining Principle Payments – GGNS (1 page)

2-C FERC Order in Docket No. ER95-1042 and Availability Agreement (39 pages)

3 Entergy Gulf States Louisiana, LLC RBS Status Report – 70% Regulated (1 page)

3-A Entergy Gulf States Louisiana, LLC – Calculation of Minimum Amount (1 page)

3-B Schedule of Remaining Principle Payments – RBS (1 page)

3-C Entergy Gulf States Louisiana, LLC RBS Status Report – 30% Non-Regulated (1 page)

3-D LPSC Order in Docket No.U-31237 (20 pages)

3-E PUCT Order in Docket No. 37744 (16 pages)

3-F FERC Order in Docket Nos. ER86-558-002 (9 pages)

3-G MSS-4 Agreement and FERC's acceptance (13 pages)

4 Entergy Louisiana, LLC – WF3 Status Report (1 page)

4-A Entergy Louisiana, LLC - Calculation of Minimum Amount (1 page)

4-B Schedule of Remaining Principle Payments – WF3 (1 page)

4-C LPSC Order in Docket No. U-31237 (20 pages)

4-D CNO Resolution R-95-1081 in Docket UD-95-1 and IRS Schedule of Ruling Amounts (6 pages)

5. Minimum Funding Assurance Calculation Worksheets (9 pages)

CNRO-2012-00007

SERIES 1 ATTACHMENTS

1 Entergy Arkansas, Inc. – ANO 1 & 2 Status Reports (2 pages)

1-A Entergy Arkansas, Inc. – Calculation of Minimum Amount (1 page)

1-B Changes to Trust Agreements, APSC Order in Docket No. 87-166-TF, Order Nos. 50 (19 pages)

1-C APSC Order in Docket No. 87-166-TF, Order Nos. 55 (6 pages)

1-D ANO Decommissioning Cost Rider NDCR Update and Rate Sch.37 Workpapers (64 pages)

1-E Entergy Arkansas, Inc. Unit Power Purchase Agreements under Service Sch MSS-4 (53 pages)

Attachment 1
(2 pages)

ENTERGY ARKANSAS, INC.
Status Report of Decommissioning Funding
For Year Ending December 31, 2011 - 10 CFR 50.75(f)(1)

Plant Name: **Arkansas Nuclear One Unit 1 (ANO 1)**

1. Minimum Financial Assurance (MFA) Estimated per 10 CFR 50.75(b) and (c) (2011$):	$440.9 million[1]
2. Decommissioning Trust Fund Total As of 12/31/11:	$303.9 million
3. Annual amounts remaining to be collected:	$0[2]
4. Assumptions used: Rate of Escalation of Decommissioning Costs:	Approx. 2.66%[3]
Rate of Earnings on Decommissioning Funds:	Approx. 5.78%[3]
Authority for use of Real Earnings Over 2%:	APSC Order[3]
5. Contracts upon which licensee is relying For Decommissioning Funding:	See footnote[4]
6. Modifications to Method of Financial Assurance since Last Report:	None
7. Material Changes to Trust Agreements:	None

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1 See Attachment 1-A

2 Decommissioning funding has been suspended by the Arkansas Public Service Commission in Docket No. 87-166-TF. The NRC has granted license renewal to 5/2034.

3 Approved in APSC Docket No. 87-166-TF, Order Nos. 50 & 55 –See Attachments 1-B, 1-C and 1-D.

4 See the agreements in Attachment 1-E which are unit power purchase agreements under the MSS-4 Agreement, a FERC tariff. It is the licensee's position that these are not 10 CFR §50.75(e)(1)(v) "contractual obligations", but rather cost of service tariffs which may appropriately be used to fund the external sinking fund in accordance with 10 CFR §50.75(e)(1)(ii). Out of abundance of caution, the licensee identifies this information here.

Attachment 1

ENTERGY ARKANSAS, INC.
Status Report of Decommissioning Funding
For Year Ending December 31, 2011 - 10 CFR 50.75(f)(1)

Plant Name: **Arkansas Nuclear One Unit 2 (ANO 2)**

1.	Minimum Financial Assurance (MFA) Estimated per10CFR50.75(b) and (c) (2011$):	$459.1 million[1]
2.	Decommissioning Fund Total As of 12/31/11:	$237.7 million
3.	Annual amounts remaining to be collected:	$0[2]
4.	Assumptions used:	
	Rate of Escalation of Decommissioning Costs:	Approx. 2.66%[3]
	Rate of Earnings on Decommissioning Funds:	Approx. 6.06%[3]
	Authority for use of Real Earnings Over 2%:	APSC Order[3]
5.	Contracts upon which licensee is relying For Decommissioning Funding:	See footnote[4]
6.	Modifications to Method of Financial Assurance since Last Report:	None
7.	Material Changes to Trust Agreements:	None

1 See Attachment 1-A

2 Decommissioning funding has been suspended by the Arkansas Public Service Commission in Docket No. 87-166-TF. The NRC has granted license renewal to 7/2038.

3 Approved in APSC Docket No. 87-166-TF,Order Nos. 50 & 55, see Attachments 1-B, 1-C and 1-D.

4 See the agreements in Attachment 1-E which are unit power purchase agreements under the MSS-4 Agreement, a FERC tariff. It is the licensee's position that these are not 10 CFR §50.75(e)(1)(v) "contractual obligations", but rather cost of service tariffs which may appropriately be used to fund the external sinking fund in accordance with 10 CFR §50.75(e)(1)(ii). Out of abundance of caution, the licensee identifies this information here.

Attachment 1-A
(1 page)

ENTERGY ARKANSAS, INC.
Calculation of Minimum Amount
For Year Ending December 31, 2011 - 10 CFR 50.75(f)(1)

Entergy Arkansas, Inc.: 100% ownership interest
Plant Location: Russellville, Arkansas
Reactor Type: Pressurized Water Reactor ("PWR")
ANO Unit 1 Power Level: <3,400 MWt (2,568 MWt)
ANO Unit 1 PWR Base Year 1986$: $97,598,400
ANO Unit 2 Power Level: <3,400 MWt (3,026 MWt)
ANO Unit 2 PWR Base Year 1986$: $101,628,800
Labor Region: South
Waste Burial Facility: Generic Disposal Site

10CFR50.75(c)(2) Escalation Factor Formula:
0.65(L) +0.13(E) +0.22(B)

	Factor
L=Labor (South)	2.28[1]
E=Energy (PWR)	2.58[2]
B=Waste Burial-Vendor (PWR)	12.28[3]

PWR Escalation Factor:
0.65(L) +0.13(E) +0.22(B)= 4.51703

1986 PWR Base Year $ Escalated:

ANO1: $97,598,400 * Factor= $440,854,517

ANO2: $101,628,800 * Factor= $459,059,939

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1 Bureau of Labor Statistics, Series Report ID: CIU2010000000220i (4th Quarter 2011)
2 Bureau of Labor Statistics, Series Report ID: wpu0543 and wpu0573 (December 2011)
3 Nuclear Regulatory Commission: NUREG-1307 Revision 14, Table 2.1 (2010)

Attachment 1-B
(19 pages)

APSC Order in Docket No. 87-166-TF, Order No. 50

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF ARKANSAS POWER & LIGHT COMPANY'S PROPOSED NUCLEAR DECOMMISSIONING COST RIDER M26 AND PROPOSED DEPRECIATION RATE RIDER M41	)))))	DOCKET NO. 87-166-TF ORDER NO. 50

ORDER

On March 31, 2009, Entergy Arkansas, Inc.[1] ("EAI" or "Company") filed its *Motion for Approval of Revised Estimate of Arkansas Nuclear One Decommissioning Costs and Certain Other Changes to the ANO Decommissioning Trust Funds* ("Motion") with the supporting Second Supplemental Testimony of EAI witness Michael A. Caruso, and the Direct Testimonies and Exhibits of EAI witnesses Rory L. Roberts, Rebecca L. Bowden and William A. Cloutier, Jr. In addition, EAI previously filed the Supplemental Testimony and Exhibits of EAI witness Caruso on July 24, 2008, which, pursuant to Order No. 47 in this Docket, had been held in abeyance until such time that EAI filed its revised estimate of the Arkansas Nuclear One ("ANO") Decommissioning Costs.

On April 23, 2009, the Arkansas Public Service Commission ("APSC" or "the Commission") issued Order No. 48 in this Docket suspending EAI's Motion and establishing a procedural schedule. Pursuant to Order No. 48, on July 24, 2009, the General Staff of the Commission ("Staff") filed the Direct Testimony and Exhibits of its witness, Donna Gray, Director of the General Staff Financial Analysis. On August 24, 2009, EAI filed the Rebuttal Testimonies and Exhibits of EAI witnesses Steven K. Strickland, Albert C. King, III, Caruso, Bowden, and Cloutier. Staff filed the Surrebuttal

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[1] Previously Arkansas Power and Light Company.

Testimony of Staff witness Gray on August 28, 2009. On September 4, 2009, EAI filed the Sur-Surrebuttal Testimony of EAI witness Strickland.

On September 11, 2009, EAI and Staff filed a *Joint Motion to Adopt Stipulation of Entergy Arkansas, Inc. and the General Staff of the Commission* ("Joint Motion"), which included, as Attachment A, the *Stipulation of Entergy Arkansas, Inc. and the General Staff of the Commission* ("Stipulation") proposing a settlement of all issues related to EAI's March 31, 2009, Motion. In that Joint Motion, the parties asked that the Commission cancel the hearing set for September 15, 2009, and, after it had reviewed and considered the Stipulation, "enter an order approving the Stipulation without a hearing, or, if the Commission desires a hearing to consider the Stipulation or the full merits of the case, that the Commission set a hearing at a later time to accommodate the entry of an order no later than October, 15, 2009." (Joint Motion at 1, Footnote Omitted). On September 11, 2009, the Commission issued Order No. 49 canceling the hearing subject to its being rescheduled by subsequent order.

Background

In 2007, EAI and the Staff agreed to postpone the 5-year ANO decommissioning cost study that was due to be filed on March 31, 2008, pursuant to Order No. 5 of this Docket. Order No. 5 of this Docket provides that, if EAI and the Staff agree, the preparation of a new cost estimate may be deferred. Order No. 46 directed EAI to continue to monitor ANO decommissioning costs and to notify the Staff when the Company believed that changes in conditions justified that a decommissioning cost study be performed.

On July 24, 2008, EAI filed the Supplemental Testimony and Exhibits of EAI witness Caruso introducing the asset allocation studies, completed by Callan Associates

Inc. ("Callan") on April 10, 2008, ("Asset Allocation Studies")[2] for the ANO decommissioning trust funds ("Funds") requesting Commission approval of several proposed changes to the existing investment practices related to the Funds. Mr. Caruso reported that Callan felt it important to point out that, while the Funds are currently well funded, the future funded status is very sensitive to decommissioning cost escalation. The cost escalation rate used in the studies, as required by ANO Nuclear Decommissioning Cost Rider ("Rider NDCR")[3], was the Consumer Price Index - Urban ("CPI-U"); and Callan's estimate of future CPI-U is a 2.75 percent annual increase. The Asset Allocation Studies pointed out that, if actual annual cost escalation exceeds CPI-U by just l percent for ANO Unit 1 and by just 0.5 percent for ANO Unit 2, the Funds likely will be under-funded at the time of decommissioning.

By its Order No. 47, the Commission directed EAI to file a new cost study by March 31, 2009, and held Mr. Caruso's July 24, 2008, Supplemental Testimony and Exhibits in abeyance, subject to subsequent Commission order. In compliance with Order 47, EAI filed its updated cost study ("2008 Cost Study")[4] on March 31, 2009, and in its Motion requested certain considerations related to the Funds and Rider NDCR.

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[2] Caruso Exh. MAC-5 and Mac-6.

[3] Rider NDCR, formerly Rider M26, recovers from ratepayers the expected cost to decommission the two ANO nuclear units. The amounts collected are invested in external trust funds until such time as decommissioning takes place. To calculate the annual recovery under the tariff, Rider NDCR measures the expected future costs to decommission the units compared to the expected future external fund balances available to pay those costs. Since 2001, recovery under Rider NDCR has been zero because expected fund balances have exceeded expected costs. (Gray Direct at 4-5).

[4] (Cloutier Exh. WAC-4).

2008 Cost Study

By its Motion, EAI seeks Commission approval of its 2008 Cost Study[5], which indicates expected cost of $1.265 billion in 2008 dollars to decommission both ANO Unit 1 and 2 which includes costs not previously defined as decommissioning costs for purposes of recovery under the tariff. (Motion at 3-4, Cloutier Direct at 31-33, Cloutier Rebuttal at 5-6, Strickland Rebuttal at 4-5).

EAI witness Cloutier explains that such newly-defined costs included post-shutdown spent fuel management ("Spent Fuel") costs and certain site restoration costs not related to removal of decontaminated material ("Site Restoration"). (Cloutier Direct at 31-33). Mr. Cloutier testifies that Spent Fuel costs are heretofore unanticipated costs EAI will now incur to manage spent fuel because the Department of Energy ("DOE") has breached its contract to timely remove that spent fuel. (Cloutier Rebuttal at 6-9). Mr. Cloutier explains that, pursuant to the Nuclear Waste Policy Act of 1982, DOE is required to contract with nuclear generation owners for disposal of high-level nuclear waste for which DOE assesses a fee. (Cloutier Direct at 28). In this regard, Mr. Cloutier further testifies that EAI has such a contract with the DOE under which DOE was to begin removing spent fuel in January 1998 and under which EAI has already paid $295.9 million in fees and remains obligated to pay an additional one-time fee for pre-April 7, 1983, spent fuel removal, currently measured at $180.4 million ("DOE Obligation"). (Cloutier Direct at 28, Cloutier Rebuttal at 9). According to Mr. Cloutier, EAI now estimates the earliest date DOE will commence removal is 2020 and that EAI will now incur unexpected costs to manage the spent fuel until removal is complete. (Cloutier Rebuttal at 9).

[5] The 2008 Cost Study was performed pursuant to requirements of Order No. 27 issued by the Commission in this Docket and updated to reflect license renewal for both ANO units. (Cloutier Direct at 12-15).

In support of including these costs, EAI witness Strickland testifies that, because these costs will be incurred, they "will have to be addressed at some time, whether through the decommissioning funds or other means." Mr. Strickland, however, states that EAI will agree to defer this issue for later Commission determination. Mr. Strickland testifies that EAI "reserves the right to seek a decision from the Commission on this issue prior to the next required decommissioning cost filing..." and asks that the Commission not foreclose EAI's ability to file an interim update if changes in circumstances warrant. (Strickland Rebuttal at 7-8, Strickland Sur-Surrebuttal at 7-8). Mr. Strickland also clarifies EAI's position with regard to its cost escalation factor used in Rider NDCR, stating that EAI was not, in its current Motion, requesting a change to that factor "but believe[d] it important to inform the Commission that experience is indicating actual decommissioning costs are escalating at a rate higher than the CPI factor...." (Strickland Rebuttal at 16).

Staff witness Gray recommends the Commission deny EAI's request to include costs related to Spent Fuel and Site Restoration in the 2008 Cost Study and further recommends the Commission not defer making a finding on this issue. Ms. Gray recommends the Commission approve the 2008 Cost Study in the amount of $1,049.8 million, exclusive of Spent Fuel and Site Restoration costs. She further recommends that this amount be used in each of the Rider NDCR November 1 filings until the next cost study is due[6]. (Gray Direct at 9, Gray Surrebuttal at 6). Ms. Gray testifies that EAI has failed to substantiate the need to expand the scope of decommissioning costs to include Spent Fuel and Site Restoration costs. She notes that such costs are not recognized by the Nuclear Regulatory Commission ("NRC") as decommissioning costs for purposes of the

[6] EAI's next cost study will be due March 31, 2014. (Gray Surrebuttal at 6).

NRC *Status of Decommissioning Funding Report* ("NRC Funding Report")[7] and that to include such costs "expands . . . the scope of this proceeding and significantly lengthens the time frame over which the trust fund balances remain invested." (Gray Direct at 7-9). She concludes that there will be "ample opportunity" to address these costs as additional information becomes available. (*Id.*).

Equity Investment in Funds

By its Motion, EAI also asks the Commission to approve certain changes in the equity investment currently allowed for the Funds. (Motion at 5-7). EAI witness Caruso testifies that, as recommended in the Asset Allocation Studies prepared by Callan, EAI asks the Commission to approve an increase in the equity allocation targets for the Funds from 50% to 60%, with a plus or minus 5% rebalancing around that 60%, and a general broadening of investment in the U. S. stock market for the Funds. (Caruso Supplemental at 11-12, Caruso Second Supplemental at 3-4, Caruso Exh. MAC-5 and MAC-6). EAI witness Bowden testifies that a change to a 60% equity target results in "greater growth" in the Fund balances than presently under the 50% target, estimating the projected balance in the Funds would be $222.4 million more using a 60% equity target rather than 50%. (Bowden Direct at 7-8).

Staff witness Gray testifies that, based on her review of the Asset Allocation Studies, supporting testimony and exhibits of EAI witnesses Caruso and Bowden, and EAI response to discovery, EAI has substantiated its requests in this regard. Witness Gray recommends the Commission approve EAI's request for a 60% equity allocation target with a +/- 5% rebalancing guideline, and its proposed broadening of equity exposure in the Funds. (Gray Direct at 17).

[7] EAI provides this report to the NRC pursuant to 10 CFR §50.75. (Gray Direct at 8).

Transfer, or "Pour-Over", of Non-Tax Qualified Funds to Tax-Qualified Funds

EAI also asks in its Motion that the Commission approve a transfer of all funds currently invested in its Non-Tax Qualified Trust Fund to the Tax-Qualified Trust Funds.[8] (Motion at 7-9). EAI witness Roberts testifies that prior limits[9] on investment in tax-favorable trust funds have been lifted and that new IRS rules allow, upon IRS approval, a transfer, or "pour-over", of balances held in non-tax qualified funds to tax-qualified funds. (Roberts Direct at 4-6). EAI witness Caruso testifies that allowing a pour-over into EAI's Tax-Qualified Funds will provide a benefit through lower taxes for the amounts transferred which will allow the Funds to grow faster than if held in the Non-Tax Qualified Fund. (Caruso Second Supplemental at 7). EAI witness Bowden projects that Fund balances would be $289.3 million greater as a result of the pour-over. (Bowden Direct at 9).

Staff witness Gray testifies that the Company has substantiated the economic benefits of the pour-over of the amounts held in the Non-Tax Qualified Fund to the Tax-Qualified Funds and, based on those benefits, Ms. Gray recommends the Commission approve that pour-over. (Gray Direct at 18-19). In addition, Ms. Gray also recommends that EAI be required "to demonstrate in annual filings in this docket the actual net tax benefits for ratepayers, with full explanation of the variations from the annual estimates [EAI witness]... Roberts determined in EAI Exhibit RLR-2." (*Id.* at 20).

Revocation of Non-Tax Qualified Trust Agreement

In conjunction with its approval of the pour-over, EAI asks in its Motion for Commission approval to revoke the currently approved Non-Tax Qualified Trust

[8] Investments in tax-qualified funds enjoy tax benefits not shared by investments in non-tax qualified funds, including tax deductibility and a lower tax rate applied to earnings. (Roberts Direct at 4).
[9] Limitations were set by rules under the Internal Revenue Service ("IRS") Code. (*Id.*).

Agreement. The Motion states that the Non-Tax Qualified Trust Agreement will not be needed once the pour-over is complete. (Motion at 9). EAI witness Caruso testifies that the Non-Tax Qualified Trust Agreement is revocable and, pursuant to the Trust Agreement itself and the ANO Decommissioning Trust Fund Guidelines, Commission approval is needed prior to revocation. (Caruso Second Supplemental at 7-8).

Responding to this request, Staff witness Gray asserts that revocation of the Non-Tax Qualified Trust Agreement may be premature absent assurance all funds will be approved by IRS to be transferred. (Gray Direct at 19-20). Ms. Gray, therefore, recommends that the Commission either withhold its approval of the revocation or, alternatively, condition Commission approval on EAI receiving IRS authorization to pour-over the full amount. Ms. Gray additionally recommends the Commission require EAI to file in this docket its request for that authorization and the IRS response. *(Id.)*.

EAI witness Strickland testifies that EAI agrees with Ms. Gray's recommendation that the Commission condition approval of the revocation on IRS authorization to pour-over the entire Non-Tax Qualified Fund balance and, additionally, Mr. Strickland states that EAI will, as Ms. Gray recommends, file its IRS request for that authorization in this docket, as well as the authorization itself. (Strickland Rebuttal at 9).

<u>NRC Funding Report and the DOE Obligation</u>

In addition to addressing the proposals EAI makes in its Motion, Staff witness Gray makes additional recommendations related respectively to the Funding Report EAI provides the NRC and with the status of EAI's DOE Obligation.

Ms. Gray recommends, first, that EAI be ordered to file in this docket its NRC Funding Reports, beginning with the next report which is due March 31, 2011, and every two years thereafter or as required by the NRC. (Gray Direct at 8-9, 12).

Ms. Gray additionally recommends that EAI be ordered to provide substantiation that the DOE Obligation funds will be available when payment is due and that ratepayers will be insulated from any adverse impacts from that payment. Ms. Gray advises that ratepayers have provided funding of the DOE Obligation and continue to pay interest on the on-going obligation. (Gray Direct at 12).

EAI witness Strickland proposes to work with Staff witness Gray in framing an appropriate analysis to address her recommendations regarding EAI's DOE Obligation and to provide that analysis to the Commission within 90 days after the Commission's order in this docket. (Strickland Sur-Surrebuttal at 4-5).

Stipulation

By their Joint Motion, Staff and EAI propose a Stipulation (Attachment A hereto) to settle all issues addressed in this proceeding and ask that the Commission consider the Stipulation based upon the evidence of record and that the scheduled public hearing be cancelled. By Order No. 49, issued on September 11, 2009, the Commission cancelled the hearing previously set for September 15, 2009, and took this matter under advisement based upon the pre-filed testimony and exhibits of the parties.[10] Further, EAI and Staff request that the Commission issue its final Order in this matter by October 15, 2009.

A summary[11] of the Stipulation terms follows:

- The Commission should approve EAI's nuclear decommissioning cost estimate of $1,049.8 million[12] for use in the annual November 1 tariff filings for the years 2009 through 2013;

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[10] The only other party to this Docket, the Arkansas Electric Energy Consumers, Inc., has not participated in this specific phase of this Docket.
[11] This summary is not intended to supplant the actual language of the Stipulation.
[12] The amount specifically excludes Spent Fuel costs.

- EAI will file its next scheduled nuclear decommissioning cost estimate by March 31, 2014, unless EAI and Staff agree to an earlier filing;

- EAI will not file to recover Spent Fuel costs in any proceeding without first providing Staff a reasonable opportunity to examine the proposal, and giving a good faith consideration of any questions, suggestions, or proposed modifications Staff may recommend;

- For the years 2009 through 2013, EAI will use the Annual CPI-U as the escalation rate in its Rider NDCR annual November 1 filings and, absent a Commission-approved change in the established process and methodology, EAI will continue to use the Annual CP - U as the escalation rate for the years 2014 and thereafter;

- EAI's customers have provided and continue to provide funding[13] for the DOE Obligation and as a result no other amount is needed from EAI's retail customers;

- If the current DOE Obligation rate treatment[14] continues until it is paid, EAI will not seek additional amounts from its retail customers for that obligation, except, as discussed below, for prudent costs incurred to provide the Commission with assurance that payment will be made;

- Within ninety (90) days of this Order, EAI will conduct a comprehensive analysis of the costs and benefits of identified options for providing assurance that funds to pay the DOE Obligation will be available when due and EAI and Staff will work cooperatively to jointly propose a recommendation to the Commission within 180 days;

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[13] Ratepayers have provided this funding through "the ratemaking treatment established in Order No. 16 in Docket No. U-2972 and in every general rate case from that point through EAI's most recent rate case in Docket No. 06-101-U." (Settlement at 3).
[14] (*Id.*).

- The Commission should approve the "pour-over" as requested by EAI, with EAI contributing both the funds in the Non-Tax Qualified Trust Fund and the cash benefit of the resulting tax deduction;

- EAI will file in this docket both its request to IRS for approval of the pour-over and the IRS response to substantiate that approval;

- EAI will demonstrate in annual filings in this docket the actual net tax benefits to ratepayers of the pour-over, with full explanation of variations in actual benefits from those reflected in EAI Exhibit RLR-2;

- EAI shall identify the pour-over amounts and the timing thereof in the respective quarterly trust fund reports filed in Docket No. 96-341-U;

- The Commission should condition its approval of the revocation of the Non-Tax Qualified Trust Fund on IRS authorization to pour-over the full amount in that fund;

- The Commission should approve the change in the equity allocation targets for the Funds from 50 percent to 60 percent, maintaining re-balancing at +/- 5 percent around the 60 percent equity target and approve the broadening of the equity market exposure[15] in the funds, and;

- EAI will file with this Commission the NRC Funding Report beginning with the report due March 31, 2011, and every two years thereafter or at such other interval as the NRC may require.

Findings

The Commission has considered the proposed Stipulation in conjunction with the parties' filed Testimony and Exhibits and finds that the Stipulation is fully supported by

[15] The Stipulation states that broadening should be accomplished by "increasing the exposure in the Wilshire 4500 Stock Index Fund, over a reasonable period of time, for both Units so that the ratio of investment in the Wilshire 4500 Stock Index Fund to the total equity in each fund is the same as the Wilshire 4500 Index is to the total U.S. stock market, or about 20 percent." (Stipulation at 5).

the record, settles all issues addressed herein in a reasonable manner, and is in the public interest. Accordingly, the Commission hereby approves in its entirety the Stipulation attached hereto as Attachment A. EAI shall fully comply with the terms and conditions set forth in said Stipulation.

BY ORDER OF THE COMMISSION,

This 13th of October, 2009.

Paul Suskie, Chairman

Colette D. Honorable, Commissioner

Olan W. Reeves, Commissioner

Kristi Rhude (Acting)
Office of the Secretary of the Commission

I hereby certify that the following order issued by the Arkansas Public Service Commission has been served on all parties of record this date by U.S. mail with postage prepaid, using the address of each party as indicated in the official docket file.

Secretary of the Commission
Date 10/13/09

Attachment A

BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF ARKANSAS POWER & LIGHT COMPANY'S PROPOSED NUCLEAR DECOMMISSIONING COST RIDER M26 AND PROPOSED DEPRECIATION RATE RIDER M41	))))	DOCKET NO. 87-166-TF

STIPULATION OF ENTERGY ARKANSAS, INC.
AND THE GENERAL STAFF OF THE COMMISSION

This Stipulation is made by Entergy Arkansas Inc. (EAI) and the General Staff of the Arkansas Public Service Commission (Staff). This Stipulation is voluntarily executed and intended to bind EAI and Staff. EAI and Staff believe that this Stipulation is in the public interest and recommend that the Commission approve and adopt it as the basis for concluding this portion of this Docket.

On March 31, 2009, EAI filed a Motion for Approval of Revised Estimate of Arkansas Nuclear One (ANO) Decommissioning Costs, along with the supporting Second Supplemental Testimony of Michael A. Caruso, Direct Testimony and Exhibits of Rory L. Roberts, Direct Testimony and Exhibits of Rebecca L. Bowden and Direct Testimony and Exhibits of William A. Cloutier, Jr. EAI had also filed the Supplemental Testimony of Michael A. Caruso on July 24, 2008. Staff filed the Direct Testimony and Exhibits of Donna Gray on July 24, 2009. EAI filed the Rebuttal Testimony of Steven K. Strickland, Michael A. Caruso, Rebecca L. Bowden, William A. Cloutier, Jr. and Albert C. King, III on August 14, 2009. On August 28, 2009, Staff filed the Surrebuttal Testimony of Donna Gray. On September 4, 2009, EAI filed the Sur-Surrebuttal

Testimony of Steven K. Strickland.

The testimony filed in this Docket enabled Staff and EAI to better understand the positions taken and the reasons supporting those positions. Following their consideration of such testimony, Staff and EAI discussed their respective positions and sought to achieve a resolution of their differences in a manner which each believes serves the public interest. Staff and EAI now believe that they have achieved such a resolution and have agreed to urge the Commission to issue an order in this docket that incorporates that resolution.

In order to resolve the issues in this docket, Staff and EAI have agreed, after discussions and thorough consideration of respective positions, to recommend the following to the Commission.

1. The Commission should approve the Company's nuclear decommissioning cost estimate of $1,049.8 million, which specifically does not include projections of costs associated with post-shutdown spent fuel management, for use in the annual November 1 tariff filings for the years 2009 through 2013. EAI agrees its next scheduled nuclear decommissioning cost estimate filing is due by March 31, 2014, unless EAI and Staff agree to an earlier filing should a significant change in relevant facts and circumstances warrant, which EAI could then propose for Commission consideration.

EAI agrees it will not file to recover projected costs associated with post-shutdown spent fuel management in any proceeding without first presenting its proposed method to Staff, providing Staff a reasonable opportunity to examine the proposal, and giving a good faith consideration of any questions, suggestions, or proposed modifications Staff may recommend. EAI and Staff agree to work cooperatively to comprehensively identify the relevant issues and evaluate any need for and possible methods of recovery of projected costs associated with post-shutdown spent fuel management.

2. EAI agrees to use the required Annual CPI – Urban as the escalation rate in its annual November 1 filings for the ANO Decommissioning Cost Rider (Rider NDCR) for the years 2009 through 2013. EAI further agrees to use the Annual CPI - Urban as the escalation rate in its annual November 1 filings for 2014 and thereafter unless the Commission approves a change in the established process and methodology, including Rider NDCR, based upon a comprehensive reassessment.

3. EAI acknowledges that its customers have provided and continue to provide funding for EAI's obligation to the DOE for the one-time fee assessed for the disposal of spent nuclear fuel consumed prior to April 7, 1983 through the ratemaking treatment established in Order No. 16 in Docket No. U-2972 and in every general rate case from that point through EAI's most recent rate case in Docket No. 06-101-U. As a result, no other amount is needed from EAI's retail customers, and EAI will not seek, directly or indirectly, any additional amount from its retail customers for this DOE obligation, if this ratemaking treatment continues until EAI pays the DOE obligation pursuant to the contract between EAI and DOE. The exclusive exception for which EAI's retail ratepayers could be charged any additional amounts would be for the reasonable and prudent cost of a method of assurance developed pursuant to paragraph 4 below and approved by the Commission.

4. EAI agrees to conduct a comprehensive analysis within ninety (90) days

of the order approving this Stipulation of the costs and benefits of identified options for providing assurance that the funds owed DOE and collected from ratepayers since 1985 are readily available when due. EAI and Staff agree to work cooperatively to jointly propose a recommendation to the Commission within 180 days of the order approving this Stipulation.

5. The Commission should approve the Company's requested "special transfer" or "pourover" of the balance from the non-tax qualified trust into the tax qualified trust balance, with the Company contributing both the funds in the non-tax qualified trust fund and the cash benefit of the tax deduction for the special transfer to the qualified trust fund. EAI agrees to file in this docket its request to the Internal Revenue Service (IRS) and IRS response to substantiate this approval. EAI agrees to demonstrate in annual filings in this docket the actual net tax benefits for ratepayers, with full explanation of variations from the annual estimates in EAI Exhibit RLR-2. The transferred amounts and the timing thereof shall also be identified in the respective quarterly trust fund reports filed in Docket No. 96-341-U.

The Commission should condition its approval of the revocation of the non-tax qualified fund on the IRS's approval of the pourover, and if the IRS approval is for any amount less than the full amount of the fund, the Commission should not allow revocation of the non-tax qualified fund.

6. The Commission should approve EAI's request to change the equity allocation targets for the ANO funds from the current 50 percent targets to 60 percent, and to maintain the current re-balancing ranges of +/- 5 percent around the 60 percent equity target. The Commission should also approve EAI's request to broaden the equity

market exposure in the funds by increasing the exposure in the Wilshire 4500 Stock Index Fund, over a reasonable period of time, for both Units so that the ratio of investment in the Wilshire 4500 Stock Index Fund to the total equity in each fund is the same as the Wilshire 4500 Index is to the total U.S. stock market, or about 20 percent.

7. EAI agrees to file with this Commission the Nuclear Regulatory Commission (NRC) Status of Decommissioning Funding report required by 10 CFR §50.75 beginning with the next required report due March 31, 2011 and every two years thereafter or at such other interval as the NRC may require.

8. Nothing herein shall revise the current obligations of EAI to comply with any requirements previously established in this docket.

9. Staff and EAI herby waive the need for a hearing as set forth in Order No. 48 in this docket. Staff and EAI hereby also agree to waive their respective rights to cross-examine any witness of either party who would have been called at the hearing scheduled in this docket to support the respective positions of Staff or EAI.

10. In signing and submitting this Stipulation, Staff and EAI recommend to the Commission a resolution of the issues in this docket. However, by signing and submitting this Stipulation, neither Staff nor EAI shall be deemed to have approved or acquiesced in any specific methodologies, procedures, calculation techniques, recommendations or conclusions set forth in the testimony of any party or approved in this Stipulation. Further, none of the provisions in this Stipulation shall constitute an admission by Staff or EAI.

11. This Stipulation shall not have any precedential value in any other proceeding except to the extent necessary to give effect to the terms of this Stipulation.

12. In the event that the Commission does not approve and adopt the terms of this Stipulation in its entirety, this Stipulation shall be void and neither Staff nor EAI shall be bound by any of the agreements or provisions hereof. None of the provisions of this Stipulation shall prejudice, bind, or otherwise affect any party executing this Stipulation should the Commission decide not to approve this Stipulation in its entirety without modification or condition.

13. EAI and Staff agree that this Stipulation is in the public interest and recommend that the Commission adopt and approve this Stipulation.

Dated this 11th day of September, 2009.

Respectfully submitted,

General Staff of the Arkansas
Public Service Commission

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Attachment 1-C
(6 pages)

APSC Order in Docket No. 87-166-TF, Order No. 55

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF ARKANSAS POWER & LIGHT COMPANY'S PROPOSED NUCLEAR DECOMMISSIONING COST RIDER M26 AND PROPOSED DEPRECIATION RATE RIDER M41	)	DOCKET NO. 87-166-TF ORDER NO. 55

ORDER

On November 1, 2011, Entergy Arkansas, Inc.[1] (EAI or the Company) filed in the above-styled Docket its required annual Arkansas Nuclear One (ANO) Decommissioning Cost Rider NDCR[2] (Rider NDCR) update.[3] Contemporaneous with the filing of its update EAI also filed the supporting Supplemental Testimony and Exhibits of its witness Rebecca L. Bowden.

Attachment 1 to EAI's November 1, 2011, filing is EAI's proposed Revised Attachment A to Rider NDCR (Attachment A). Attachment A contains the ANO decommissioning rate adjustments to be effective from January 1, 2012 through December 31, 2012; the supporting Revenue Requirement Summary page of the ANO decommissioning model; and a summary of the ANO decommissioning fund balances reflecting a 20-year life extension for both ANO units. *See* Order No. 41, Scenario 2. Attachment A reflects that both the ANO decommissioning revenue requirement and the decommissioning rate will remain at the current zero level for 2012.

As required by the Stipulation approved by Order No. 50, issued in this Docket on October 13, 2009, EAI's current update incorporates the approved nuclear decommissioning cost estimate of approximately $1,049,800,000, excluding Spent Fuel

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[1] Formerly Arkansas Power & Light Company.
[2] Previously known as Rider M26.
[3] Filed pursuant to Order Nos. 5, 27, 32, 41, 45, 46 and 50 of this Docket.

costs, and the annual Consumer Price Index-Urban as the escalation rate. Also as required by Order No. 50, EAI witness Bowden provides, in EAI Exhibit RLB-11, the actual net tax benefits to ratepayers of the pour-over of the ANO non-tax qualified trust fund balances to the ANO tax qualified trust fund.[4]

On December 2, 2011, the General Staff of the Commission (Staff) filed the testimony of Staff witness Robert Daniel, Financial Analyst in the Financial Analysis Section, in response to EAI's November 1, 2011, Rider NDCR filing.

Rider NDCR

Rider NDCR is an exact recovery rider that recovers a levelized (inflation adjusted) revenue requirement necessary to fund the decommissioning trusts for ANO Units 1 and 2. Rider NDCR rate adjustments are redetermined annually in order to assure that sufficient funds exist to decommission both ANO Units at the end of their operating lives. The rate redetermination requires many inputs, including projected trust fund balances as of December 31 of the filing year, projected trust fund earnings and inflation rates, decommissioning cost estimates and the operating life of each unit. The annual Rider NDCR update is filed on or before November 1 each year with revised rates becoming effective for the first billing cycle of the following January.

Addressing the current decommissioning fund balances, EAI witness Bowden testified that the pour-over of the ANO Non-Tax Qualified Trust Fund Balances to the ANO Tax Qualified Trust Fund "was completed in March 2011 ... [and that] ... EAI Exhibit RLB-11 contains a schedule comparing the actual pour-over and net tax benefits

[4] Pursuant to Order No. 50, the Commission approved the pour-over and directed EAI to demonstrate in its annual filings the actual net tax benefits to ratepayers of the pour-over, with an explanation of any differences from those estimated in its March 31, 2009, EAI Exhibit RLR-2.

to the estimate provided in EAI Exhibit RLR-2 attached to EAI witness Rory L. Roberts' Direct Testimony filed on March 31, 2009 in this docket. The schedule shows the amount of variation between the actual amount of the net tax benefits and the estimated amount. The schedule also provides an explanation of the variation for each line." Bowden Supplemental Testimony at 3-4.

Ms. Bowden also testified that "[t]he decommissioning revenue requirement for 2011 is zero because the projected trust fund balances exceed the current escalated decommissioning cost estimate." *Id.* at 4. Based on the 2011 inputs, Ms. Bowden testified that "once the decommissioning process is complete which is currently estimated to be in 2046, the accumulated excess trust fund balance is estimated to be $570.0 million for Unit 1 and $298.4 million for Unit 2 (combined $868.4 million)."[5] *Id.* Given that the current decommissioning revenue requirement is zero, the kWh rate under Rider NDCR will remain at zero for all rate classes for year 2012.

Staff witness Daniel testified that EAI's November 1, 2011, Rider NDCR filing is in compliance with the Commission's directives in this Docket. Daniel Direct Testimony at 4. Mr. Daniel also testified that EAI provided, as required by Order No. 50, the actual net tax benefits as required by Order No. 50. Mr. Daniel testified that "[a]s referenced on page 3 of Rebecca L. Bowden's Supplemental Testimony, the pour-over was completed in March of 2011. Exhibit RLB-11 identifies that for ANO 1, the tax benefit is $21,787,365 or $292,060 higher than estimated. For ANO 2, the tax benefit is $8,733,406 or $111,434 higher than estimated." *Id.* at 5.

[5] Pursuant to Orders No. 27 and 29, respectively issued in this Docket on October 30, 1998 and June 25, 1999, any excess trust funds remaining after the decommissioning process has been completed will be refunded to EAI ratepayers.

Regarding the adequacy of the ANO decommissioning trust funds, Mr. Daniel testified as follows:

> As reflected on [EAI's] Attachment 1 ... the decommissioning trust fund balance for ANO Unit 1 continues to increase annually (from 2011 to 2033) until the current operating license expires in 2034 and decommissioning expenditures begin. Also, the trust fund balance for ANO Unit 2 continues to grow annually (2011 through 2038) until its current operating license expires in 2038 and decommissioning expenditures begin. As shown ..., without any further contributions from ratepayers and after decommissioning expenditures, the over-collection for ANO Units 1 and 2 is projected to be $569,991,000 and $298,416,000, respectively, for a total of $868,407,000.

Id.

Mr. Daniel further testified, that "[g]iven the adequacy of decommissioning funding at this time, continued suspension [of Rider NDCR collections] for 2012 is warranted ... [and, therefore,] ... [t]he Commission should approve a continued zero revenue requirement, and ... a continued zero rate for all classes for both ANO Unit 1 and ANO Unit 2 as reflected in attachment A to Rate Schedule No. 37 ... [of EAI's November 1, 2011 Rider NDCR update]. *Id.* at 7.

Findings and Rulings

Based upon the information contained in EAI's November 1, 2011, Rider NDCR update filing and the testimony of EAI witness Bowden and Staff witness Daniel, the Commission finds that the continuation of a zero rate for Rider NDCR for 2012 is in the public interest. Accordingly, the Commission approves an ANO decommissioning revenue requirement of zero for 2012 and approves EAI's Rider NDCR – Attachment A as filed on November 1, 2011.

BY ORDER OF THE COMMISSION,

This 13th day of December, 2011.

Colette D. Honorable, Chairman

Olan W. Reeves, Commissioner

Elana C. Wills, Commissioner

I hereby certify that the following order issued by the Arkansas Public Service Commission has been served on all parties of record this date by electronic mail, using the email address of each party as indicated in the official docket file.

KS

Secretary of the Commission

Date 12-13-2011

Karen Shook (Acting)

Jan Sanders, Secretary of the Commission

Attachment 1-D
(64 pages)

ANO Decommissioning Cost Rider NDCR Update
Rate Schedule No. 37 Workpapers

ENTERGY ARKANSAS, INC.

2011 ANO DECOMMISSIONING
COST RIDER NDCR UPDATE
RATE SCHEDULE NO. 37
WORKPAPERS

RATES EFFECTIVE JANUARY 2012

Entergy

Revenue Requirements & Analyses

ENTERGY ARKANSAS, INC.
2011 NUCLEAR DECOMMISSIONING RIDER (RIDER NDCR) UPDATE
RATES EFFECTIVE JANUARY 2012

TABLE OF CONTENTS

A

Rate Development

Entergy Arkansas, Inc.
ANO Decommissioning Rider NDCR
Rate Development For 2012

Line No.	Rate Class	Revenue Requirement 09-084-U ($000) [1]	Revenue Requirement ($000)	Billing Units [2]		Rate Adjustment	
	ANO-1						
1	Residential	$453,127	0	7,831,730,441	kWh	0.00000	$/kWh
2	Small General Service	232,421	0	4,555,064,986	kWh	0.00000	$/kWh
3	Large General Service	250,660	0	16,567,856	kW	0.00	$/kW
4	Lighting	21,042	0	261,109,179	kWh	0.00000	$/kWh
5	Arkansas Retail	$957,250	0 [3]	N/A		N/A	
	ANO-2						
6	Residential	$453,127	0	7,831,730,441	kWh	0.00000	$/kWh
7	Small General Service	232,421	0	4,555,064,986	kWh	0.00000	$/kWh
8	Large General Service	250,660	0	16,567,856	kW	0.00	$/kW
9	Lighting	21,042	0	261,109,179	kWh	0.00000	$/kWh
10	Arkansas Retail	$957,250	0 [3]	N/A		N/A	
	Summary						
11	Residential	$453,127	0	7,831,730,441	kWh	0.00000	$/kWh
12	Small General Service	232,421	0	4,555,064,986	kWh	0.00000	$/kWh
13	Large General Service	250,660	0	16,567,856	kW	0.00	$/kW
14	Lighting	21,042	0	261,109,179	kWh	0.00000	$/kWh
15	Arkansas Retail	$957,250	0 [3]	N/A		N/A	

Notes:

[1] According to Rider NDCR the Arkansas jurisdictional revenue requirement shall be allocated to the same rate classes and in the same proportions as the Arkansas retail revenue requirement in EAI's most recent general rate filing in which a final order has been issued and which has resulted in non-appealable rates. See Workpapers D.1 - D.5 for excerpts from Order No. 20 in Docket No. 09-084-U issued June 23, 2010.

[2] See Workpaper D.6.

[3] See Workpaper B.1, Line 1.

Entergy Arkansas, Inc.
ANO Decommissioning Rider NDCR
Wholesale Revenue Requirement and Summary
2012 Wholesale Contribution

Line No.	Rate Class	Annual Revenue Requirement ($000)	Monthly Wholesale Contribution to Trust Funds ($)
	ANO-1		
1	Sales For Resale [1]	0	0
	ANO-2		
2	Sales For Resale [1]	0	0
	Summary		
3	Total Sales For Resale	0	0
4	Total Arkansas Retail [2]	0	
5	Total Decommissioning Revenue Requirement [3]	0	

Notes:
[1] Total Revenue Requirement excluding Arkansas Retail.
[2] See Workpaper A.1 Line 15.
[3] See Workpaper B.1 Line 1.

B
Rev Rqmt Dev

Entergy Arkansas, Inc.
ANO Decommissioning Model
Revenue Requirement Summary
($000)

		Unit 1		Unit 2		Both Units	
Line No	Year	Total Company [1]	Arkansas Retail [2]	Total Company [1]	Arkansas Retail [2]	Total Company	Arkansas Retail [2]
1	2012	0	0	0	0	0	0
2	2013	0	0	0	0	0	0
3	2014	0	0	0	0	0	0
4	2015	0	0	0	0	0	0
5	2016	0	0	0	0	0	0
6	2017	0	0	0	0	0	0
7	2018	0	0	0	0	0	0
8	2019	0	0	0	0	0	0
9	2020	0	0	0	0	0	0
10	2021	0	0	0	0	0	0
11	2022	0	0	0	0	0	0
12	2023	0	0	0	0	0	0
13	2024	0	0	0	0	0	0
14	2025	0	0	0	0	0	0
15	2026	0	0	0	0	0	0
16	2027	0	0	0	0	0	0
17	2028	0	0	0	0	0	0
18	2029	0	0	0	0	0	0
19	2030	0	0	0	0	0	0
20	2031	0	0	0	0	0	0
21	2032	0	0	0	0	0	0
22	2033	0	0	0	0	0	0
23	2034	0	0	0	0	0	0
24	2035	0	0	0	0	0	0
25	2036	0	0	0	0	0	0
26	2037	0	0	0	0	0	0
27	2038	0	0	0	0	0	0
28	2039	0	0	0	0	0	0
29	2040	0	0	0	0	0	0
30	2041	0	0	0	0	0	0
31	2042	0	0	0	0	0	0
32	2043	0	0	0	0	0	0
33	2044	0	0	0	0	0	0
34	2045	0	0	0	0	0	0
35	2046	0	0	0	0	0	0

Notes:
[1] See Workpaper B.2 for ANO Unit 1 Summary and B.4 for ANO Unit 2 Summary.
[2] Total Company * Retail Allocation Factor (0.8613). See Workpaper B.7.

Entergy Arkansas, Inc.
ANO Decommissioning Model
Unit 1 Summary
($000)

		Total Company	Tax Qualified Trust [2]		
Line No.	Year	Revenue Rqmt. [1]	Net Additions	Trust Balance	Decomm. Expend.[3]
1	Beginning Balance			306,406	
2	2012	0	17,769	324,175	0
3	2013	0	18,967	343,142	0
4	2014	0	20,855	363,997	0
5	2015	0	23,325	387,322	0
6	2016	0	25,301	412,623	0
7	2017	0	27,040	439,663	0
8	2018	0	28,904	468,567	0
9	2019	0	30,903	499,470	0
10	2020	0	33,097	532,567	0
11	2021	0	35,402	567,969	0
12	2022	0	37,933	605,902	0
13	2023	0	40,593	646,495	0
14	2024	0	43,448	689,942	0
15	2025	0	46,583	736,525	0
16	2026	0	49,958	786,483	0
17	2027	0	53,592	840,076	0
18	2028	0	57,419	897,495	0
19	2029	0	61,716	959,211	0
20	2030	0	66,260	1,025,471	0
21	2031	0	71,156	1,096,627	0
22	2032	0	71,564	1,168,191	0
23	2033	0	66,488	1,234,679	0
24	2034	0	59,886	1,233,132	61,433
25	2035	0	55,017	1,097,872	190,277
26	2036	0	48,980	899,142	247,710
27	2037	0	40,110	772,521	166,730
28	2038	0	34,458	691,981	114,997
29	2039	0	30,863	604,983	117,861
30	2040	0	26,980	598,999	32,965
31	2041	0	26,713	618,015	7,697
32	2042	0	27,562	637,674	7,903
33	2043	0	28,439	658,001	8,112
34	2044	0	29,346	641,638	45,710
35	2045	0	28,616	624,953	45,301
36	2046	0	27,871	569,991	82,833

Notes:
[1] The Revenue Requirements are set to zero for every year.
[2] See Workpaper B.3
[3] See Workpaper B.6

Entergy Arkansas, Inc.
ANO Decommissioning Model
Tax Qualified Trust Detail — Unit 1
($000)

			Tax Qualified Trust						
Line No	Year	Revenue Rqmt. [1]	Earning Rate [2]	Transfer To Trust [3] [9]	Earnings [4]	Mgmt. Fee [5]	Net Additions [6]	Decomm. Expend. [7]	Balance [8]
1	Beginning Balance								306,406
2	2012	0	5.81%	0	18,061	292	17,769	0	324,175
3	2013	0	5.86%	0	19,275	308	18,967	0	343,142
4	2014	0	6.08%	0	21,180	325	20,855	0	363,997
5	2015	0	6.40%	0	23,669	344	23,325	0	387,322
6	2016	0	6.52%	0	25,665	364	25,301	0	412,623
7	2017	0	6.54%	0	27,427	387	27,040	0	439,663
8	2018	0	6.56%	0	29,315	411	28,904	0	468,567
9	2019	0	6.58%	0	31,339	436	30,903	0	499,470
10	2020	0	6.61%	0	33,561	463	33,097	0	532,567
11	2021	0	6.63%	0	35,894	492	35,402	0	567,969
12	2022	0	6.66%	0	38,457	524	37,933	0	605,902
13	2023	0	6.68%	0	41,150	557	40,593	0	646,495
14	2024	0	6.70%	0	44,041	593	43,448	0	689,942
15	2025	0	6.73%	0	47,214	631	46,583	0	736,525
16	2026	0	6.76%	0	50,631	673	49,958	0	786,483
17	2027	0	6.79%	0	54,309	717	53,592	0	840,076
18	2028	0	6.81%	0	58,183	764	57,419	0	897,495
19	2029	0	6.85%	0	62,531	815	61,716	0	959,211
20	2030	0	6.88%	0	67,129	869	66,260	0	1,025,471
21	2031	0	6.91%	0	72,084	928	71,156	0	1,096,627
22	2032	0	6.51%	0	72,552	989	71,564	0	1,168,191
23	2033	0	5.70%	0	67,536	1,048	66,488	0	1,234,679
24	2034	0	4.88%	0	60,987	1,101	59,886	61,433	1,233,132
25	2035	0	4.50%	0	56,115	1,098	55,017	190,277	1,097,872
26	2036	0	4.50%	0	49,960	980	48,980	247,710	899,142
27	2037	0	4.50%	0	40,917	807	40,110	166,730	772,521
28	2038	0	4.50%	0	35,155	697	34,458	114,997	691,981
29	2039	0	4.50%	0	31,489	626	30,863	117,861	604,983
30	2040	0	4.50%	0	27,531	551	26,980	32,965	598,999
31	2041	0	4.50%	0	27,258	545	26,713	7,697	618,015
32	2042	0	4.50%	0	28,124	562	27,562	7,903	637,674
33	2043	0	4.50%	0	29,018	579	28,439	8,112	658,001
34	2044	0	4.50%	0	29,943	597	29,346	45,710	641,638
35	2045	0	4.50%	0	29,199	583	28,616	45,301	624,953
36	2046	0	4.50%	0	28,439	568	27,871	82,833	569,991

Notes:

[1] See Workpaper B.2
[2] Projected After Tax Earnings Rates See Workpaper C.1.
[3] Revenue Requirement * (1 - Bad Debt Rate). See Workpaper B.7 for Bad Debt Rate.
[4] Prior Year Balance Compounded Semiannually At Current Year Earning Rate + 1/2 Current Year Transfer * Current Year Earning Rate.
[5] Calculated on average balance according to the schedules on Workpaper B.7 multiplied by (1 - TQ Fund Tax Rate).
[6] Transfer + Earnings - Management Fee.
[7] Assumes that decommissioning expenditures are made at year end.
See Workpaper B.6 for the total.
[8] Prior Year Balance + Net Additions - Decommissioning Expenditures. For Beginning Balance see Workpaper C.4.
[9] The percentage to be contributed to the Tax Qualified Trust Fund is 100%.

Entergy Arkansas, Inc.
ANO Decommissioning Model
Unit 2 Summary
($000)

Line No	Year	Total Company Revenue Rqmt. [1]	Tax Qualified Trust [2] Net Additions	Tax Qualified Trust [2] Trust Balance	Decomm. Expend.[3]
1	Beginning Balance			239,972	
2	2012	0	13,911	253,883	0
3	2013	0	14,849	268,733	0
4	2014	0	16,328	285,061	0
5	2015	0	18,262	303,322	0
6	2016	0	19,809	323,131	0
7	2017	0	21,170	344,301	0
8	2018	0	22,630	366,931	0
9	2019	0	24,195	391,126	0
10	2020	0	25,913	417,038	0
11	2021	0	27,717	444,756	0
12	2022	0	29,699	474,454	0
13	2023	0	31,781	506,236	0
14	2024	0	34,016	540,252	0
15	2025	0	36,471	576,724	0
16	2026	0	39,114	615,837	0
17	2027	0	41,959	657,796	0
18	2028	0	44,955	702,751	0
19	2029	0	48,320	751,071	0
20	2030	0	51,877	802,948	0
21	2031	0	55,711	858,659	0
22	2032	0	59,578	918,236	0
23	2033	0	63,713	981,949	0
24	2034	0	68,135	1,050,084	0
25	2035	0	72,865	1,122,949	0
26	2036	0	73,282	1,196,231	0
27	2037	0	68,085	1,264,316	0
28	2038	0	61,324	1,282,401	43,239
29	2039	0	57,216	1,196,868	142,750
30	2040	0	53,399	968,406	281,860
31	2041	0	43,201	790,906	220,701
32	2042	0	35,279	669,760	156,425
33	2043	0	29,871	539,064	160,567
34	2044	0	24,038	470,397	92,705
35	2045	0	20,973	413,588	77,781
36	2046	0	18,437	298,416	133,609

Notes:

[1] The Revenue Requirements are set to zero for every year.

[2] See Workpaper B.5.

[3] See Workpaper B.6.

Entergy Arkansas, Inc.
ANO Decommissioning Model
Tax Qualified Trust Detail — Unit 2
($000)

			Tax Qualified Trust						
Line No	Year	Revenue Rqmt. [1]	Earning Rate [2]	Transfer To Trust [3] [9]	Earnings [4]	Mgmt. Fee [5]	Net Additions [6]	Decomm. Expend. [7]	Balance [8]
1	Beginning Balance								239,972
2	2012	0	5.81%	0	14,145	234	13,911	0	253,883
3	2013	0	5.86%	0	15,096	246	14,849	0	268,733
4	2014	0	6.08%	0	16,587	259	16,328	0	285,061
5	2015	0	6.40%	0	18,536	274	18,262	0	303,322
6	2016	0	6.52%	0	20,099	290	19,809	0	323,131
7	2017	0	6.54%	0	21,478	308	21,170	0	344,301
8	2018	0	6.56%	0	22,957	327	22,630	0	366,931
9	2019	0	6.58%	0	24,541	347	24,195	0	391,126
10	2020	0	6.61%	0	26,281	368	25,913	0	417,038
11	2021	0	6.63%	0	28,108	391	27,717	0	444,756
12	2022	0	6.66%	0	30,114	415	29,699	0	474,454
13	2023	0	6.68%	0	32,223	441	31,781	0	506,236
14	2024	0	6.70%	0	34,486	469	34,016	0	540,252
15	2025	0	6.73%	0	36,971	499	36,471	0	576,724
16	2026	0	6.76%	0	39,645	532	39,114	0	615,837
17	2027	0	6.79%	0	42,525	566	41,959	0	657,796
18	2028	0	6.81%	0	45,559	603	44,955	0	702,751
19	2029	0	6.85%	0	48,963	643	48,320	0	751,071
20	2030	0	6.88%	0	52,562	686	51,877	0	802,948
21	2031	0	6.91%	0	56,442	732	55,711	0	858,659
22	2032	0	6.91%	0	60,358	781	59,578	0	918,236
23	2033	0	6.91%	0	64,546	833	63,713	0	981,949
24	2034	0	6.91%	0	69,025	889	68,135	0	1,050,084
25	2035	0	6.91%	0	73,814	950	72,865	0	1,122,949
26	2036	0	6.51%	0	74,294	1,012	73,282	0	1,196,231
27	2037	0	5.70%	0	69,157	1,072	68,085	0	1,264,316
28	2038	0	4.88%	0	62,451	1,127	61,324	43,239	1,282,401
29	2039	0	4.50%	0	58,357	1,141	57,216	142,750	1,196,868
30	2040	0	4.50%	0	54,465	1,066	53,399	281,860	968,406
31	2041	0	4.50%	0	44,069	867	43,201	220,701	790,906
32	2042	0	4.50%	0	35,991	713	35,279	156,425	669,760
33	2043	0	4.50%	0	30,478	607	29,871	160,567	539,064
34	2044	0	4.50%	0	24,531	493	24,038	92,705	470,397
35	2045	0	4.50%	0	21,406	433	20,973	77,781	413,588
36	2046	0	4.50%	0	18,821	384	18,437	133,609	298,416

Notes:

[1] See Workpaper B.4.
[2] Projected After Tax Earnings Rates See Workpaper C.1.
[3] Revenue Requirement * (1 - Bad Debt Rate). See Workpaper B.7 for Bad Debt Rate.
[4] Prior Year Balance Compounded Semiannually At Current Year Earning Rate + 1/2 Current Year Transfer * Current Year Earning Rate.
[5] Calculated on average balance according to the schedules in Workpaper B.7 multiplied by (1 - TQ Fund Tax Rate).
[6] Transfer + Earnings - Management Fee.
[7] Assumes that decommissioning expenditures are made at year end.
See Workpaper B.6 for the total.
[8] Prior Year Balance + Net Additions - Decommissioning Expenditures. For Beginning Balance see Workpaper C.4.
[9] The percentage to be contributed to the Tax Qualified Trust Fund is 100%.

Entergy Arkansas, Inc.
ANO Decommissioning Model
CPIU and Decommissioning Expenditures
($000)

Line No	Year	CPIU [1]	Cumulative CPIU [2]	Cumulative Nuclear Cost Escalator [3]	Decommissioning Expenditures Estimate [4] Unit 1	Decommissioning Expenditures Estimate [4] Unit 2	Decommissioning Expenditures Escalated [5] Unit 1	Decommissioning Expenditures Escalated [5] Unit 2
1	2008	1.0215	1.000	1.000	0	0	0	0
2	2009	1.0215	1.000	1.022	0	0	0	0
3	2010	1.0218	1.000	1.044	0	0	0	0
4	2011	1.0225	1.000	1.067	0	0	0	0
5	2012	1.0228	1.000	1.091	0	0	0	0
6	2013	1.0232	1.023	1.116	0	0	0	0
7	2014	1.0237	1.047	1.142	0	0	0	0
8	2015	1.0242	1.072	1.170	0	0	0	0
9	2016	1.0248	1.099	1.199	0	0	0	0
10	2017	1.0253	1.127	1.229	0	0	0	0
11	2018	1.0258	1.156	1.261	0	0	0	0
12	2019	1.0262	1.186	1.294	0	0	0	0
13	2020	1.0267	1.218	1.329	0	0	0	0
14	2021	1.0272	1.251	1.365	0	0	0	0
15	2022	1.0277	1.286	1.403	0	0	0	0
16	2023	1.0282	1.322	1.443	0	0	0	0
17	2024	1.0287	1.360	1.484	0	0	0	0
18	2025	1.0293	1.400	1.527	0	0	0	0
19	2026	1.0298	1.442	1.573	0	0	0	0
20	2027	1.0304	1.486	1.621	0	0	0	0
21	2028	1.0310	1.532	1.671	0	0	0	0
22	2029	1.0317	1.581	1.724	0	0	0	0
23	2030	1.0323	1.632	1.780	0	0	0	0
24	2031	1.0330	1.686	1.839	0	0	0	0
25	2032	1.0266	1.731	1.888	0	0	0	0
26	2033	1.0266	1.777	1.938	0	0	0	0
27	2034	1.0266	1.824	1.990	30,871	0	61,433	0
28	2035	1.0266	1.873	2.043	93,136	0	190,277	0
29	2036	1.0266	1.923	2.097	118,126	0	247,710	0
30	2037	1.0266	1.974	2.153	77,441	0	166,730	0
31	2038	1.0266	2.027	2.210	52,035	19,565	114,997	43,239
32	2039	1.0266	2.081	2.269	51,944	62,913	117,861	142,750
33	2040	1.0266	2.136	2.329	14,154	121,022	32,965	281,860
34	2041	1.0266	2.193	2.391	3,219	92,305	7,697	220,701
35	2042	1.0266	2.251	2.455	3,219	63,717	7,903	156,425
36	2043	1.0266	2.311	2.520	3,219	63,717	8,112	160,567
37	2044	1.0266	2.373	2.587	17,669	35,835	45,710	92,705
38	2045	1.0266	2.436	2.656	17,056	29,285	45,301	77,781
39	2046	1.0266	2.501	2.727	30,375	48,995	82,833	133,609
	Total Decommissioning Expenditures				512,464	537,354	1,129,528	1,309,637

Notes:

[1] See Workpaper C.32 for CPIU for years 2010-2031; the average for 2008 to 2031 is 2.66% and is used for 2032-2046.
[2] Cumulative CPIU from 2012 (Revision Year). Cumulative CPIU (Prior Year) * CPIU (Current year).
[3] Cumulative CPIU from 2008 (Estimate Year). Cumulative CPIU (Prior Year) * CPIU (Current year).
[4] Decommissioning Cost Estimate (2008 dollars) approved in Docket No. 87-166-TF Order 50.
See Workpapers D.7 to D.11.
[5] Decommissioning Cost Estimate * Cumulative Nuclear Cost Escalator.

Entergy Arkansas, Inc.
ANO Decommissioning Model
Fees and Miscellaneous Input Data

Fees [1]

	($000)
TQ Annual Fee [1]	11.700

	Breakpoints ($000)	Basis Points	Adder ($000) Fixed [1]	Adder ($000) Cumulative
Trustee Fees	0	1.00		
	0	1.00	0.000	0.000
	0	1.00	0.000	0.000
TQ Investment Manager	0	20.23		
	7,100	18.98	14.363	14.363
	8,000	18.21	1.708	16.072
	10,000	16.96	3.642	19.714
	16,000	15.81	10.176	29.890
	17,750	13.31	2.767	32.656
	20,000	12.15	2.995	35.651
	25,000	9.65	6.075	41.726

Miscellaneous Input Data

Arkansas Retail Bad Debt Rate [2]	0.5015%	Nuclear Cost Escalator [7]	CPIU
Revision Year [3]	2012	TQ Fund Federal Tax Rate [8]	20.00%
Cost Estimate Year [4]	2008	End Date - ANO 1	5/20/2034
Retail Allocation Factor [5]	0.8613	End Date - ANO 2	7/17/2038
Wholesale Allocation Factor [6]	0.1387		

Notes:

[1] Investment Manager Fee is calculated as in the following example for a balance of $20 million:
TQ Investor Management Fee = 35.651 which is 32.656 + (13.31 bp * (20,000-17,750)) / 10,000.
See Workpaper C.31.

[2] Most recent five-year average. See Workpaper D.13.

[3] First year showing impact of revised decommissioning revenue requirements.

[4] Year upon which the decommissioning cost estimate is based.

[5] Production demand allocator for retail approved in Docket No. 09-084-U. See Workpaper D.12.

[6] Wholesale allocation factor equals 1 minus the Retail Allocation Factor.

[7] Nuclear Cost Escalator is based on CPIU. See Workpaper B.6.

[8] See Workpaper C.5.

C
Financial Workpapers

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
2011 THROUGH 2046

	2011	2012	2013	2014	2015	2016	2017	2018	2019
ANO 1 - Tax Qualified Fund	6.04%	5.81%	5.86%	6.08%	6.40%	6.52%	6.54%	6.56%	6.58%
ANO 2 - Tax Qualified Fund	6.01%	5.81%	5.86%	6.08%	6.40%	6.52%	6.54%	6.56%	6.58%

	2020	2021	2022	2023	2024	2025	2026	2027	2028
ANO 1 - Tax Qualified Fund	6.61%	6.63%	6.66%	6.68%	6.70%	6.73%	6.76%	6.79%	6.81%
ANO 2 - Tax Qualified Fund	6.61%	6.63%	6.66%	6.68%	6.70%	6.73%	6.76%	6.79%	6.81%

	2029	2030	2031	2032	2033	2034	2035	2036	2037
ANO 1 - Tax Qualified Fund	6.85%	6.88%	6.91%	6.51%	5.70%	4.88%	4.50%	4.50%	4.50%
ANO 2 - Tax Qualified Fund	6.85%	6.88%	6.91%	6.91%	6.91%	6.91%	6.91%	6.51%	5.70%

	2038	2039	2040	2041	2042	2043	2044	2045	2046
ANO 1 - Tax Qualified Fund	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
ANO 2 - Tax Qualified Fund	4.88%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED EARNINGS RATES
2011 THROUGH 2046
INDEX TO SUPPORTING SCHEDULES

SCHEDULE:	DESCRIPTION:
Attachment 1	Portfolio Asset Allocations at June 30, 2011
Attachment 2	Projected Portfolio Liquidation Values at December 31, 2011
Attachment 3	Income Tax Rates
Attachment 4	Projected Before Tax Returns
Attachment 5A	Projected After Tax Returns - ANO 1 Tax Qualified
Attachment 5B	Projected After Tax Returns - ANO 2 Tax Qualified
Attachment 6	Trustee and Investment Manager Fees (Summary)
Attachment 7	Trustee and Investment Manager Fee Schedules
Attachment 8	CPIU and Interest Rates - Global Insight Forecasts
Attachment 9	Inflation Adjusted Total Equity Index and Average Compound Real Returns

ENTERGY ARKANSAS, INC. NUCLEAR DECOMMISSIONING FUNDS
PORTFOLIO ASSET ALLOCATIONS
JUNE 30, 2011 (In Thousands)

Description	ANO 1 TAX QUALIFIED	ANO 2 TAX QUALIFIED
Cash	$367	$148
Taxable Bonds - Corporates/Treasuries	$113,937	$84,688
Municipal Bonds	$0	$8,437
Equities	$193,234	$148,253
Interest & Dividend Rec.	$949	$990
Portfolio Market Value*	$308,487	$242,516

* Includes final contributions made in 2010 and 2011 that represent the 2011 and 2012 tax benefit associated with the Non-Qualified Trust pourover in 2010.

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED PORTFOLIO LIQUIDATION VALUES
DECEMBER 31, 2011
(In Thousands)

	ANO 1 Tax Qualified	ANO 2 Tax Qualified
Portfolio Market Value 6/30/11 (1)	$308,487	$242,516
Estimated Accrued Taxes and Accrued Fees	(10,925)	(9,433)
Estimated Liquidation Value 6/30/11	$297,562	$233,083
Estimated Contributions:		
July 2011	0	0
August 2011	0	0
September 2011	0	0
October 2011	0	0
November 2011	0	0
December 2011	0	0
Subtotal	$297,562	$233,083
Estimated after-tax earnings from 7/1/11 through 12/31/11 (2)	8,987	7,004
Before Fee Liquidation Value	$306,549	$240,087
Trustee/Manager Fees (After-tax)	(143)	(115)
Estimated 12/31/11 Liquidation Value	$306,406	$239,972

Notes:
1. Includes final contributions made in 2010 and 2011 that represent the 2011 and 2012 tax benefit associated with the Non-Qualified Trust pourover in 2010.
2. Estimated after-tax earnings from 7/1/11 through 12/31/11 were calculated using 2011 projected after tax returns on page C.1.

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
INCOME TAX RATES

TAX QUALIFIED FUNDS:

Short Term Investment Funds Interest	20.00%
U.S. Treasury Notes - Interest	20.00%
Corporate Bond Interest	20.00%
Municipal Bond Interest	0.00%
Dividends	20.00%
Capital Gains	20.00%

Explanation of Income Tax Rates:

Tax Qualified Funds:

The tax qualified funds are separate taxable entities for income tax purposes and Federal Income Tax Form 1120ND is required for all tax qualified funds. Arkansas state income tax rates do not apply. The trusts are located in Pennsylvania and exempt from Pennsylvania state taxes. Income tax rates reflect the 1992 Energy Policy Act provisions. According to the Internal Revenue Code, as amended, qualified trust income is not subject to Alternative Minimum Tax.

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED BEFORE TAX RETURNS

DESCRIPTION	2010	2011	2012	2013	2014	2015	2016	2017	2018
SHORT TERM RATE:									
Federal Funds Rate (1)	0.18%	0.11%	0.10%	0.11%	1.23%	3.27%	4.00%	4.00%	4.00%
Treasury Note, 2 -Year (1)	0.70%	0.44%	0.33%	0.52%	1.96%	3.76%	4.12%	4.12%	4.12%
MUNICIPAL BOND RATE:									
Bond Buyer 20 Municipals (1)	4.29%	4.55%	4.32%	4.48%	4.84%	5.49%	5.70%	5.70%	5.70%
TAXABLE BOND RATE:									
Moody's Corporate Composite (4)	5.49%	5.23%	5.01%	5.14%	5.71%	6.54%	6.80%	6.80%	6.80%
Moody's Aaa Corporate Bond (1)	4.94%	4.78%	4.53%	4.60%	5.13%	5.96%	6.22%	6.22%	6.22%
Moody's Baa Corporate Bond (1)	6.04%	5.68%	5.49%	5.68%	6.29%	7.12%	7.38%	7.38%	7.38%
EQUITY RETURN:									
Consumer Price Index - Urban (1)	2.18%	2.25%	2.28%	2.32%	2.37%	2.42%	2.48%	2.53%	2.58%
Percent Equities Historically Outperform CPIU (2)	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%
Total Equity Return	8.86%	8.93%	8.96%	9.00%	9.05%	9.10%	9.16%	9.21%	9.26%
Dividend Component (3)	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%
Capital Gain Component	6.76%	6.83%	6.86%	6.90%	6.95%	7.00%	7.06%	7.11%	7.16%

NOTES:
1. See Attachment 8 - Global Insight Forecasts
2. See Attachment 9 - Inflation Adjusted Total Equity Index and Average Compound Real Returns
3. Agrees with dividend assumptions in Callan 2008 asset allocation study for ANO
4. Average of Moody's Aaa & Baa Corporates
5. All years after 2031 are assumed to have the same before tax returns as 2031.

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED BEFORE TAX RETURNS

DESCRIPTION	2019	2020	2021	2022	2023	2024	2025	2026	2027
SHORT TERM RATE:									
Federal Funds Rate (1)	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Treasury Note, 2 -Year (1)	4.12%	4.12%	4.12%	4.12%	4.12%	4.12%	4.12%	4.12%	4.12%
MUNICIPAL BOND RATE:									
Bond Buyer 20 Municipals (1)	5.70%	5.70%	5.70%	5.70%	5.70%	5.70%	5.70%	5.70%	5.70%
TAXABLE BOND RATE:									
Moody's Corporate Composite (4)	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%
Moody's Aaa Corporate Bond (1)	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%
Moody's Baa Corporate Bond (1)	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%	7.38%
EQUITY RETURN:									
Consumer Price Index - Urban (1)	2.62%	2.67%	2.72%	2.77%	2.82%	2.87%	2.93%	2.98%	3.04%
Percent Equities Historically Outperform CPIU (2)	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%
Total Equity Return	9.30%	9.35%	9.40%	9.45%	9.50%	9.55%	9.61%	9.66%	9.72%
Dividend Component (3)	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%
Capital Gain Component	7.20%	7.25%	7.30%	7.35%	7.40%	7.45%	7.51%	7.56%	7.62%

NOTES:
1. See Attachment 8 - Global Insight Forecasts
2. See Attachment 9 - Inflation Adjusted Total Equity Index and Average Compound Real Returns
3. Agrees with dividend assumptions in Callan 2008 asset allocation study for ANO
4. Average of Moody's Aaa & Baa Corporates
5. All years after 2031 are assumed to have the same before tax returns as 2031.

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED BEFORE TAX RETURNS

DESCRIPTION	2028	2029	2030	2031
SHORT TERM RATE:				
Federal Funds Rate (1)	4.00%	4.00%	4.00%	4.00%
Treasury Note, 2 -Year (1)	4.12%	4.12%	4.12%	4.12%
MUNICIPAL BOND RATE:				
Bond Buyer 20 Municipals (1)	5.70%	5.70%	5.70%	5.70%
TAXABLE BOND RATE:				
Moody's Corporate Composite (4)	6.80%	6.80%	6.80%	6.80%
Moody's Aaa Corporate Bond (1)	6.22%	6.22%	6.22%	6.22%
Moody's Baa Corporate Bond (1)	7.38%	7.38%	7.38%	7.38%
EQUITY RETURN:				
Consumer Price Index - Urban (1)	3.10%	3.17%	3.23%	3.30%
Percent Equities Historically Outperform CPIU (2)	6.68%	6.68%	6.68%	6.68%
Total Equity Return	9.78%	9.85%	9.91%	9.98%
Dividend Component (3)	2.10%	2.10%	2.10%	2.10%
Capital Gain Component	7.68%	7.75%	7.81%	7.88%

NOTES:
1. See Attachment 8 - Global Insight Forecasts
2. See Attachment 9 - Inflation Adjusted Total Equity Index and Average Compound Real Returns
3. Agrees with dividend assumptions in Callan 2008 asset allocation study for ANO
4. Average of Moody's Aaa & Baa Corporates
5. All years after 2031 are assumed to have the same before tax returns as 2031.

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 1 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	Market Value 6/30/2011 (000's)	Portfolio %	2011 Before Tax Return	2011 After Tax Return	2011 Weighted After Tax Return	2012 Estimated Portfolio %	2012 Before Tax Return	2012 After Tax Return	2012 Weighted After Tax Return
Cash/(Federal Funds Rate)	$367	0.12%	0.11%	0.09%	0.00%	2.50%	0.10%	0.08%	0.00%
Treasuries/(Treasury Note, 2-Year)	$0	0.00%	0.44%	0.35%	0.00%	0.00%	0.33%	0.26%	0.00%
Municipal Bonds/(Bond Buyer-20 Municipals)	$0	0.00%	4.55%	4.55%	0.00%	0.00%	4.32%	4.32%	0.00%
Taxable Bonds/(Corporate Composite)	$113,937	37.05%	5.23%	4.18%	1.55%	37.50%	5.01%	4.01%	1.50%
Equities	$193,234	62.83%				60.00%			
Equity - Capital Gain Component			6.83%	5.46%	3.43%		6.86%	5.49%	3.29%
Equity - Dividend Component			2.10%	1.68%	1.06%		2.10%	1.68%	1.01%
Total Equity Return			8.93%	7.14%	4.49%		8.96%	7.17%	4.30%
Subtotal	$307,538	100.00%				100.00%			
Interest & Dividend Receivable	$949								
Portfolio Totals	$308,487				6.04%				5.81%

NOTES:
* See Attachment 1
1. After Tax Return = Before Tax Return*(1-tax rate)
2. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2031 = 2012
5. Assume receivables are invested at same ratio as current funds

C.9

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 1 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2013 Estimated Portfolio %	2013 Before Tax Return	2013 After Tax Return	2013 Weighted After Tax Return	2014 Before Tax Return	2014 After Tax Return	2014 Weighted After Tax Return	2015 Before Tax Return	2015 After Tax Return
Cash/(Federal Funds Rate)	2.50%	0.11%	0.09%	0.00%	1.23%	0.98%	0.02%	3.27%	2.62%
Treasuries/(Treasury Note, 2-Year)	0.00%	0.52%	0.42%	0.00%	1.96%	1.57%	0.00%	3.76%	3.01%
Municipal Bonds/(Bond Buyer-20 Municipals)	0.00%	4.48%	4.48%	0.00%	4.84%	4.84%	0.00%	5.49%	5.49%
Taxable Bonds/(Corporate Composite)	37.50%	5.14%	4.11%	1.54%	5.71%	4.57%	1.71%	6.54%	5.23%
Equities	60.00%								
Equity - Capital Gain Component		6.90%	5.52%	3.31%	6.95%	5.56%	3.34%	7.00%	5.60%
Equity - Dividend Component		2.10%	1.68%	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%
Total Equity Return		9.00%	7.20%	4.32%	9.05%	7.24%	4.34%	9.10%	7.28%
Subtotal	100.00%								
Interest & Dividend Receivable									
Portfolio Totals				5.86%			6.08%		

NOTES:
* See Attachment 1
1. After Tax Return = Before Tax Return*(1-tax rate)
2. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2031 = 2012
5. Assume receivables are invested at same ratio as current funds

C.10

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 1 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2015 Weighted After Tax Return	2016 Before Tax Return	2016 After Tax Return	2016 Weighted After Tax Return	2017 Before Tax Return	2017 After Tax Return	2017 Weighted After Tax Return	2018 Before Tax Return	2018 After Tax Return
Cash/(Federal Funds Rate)	0.07%	4.00%	3.20%	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%
Treasuries/(Treasury Note, 2-Year)	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%
Municipal Bonds/(Bond Buyer-20 Municipals)	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%
Taxable Bonds/(Corporate Composite)	1.96%	6.80%	5.44%	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%
Equities									
Equity - Capital Gain Component	3.36%	7.06%	5.65%	3.39%	7.11%	5.69%	3.41%	7.16%	5.73%
Equity - Dividend Component	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%
Total Equity Return	4.37%	9.16%	7.33%	4.40%	9.21%	7.37%	4.42%	9.26%	7.41%
Subtotal									
Interest & Dividend Receivable									
Portfolio Totals	6.40%			6.52%			6.54%		

NOTES:
* See Attachment 1
1. After Tax Return = Before Tax Return*(1-tax rate)
2. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2031 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 1 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2018 Weighted After Tax Return	2019 Before Tax Return	2019 After Tax Return	2019 Weighted After Tax Return	2020 Before Tax Return	2020 After Tax Return	2020 Weighted After Tax Return	2021 Before Tax Return	2021 After Tax Return
Cash/(Federal Funds Rate)	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%
Treasuries/(Treasury Note, 2-Year)	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%
Municipal Bonds/(Bond Buyer-20 Municipals)	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%
Taxable Bonds/(Corporate Composite)	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%
Equities									
Equity - Capital Gain Component	3.44%	7.20%	5.76%	3.46%	7.25%	5.80%	3.48%	7.30%	5.84%
Equity - Dividend Component	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%
Total Equity Return	4.44%	9.30%	7.44%	4.46%	9.35%	7.48%	4.49%	9.40%	7.52%
Subtotal									
Interest & Dividend Receivable									
Portfolio Totals	6.56%			6.58%			6.61%		

NOTES:
* See Attachment 1
1. After Tax Return = Before Tax Return*(1-tax rate)
2. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2031 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 1 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2021 Weighted After Tax Return	2022 Before Tax Return	2022 After Tax Return	2022 Weighted After Tax Return	2023 Before Tax Return	2023 After Tax Return	2023 Weighted After Tax Return	2024 Before Tax Return	2024 After Tax Return
Cash/(Federal Funds Rate)	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%
Treasuries/(Treasury Note, 2-Year)	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%
Municipal Bonds/(Bond Buyer-20 Municipals)	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%
Taxable Bonds/(Corporate Composite)	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%
Equities									
Equity - Capital Gain Component	3.50%	7.35%	5.88%	3.53%	7.40%	5.92%	3.55%	7.45%	5.96%
Equity - Dividend Component	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%
Total Equity Return	4.51%	9.45%	7.56%	4.54%	9.50%	7.60%	4.56%	9.55%	7.64%
Subtotal									
Interest & Dividend Receivable									
Portfolio Totals	6.63%			6.66%			6.68%		

NOTES:
* See Attachment 1
1. After Tax Return = Before Tax Return*(1-tax rate)
2. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2031 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 1 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2024 Weighted After Tax Return	2025 Before Tax Return	2025 After Tax Return	2025 Weighted After Tax Return	2026 Before Tax Return	2026 After Tax Return	2026 Weighted After Tax Return	2027 Before Tax Return	2027 After Tax Return
Cash/(Federal Funds Rate)	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%
Treasuries/(Treasury Note, 2-Year)	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%
Municipal Bonds/(Bond Buyer-20 Municipals)	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%
Taxable Bonds/(Corporate Composite)	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%
Equities									
Equity - Capital Gain Component	3.58%	7.51%	6.01%	3.60%	7.56%	6.05%	3.63%	7.62%	6.10%
Equity - Dividend Component	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%
Total Equity Return	4.58%	9.61%	7.69%	4.61%	9.66%	7.73%	4.64%	9.72%	7.78%
Subtotal									
Interest & Dividend Receivable									
Portfolio Totals	6.70%			6.73%			6.76%		

NOTES:
* See Attachment 1
1. After Tax Return = Before Tax Return*(1-tax rate)
2. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2031 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 1 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2027 Weighted After Tax Return	2028 Before Tax Return	2028 After Tax Return	2028 Weighted After Tax Return	2029 Before Tax Return	2029 After Tax Return	2029 Weighted After Tax Return	2030 Before Tax Return	2030 After Tax Return
Cash/(Federal Funds Rate)	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%
Treasuries/(Treasury Note, 2-Year)	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%
Municipal Bonds/(Bond Buyer-20 Municipals)	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%
Taxable Bonds/(Corporate Composite)	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%
Equities									
Equity - Capital Gain Component	3.66%	7.68%	6.14%	3.69%	7.75%	6.20%	3.72%	7.81%	6.25%
Equity - Dividend Component	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%
Total Equity Return	4.67%	9.78%	7.82%	4.69%	9.85%	7.88%	4.73%	9.91%	7.93%
Subtotal									
Interest & Dividend Receivable									
Portfolio Totals	6.79%			6.81%			6.85%		

NOTES:
* See Attachment 1
1. After Tax Return = Before Tax Return*(1-tax rate)
2. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2031 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 1 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2030 Weighted After Tax Return	2031 Before Tax Return	2031 After Tax Return	2031 Weighted After Tax Return	2032 Estimated Portfolio %	2032 Before Tax Return	2032 After Tax Return	2032 Weighted After Tax Return	2033 Estimated Portfolio %
Cash/(Federal Funds Rate)	0.08%	4.00%	3.20%	0.08%	2.50%	4.00%	3.20%	0.08%	2.50%
Treasuries/(Treasury Note, 2-Year)	0.00%	4.12%	3.30%	0.00%	8.00%	4.12%	3.30%	0.26%	24.00%
Municipal Bonds/(Bond Buyer-20 Municipals)	0.00%	5.70%	5.70%	0.00%	8.50%	5.70%	5.70%	0.48%	25.00%
Taxable Bonds/(Corporate Composite)	2.04%	6.80%	5.44%	2.04%	31.00%	6.80%	5.44%	1.69%	18.50%
Equities					50.00%				30.00%
Equity - Capital Gain Component	3.75%	7.88%	6.30%	3.78%		7.88%	6.30%	3.15%	
Equity - Dividend Component	1.01%	2.10%	1.68%	1.01%		2.10%	1.68%	0.84%	
Total Equity Return	4.76%	9.98%	7.98%	4.79%		9.98%	7.98%	3.99%	
Subtotal					100.00%				100.00%
Interest & Dividend Receivable									
Portfolio Totals	6.88%			6.91%				6.51%	

NOTES:
* See Attachment 1
1. After Tax Return = Before Tax Return*(1-tax rate)
2. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2031 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 1 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2033 Before Tax Return	2033 After Tax Return	2033 Weighted After Tax Return	2034 Estimated Portfolio %	2034 Before Tax Return	2034 After Tax Return	2034 Weighted After Tax Return	2035-2046 Estimated Portfolio %	2035-2046 Before Tax Return
Cash/(Federal Funds Rate)	4.00%	3.20%	0.08%	2.50%	4.00%	3.20%	0.08%	2.50%	4.00%
Treasuries/(Treasury Note, 2-Year)	4.12%	3.30%	0.79%	40.50%	4.12%	3.30%	1.33%	47.50%	4.12%
Municipal Bonds/(Bond Buyer-20 Municipals)	5.70%	5.70%	1.43%	41.00%	5.70%	5.70%	2.34%	50.00%	5.70%
Taxable Bonds/(Corporate Composite)	6.80%	5.44%	1.01%	6.00%	6.80%	5.44%	0.33%	0.00%	6.80%
Equities				10.00%				0.00%	
Equity - Capital Gain Component	7.88%	6.30%	1.89%		7.88%	6.30%	0.63%		7.88%
Equity - Dividend Component	2.10%	1.68%	0.50%		2.10%	1.68%	0.17%		2.10%
Total Equity Return	9.98%	7.98%	2.40%		9.98%	7.98%	0.80%		9.98%
Subtotal				100.00%				100.00%	
Interest & Dividend Receivable									
Portfolio Totals			5.70%				4.88%		

NOTES:
* See Attachment 1
1. After Tax Return = Before Tax Return*(1-tax rate)
2. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2031 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 1 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2035-2046 After Tax Return	2035-2046 Weighted After Tax Return
Cash/(Federal Funds Rate)	3.20%	0.08%
Treasuries/(Treasury Note, 2-Year)	3.30%	1.57%
Municipal Bonds/(Bond Buyer-20 Municipals)	5.70%	2.85%
Taxable Bonds/(Corporate Composite)	5.44%	0.00%
Equities		
Equity - Capital Gain Component	6.30%	0.00%
Equity - Dividend Component	1.68%	0.00%
Total Equity Return	7.98%	0.00%
Subtotal		
Interest & Dividend Receivable		
Portfolio Totals		4.50%

NOTES:
* See Attachment 1
1. After Tax Return = Before Tax Return*(1-tax rate)
2. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2031 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 2 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	Market Value 6/30/2011 (000's)	Portfolio %	2011 Before Tax Return	2011 After Tax Return	2011 Weighted After Tax Return	2012 Estimated Portfolio %	2012 Before Tax Return	2012 After Tax Return	2012 Weighted After Tax Return
Cash/(Federal Funds Rate)	$148	0.06%	0.11%	0.09%	0.00%	2.50%	0.10%	0.08%	0.00%
Treasuries/(Treasury Note, 2-Year)		0.00%	0.44%	0.35%	0.00%	0.00%	0.33%	0.26%	0.00%
Municipal Bonds/(Bond Buyer-20 Municipals)	$8,437	3.49%	4.55%	4.55%	0.16%	0.00%	4.32%	4.32%	0.00%
Taxable Bonds - (Corporate Composite)	$84,688	35.06%	5.23%	4.18%	1.47%	37.50%	5.01%	4.01%	1.50%
Equities	$148,253	61.38%				60.00%			
Equity - Capital Gain Component			6.83%	5.46%	3.35%		6.86%	5.49%	3.29%
Equity - Dividend Component			2.10%	1.68%	1.03%		2.10%	1.68%	1.01%
Total Equity Return			8.93%	7.14%	4.39%		8.96%	7.17%	4.30%
Subtotal	$241,526	100.00%				100.00%			
Interest & Dividend Receivable	$990								
Portfolio Totals	$242,516				6.01%				5.81%

NOTES:
* See Attachment 1
1. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
2. After Tax Return = Before Tax Return*(1-tax rate)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2035 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 2 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2013 Estimated Portfolio %	2013 Before Tax Return	2013 After Tax Return	2013 Weighted After Tax Return	2014 Before Tax Return	2014 After Tax Return	2014 Weighted After Tax Return	2015 Before Tax Return	2015 After Tax Return
Cash/(Federal Funds Rate)	2.50%	0.11%	0.09%	0.00%	1.23%	0.98%	0.02%	3.27%	2.62%
Treasuries/(Treasury Note, 2-Year)	0.00%	0.52%	0.42%	0.00%	1.96%	1.57%	0.00%	3.76%	3.01%
Municipal Bonds/(Bond Buyer-20 Municipals)	0.00%	4.48%	4.48%	0.00%	4.84%	4.84%	0.00%	5.49%	5.49%
Taxable Bonds - (Corporate Composite)	37.50%	5.14%	4.11%	1.54%	5.71%	4.57%	1.71%	6.54%	5.23%
Equities	60.00%								
Equity - Capital Gain Component		6.90%	5.52%	3.31%	6.95%	5.56%	3.34%	7.00%	5.60%
Equity - Dividend Component		2.10%	1.68%	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%
Total Equity Return		9.00%	7.20%	4.32%	9.05%	7.24%	4.34%	9.10%	7.28%
Subtotal	100.00%								
Interest & Dividend Receivable									
Portfolio Totals				5.86%			6.08%		

NOTES:
* See Attachment 1
1. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
2. After Tax Return = Before Tax Return*(1-tax rate)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2035 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 2 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2015 Weighted After Tax Return	2016 Before Tax Return	2016 After Tax Return	2016 Weighted After Tax Return	2017 Before Tax Return	2017 After Tax Return	2017 Weighted After Tax Return	2018 Before Tax Return	2018 After Tax Return
Cash/(Federal Funds Rate)	0.07%	4.00%	3.20%	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%
Treasuries/(Treasury Note, 2-Year)	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%
Municipal Bonds/(Bond Buyer-20 Municipals)	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%
Taxable Bonds - (Corporate Composite)	1.96%	6.80%	5.44%	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%
Equities									
Equity - Capital Gain Component	3.36%	7.06%	5.65%	3.39%	7.11%	5.69%	3.41%	7.16%	5.73%
Equity - Dividend Component	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%
Total Equity Return	4.37%	9.16%	7.33%	4.40%	9.21%	7.37%	4.42%	9.26%	7.41%
Subtotal									
Interest & Dividend Receivable									
Portfolio Totals	6.40%			6.52%			6.54%		

NOTES:
* See Attachment 1
1. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
2. After Tax Return = Before Tax Return*(1-tax rate)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2035 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 2 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2018 Weighted After Tax Return	2019 Before Tax Return	2019 After Tax Return	2019 Weighted After Tax Return	2020 Before Tax Return	2020 After Tax Return	2020 Weighted After Tax Return	2021 Before Tax Return	2021 After Tax Return
Cash/(Federal Funds Rate)	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%
Treasuries/(Treasury Note, 2-Year)	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%
Municipal Bonds/(Bond Buyer-20 Municipals)	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%
Taxable Bonds - (Corporate Composite)	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%
Equities									
Equity - Capital Gain Component	3.44%	7.20%	5.76%	3.46%	7.25%	5.80%	3.48%	7.30%	5.84%
Equity - Dividend Component	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%
Total Equity Return	4.44%	9.30%	7.44%	4.46%	9.35%	7.48%	4.49%	9.40%	7.52%
Subtotal									
Interest & Dividend Receivable									
Portfolio Totals	6.56%			6.58%			6.61%		

NOTES:
* See Attachment 1
1. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
2. After Tax Return = Before Tax Return*(1-tax rate)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2035 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 2 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2021 Weighted After Tax Return	2022 Before Tax Return	2022 After Tax Return	2022 Weighted After Tax Return	2023 Before Tax Return	2023 After Tax Return	2023 Weighted After Tax Return	2024 Before Tax Return	2024 After Tax Return
Cash/(Federal Funds Rate)	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%
Treasuries/(Treasury Note, 2-Year)	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%
Municipal Bonds/(Bond Buyer-20 Municipals)	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%
Taxable Bonds - (Corporate Composite)	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%
Equities									
Equity - Capital Gain Component	3.50%	7.35%	5.88%	3.53%	7.40%	5.92%	3.55%	7.45%	5.96%
Equity - Dividend Component	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%
Total Equity Return	4.51%	9.45%	7.56%	4.54%	9.50%	7.60%	4.56%	9.55%	7.64%
Subtotal									
Interest & Dividend Receivable									
Portfolio Totals	6.63%			6.66%			6.68%		

NOTES:
* See Attachment 1
1. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
2. After Tax Return = Before Tax Return*(1-tax rate)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2035 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 2 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2024 Weighted After Tax Return	2025 Before Tax Return	2025 After Tax Return	2025 Weighted After Tax Return	2026 Before Tax Return	2026 After Tax Return	2026 Weighted After Tax Return	2027 Before Tax Return	2027 After Tax Return
Cash/(Federal Funds Rate)	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%
Treasuries/(Treasury Note, 2-Year)	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%
Municipal Bonds/(Bond Buyer-20 Municipals)	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%
Taxable Bonds - (Corporate Composite)	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%
Equities									
Equity - Capital Gain Component	3.58%	7.51%	6.01%	3.60%	7.56%	6.05%	3.63%	7.62%	6.10%
Equity - Dividend Component	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%
Total Equity Return	4.58%	9.61%	7.69%	4.61%	9.66%	7.73%	4.64%	9.72%	7.78%
Subtotal									
Interest & Dividend Receivable									
Portfolio Totals	6.70%			6.73%			6.76%		

NOTES:
* See Attachment 1
1. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
2. After Tax Return = Before Tax Return*(1-tax rate)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2035 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 2 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2027 Weighted After Tax Return	2028 Before Tax Return	2028 After Tax Return	2028 Weighted After Tax Return	2029 Before Tax Return	2029 After Tax Return	2029 Weighted After Tax Return	2030 Before Tax Return	2030 After Tax Return
Cash/(Federal Funds Rate)	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%
Treasuries/(Treasury Note, 2-Year)	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%
Municipal Bonds/(Bond Buyer-20 Municipals)	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%
Taxable Bonds - (Corporate Composite)	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%
Equities									
Equity - Capital Gain Component	3.66%	7.68%	6.14%	3.69%	7.75%	6.20%	3.72%	7.81%	6.25%
Equity - Dividend Component	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%
Total Equity Return	4.67%	9.78%	7.82%	4.69%	9.85%	7.88%	4.73%	9.91%	7.93%
Subtotal									
Interest & Dividend Receivable									
Portfolio Totals	6.79%			6.81%			6.85%		

NOTES:
* See Attachment 1
1. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
2. After Tax Return = Before Tax Return*(1-tax rate)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2035 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 2 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2030 Weighted After Tax Return	2031 Before Tax Return	2031 After Tax Return	2031 Weighted After Tax Return	2032-2035 Before Tax Return	2032-2035 After Tax Return	2032-2035 Weighted After Tax Return	2036 Estimated Portfolio %	2036 Before Tax Return
Cash/(Federal Funds Rate)	0.08%	4.00%	3.20%	0.08%	4.00%	3.20%	0.08%	2.50%	4.00%
Treasuries/(Treasury Note, 2-Year)	0.00%	4.12%	3.30%	0.00%	4.12%	3.30%	0.00%	8.00%	4.12%
Municipal Bonds/(Bond Buyer-20 Municipals)	0.00%	5.70%	5.70%	0.00%	5.70%	5.70%	0.00%	8.50%	5.70%
Taxable Bonds - (Corporate Composite)	2.04%	6.80%	5.44%	2.04%	6.80%	5.44%	2.04%	31.00%	6.80%
Equities								50.00%	
Equity - Capital Gain Component	3.75%	7.88%	6.30%	3.78%	7.88%	6.30%	3.78%		7.88%
Equity - Dividend Component	1.01%	2.10%	1.68%	1.01%	2.10%	1.68%	1.01%		2.10%
Total Equity Return	4.76%	9.98%	7.98%	4.79%	9.98%	7.98%	4.79%		9.98%
Subtotal								100.00%	
Interest & Dividend Receivable									
Portfolio Totals	6.88%			6.91%			6.91%		

NOTES:
* See Attachment 1
1. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
2. After Tax Return = Before Tax Return*(1-tax rate)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2035 = 2012
5. Assume receivables are invested at same ratio as current funds

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 2 TAX QUALIFIED TRUST (2011-2046)

Portfolio Assets/(Return Indices for Portfolio Assets)	2036 After Tax Return	2036 Weighted After Tax Return	2037 Estimated Portfolio %	2037 Before Tax Return	2037 After Tax Return	2037 Weighted After Tax Return	2038 Estimated Portfolio %	2038 Before Tax Return	2038 After Tax Return
Cash/(Federal Funds Rate)	3.20%	0.08%	2.50%	4.00%	3.20%	0.08%	2.50%	4.00%	3.20%
Treasuries/(Treasury Note, 2-Year)	3.30%	0.26%	24.00%	4.12%	3.30%	0.79%	40.50%	4.12%	3.30%
Municipal Bonds/(Bond Buyer-20 Municipals)	5.70%	0.48%	25.00%	5.70%	5.70%	1.43%	41.00%	5.70%	5.70%
Taxable Bonds - (Corporate Composite)	5.44%	1.69%	18.50%	6.80%	5.44%	1.01%	6.00%	6.80%	5.44%
Equities			30.00%				10.00%		
Equity - Capital Gain Component	6.30%	3.15%		7.88%	6.30%	1.89%		7.88%	6.30%
Equity - Dividend Component	1.68%	0.84%		2.10%	1.68%	0.50%		2.10%	1.68%
Total Equity Return	7.98%	3.99%		9.98%	7.98%	2.40%		9.98%	7.98%
Subtotal			100.00%				100.00%		
Interest & Dividend Receivable									
Portfolio Totals		6.51%				5.70%			

NOTES:
* See Attachment 1
1. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
2. After Tax Return = Before Tax Return*(1-tax rate)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2035 = 2012
5. Assume receivables are invested at same ratio as current funds

**ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
PROJECTED AFTER TAX RETURNS
ANO 2 TAX QUALIFIED TRUST (2011-2046)**

Portfolio Assets/(Return Indices for Portfolio Assets)	2038 Weighted After Tax Return	2039-2046 Estimated Portfolio %	2039-2046 Before Tax Return	2039-2046 After Tax Return	2039-2046 Weighted After Tax Return
Cash/(Federal Funds Rate)	0.08%	2.50%	4.00%	3.20%	0.08%
Treasuries/(Treasury Note, 2-Year)	1.33%	47.50%	4.12%	3.30%	1.57%
Municipal Bonds/(Bond Buyer-20 Municipals)	2.34%	50.00%	5.70%	5.70%	2.85%
Taxable Bonds - (Corporate Composite)	0.33%	0.00%	6.80%	5.44%	0.00%
Equities		0.00%			
Equity - Capital Gain Component	0.63%		7.88%	6.30%	0.00%
Equity - Dividend Component	0.17%		2.10%	1.68%	0.00%
Total Equity Return	0.80%		9.98%	7.98%	0.00%
Subtotal		100.00%			
Interest & Dividend Receivable					
Portfolio Totals	4.88%				4.50%

NOTES:
* See Attachment 1
1. Before Tax Returns (Attachment 4); Tax Rates (Attachment 3)
2. After Tax Return = Before Tax Return*(1-tax rate)
3. Weighted After Tax Return = (After Tax Return*Portfolio %)
4. Portfolio percentages: 2013 to 2035 = 2012
5. Assume receivables are invested at same ratio as current funds

Entergy Arkansas, Inc.
Arkansas Nuclear One Units 1 & 2
2011 Decommissioning Trustee and Investment Manager Fees

Administrative Fees Paid to Trustee (1)

Per Fund	$11,700

Trustee Fees (2)

	ANO 1 TQ and ANO 2 TQ			
Range	Breakpoints ($)	Basis Points	Max. Rate for Breakpoint ($)	Cumulative Max. Rate ($)
$ Full amount	None	1.00		

Investment Manager Fees (3)

	Tax Qualified Trust			
Range	Breakpoints ($)	Basis Points	Max. Rate for Breakpoint ($)	Cumulative Max. Rate ($)
$ 0 M to $ 7.1 M	7,100,000	20.23	14,363	14,363
$ 7.1 M to $ 8 M	8,000,000	18.98	1,708	16,072
$ 8 M to $ 10 M	10,000,000	18.21	3,642	19,714
$ 10 M to $ 16 M	16,000,000	16.96	10,176	29,890
$ 16 M to $ 17.75 M	17,750,000	15.81	2,767	32,656
$ 17.75 M to $ 20 M	20,000,000	13.31	2,995	35,651
$ 20 M to $ 25 M	25,000,000	12.15	6,075	41,726
Over $25 M		9.65		

Notes:
(1) Refer to Attachment 7 section 1.A. Administrative Fees Paid to Trustee.
(2) Refer to Attachment 7 section 1.B. Consolidated Funds Fee Structure.
(3) Refer to Attachment 7 section 2. Investment Manager Fees for breakdown of fees.

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
TRUSTEE & INVESTMENT MANAGER FEES

1. Trustee Fees:

1A. Administrative Fees Paid to Trustee

Account Administration, Tax Return Preparation, Performance Reporting, and Report Production	$11,700 annually per fund

1B. Consolidated Funds Fee Structure

All funds	1bp

2. Investment Manager Fees

2A. ANO 1 Tax Qualified Fund - Fixed Income

$ 0 to $10 million	30bp
$10 to $25 million	25bp
over $25 million	15bp

2B. Assumed ANO 1 Tax Qualified - Fixed Income Allocation*

$ 0 to $7.1 million	30bp
$7.1 to $17.75 million	25bp
over $17.75 million	15bp

*Assume ANO 1 and Indian Point receive benefits of the declining rate structure in 2A. above, in the ratio of 71 - 29, respectively.

2C. ANO 2 Tax Qualified Fund - Fixed Income

$ 0 to $10 million	30bp
$10 to $25 million	25bp
over $25 million	15bp

2D. Average ANO 1 & 2 Tax Qualified Fund - Fixed Income*

$ 0 to $7.1 million	30bp
$7.1 to $10 million	27.5bp
$10 to $17.75 million	25bp
$17.75 to $25 million	20bp
over $25 million	15bp

*Average of B and C above.

ENTERGY ARKANSAS, INC.
NUCLEAR DECOMMISSIONING FUNDS
TRUSTEE & INVESTMENT MANAGER FEES

2E. Mellon Stock Index Fund

$ 0 to $40 million	10bp
$40 to $80 million	8bp
$80 to $100 million	5bp
over $100 million	2bp

2F. Assumed Mellon Stock Index Allocation for ANO Funds*

$ 0 to $8 million	10bp
$ 8 to $16 million	8bp
$16 to $20 million	5bp
over $20 million	2bp

*Assume ANO Unit 1, ANO Unit 2, Grand Gulf, River Bend, and Waterford 3 funds receive equal benefits of the declining rate structure in 2E above.

2G. Mellon Market Completion Fund

$ 0 to $125 million	12bp

2H. Average ANO 1 & 2 Tax Qualified Fund - Equity

$ 0 to $8 million	10.46bp
$ 8 to $16 million	8.92bp
$16 to $20 million	6.61bp
over $20 million	4.30bp

*Average of F and G above, weighted as follows: F - 77% and G - 23%.

2I. Assumed Average Investment Manager Fee for Each ANO Tax Qualified Fund*

$ 0 to $ 7.1 million	20.23bp
$ 7.1 to $ 8 milllion	18.98bp
$ 8 to $10 million	18.21bp
$10 to $16 million	16.96bp
$16 to $17.75 million	15.81bp
$17.75 to $20 million	13.31bp
$20 to $25 million	12.15bp
over $25 million	9.65bp

* Assumes an average of each unit's tax qualified fund's investment management fees (average of 2D and 2H above)

GLOBAL INSIGHT

Updated on Fri 30 Sep 2011, 1:06 AM EDT (06:06 GMT)

SeriesType	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Updated 9/30/2011											
Consumer Price Index, All-Urban	2.18	2.25	2.28	2.32	2.37	2.42	2.48	2.53	2.58	2.62	2.67
Effective Rate On Federal Funds	0.18	0.11	0.10	0.11	1.23	3.27	4.00	4.00	4.00	4.00	4.00
Yield On 10-Year Treasury Notes	3.21	2.90	2.69	2.91	3.58	4.60	4.91	4.91	4.91	4.91	4.91
Yield On 2-Year Treasury Notes	0.70	0.44	0.33	0.52	1.96	3.76	4.12	4.12	4.12	4.12	4.12
Yield On 5-Year Treasury Notes	1.93	1.58	1.39	1.64	2.66	4.18	4.50	4.50	4.50	4.50	4.50
Yield On Aaa-Rated Corporate Bonds	4.94	4.78	4.53	4.60	5.13	5.96	6.22	6.22	6.22	6.22	6.22
Yield On Baa-Rated Corporate Bonds	6.04	5.68	5.49	5.68	6.29	7.12	7.38	7.38	7.38	7.38	7.38
Yield On Bond Buyer 20-Bond Index	4.29	4.55	4.32	4.48	4.84	5.49	5.70	5.70	5.70	5.70	5.70

SeriesType	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Updated 9/30/2011											
Consumer Price Index, All-Urban	2.72	2.77	2.82	2.87	2.93	2.98	3.04	3.10	3.17	3.23	3.30
Effective Rate On Federal Funds	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Yield On 10-Year Treasury Notes	4.91	4.91	4.91	4.91	4.91	4.91	4.91	4.91	4.91	4.91	4.91
Yield On 2-Year Treasury Notes	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12
Yield On 5-Year Treasury Notes	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50
Yield On Aaa-Rated Corporate Bonds	6.22	6.22	6.22	6.22	6.22	6.22	6.22	6.22	6.22	6.22	6.22
Yield On Baa-Rated Corporate Bonds	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38
Yield On Bond Buyer 20-Bond Index	5.70	5.70	5.70	5.70	5.70	5.70	5.70	5.70	5.70	5.70	5.70

INFLATION ADJUSTED TOTAL EQUITY INDEX AND AVERAGE COMPOUND REAL RETURNS LARGE COMPANY STOCKS 1926 TO YEAR INDICATED

1926 To Year	Equity Index Net of Inflation (A)	Average Annual Compound Real Returns
1989	75.977	7.00%
1990	69.333	6.74%
1991	87.822	7.02%
1992	91.893	6.98%
1993	98.369	6.98%
1994	97.059	6.86%
1995	130.085	7.20%
1996	154.953	7.36%
1997	203.190	7.66%
1998	257.121	7.90%
1999	303.094	8.03%
2000	266.472	7.73%
2001	231.215	7.43%
2002	175.925	6.94%
2003	222.231	7.17%
2004	238.625	7.18%
2005	242.070	7.10%
2006	273.361	7.17%
2007	277.071	7.10%
2008	174.755	6.42%
2009	215.148	6.60%
2010	243.909	6.68%

(A) The source for the 2010 equity index number is the Ibbotson (Morningstar) 2011 Yearbook. Data for all other years from prior Ibbotson (Morningstar) yearbooks.

(B) All average annual compound real returns are a geometric mean return.

D

Misc Workpapers

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE)

DOCKET NO. 09-084-U
ORDER NO. 20

ORDER

HISTORY

On September 4, 2009, pursuant to Ark. Code Ann. § 23-4-401, *et seq.*, Entergy Arkansas, Inc. (EAI) filed its *Application For Approval Of Changes In Rates For Retail Electric Service* (Application) claiming a retail revenue requirement of $1,137.2 million and resulting revenue deficiency of $223.2 million. *See* EAI's Minimum Filling Requirements (MFR) Schedule A-1 (September 4, 2009). EAI is a public utility as defined by Ark. Code Ann. § 23-1-101, *et seq.* and is subject to the jurisdiction of the Arkansas Public Service Commission (Commission).[1] In support of its Application, EAI concurrently filed the Testimony and Exhibits of its witnesses as follows: John J. Spanos; Hugh T. McDonald; Myra L. Talkington; Gregory R. Zakrezewski; Gordon D. Meyer; Eric Fox; Samuel C. Hadaway; Kevin G. Gardner; Jay C. Hartzell; Lenoal R. Hartwick; Timothy G. Mitchell; Oscar D. Washington; Jeff D. Makholm; Kurtis W. Castleberry; Charles W. Long; S. Brady Aldy; and Jon A. Majewski.

On October 2, 2009, the Commission issued its Order No. 3 by which it suspended the proposed rates and tariffs filed by EAI, set a public evidentiary hearing for May 24, 2010, and directed the parties to propose a fully-developed procedural schedule for the Commission's consideration, with which the parties complied.

[1] EAI provides service to approximately 687,000 Arkansas retail customers.

THE AGREEMENT
Filed May 10, 2010 and Revised on May 25, 2010

As discussed above, certain Parties filed an Agreement on May 10, which was revised and ultimately joined by all Parties to the Docket on May 25, 2010. To the extent the two differ, the Revised Agreement filed on May 25 controls, but the word "Agreement" as used in this order will refer to both Agreements in totality to the extent they represent the Parties' request for Commission approval.

A. REVENUE REQUIREMENT

1. The Agreement proposes EAI's non-fuel rate schedule revenue requirement, Arkansas jurisdiction, is $967,361,325, with a resulting revenue deficiency of $73,781,760, both of which are based on Staff's recommended amounts as reflected in Staff's Surrebuttal Testimonies and Exhibits with the following exceptions (May 10, 2010 Agreement, Joint Exhibit at 2-5):

- Increase in rate base by $18,838,802 to reflect the removal of Staff Adjustment RB-10, which adjusted rate base for historical capitalized incentive compensation. Prospectively, beginning July 1, 2010, EAI will account for capitalized incentive compensation consistent with Staff's recommendation for retail ratemaking purposes. The increase in retail revenue requirement resulting from this change is $1,114,792;
- Update retirements to include actual amounts through March 2010, which results in an increase in total company depreciation expense of $248,771. The increase in retail revenue requirement resulting from this change is $196,537;

In compliance with Order No. 18, all Parties to this Docket filed on June 3, 2010, the results of the new cost of service study reflecting the removal of $10,111,517 in securitized storm costs and reflecting an adjusted revenue deficiency of $63,670,243. *See* Joint Submission of Revised Cost of Service at 2 ¶ 2 (June 3, 2010). With the removal of those costs, the revised revenue deficiency for each rate class results in an increase to base rates as depicted below:

Cost Allocation Based on a $63,670,243 Rate Increase By Class				
	Residential	SGS	LGS	Lighting
Rate Increase by Class	$13,409,410	$24,264,652	$26,168,503	($172,322)
% Change in Base Rates	3.05%	11.66%	11.66%	-0.81%

Id. at Joint Attachment 1, lines 7-8. Subsequently, on June 7, 2010, Entergy filed compliance tariffs to implement the proposed rate increase, which were amended on June 11, 2010. Staff, the only party to file a response to EAI's compliance tariff filing, filed the Compliance Testimony of Witness Kim O. Davis on June 11, 2010. Staff Witness Davis' testimony recommended approval of EAI's compliance tariffs, as amended.

CONCLUSION

Having considered all of this Docket's pre-filed written testimonies and exhibits as delineated above, before settlement negotiations began, as well as the resulting Agreement and Revised Agreement and testimonies and exhibits in support of those agreements, the Commission finds that the evidence presented could support a non-fuel revenue requirement for EAI in the range of $995.422 Million (Staff's Surrebuttal case) to $1,130.871 million (EAI's Rebuttal case) without the transfer of costs to be securitized. The Agreement, as revised, proposes a revenue requirement of $1,020.170 million (Revised Agreement, Joint Attachment 1) falling within the range supported by

June 11, 2010, the Commission finds that the Agreement, as filed on May 10 and revised on May 25, is just and reasonable and in the public interest. As such the Commission directs and orders as follows:

1. The Agreement filed on May 25, 2010,[10] is hereby approved; and

2. The Compliance Tariffs filed on June 7, 2010, as amended on June 11, 2010, that were based on the Revised Agreement's mitigated cost of service and reduced by the 2009 storm costs, are approved hereby to be effective for all bills rendered on and after June 30, 2010.

BY ORDER OF THE COMMISSION,

This 23rd day of June 2010.

Paul Suskie, Chairman

I hereby certify that this order, issued by the Arkansas Public Service Commission, has been served on all parties of record on this date by the following method:

____U.S. mail with postage prepaid using the mailing address of each party as indicated in the official docket file, or

X Electronic mail using the email address of each party as indicated in the official docket file.

Colette D. Honorable, Commissioner

Olan W. Reeves, Commissioner

Keith Plunkett (Acting)
Jan Sanders
Secretary of the Commission

[10] The May 25 Agreement incorporated by reference all provisions included in the May 10 Agreement not superseded by the revisions made in the May 25 filing.

JOINT ATTACHMENT 2

STORM SECURITIZATION
COST OF SERVICE RESULTS

Line No	Description	Total Company Pro Forma 1	Total Wholesale 2	Total Retail 3	Residential 4	SGS 5	LGS 6	Lighting 7
	RATE BASE							
1	Gross Plant in Service	$ 7,581,525,452	$ 817,888,506	$ 6,763,636,946	$ 3,061,491,094	$ 1,656,467,520	$ 1,892,327,158	$ 153,351,174
2	Accumulated Depreciation	$ 3,579,342,588	$ 405,135,358	$ 3,174,207,230	$ 1,397,121,408	$ 763,160,981	$ 919,409,766	$ 94,515,076
3	Total Net Plant	$ 4,002,182,864	$ 412,753,148	$ 3,589,429,715	$ 1,664,369,686	$ 893,306,539	$ 972,917,392	$ 58,836,098
4	Working Capital Assets	$ 455,176,523	$ 48,998,635	$ 406,177,888	$ 183,062,712	$ 99,367,613	$ 116,479,877	$ 7,267,686
5	TOTAL RATE BASE	$ 4,457,359,387	$ 461,751,784	$ 3,995,607,604	$ 1,847,432,399	$ 992,674,152	$ 1,089,397,269	$ 66,103,784
	NON-FUEL OPERATING REVENUES							
6	Present Rate Schedule Revenues	$ 997,052,882	$ 103,473,317	$ 893,579,565	$ 439,717,619	$ 208,156,458	$ 224,491,339	$ 21,214,149
7	System Sales and Other Revenues	$ 62,689,095	$ 9,621,518	$ 53,067,577	$ 28,365,302	$ 10,885,894	$ 13,008,594	$ 807,787
8	TOTAL OPERATING REVENUES	$ 1,059,741,977	$ 113,094,835	$ 946,647,142	$ 468,082,921	$ 219,042,352	$ 237,499,933	$ 22,021,936
	EXPENSES							
9	Operations and Maintenance	$ 526,662,620	$ 53,941,790	$ 472,720,830	$ 219,217,844	$ 109,620,008	$ 134,930,858	$ 8,952,121
10	Depreciation and Amortization	$ 210,205,929	$ 21,110,552	$ 189,095,376	$ 88,738,089	$ 46,247,163	$ 50,222,695	$ 3,887,430
11	Regulatory Debits	$ 526,655	$ (0)	$ 526,655	$ 238,385	$ 128,982	$ 147,347	$ 11,941
12	Loss (Gains) from Disposition of Allowances	$ (33,340)	$ (3,594)	$ (29,747)	$ (13,323)	$ (7,338)	$ (8,395)	$ (690)
13	Taxes Other Than Income Taxes	$ 44,723,067	$ 4,628,110	$ 40,094,957	$ 18,238,482	$ 9,623,944	$ 11,341,478	$ 891,054
14	Federal & State Income Taxes	$ 93,562,013	$ 11,278,026	$ 82,248,986	$ 49,372,836	$ 18,727,159	$ 12,850,127	$ 1,298,864
15	TOTAL EXPENSES	$ 875,646,944	$ 90,954,884	$ 784,657,058	$ 375,792,312	$ 184,339,916	$ 209,484,110	$ 15,040,719
16	OPERATING INCOME	$ 184,095,033	$ 22,139,951	$ 161,990,083	$ 92,290,609	$ 34,702,436	$ 28,015,822	$ 6,981,217
17	EARNED RETURN ON RATE BASE	4.13%	4.79%	4.05%	5.00%	3.50%	2.57%	10.56%
	COST OF SERVICE REVENUE REQUIREMENT							
18	REQUIRED RETURN ON RATE BASE GIVEN EQUAL RATES OF RETURN			5.04%	5.04%	5.04%	5.04%	5.04%
19	REQUIRED OPERATING INCOME (L6*L19)			$ 201,378,623	$ 93,110,593	$ 50,030,777	$ 54,905,622	$ 3,331,631
20	OPERATING INCOME DEFICIENCY / (SURPLUS) (L20-L17)			$ 39,388,540	$ 819,984	$ 15,328,342	$ 26,889,800	$ (3,649,586)
21	REVENUE CONVERSION FACTOR			1.61647	1.61406	1.61727	1.61601	1.61597
22	REVENUE DEFICIENCY / (SURPLUS) (L21*L22)			$ 63,670,243	$ 1,323,503	$ 24,790,091	$ 43,454,273	$ (5,897,624)
23	RATE SCHEDULE REVENUE REQUIREMENT (L23+L7)			$ 957,249,807	$ 441,041,122	$ 232,946,548	$ 267,945,612	$ 15,316,525
24	TOTAL SYSTEM SALES AND OTHER REVENUES (L8)			$ 53,067,577	$ 28,365,302	$ 10,885,894	$ 13,008,594	$ 807,787
25	TOTAL NON-FUEL REVENUE REQUIREMENT (L24+L25)			$ 1,010,317,384	$ 469,406,424	$ 243,832,443	$ 280,954,205	$ 16,124,312
26	FUEL RIDER REVENUES			$ 181,290,199	$ 67,109,634	$ 38,166,605	$ 73,738,478	$ 2,275,481
27	GRAND GULF RIDER REVENUES			$ 120,935,470	$ 58,739,952	$ 27,218,588	$ 32,203,526	$ 2,773,404
28	PRODUCTION COST ALLOCATION RIDER REVENUES			$ 381,378,934	$ 138,480,197	$ 79,578,670	$ 158,596,250	$ 4,723,817
29	ENERGY EFFICIENCY COST RECOVERY RIDER REVENUES			$ 6,435,515	$ 2,663,081	$ 1,471,275	$ 2,257,300	$ 43,858
30	OTHER RIDER REVENUES			$ 1,564,940	$ 585,878	$ 333,201	$ 627,028	$ 18,833
31	TOTAL REVENUE REQUIREMENT (L26+L27+L28+L29+L30+L31)			$ 1,701,922,441	$ 736,985,165	$ 390,600,762	$ 548,376,788	$ 25,959,706
	TOTAL BILL IMPACT							
32	REVISED SETTLEMENT COS REVENUE DEFICIENCY / (SURPLUS) (Attachment 3 L36)			$ 73,781,760	$ 18,153,470	$ 28,758,704	$ 28,869,586	$ -
33	% INCREASE/ (DECREASE) ON BASE RATE REVENUES (L32/L6)			8.26%	4.13%	12.86%	12.86%	0.00%
34	COST OF SERVICE IMPACT OF SECURITIZATION (L22-Attachment 3 L22)			$ (10,111,517)	$ (4,744,060)	$ (2,494,052)	$ (2,701,083)	$ (172,322)
36	% INCREASE/ (DECREASE) ON BASE RATE REVENUES (L34/L6)			-1.13%	-1.08%	-1.20%	-1.20%	-0.81%
36	COMPLIANCE COST OF SERVICE REVENUE DEFICIENCY / (SURPLUS) (L32+L34)			$ 63,670,243	$ 13,409,410	$ 24,264,652	$ 26,168,503	$ (172,322)
37	% INCREASE/ (DECREASE) ON BASE RATE REVENUES (L36/L6)			7.13%	3.05%	11.66%	11.66%	-0.81%
38	LESS RIDER CA REVENUES*			$ 17,295,728	$ 7,129,168	$ 4,006,387	$ 6,045,552	$ 114,620
39	INCREASE (DECREASE) TO REV. REQ. (W/ RIDER CA ELIMINATION) (L36-L38)			$ 46,374,515	$ 6,280,242	$ 20,258,264	$ 20,122,952	$ (286,942)
40	% INCREASE/ (DECREASE) ON TOTAL REVENUE REQUIREMENT (L39/(L31-L39))			2.80%	0.86%	5.47%	3.81%	-1.09%

* In accordance with the recovery of the investments and costs related to the Ouachita Plant through base rates rather than Rider CA.

Approved Base Rate Schedule Revenue ($000)(L6+L36)	957,250	453,127	232,421	250,660	21,042

Excerpt from the Joint Submission of Revised Cost of Service filed June 3, 2010 in Docket No. 09-084-U.

D.5

Note Added

ENTERGY ARKANSAS, INC.
BILLING DETERMINANT DEVELOPMENT
2011 GRAND GULF RIDER (GGR) & NUCLEAR DECOMMISSIONING COST RIDER (NDCR) UPDATE

Development of Energy (kWh) Billing Determinant for all Rate Classes except LGS

Ln No		Actual MWh (1) 2010	2009	2008	Total	Average	Ratios (%) (2)	Forecasted 2012 kWh (3)
	Residential							
1	Residential	8,427,000	7,391,585	7,605,440	23,424,025	7,808,008	99.07%	7,831,730,441
2	Lighting	73,577	72,843	72,690	219,110	73,037	0.93%	73,258,565
3	**Total Residential**	**8,500,577**	**7,464,428**	**7,678,130**	**23,643,135**	**7,881,045**		**7,904,989,006**
	Commercial							
4	Small GS	3,371,013	3,077,847	3,161,583	9,610,443	3,203,481	53.88%	3,286,669,961
5	Large GS							
6	LG-NTOU	1,265,380	1,240,901	1,251,800	3,758,081	1,252,694		
7	LG-TOU	1,409,393	1,399,442	1,362,190	4,171,025	1,390,342		
8	Total Large GS	2,674,773	2,640,343	2,613,990	7,929,106	2,643,035	44.46%	2,711,670,472
9	Lighting	97,772	98,883	99,828	296,483	98,828	1.66%	101,394,053
10	**Total Commercial**	**6,143,558**	**5,817,073**	**5,875,401**	**17,836,032**	**5,945,344**		**6,099,734,487**
	Industrial							
11	Small GS	1,334,514	1,111,351	1,207,130	3,652,995	1,217,665	17.67%	1,259,415,905
12	Large GS							
13	LG-NTOU	1,268,089	1,124,233	1,278,885	3,671,207	1,223,736		
14	LG-TOU	4,464,799	4,125,485	4,710,173	13,300,457	4,433,486		
15	Total Large GS	5,732,888	5,249,718	5,989,058	16,971,664	5,657,221	82.11%	5,851,194,317
16	Lighting	14,524	14,796	15,286	44,606	14,869	0.22%	15,378,479
17	**Total Industrial**	**7,081,926**	**6,375,865**	**7,211,474**	**20,669,265**	**6,889,755**		**7,125,988,701**
	Govt & Muni							
18	Small GS	9,341	8,872	8,277	26,490	8,830	3.23%	8,979,119
19	Large GS							
20	LG-NTOU	68,690	66,634	70,920	206,244	68,748		
21	LG-TOU	128,530	123,744	124,227	376,501	125,500		
22	Total Large GS	197,220	190,378	195,147	582,745	194,248	71.16%	197,528,753
23	Lighting	70,500	69,720	69,473	209,693	69,898	25.61%	71,078,082
24	**Total Govt & Muni**	**277,061**	**268,970**	**272,897**	**818,928**	**272,976**		**277,585,953**
25	**Total Retail**	**22,003,122**	**19,926,336**	**21,037,902**	**62,967,360**	**20,989,120**		21,408,298,147
	TOTAL BY RATE CLASS							**kWh**
26	Residential	8,427,000	7,391,585	7,605,440	23,424,025	7,808,008		**7,831,730,441**
27	Small Gen. Service	4,714,868	4,198,070	4,376,990	13,289,928	4,429,976		**4,555,064,986**
28	Large Gen. Service	8,604,881	8,080,439	8,798,195	25,483,515	8,494,505		**8,760,393,542**
29	Lighting	256,373	256,242	257,277	769,892	256,631		**261,109,179**
30	**Total Retail**	**22,003,122**	**19,926,336**	**21,037,902**	**62,967,360**	**20,989,120**		21,408,298,147

Development of Demand (kW) Billing Determinant for LGS Rate Class

Ln No	Large GS	2010	2009	2008	Total	Average	Factor (4)	kW (5)
31	LGS kW (1)	16,959,852	15,256,699	15,978,455	48,195,006	16,065,002		
32	**Total**	**16,959,852**	**15,256,699**	**15,978,455**	**48,195,006**	**16,065,002**	**1.89**	**16,567,856**

Notes:
(1) All Historical Rate Class MWh and kW provided by Rate Administration.
(2) 3 year average ratio of Rate Class MWh to the Total MWh within the Revenue Class
(3) Forecast provided on Revenue Class basis therefore converted to Rate Class based on 3 year Historical Average MWh
(4) LGS 3 year average kW (L31) / 3 year average LGS MWh (L28)
(5) Forecasted LGS MWh (L28) * Factor derived from Historical results equals Forecasted kW for LGS Rate Class (L32)

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF ARKANSAS POWER & LIGHT COMPANY'S PROPOSED NUCLEAR DECOMMISSIONING COST RIDER M26 AND PROPOSED DEPRECIATION RATE RIDER M41	)))))	DOCKET NO. 87-166-TF ORDER NO. 50

ORDER

On March 31, 2009, Entergy Arkansas, Inc.[1] ("EAI" or "Company") filed its *Motion for Approval of Revised Estimate of Arkansas Nuclear One Decommissioning Costs and Certain Other Changes to the ANO Decommissioning Trust Funds* ("Motion") with the supporting Second Supplemental Testimony of EAI witness Michael A. Caruso, and the Direct Testimonies and Exhibits of EAI witnesses Rory L. Roberts, Rebecca L. Bowden and William A. Cloutier, Jr. In addition, EAI previously filed the Supplemental Testimony and Exhibits of EAI witness Caruso on July 24, 2008, which, pursuant to Order No. 47 in this Docket, had been held in abeyance until such time that EAI filed its revised estimate of the Arkansas Nuclear One ("ANO") Decommissioning Costs.

On April 23, 2009, the Arkansas Public Service Commission ("APSC" or "the Commission") issued Order No. 48 in this Docket suspending EAI's Motion and establishing a procedural schedule. Pursuant to Order No. 48, on July 24, 2009, the General Staff of the Commission ("Staff") filed the Direct Testimony and Exhibits of its witness, Donna Gray, Director of the General Staff Financial Analysis. On August 24, 2009, EAI filed the Rebuttal Testimonies and Exhibits of EAI witnesses Steven K. Strickland, Albert C. King, III, Caruso, Bowden, and Cloutier. Staff filed the Surrebuttal

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[1] Previously Arkansas Power and Light Company.

Ms. Gray additionally recommends that EAI be ordered to provide substantiation that the DOE Obligation funds will be available when payment is due and that ratepayers will be insulated from any adverse impacts from that payment. Ms. Gray advises that ratepayers have provided funding of the DOE Obligation and continue to pay interest on the on-going obligation. (Gray Direct at 12).

EAI witness Strickland proposes to work with Staff witness Gray in framing an appropriate analysis to address her recommendations regarding EAI's DOE Obligation and to provide that analysis to the Commission within 90 days after the Commission's order in this docket. (Strickland Sur-Surrebuttal at 4-5).

Stipulation

By their Joint Motion, Staff and EAI propose a Stipulation (Attachment A hereto) to settle all issues addressed in this proceeding and ask that the Commission consider the Stipulation based upon the evidence of record and that the scheduled public hearing be cancelled. By Order No. 49, issued on September 11, 2009, the Commission cancelled the hearing previously set for September 15, 2009, and took this matter under advisement based upon the pre-filed testimony and exhibits of the parties.[10] Further, EAI and Staff request that the Commission issue its final Order in this matter by October 15, 2009.

A summary[11] of the Stipulation terms follows:

- The Commission should approve EAI's nuclear decommissioning cost estimate of $1,049.8 million[12] for use in the annual November 1 tariff filings for the years 2009 through 2013;

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[10] The only other party to this Docket, the Arkansas Electric Energy Consumers, Inc., has not participated in this specific phase of this Docket.
[11] This summary is not intended to supplant the actual language of the Stipulation.
[12] The amount specifically excludes Spent Fuel costs.

- The Commission should approve the "pour-over" as requested by EAI, with EAI contributing both the funds in the Non-Tax Qualified Trust Fund and the cash benefit of the resulting tax deduction;
- EAI will file in this docket both its request to IRS for approval of the pour-over and the IRS response to substantiate that approval;
- EAI will demonstrate in annual filings in this docket the actual net tax benefits to ratepayers of the pour-over, with full explanation of variations in actual benefits from those reflected in EAI Exhibit RLR-2;
- EAI shall identify the pour-over amounts and the timing thereof in the respective quarterly trust fund reports filed in Docket No. 96-341-U;
- The Commission should condition its approval of the revocation of the Non-Tax Qualified Trust Fund on IRS authorization to pour-over the full amount in that fund;
- The Commission should approve the change in the equity allocation targets for the Funds from 50 percent to 60 percent, maintaining re-balancing at +/- 5 percent around the 60 percent equity target and approve the broadening of the equity market exposure[15] in the funds, and;
- EAI will file with this Commission the NRC Funding Report beginning with the report due March 31, 2011, and every two years thereafter or at such other interval as the NRC may require.

Findings

The Commission has considered the proposed Stipulation in conjunction with the parties' filed Testimony and Exhibits and finds that the Stipulation is fully supported by

[15] The Stipulation states that broadening should be accomplished by "increasing the exposure in the Wilshire 4500 Stock Index Fund, over a reasonable period of time, for both Units so that the ratio of investment in the Wilshire 4500 Stock Index Fund to the total equity in each fund is the same as the Wilshire 4500 Index is to the total U.S. stock market, or about 20 percent." (Stipulation at 5).

the record, settles all issues addressed herein in a reasonable manner, and is in the public interest. Accordingly, the Commission hereby approves in its entirety the Stipulation attached hereto as Attachment A. EAI shall fully comply with the terms and conditions set forth in said Stipulation.

BY ORDER OF THE COMMISSION,

This 13th of October, 2009.

Paul Suskie, Chairman

Colette D. Honorable, Commissioner

Olan W. Reeves, Commissioner

Kristi Rhude (Acting)
Office of the Secretary of the Commission

I hereby certify that the following order issued by the Arkansas Public Service Commission has been served on all parties of record this date by U.S. mail with postage prepaid, using the address of each party as indicated in the official docket file.

Secretary of the Commission
Date 10/13/09

Entergy Arkansas, Inc.
Approved Nuclear Decommissioning Cost Estimate
For the annual November 1 tariff filings for the years 2009 through 2013 (1)
($000)

		Approved Decommissioning Expenditures						
		Unit 1			**Unit 2**			**Total**
Line No	Year	License Termination	Site Restoration	**Total ex Spent Fuel**	License Termination	Site Restoration	**Total ex Spent Fuel**	**Both Units (2)**
1	2034	30,497	374	**30,871**			**0**	
2	2035	92,023	1,113	**93,136**			**0**	
3	2036	117,755	371	**118,126**			**0**	
4	2037	77,094	347	**77,441**			**0**	
5	2038	51,702	333	**52,035**	19,414	151	**19,565**	
6	2039	51,651	293	**51,944**	62,322	591	**62,913**	
7	2040	14,154	0	**14,154**	119,903	1,119	**121,022**	
8	2041	3,219	0	**3,219**	89,660	2,645	**92,305**	
9	2042	3,219	0	**3,219**	59,626	4,091	**63,717**	
10	2043	3,219	0	**3,219**	59,626	4,091	**63,717**	
11	2044	17,669	0	**17,669**	35,667	168	**35,835**	
12	2045	5,281	11,775	**17,056**	5,488	23,797	**29,285**	
13	2046	13,017	17,358	**30,375**	13,913	35,082	**48,995**	
	Total	480,500	31,964	**512,464**	465,619	71,735	**537,354**	**1,049,818**

Notes:

(1) Decommissioning Cost Estimate (2008 dollars) as approved in APSC Order No. 50 in Docket No. 87-166-TF issued on October 13, 2009. See Workpapers D.7 - D.10 for excerpts from that Order.

(2) Total ANO Decommissioning Cost Estimate as stated in APSC Order No. 50.

ENTERGY ARKANSAS, INC.
DOCKET NO. 09-084-U
COMPLIANCE COST OF SERVICE - ALLOCATION FACTORS
TEST YEAR ENDED JUNE 30, 2009

LINE NO.	DESCRIPTION	COMPUTER CODE	ALLOCATION FACTOR	TOTAL COMPANY	TOTAL OF ALL FUNCTIONS: TOTAL RETAIL	RESID	SGS	LGS	LIGHTING	WHLSE
	DEMAND ALLOCATION FACTORS									
1	PRODUCTION DEMAND			1.000000	0.861300	0.353893	0.204728	0.296740	0.005939	0.138700
2	*****UNITIZED*****		**PDAF**	**1.000000**	**0.861300**	**0.353893**	**0.204728**	**0.296740**	**0.005939**	**0.138700**
3	PRODUCTION DEMAND ARKANSAS RETAIL			1.000000	1.000000	0.410882	0.237697	0.344526	0.006895	-
4	*****UNITIZED*****		**PDAFAR**	**1.000000**	**1.000000**	**0.410882**	**0.237697**	**0.344526**	**0.006895**	**-**
5	PRODUCTION DEMAND ARKANSAS WHOLESALE			0.138700	-	-	-	-	-	0.138700
6	*****UNITIZED*****		**PDAFW**	**1.000000**	**-**	**-**	**-**	**-**	**-**	**1.000000**
7	TRANSMISSION HIGH VOLTAGE DEMAND			1.000000	0.717117	0.315849	0.163856	0.237313	0.000099	0.282883
8	*****UNITIZED*****		**THDAF**	**1.000000**	**0.717117**	**0.315849**	**0.163856**	**0.237313**	**0.000099**	**0.282883**
9	TRANSMISSION HIGH VOLTAGE DEMAND ARKANSAS RETAIL			0.717117	0.717117	0.315849	0.163856	0.237313	0.000099	-
10	*****UNITIZED*****		**THDAFAR**	**1.000000**	**1.000000**	**0.440443**	**0.228493**	**0.330926**	**0.000138**	**-**
11	TRANSMISSION LOW VOLTAGE DEMAND			1.000000	0.763047	0.336078	0.174350	0.252513	0.000106	0.236953
12	*****UNITIZED*****		**TLDAF**	**1.000000**	**0.763047**	**0.336078**	**0.174350**	**0.252513**	**0.000106**	**0.236953**
13	DISTRIBUTION SUBSTATIONS DEMAND			1.000000	0.979714	0.428293	0.259371	0.277685	0.014365	0.020286
14	*****UNITIZED*****		**DSDAF**	**1.000000**	**0.979714**	**0.428293**	**0.259371**	**0.277685**	**0.014365**	**0.020286**
15	DISTRIBUTION LINES PRIMARY DEMAND			1.000000	0.987478	0.431686	0.261426	0.279886	0.014480	0.012522
16	*****UNITIZED*****		**DLPDAF**	**1.000000**	**0.987478**	**0.431686**	**0.261426**	**0.279886**	**0.014480**	**0.012522**
17	DISTRIBUTION LINES SECONDARY DEMAND			1.000000	0.999979	0.573439	0.277494	0.136638	0.012408	0.000021
18	*****UNITIZED*****		**DLSDAF**	**1.000000**	**0.999979**	**0.573439**	**0.277494**	**0.136638**	**0.012408**	**0.000021**
19	DISTRIBUTION LINE TRANSFORMER DEMAND			1.000000	0.999979	0.573439	0.277494	0.136638	0.012408	0.000021
20	*****UNITIZED*****		**DLTDAF**	**1.000000**	**0.999979**	**0.573439**	**0.277494**	**0.136638**	**0.012408**	**0.000021**

Numbers may not add due to rounding.

ENTERGY ARKANSAS, INC.
CALCULATION OF % OF UNCOLLECTIBLE ACCOUNTS
YEARS 2006 THRU 2010
($000's)

LINE NO	YEAR	RATE CLASSES	5-YEAR TOTAL JURISDICTIONAL OPERATING REVENUES	5-YEAR TOTAL JURISDICTIONAL UNCOLLECTIBLES WRITTEN OFF	5-YEAR AVERAGE % UNCOLLECTIBLES
		EAI			
		APSC RETAIL			
1		RESIDENTIAL	3,633,458	35,135	0.9670%
2		SMALL GENERAL SVC	1,835,004	2,923	0.1593%
3		LARGE GENERAL SVC-NTOU	855,187	290	0.0339%
4		LARGE GEN SVC-TOU	1,669,209	1,858	0.1113%
5		SPECIAL CONTRACT	0	0	0.0000%
6		LIGHTING - ROADWAY	42,351	0	0.0000%
7		LIGHTING - NON-ROADWAY	112,748	659	0.5845%
8		**TOTAL APSC RETAIL**	**8,147,957**	**40,865**	**0.5015%**

Per the EAI 2011 ANO Decommissioning Cost Rider NDCR Update Rate Sch. No. 37 Workpapers

Entergy Arkansas, Inc.
ANO Decommissioning Model
Tax Qualified Trust Detail — Unit 1
($000)

			Tax Qualified Trust						
Line No	Year	Revenue Rqmt. [1]	Earning Rate [2]	Transfer To Trust [3] [9]	Earnings [4]	Mgmt. Fee [5]	Net Additions [6]	Decomm. Expend. [7]	Balance [8]
1	Beginning Balance								306,406
2	2012	0	5.81%	0	18,061	292	17,769	0	324,175
3	2013	0	5.86%	0	19,275	308	18,967	0	343,142
4	2014	0	6.08%	0	21,180	325	20,855	0	363,997
5	2015	0	6.40%	0	23,669	344	23,325	0	387,322
6	2016	0	6.52%	0	25,665	364	25,301	0	412,623
7	2017	0	6.54%	0	27,427	387	27,040	0	439,663
8	2018	0	6.56%	0	29,315	411	28,904	0	468,567
9	2019	0	6.58%	0	31,339	436	30,903	0	499,470
10	2020	0	6.61%	0	33,561	463	33,097	0	532,567
11	2021	0	6.63%	0	35,894	492	35,402	0	567,969
12	2022	0	6.66%	0	38,457	524	37,933	0	605,902
13	2023	0	6.68%	0	41,150	557	40,593	0	646,495
14	2024	0	6.70%	0	44,041	593	43,448	0	689,942
15	2025	0	6.73%	0	47,214	631	46,583	0	736,525
16	2026	0	6.76%	0	50,631	673	49,958	0	786,483
17	2027	0	6.79%	0	54,309	717	53,592	0	840,076
18	2028	0	6.81%	0	58,183	764	57,419	0	897,495
19	2029	0	6.85%	0	62,531	815	61,716	0	959,211
20	2030	0	6.88%	0	67,129	869	66,260	0	1,025,471
21	2031	0	6.91%	0	72,084	928	71,156	0	1,096,627
22	2032	0	6.51%	0	72,552	989	71,564	0	1,168,191
23	2033	0	5.70%	0	67,536	1,048	66,488	0	1,234,679
24	2034	0	4.88%	0	60,987	1,101	59,886	61,433	1,233,132
25	2035	0	4.50%	0	56,115	1,098	55,017	190,277	1,097,872
26	2036	0	4.50%	0	49,960	980	48,980	247,710	899,142
27	2037	0	4.50%	0	40,917	807	40,110	166,730	772,521
28	2038	0	4.50%	0	35,155	697	34,458	114,997	691,981
29	2039	0	4.50%	0	31,489	626	30,863	117,861	604,983
30	2040	0	4.50%	0	27,531	551	26,980	32,965	598,999
31	2041	0	4.50%	0	27,258	545	26,713	7,697	618,015
32	2042	0	4.50%	0	28,124	562	27,562	7,903	637,674
33	2043	0	4.50%	0	29,018	579	28,439	8,112	658,001
34	2044	0	4.50%	0	29,943	597	29,346	45,710	641,638
35	2045	0	4.50%	0	29,199	583	28,616	45,301	624,953
36	2046	0	4.50%	0	28,439	568	27,871	82,833	569,991
	Average		5.78%						

Notes:

[1] See Workpaper B.2

[2] Projected After Tax Earnings Rates See Workpaper C.1.

[3] Revenue Requirement * (1 - Bad Debt Rate). See Workpaper B.7 for Bad Debt Rate.

[4] Prior Year Balance Compounded Semiannually At Current Year Earning Rate + 1/2 Current Year Transfer * Current Year Earning Rate.

[5] Calculated on average balance according to the schedules on Workpaper B.7 multiplied by (1 - TQ Fund Tax Rate).

[6] Transfer + Earnings - Management Fee.

[7] Assumes that decommissioning expenditures are made at year end.
See Workpaper B.6 for the total.

[8] Prior Year Balance + Net Additions - Decommissioning Expenditures. For Beginning Balance see Workpaper C.4.

[9] The percentage to be contributed to the Tax Qualified Trust Fund is 100%.

Per the EAI 2011 ANO Decommissioning Cost Rider NDCR Update Rate Sch. No. 37 Workpapers

Entergy Arkansas, Inc.
ANO Decommissioning Model
Tax Qualified Trust Detail — Unit 2
($000)

			Tax Qualified Trust						
Line No	Year	Revenue Rqmt. [1]	Earning Rate [2]	Transfer To Trust [3] [9]	Earnings [4]	Mgmt. Fee [5]	Net Additions [6]	Decomm. Expend. [7]	Balance [8]
1	Beginning Balance								239,972
2	2012	0	5.81%	0	14,145	234	13,911	0	253,883
3	2013	0	5.86%	0	15,096	246	14,849	0	268,733
4	2014	0	6.08%	0	16,587	259	16,328	0	285,061
5	2015	0	6.40%	0	18,536	274	18,262	0	303,322
6	2016	0	6.52%	0	20,099	290	19,809	0	323,131
7	2017	0	6.54%	0	21,478	308	21,170	0	344,301
8	2018	0	6.56%	0	22,957	327	22,630	0	366,931
9	2019	0	6.58%	0	24,541	347	24,195	0	391,126
10	2020	0	6.61%	0	26,281	368	25,913	0	417,038
11	2021	0	6.63%	0	28,108	391	27,717	0	444,756
12	2022	0	6.66%	0	30,114	415	29,699	0	474,454
13	2023	0	6.68%	0	32,223	441	31,781	0	506,236
14	2024	0	6.70%	0	34,486	469	34,016	0	540,252
15	2025	0	6.73%	0	36,971	499	36,471	0	576,724
16	2026	0	6.76%	0	39,645	532	39,114	0	615,837
17	2027	0	6.79%	0	42,525	566	41,959	0	657,796
18	2028	0	6.81%	0	45,559	603	44,955	0	702,751
19	2029	0	6.85%	0	48,963	643	48,320	0	751,071
20	2030	0	6.88%	0	52,562	686	51,877	0	802,948
21	2031	0	6.91%	0	56,442	732	55,711	0	858,659
22	2032	0	6.91%	0	60,358	781	59,578	0	918,236
23	2033	0	6.91%	0	64,546	833	63,713	0	981,949
24	2034	0	6.91%	0	69,025	889	68,135	0	1,050,084
25	2035	0	6.91%	0	73,814	950	72,865	0	1,122,949
26	2036	0	6.51%	0	74,294	1,012	73,282	0	1,196,231
27	2037	0	5.70%	0	69,157	1,072	68,085	0	1,264,316
28	2038	0	4.88%	0	62,451	1,127	61,324	43,239	1,282,401
29	2039	0	4.50%	0	58,357	1,141	57,216	142,750	1,196,868
30	2040	0	4.50%	0	54,465	1,066	53,399	281,860	968,406
31	2041	0	4.50%	0	44,069	867	43,201	220,701	790,906
32	2042	0	4.50%	0	35,991	713	35,279	156,425	669,760
33	2043	0	4.50%	0	30,478	607	29,871	160,567	539,064
34	2044	0	4.50%	0	24,531	493	24,038	92,705	470,397
35	2045	0	4.50%	0	21,406	433	20,973	77,781	413,588
36	2046	0	4.50%	0	18,821	384	18,437	133,609	298,416
Average			6.06%						

Notes:

[1] See Workpaper B.4.
[2] Projected After Tax Earnings Rates See Workpaper C.1.
[3] Revenue Requirement * (1 - Bad Debt Rate). See Workpaper B.7 for Bad Debt Rate.
[4] Prior Year Balance Compounded Semiannually At Current Year Earning Rate + 1/2 Current Year Transfer * Current Year Earning Rate.
[5] Calculated on average balance according to the schedules in Workpaper B.7 multiplied by (1 - TQ Fund Tax Rate).
[6] Transfer + Earnings - Management Fee.
[7] Assumes that decommissioning expenditures are made at year end.
See Workpaper B.6 for the total.
[8] Prior Year Balance + Net Additions - Decommissioning Expenditures. For Beginning Balance see Workpaper C.4.
[9] The percentage to be contributed to the Tax Qualified Trust Fund is 100%.

Attachment 1-E
(53 pages)

Entergy Arkansas, Inc. Unit Power Purchase Agreements under Service Schedule MSS-4

Entergy

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Andrea J. Weinstein
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Federal Regulation and Policy

October 13, 2009

The Honorable Kimberly Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

FILED
SECRETARY OF THE COMMISSION
2009 OCT 13 P 2:07
FEDERAL ENERGY REGULATORY COMMISSION

Re: <u>Entergy Services, Inc. -- Docket No. ER10- -000</u>

Dear Secretary Bose:

Pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d (2004), and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission") 18 C.F.R. Part 35 (2009), Entergy Services, Inc. ("ESI"), on behalf of (1) Entergy Gulf States Louisiana, L.L.C. ("EGSL") as purchaser and Entergy Arkansas, Inc., ("EAI") as seller with respect to a three-year contract[1] for certain capacity and associated energy from a portion of EAI's Wholesale Baseload ("WBL") resources;[2] (2) Entergy Texas, Inc. ("ETI") as purchaser and EAI as seller with respect to a three-year contract for certain capacity and associated energy from a portion of EAI's WBL resources;[3] (3) Entergy Mississippi, Inc. ("EMI") as purchaser and EAI as seller with respect to a three-year contract[4] for certain capacity and associated energy from a portion of EAI's WBL resources; and (4) Entergy Louisiana, LLC. ("ELL") as purchaser and EAI as seller with respect to a three-year contract[5] for certain capacity and associated energy from a portion of EAI's WBL resources hereby submit for filing six copies of the EAI-EGSL, EGS-ETI, EAI-EMI and EAI-ELL Contracts . The EAI-EGSL, EAI-ETI, EAI-EMI and EAI-ELL Contracts which are the subject of this filing are being priced at cost pursuant to the currently effective Service Schedule MSS-4 of the Entergy System Agreement.[6] The EAI-EGSL

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[1] Hereinafter, the "EAI-EGSL Contract."

[2] EAI's WBL resources include a "slice" of EAI coal and nuclear baseload generating resources. The specific resources are listed in Attachment A to the enclosed Bridge Contracts.

[3] Hereinafter, the "EAI-ETI Contract."

[4] Hereinafter, the "EAI-EMI Contract."

[5] Hereinafter, the "EAI-ELL Contract."

[6] The System Agreement is a FERC-approved rate schedule filed with and subject to the exclusive jurisdiction of this Commission.

Contract is for 101.4 MW of EAI WBL resources for the period January 1, 2010 through May 31, 2012 increasing to 104.8 MW from June, 1, 2012 through December 31, 2012. The EAI-ETI Contract is for 106.6 MW of EAI WBL resources for the period January 1, 2010 through May 31, 2012 increasing to 110.1 MW from June 1, 2012 through December 31, 2012. The EAI-EMI Contract is for 76.6 MW of EAI WBL resources for the period January 1, 2010 through May 31, 2012 increasing to 79.1 MW from June 1, 2010 through December 31, 2012. The EAI-ELL Contract is for 51.4 MW of EAI WBL resources for the period January 1, 2010 through May 31, 2012 increasing to 53.1 MW from June 1, 2012 through December 31, 2012. These contracts reflect the same pricing provisions and fundamentally similar contractual provisions (but for the three-year term) as the previous contracts accepted by the Commission in Docket No. ER09-183-000.

ESI hereby seeks acceptance of the EAI-EGSL, EAI-ETI, EAI-EMI and EAI-ELL Contracts as just and reasonable cost-based power sales pursuant to the Commission-approved formula rate in Service Schedule MSS-4. The EAI-EGSL, EAI-ETI, EAI-EMI and EAI-ELL Contracts: (1) are expected to result in savings to EGSL, ETI, EMI and ELL customers as compared to other alternatives for meeting customer needs, (2) are expected to benefit customers by reducing the disparity in production cost responsibility among the Entergy Operating Companies in accordance with Opinion Nos. 480 and 480-A, and (3) will reduce the extent to which EGSL, ETI, EMI and ELL are dependent upon natural gas, a fuel source that has experienced substantial price volatility.[7] For these reasons, the Contracts are just and reasonable and the Commission should accept and approve these contracts as filed effective as of January 1, 2010, without further proceedings.

I. SUMMARY OF FILING

EAI, EGSL, ETI, EMI, ELL along with Entergy New Orleans, Inc. (collectively, the "Operating Companies"), are wholly-owned subsidiaries of Entergy Corporation. Each Operating Company is a public utility within the meaning of the FPA and, in addition, provides retail electric services to native load customers within franchised service territories subject to regulation by State or local regulatory bodies. ESI, also a wholly-owned subsidiary of Entergy Corporation, acts as agent for the Operating Companies.

In January 2003, the Operating Companies adopted a Strategic Supply Resource Plan ("SSRP"), which represents a balanced portfolio method to generation resource planning, incorporating short-term and long-term contracts in order to maintain price stability among the Entergy Operating Companies. The SSRP outlines the long-term view of the Operating Companies' planning needs for the 2003 through 2012 timeframe and describes the Operating Companies' strategy for obtaining the generation resources required to meet the needs of retail customers. The principal goals of the SSRP include providing low cost base load resources to all of the Entergy Operating Companies equivalent to their individual baseload requirements. The EAI-EGSL, EAI-ETI, EAI-EMI and EAI-ELL Contracts are a continuation of the SSRP process.

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[7] *Louisiana Public Service Commission v. Entergy Services, Inc.*, Opinion No. 480, 111 FERC ¶ 61,311 (2005), Opinion No. 480-A, 113 FERC ¶ 61,282 (2005).

In Opinion No. 480, the Commission, among other things, affirmed the presiding judge's finding that the Entergy System was no longer in rough production cost equalization and that a bandwidth remedy was a just and reasonable backstop if the SSRP proved to be an ineffective remedy for production cost disparities.

As discussed below, the EAI-EGSL, EAI-ETI, EAI-EMI and EAI-ELL Contracts have been entered into pursuant to Service Schedule MSS-4 of the Entergy System Agreement. Service Schedule MSS-4 was modified pursuant to a settlement and approved by the Commission in Docket No. ER03-753, *et al.* Because the contracts are priced pursuant to MSS-4, the contracts are just and reasonable under a Commission-approved cost-based formula rate.

Furthermore, the price terms reflected in the EAI-EGSL, EAI-ETI, EAI-EMI and EAI-ELL Contracts are comparable to the price terms for similar EAI-WBL contracts that were accepted by the Commission in Docket Nos. ER06-342, ER07-135, ER08-160 and ER09-183. Accordingly, approval of the subject PPAs is consistent with the Commission's standards for sales between affiliates, is in the public interest, and satisfies the requirements of section 205 of the FPA.

II. INFORMATION REQUIRED BY PART 35

Consistent with the requirements of Part 35 of the Commission's regulations, ESI states that in addition to this transmittal letter, this filing includes:

A. Copies of the EAI-EMI (Attachment A), EAI-EGSL (Attachment B), EAI-ETI (Attachment C) and EAI-ELL Contracts (Attachment D); and

B. Additional supporting evidence (NYMEX Henry Hub natural gas futures price for calendar years 2010, 2011 and 2012) (Attachment E).

To the extent necessary, ESI requests a waiver of the information required by section 35.13. As these contracts are fundamentally identical to previously-approved Contracts and are being filed pursuant to Service Schedule MSS-4, which is a Commission-approved cost-based formula rate for cost-of-service sales among the Entergy Operating Companies, the cost information required by that section is not relevant.

III. COMMUNICATIONS

The following persons are authorized to receive notices and communications with respect to the instant filing:

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* persons designated to receive service in this proceeding.

IV. DISCUSSION

A. The Contracts are Low Cost Transactions and Represent Cost Savings to Ratepayers, and thus are Just and Reasonable.

The Contracts are just and reasonable because they provide low cost baseload resources to EGSL, ETI, EMI and ELL and represent significant savings to ratepayers as compared to alternatives available in the marketplace. The EAI WBL resources reflect a slice of excess EAI solid fuel capacity. As early as the Spring of 2002, ESI began to study the possibility of selling excess EAI WBL resources from EAI to other Entergy Operating Companies, among other things, to allocate additional low-cost solid fuel baseload resources to Operating Companies with higher than System average total production costs.[8] Moreover, the 2006 tranche of EAI-WBL resources was the subject of Docket No. ER06-342, the 2007 tranche of EAI-WBL resources was the subject of Docket No. ER07-135, the 2008 tranche of EAI-WBL resources was the subject of Docket No. ER08-160, and the 2009 tranche of EAI-WBL resources was the subject of Docket No. ER09-183.

The EAI WBL resources comprising the Contracts include two nuclear resources, EAI's Arkansas Nuclear One Units 1 and 2 and EAI's share of the Grand Gulf nuclear facility, and two coal-fired resources, EAI's Independence Steam Electric Station Unit 1 and EAI's White Bluff Units 1 and 2. These solid-fuel resources, priced at cost pursuant to MSS-4, are expected to be less costly over the three year horizon of the Contracts when compared to the cost of gas-fired resources at prevailing market prices.

Typically, nuclear fuel costs on the Entergy System average approximately \$6/MWh, while the energy cost of coal-fired generation averages approximately \$21/MWh. In contrast, at

[8] *Entergy Services, Inc.*, Initial Decision, 111 FERC ¶ 63,077 at P 41 (2005), Opinion No. 485, 116 FERC ¶ 61,296 (2006), *order on reh'g*, Opinion 485-A, 119 FERC ¶ 61,019 (2007).

current forward market data for the three-year horizon, natural gas prices are expected to be about $6.49/mmBtu, the fuel cost of a modern fuel efficient, gas-fired resource operating at a 7000 Btu/kWh heat rate would be approximately $45.43/MWh.[9] This compares to the projected all-in price of the EAI WBL PPAs of $40.60/MWh, and hence, represents savings compared to the alternatives available to EGSL, ETI, EMI and ELL.

The Contracts were market tested against a July 2009 Baseload Request for Proposals ("RFP"), which was conducted by the ESI, under the supervision of an Independent Monitor. The RFP was designed the match the design of the products sought to correspond, to the extent possible, to the supply role that would be filled by the Contracts. The levelized cost of the conforming proposals that were received in response to the RFP significantly exceeded the levelized cost of the Contracts.

In addition, the solid fuel resources offer numerous other benefits to EGSL, ETI, EMI and ELL ratepayers. Among these benefits are fuel diversity, fuel security, and fuel and price stability. Furthermore, the baseload resources in the Contracts match the load shape needs of EGSL, ETI, EMI and ELL. Finally, as in prior years, the Contracts are expected to continue to reduce the disparity in production cost responsibility among the Entergy Operating Companies pursuant to Opinion No. 480.

B. The Cost-Based Rates of the Contracts, Priced Pursuant to Commission-Approved Service Schedule MSS-4, are Just and Reasonable

1. Operation of MSS-4

Service Schedule MSS-4 of the Entergy System Agreement relates to a unit power purchase between Entergy Operating Companies and/or a sale of power purchased by an Operating Company. A unit power purchase is defined as the purchase of a portion of the capability of a generating resource sold pursuant to MSS-4 (the "Designated Generating Unit" or "DGU"), which entitles the purchaser to receive each hour, the same portion of the total energy generated by that resource. MSS-4 prescribes a formula rate for calculating the payment by one Operating Company to another Operating Company for a sale of the capability and associated energy of a DGU. By its terms, MSS-4 applies to capacity and associated energy owned by Operating Companies and offered to *other* Operating Companies. *See* System Agreement § 40.01. Section 2.02 of the System Agreement defines "Company" as one of the Entergy Operating Companies.

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9 As of August 14, 2009, the levelized NYMEX Henry Hub natural gas futures price for calendar years 2010-2012 is $6.49/mmBtu. *See* Attachment E. ESI notes that the NYMEX Henry Hub natural gas futures price has increased since August 14, 2009. As of September 30, 2009, the levelized NYMEX Henry Hub natural gas futures price for calendar years 2010-2012 was $6.67/mmBtu, which results in a generation fuel cost of $46.69/MWh.

2. *Approved Revisions to MSS-4*

On April 18, 2003, ESI filed for Commission approval of certain limited modifications to Service Schedule MSS-4. On June 10, 2003, the Commission issued an order accepting and suspending the amendments to Service Schedule MSS-4, subject to hearing, and establishing hearing procedures.[10] The MSS-4 proceeding was coordinated with, but not consolidated with, the PPA Proceeding, which involved the approval of eight PPAs among affiliated Entergy companies.[11] On August 13, 2004, following settlement discussions, ESI filed an MSS-4 Settlement Offer on behalf of the Settling Parties[12] and FERC Trial Staff. On October 6, 2004, the Presiding Administrative Law Judge certified the Settlement Offer to the Commission.[13] Subsequently, on November 24, 2004, ESI filed a revised Service Schedule MSS-4 to incorporate two minor issues raised by FERC Trial Staff.

On April 14, 2005, the Commission approved the MSS-4 Settlement, thus making the November 24, 2004 MSS-4 the currently effective MSS-4.[14] As a condition in its order, the Commission required ESI to file a notice with the Commission within 30 days of any Operating Company's entering into any long-term transaction pursuant to Service Schedule MSS-4."[15] The Commission defined "long-term" transactions as "one year or more."[16] According to the Commission, such a notice condition "will provide interested parties with the ability to identify and the opportunity to challenge the transaction under section 206 of the FPA," and is therefore a reasonable resolution of the MSS-4 settlement.[17]

In this instance, however, ESI is not making an informational filing regarding an MSS-4 transaction. Rather, ESI is filing these contracts under FPA section 205. Indeed, the reason ESI is making a section 205 filing here, as opposed to providing notice of long-term MSS-4 transactions within 30 days after Operating Companies enter into the transactions, stems from Section 40.09 of MSS-4. That section provides that a resale under MSS-4 of energy from the Grand Gulf nuclear facility shall be subject to the approval of the Commission. It is important that the Commission understand that the sole trigger for this particular filing requirement is the presence of Grand Gulf energy in the transaction. In other words, but for the inclusion of any Grand Gulf energy in the sale, there would not be and need not be a section 205 filing under the terms of the Commission approved settlement.

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10 *Entergy Services, Inc.*, 103 FERC ¶ 61,322 (2003).

11 Docket Nos. ER03-583-000, ER03-681-000, ER03-682-000, and ER03-744-000, *et al.*

12 The Settling Parties are ESI, the APSC, the LPSC, and CNO.

13 *Certification of Contested Settlement*, Docket No. ER03-753-000 (October 6, 2004).

14 *Entergy Services, Inc.*, 111 FERC ¶ 61,035 (2005).

15 *Id.* at PP 1, 20.

16 *Id.* at P 20.

17 *Id.* at PP 20, 21.

There is no dispute that the formula rate reflected in the revised MSS-4 produces a just and reasonable cost-based rate. Indeed, as the Commission noted, even the non-settling parties do not object to any of the proposed revisions to Service Schedule MSS-4 set forth in the settlement.[18] Because these contracts are being filed pursuant to Service Schedule MSS-4, the 2009 contracts are just and reasonable under a Commission-approved cost-based formula rate.

V. EFFECTIVE DATE

ESI requests that the Contracts be made effective as of January 1, 2010.

VI. OTHER FILING REQUIREMENTS

ESI knows of no costs included in the cost of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are the product of discriminatory practices. The cost of service specifically is made subject to the Commission-approved Service Schedule MSS-4.

VII. CONCLUSION

Accordingly, ESI asks that the Commission accept the EAI-EGSL Contract, EAI-ETI Contract, EAI-EMI Contract and the EAI-ELL Contract for filing, and grant any waivers of the requirements in 18 C.F.R. Part 35 necessary to allow the contracts to go into effect on January 1, 2010.

If you have any questions concerning this filing, please feel free to contact the undersigned.

Very truly yours,

Andrea Weinstein

Andrea J. Weinstein

Attorney for
Entergy Services, Inc.

Attachments

cc: Service List in Docket No. ER03-583-000

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18 *Id.* at P 18.

ATTACHMENT A

Entergy Operating Companies Service Agreement No. 564

Service Schedule MSS-4 Agreement by and between Entergy Arkansas, Inc., (Seller) and Entergy Mississippi, Inc. (Buyer)

AGREEMENT

This Agreement is dated as of September 8, 2009 between Entergy Arkansas, Inc., ("EAI" or "Seller"), and Entergy Mississippi, Inc. ("EMI" or "Buyer").

WHEREAS, EAI has agreed to make a unit power sale from the designated units set forth on Attachment A (individually a "Designated Unit" and collectively "Designated Units") to EMI; and

WHEREAS, the Agreement among the Entergy Operating Companies (hereinafter referred to as the "System Agreement"), was filed with the FERC on April 30, 1982, and became effective on January 1, 1983, and amended to incorporate Entergy Gulf States, Inc. in 1993 and further amended in 2008 to split Entergy Gulf States, Inc, into Entergy Gulf States, Louisiana, L.L.C. and Entergy Texas, Inc.; and

WHEREAS, the System Agreement contains a Service Schedule MSS-4 providing the basis for making a unit power purchase between the Companies that are participants in that Agreement; and

WHEREAS, the parties herein wish to execute this Agreement to provide for a unit power purchase by EMI under Service Schedule MSS-4 from the Designated Units.

THEREFORE, the parties agree as follows:

1. <u>Designated Units</u>. The designated generating units for purposes of this unit power purchase under Service Schedule MSS-4 of the System Agreement shall be those units set forth on Attachment A.

2. <u>Unit Power Purchase</u>. EAI agrees to sell and EMI agrees to purchase that quantity of generating capacity and associated energy from the Designated Units equivalent to the percentage (the "Allocated Percentage") of EAI's baseload capacity in each such Designated

Unit set forth on Attachment A, with such sale and purchase to become effective on January 1, 2010 and to continue thereafter until December 31, 2012.

3. Pricing. The pricing of the capacity and energy to be sold and purchased pursuant to paragraph 2 above shall be as specified in Service Schedule MSS-4 of the System Agreement.

4. Energy Entitlement. EMI is entitled to receive on an hourly basis the Allocated Percentage of the energy generated by each of the Designated Units.

5. Termination. Neither party shall have the right to terminate the unit power purchase and sale required by this Agreement without the express written consent of the other party.

6. Condition Precedent. This contract shall be conditioned upon Buyer receiving all regulatory approvals required for this Agreement no later than December 21, 2009.

7. Notices. Unless specifically stated otherwise herein, any notice to be given hereunder shall be sent by Registered Mail, postage prepaid, to the party to be notified at the address set forth below, and shall be deemed given when so mailed.

To EAI: Entergy Arkansas, Inc.
425 West Capitol Avenue
Little Rock, AR 72201
ATTN: Chief Executive Officer

To EMI: Entergy Mississippi, Inc.
P.O. Box 1640
Jackson, MS 39215
ATTN: Chief Executive Officer

8. Nonwaiver: The failure of either party to insist upon or enforce, in any instance, strict performance by the other of any of the terms of this Agreement or to exercise any rights herein conferred shall not be considered as a waiver or relinquishment to any extent of its rights to assert or rely upon any such terms or rights on any future occasion.

9. Amendments. No waiver, alteration, amendment or modification of any of the provisions of this Agreement shall be binding unless in writing and signed by a duly authorized representation of both parties.

10. Entire Agreement. This Agreement, which is entered into in accordance with the authority of Service Schedule MSS-4 of the System Agreement, constitutes the entire agreement between the parties with respect to the subject matter hereof and supersedes all previous and collateral agreements or understandings with respect to the subject matter hereof.

11. Severability. It is agreed that if any clause or provision of this Agreement is held by the courts to be illegal or void, the validity of the remaining portions and provisions of the Agreement shall not be affected, and the rights and obligations of the parties shall be enforced as if the Agreement did not contain such illegal or void clauses or provisions.

ENTERGY ARKANSAS, INC.

BY: ____________________

TITLE: Pres / CEO EAI

ENTERGY MISSISSIPPI, INC.

BY: ____________________

TITLE: ____________________

9. Amendments. No waiver, alteration, amendment or modification of any of the provisions of this Agreement shall be binding unless in writing and signed by a duly authorized representation of both parties.

10. Entire Agreement. This Agreement, which is entered into in accordance with the authority of Service Schedule MSS-4 of the System Agreement, constitutes the entire agreement between the parties with respect to the subject matter hereof and supersedes all previous and collateral agreements or understandings with respect to the subject matter hereof.

11. Severability. It is agreed that if any clause or provision of this Agreement is held by the courts to be illegal or void, the validity of the remaining portions and provisions of the Agreement shall not be affected, and the rights and obligations of the parties shall be enforced as if the Agreement did not contain such illegal or void clauses or provisions.

ENTERGY ARKANSAS, INC.

BY: ______________________

TITLE: ______________________

ENTERGY MISSISSIPPI, INC.

BY: [signature]

TITLE: PRESIDENT + CEO

ATTACHMENT A

SALE OF CAPACITY AND ENERGY

BY ENTERGY ARKANSAS, INC. TO ENTERGY MISSISSIPPI, INC.

During the period, January 1, 2010 through May 31, 2012, the capacity and energy amount is as follows:

DESIGNATED UNITS	EAI's BASELOAD CAPACITY*	EAI's AVAILABLE BASELOAD CAPACITY*	BUYER'S ALLOCATED CAPACITY*	BUYER'S ALLOCATED PERCENTAGE
ANO Unit 1	842.00	71.0	16.2	22.8%
ANO Unit 2	997.00	84.2	19.2	22.8%
White Bluff Unit 1	465.00	39.3	8.9	22.8%
White Bluff Unit 2	481.00	40.6	9.3	22.8%
Independence Unit 1	263.00	22.2	5.1	22.8%
Grand Gulf – No Retained Share	318.00	26.4	6.0	22.8%
Grand Gulf Retained Share	90.00	52.3	11.9	22.8%
TOTAL		336.0	76.6	22.8%

During the period, June 1, 2012 through December 31, 2012 (including the Grand Gulf Uprate), the capacity and energy amount is as follows:

DESIGNATED UNITS	EAI's BASELOAD CAPACITY*	EAI's AVAILABLE BASELOAD CAPACITY*	BUYER'S ALLOCATED CAPACITY*	BUYER'S ALLOCATED PERCENTAGE
ANO Unit 1	842.00	71.0	16.2	22.8%
ANO Unit 2	997.00	84.2	19.2	22.8%
White Bluff Unit 1	465.00	39.3	8.9	22.8%
White Bluff Unit 2	481.00	40.6	9.3	22.8%
Independence Unit 1	263.00	22.2	5.1	22.8%
Grand Gulf – No Retained Share	363.00	30.2	6.9	22.8%
Grand Gulf Retained Share	102.00	59.7	13.6	22.8%
TOTAL		347.1	79.1	22.8%

*Expressed in megawatts. To the extent EAI's Baseload Capacity increases or decreases, Buyer's Allocated Capacity shall adjust correspondingly based on Buyer's Allocated Percentage of EAI's Baseload Capacity.

ATTACHMENT B

Entergy Arkansas, Inc., Third Revised Rate Schedule FERC No. 94
Entergy Gulf States Louisiana, L.L.C., Rate Schedule FERC No. 181
Entergy Louisiana, LLC, Third Revised Rate Schedule FERC No. 69
Entergy Mississippi, Inc., Third Revised Rate Schedule FERC No. 262
Entergy New Orleans, Inc., Third Revised Rate Schedule FERC No. 8
Entergy Texas, Inc., Rate Schedule FERC No. 181

Entergy Operating Companies Service Agreement No. 565

Service Schedule MSS-4 Agreement by and between Entergy Arkansas, Inc., (Seller) and Entergy Gulf States Louisiana, L.L.C. (Buyer)

Issued by: Kimberly Despeaux
VP and Associate General Counsel

Effective: January 1, 2010

Issued on: October 13, 2009

AGREEMENT

This Agreement is dated as of 9/9/09 between Entergy Arkansas, Inc., ("EAI" or "Seller"), and Entergy Gulf States Louisiana, L.L.C. ("EGSL" or "Buyer").

WHEREAS, EAI has agreed to make a unit power sale from the designated units set forth on Attachment A (individually a "Designated Unit" and collectively "Designated Units") to EGSL; and

WHEREAS, the Agreement among EAI, Entergy Gulf States, Inc. ("EGS"), and Entergy Louisiana, LLC, Entergy Mississippi, Inc., Entergy New Orleans, Inc. and Entergy Services, Inc. (hereinafter referred to as the "System Agreement"), was filed with the FERC on April 30, 1982, and became effective on January 1, 1983, and amended to incorporate Entergy Gulf States, Inc. in 1993 and further amended in 2008 to split Entergy Gulf States, Inc, into Entergy Gulf States, Louisiana, L.L.C. and Entergy Texas, Inc.; and

WHEREAS, the System Agreement contains a Service Schedule MSS-4 providing the basis for making a unit power purchase between the Companies that are participants in that Agreement; and

WHEREAS, the parties herein wish to execute this Agreement to provide for a unit power purchase by EGSL under Service Schedule MSS-4 from the Designated Units.

THEREFORE, the parties agree as follows:

1. Designated Units. The designated generating units for purposes of this unit power purchase under Service Schedule MSS-4 of the System Agreement shall be those units set forth on Attachment A.

2. Unit Power Purchase. EAI agrees to sell and EGSL agrees to purchase that quantity of generating capacity and associated energy from the Designated Units equivalent to the percentage (the "Allocated Percentage") of EAI's baseload capacity in each such Designated

Unit set forth on Attachment A, with such sale and purchase to become effective upon January 1, 2010 and to continue thereafter until December 31, 2012.

3. Pricing. The pricing of the capacity and energy to be sold and purchased pursuant to paragraph 2 above shall be as specified in Service Schedule MSS-4 of the System Agreement.

4. Energy Entitlement. EGSL is entitled to receive on an hourly basis the Allocated Percentage of the energy generated by each of the Designated Units.

5. Termination. Neither party shall have the right to terminate the unit power purchase and sale required by this Agreement without the express written consent of the other party.

6. Condition Precedent. This contract shall be conditioned upon Buyer receiving all regulatory approvals required for this Agreement no later than December 21, 2009.

7. Notices. Unless specifically stated otherwise herein, any notice to be given hereunder shall be sent by Registered Mail, postage prepaid, to the party to be notified at the address set forth below, and shall be deemed given when so mailed.

To EAI:
Entergy Arkansas, Inc.
425 West Capitol Avenue
Little Rock, AR 72201
ATTN: Chief Executive Officer

To EGS:
Entergy Gulf States Louisiana, L.L.C.
446 North Boulevard
Baton Rouge, Louisiana 70802
ATTN: Chief Executive Officer

8. Nonwaiver: The failure of either party to insist upon or enforce, in any instance, strict performance by the other of any of the terms of this Agreement or to exercise any rights herein conferred shall not be considered as a waiver or relinquishment to any extent of its rights to assert or rely upon any such terms or rights on any future occasion.

9. Amendments. No waiver, alteration, amendment or modification of any of the provisions of this Agreement shall be binding unless in writing and signed by a duly authorized representation of both parties.

10. Entire Agreement. This Agreement, which is entered into in accordance with the authority of Service Schedule MSS-4 of the System Agreement, constitutes the entire agreement between the parties with respect to the subject matter hereof and supersedes all previous and collateral agreements of understandings with respect to the subject matter hereof.

11. Severability. It is agreed that if any clause or provision of this Agreement is held by the courts to be illegal or void, the validity of the remaining portions and provisions of the Agreement shall not be affected, and the rights and obligations of the parties shall be enforced as if the Agreement did not contain such illegal or void clauses or provisions.

ENTERGY ARKANSAS, INC.

BY: [signature]

TITLE: Pres & CEO, EAI

ENTERGY GULF STATES
LOUISIANA, L.L.C.

BY: ______________________

TITLE: ______________________

ATTACHMENT A

SALE OF CAPACITY AND ENERGY

BY ENTERGY ARKANSAS, INC. TO ENTERGY GULF STATES LOUISIANA, L.L.C.

During the period, January 1, 2010 through May 31, 2012, the capacity and energy amount is as follows:

DESIGNATED UNITS	EAI's BASELOAD CAPACITY*	EAI's AVAILABLE BASELOAD CAPACITY*	BUYER'S ALLOCATED CAPACITY*	BUYER'S ALLOCATED PERCENTAGE
ANO Unit 1	842.00	71.0	21.4	30.2%
ANO Unit 2	997.00	84.2	25.4	30.2%
White Bluff Unit 1	465.00	39.3	11.8	30.2%
White Bluff Unit 2	481.00	40.6	12.3	30.2%
Independence Unit 1	263.00	22.2	6.7	30.2%
Grand Gulf – No Retained Share	318.00	26.4	8.0	30.2%
Grand Gulf Retained Share	90.00	52.3	15.8	30.2%
TOTAL		336.0	101.4	30.2%

During the period, June 1, 2012 through December 31, 2012 (including the Grand Gulf Uprate), the capacity and energy amount is as follows:

DESIGNATED UNITS	EAI's BASELOAD CAPACITY*	EAI's AVAILABLE BASELOAD CAPACITY*	BUYER'S ALLOCATED CAPACITY*	BUYER'S ALLOCATED PERCENTAGE
ANO Unit 1	842.00	71.0	21.4	30.2%
ANO Unit 2	997.00	84.2	25.4	30.2%
White Bluff Unit 1	465.00	39.3	11.8	30.2%
White Bluff Unit 2	481.00	40.6	12.3	30.2%
Independence Unit 1	263.00	22.2	6.7	30.2%
Grand Gulf – No Retained Share	363.00	30.2	9.1	30.2%
Grand Gulf Retained Share	102.00	59.7	18.0	30.2%
TOTAL		347.1	104.8	30.2%

*Expressed in megawatts. To the extent EAI's Baseload Capacity increases or decreases, Buyer's Allocated Capacity shall adjust correspondingly based on Buyer's Allocated Percentage of EAI's Baseload Capacity.

ATTACHMENT C

Entergy Operating Companies Service Agreement No. 566

Service Schedule MSS-4 Agreement by and between Entergy Arkansas, Inc., (Seller) and Entergy Texas, Inc. (Buyer)

<u>AGREEMENT</u>

This Agreement is dated as of 9/9/09 between Entergy Arkansas, Inc., ("EAI" or "Seller"), and Entergy Texas, Inc. ("ETI" or "Buyer").

WHEREAS, EAI has agreed to make a unit power sale from the designated units set forth on Attachment A (individually a "Designated Unit" and collectively "Designated Units") to ETI; and

WHEREAS, the Agreement among EAI, Entergy Gulf States, Inc. ("EGS"), and Entergy Louisiana, LLC, Entergy Mississippi, Inc., Entergy New Orleans, Inc. and Entergy Services, Inc. (hereinafter referred to as the "System Agreement"), was filed with the FERC on April 30, 1982, and became effective on January 1, 1983, and amended to incorporate Entergy Gulf States, Inc. in 1993 and further amended in 2008 to split Entergy Gulf States, Inc, into Entergy Gulf States, Louisiana, L.L.C. and Entergy Texas, Inc.; and

WHEREAS, by Order dated July 20, 2007, the FERC approved the addition of Entergy Gulf States Louisiana, L.L.C. and ETI as parties to the System Agreement; and

WHEREAS, the System Agreement contains a Service Schedule MSS-4 providing the basis for making a unit power purchase between the Companies that are participants in that Agreement; and

WHEREAS, the parties herein wish to execute this Agreement to provide for a unit power purchase by ETI under Service Schedule MSS-4 from the Designated Units.

THEREFORE, the parties agree as follows:

1. <u>Designated Units</u>. The designated generating units for purposes of this unit power purchase under Service Schedule MSS-4 of the System Agreement shall be those units set forth on Attachment A.

2. Unit Power Purchase. EAI agrees to sell and ETI agrees to purchase that quantity of generating capacity and associated energy from the Designated Units equivalent to the percentage (the "Allocated Percentage") of EAI's baseload capacity in each such Designated Unit set forth on Attachment A, with such sale and purchase to become effective upon January 1, 2010 and to continue thereafter until December 31, 2012.

3. Pricing. The pricing of the capacity and energy to be sold and purchased pursuant to paragraph 2 above shall be as specified in Service Schedule MSS-4 of the System Agreement.

4. Energy Entitlement. ETI is entitled to receive on an hourly basis the Allocated Percentage of the energy generated by each of the Designated Units.

5. Termination. Neither party shall have the right to terminate the unit power purchase and sale required by this Agreement without the express written consent of the other party.

6. Condition Precedent. This contract shall be conditioned upon Buyer receiving all regulatory approvals required for this Agreement no later than December 21, 2009.

7. Notices. Unless specifically stated otherwise herein, any notice to be given hereunder shall be sent by Registered Mail, postage prepaid, to the party to be notified at the address set forth below, and shall be deemed given when so mailed.

To EAI: Entergy Arkansas, Inc.
425 West Capitol Avenue
Little Rock, AR 72201
ATTN: Chief Executive Officer

To ETI: Entergy Texas, Inc.
350 Pine Street
Beaumont, TX 77701
ATTN: Chief Executive Officer

8. Nonwaiver: The failure of either party to insist upon or enforce, in any instance, strict performance by the other of any of the terms of this Agreement or to exercise any rights herein conferred shall not be considered as a waiver or relinquishment to any extent of its rights to assert or rely upon any such terms or rights on any future occasion.

9. Amendments. No waiver, alteration, amendment or modification of any of the provisions of this Agreement shall be binding unless in writing and signed by a duly authorized representation of both parties.

10. Entire Agreement. This Agreement, which is entered into in accordance with the authority of Service Schedule MSS-4 of the System Agreement, constitutes the entire agreement between the parties with respect to the subject matter hereof and supersedes all previous and collateral agreements of understandings with respect to the subject matter hereof.

11. Severability. It is agreed that if any clause or provision of this Agreement is held by the courts to be illegal or void, the validity of the remaining portions and provisions of the Agreement shall not be affected, and the rights and obligations of the parties shall be enforced as if the Agreement did not contain such illegal or void clauses or provisions.

ENTERGY ARKANSAS, INC.

BY: [signature]

TITLE: Pres + CEO, EAI

ENTERGY TEXAS, INC.

BY: ____________________

TITLE: ____________________

8. Nonwaiver: The failure of either party to insist upon or enforce, in any instance, strict performance by the other of any of the terms of this Agreement or to exercise any rights herein conferred shall not be considered as a waiver or relinquishment to any extent of its rights to assert or rely upon any such terms or rights on any future occasion.

9. Amendments. No waiver, alteration, amendment or modification of any of the provisions of this Agreement shall be binding unless in writing and signed by a duly authorized representation of both parties.

10. Entire Agreement. This Agreement, which is entered into in accordance with the authority of Service Schedule MSS-4 of the System Agreement, constitutes the entire agreement between the parties with respect to the subject matter hereof and supersedes all previous and collateral agreements of understandings with respect to the subject matter hereof.

11. Severability. It is agreed that if any clause or provision of this Agreement is held by the courts to be illegal or void, the validity of the remaining portions and provisions of the Agreement shall not be affected, and the rights and obligations of the parties shall be enforced as if the Agreement did not contain such illegal or void clauses or provisions.

ENTERGY ARKANSAS, INC.

BY: ______________________

TITLE: ______________________

ENTERGY TEXAS, INC.

BY: [signature]

TITLE: PRESIDENT & CEO

ATTACHMENT A

SALE OF CAPACITY AND ENERGY

BY ENTERGY ARKANSAS, INC. TO ENTERGY TEXAS, INC.

During the period, January 1, 2010 through May 31, 2012, the capacity and energy amount is as follows:

PERCENTAGE **DESIGNATED UNITS**	EAI's BASELOAD CAPACITY*	EAI's AVAILABLE BASELOAD CAPACITY*	BUYER'S ALLOCATED CAPACITY*	BUYER'S ALLOCATED
ANO Unit 1	842.00	71.0	22.5	31.7%
ANO Unit 2	997.00	84.2	26.7	31.7%
White Bluff Unit 1	465.00	39.3	12.4	31.7%
White Bluff Unit 2	481.00	40.6	12.9	31.7%
Independence Unit 1	263.00	22.2	7.0	31.7%
Grand Gulf – No Retained Share	318.00	26.4	8.4	31.7%
Grand Gulf Retained Share	90.00	52.3	16.6	31.7%
TOTAL		336.0	106.6	31.7%

During the period, June 1, 2012 through December 31, 2012 (including the Grand Gulf Uprate), the capacity and energy amount is as follows:

PERCENTAGE **DESIGNATED UNITS**	EAI's BASELOAD CAPACITY*	EAI's AVAILABLE BASELOAD CAPACITY*	BUYER'S ALLOCATED CAPACITY*	BUYER'S ALLOCATED
ANO Unit 1	842.00	71.0	22.5	31.7%
ANO Unit 2	997.00	84.2	26.7	31.7%
White Bluff Unit 1	465.00	39.3	12.4	31.7%
White Bluff Unit 2	481.00	40.6	12.9	31.7%
Independence Unit 1	263.00	22.2	7.0	31.7%
Grand Gulf – No Retained Share	363.00	30.2	9.6	31.7%
Grand Gulf Retained Share	102.00	59.7	18.9	31.7%
TOTAL		347.1	110.1	31.7%

*Expressed in megawatts. To the extent EAI's Baseload Capacity increases or decreases, Buyer's Allocated Capacity shall adjust correspondingly based on Buyer's Allocated Percentage of EAI's Baseload Capacity.

ATTACHMENT D

Entergy Arkansas, Inc., Third Revised Rate Schedule FERC No. 94
Entergy Gulf States Louisiana, L.L.C., Rate Schedule FERC No. 181
Entergy Louisiana, LLC, Third Revised Rate Schedule FERC No. 69
Entergy Mississippi, Inc., Third Revised Rate Schedule FERC No. 262
Entergy New Orleans, Inc., Third Revised Rate Schedule FERC No. 8
Entergy Texas, Inc., Rate Schedule FERC No. 181

Entergy Operating Companies Service Agreement No. 567

Service Schedule MSS-4 Agreement by and between Entergy Arkansas, Inc., (Seller) and Entergy Louisiana, LLC (Buyer)

Issued by: Kimberly Despeaux
VP and Associate General Counsel

Effective: January 1, 2010

Issued on: October 13, 2009

AGREEMENT

This Agreement is dated as of 9/9/09 between Entergy Arkansas, Inc., ("EAI" or "Seller"), and Entergy Louisiana, LLC ("ELL" or "Buyer").

WHEREAS, EAI has agreed to make a unit power sale from the designated units set forth on Attachment A (individually a "Designated Unit" and collectively "Designated Units") to ELL; and

WHEREAS, the Agreement among the Entergy Operating Companies (hereinafter referred to as the "System Agreement"), was filed with the FERC on April 30, 1982, and became effective on January 1, 1983, and amended to incorporate Entergy Gulf States, Inc. in 1993 and further amended in 2008 to split Entergy Gulf States, Inc, into Entergy Gulf States, Louisiana, L.L.C. and Entergy Texas, Inc.; and

WHEREAS, the System Agreement contains a Service Schedule MSS-4 providing the basis for making a unit power purchase between the Companies that are participants in that Agreement; and

WHEREAS, the parties herein wish to execute this Agreement to provide for a unit power purchase by ELL under Service Schedule MSS-4 from the Designated Units.

THEREFORE, the parties agree as follows:

1. Designated Units. The designated generating units for purposes of this unit power purchase under Service Schedule MSS-4 of the System Agreement shall be those units set forth on Attachment A.

2. Unit Power Purchase. EAI agrees to sell and ELL agrees to purchase that quantity of generating capacity and associated energy from the Designated Units equivalent to the percentage (the "Allocated Percentage") of EAI's baseload capacity in each such

Designated Unit set forth on Attachment A, with such sale and purchase to become effective on January 1, 2010 and to continue thereafter until December 31, 2012.

3. Pricing. The pricing of the capacity and energy to be sold and purchased pursuant to paragraph 2 above shall be as specified in Service Schedule MSS-4 of the System Agreement.

4. Energy Entitlement. ELL is entitled to receive on an hourly basis the Allocated Percentage of the energy generated by each of the Designated Units.

5. Termination. Neither party shall have the right to terminate the unit power purchase and sale required by this Agreement without the express written consent of the other party.

6. Condition Precedent. This contract shall be conditioned upon Buyer receiving all regulatory approvals required for this Agreement no later than December 21, 2009.

7. Notices. Unless specifically stated otherwise herein, any notice to be given hereunder shall be sent by Registered Mail, postage prepaid, to the party to be notified at the address set forth below, and shall be deemed given when so mailed.

To EAI: Entergy Arkansas, Inc.
425 West Capitol Avenue
Little Rock, AR 72201
ATTN: Chief Executive Officer

To ELL: Entergy Louisiana, LLC
4809 Jefferson Hwy
Jefferson, LA 70121
ATTN: Chief Executive Officer

8. Nonwaiver: The failure of either party to insist upon or enforce, in any instance, strict performance by the other of any of the terms of this Agreement or to exercise any rights herein conferred shall not be considered as a waiver or relinquishment to any extent of its rights to assert or rely upon any such terms or rights on any future occasion.

9. Amendments. No waiver, alteration, amendment or modification of any of the provisions of this Agreement shall be binding unless in writing and signed by a duly authorized representation of both parties.

10. Entire Agreement. This Agreement, which is entered into in accordance with the authority of Service Schedule MSS-4 of the System Agreement, constitutes the entire agreement between the parties with respect to the subject matter hereof and supersedes all previous and collateral agreements or understandings with respect to the subject matter hereof.

11. Severability. It is agreed that if any clause or provision of this Agreement is held by the courts to be illegal or void, the validity of the remaining portions and provisions of the Agreement shall not be affected, and the rights and obligations of the parties shall be enforced as if the Agreement did not contain such illegal or void clauses or provisions.

ENTERGY ARKANSAS, INC.

BY: [signature]

TITLE: Pres & CEO, EAI

ENTERGY LOUISIANA, LLC

BY: ______________________

TITLE: ______________________

ATTACHMENT A

SALE OF CAPACITY AND ENERGY

BY ENTERGY ARKANSAS, INC. TO ENTERGY LOUISIANA, LLC

During the period, January 1, 2010 through May 31, 2012, the capacity and energy amount is as follows:

	EAI's BASELOAD CAPACITY*	EAI's AVAILABLE BASELOAD CAPACITY*	BUYER'S ALLOCATED CAPACITY*	BUYER'S ALLOCATED
PERCENTAGE				
DESIGNATED UNITS				
ANO Unit 1	842.00	71.0	10.9	15.3%
ANO Unit 2	997.00	84.2	12.9	15.3%
White Bluff Unit 1	465.00	39.3	6.0	15.3%
White Bluff Unit 2	481.00	40.6	6.2	15.3%
Independence Unit 1	263.00	22.2	3.4	15.3%
Grand Gulf – No Retained Share	318.00	26.4	4.0	15.3%
Grand Gulf Retained Share	90.00	52.3	8.0	15.3%
TOTAL		336.0	51.4	15.3%

During the period, June 1, 2012 through December 31, 2012 (including the Grand Gulf Uprate), the capacity and energy amount is as follows:

	EAI's BASELOAD CAPACITY*	EAI's AVAILABLE BASELOAD CAPACITY*	BUYER'S ALLOCATED CAPACITY*	BUYER'S ALLOCATED
PERCENTAGE				
DESIGNATED UNITS				
ANO Unit 1	842.00	71.0	10.9	15.3%
ANO Unit 2	997.00	84.2	12.9	15.3%
White Bluff Unit 1	465.00	39.3	6.0	15.3%
White Bluff Unit 2	481.00	40.6	6.2	15.3%
Independence Unit 1	263.00	22.2	3.4	15.3%
Grand Gulf – No Retained Share	363.00	30.2	4.6	15.3%
Grand Gulf Retained Share	102.00	59.7	9.1	15.3%
TOTAL		347.1	53.1	15.3%

*Expressed in megawatts. To the extent EAI's Baseload Capacity increases or decreases, Buyer's Allocated Capacity shall adjust correspondingly based on Buyer's Allocated Percentage of EAI's Baseload Capacity.

ATTACHMENT E

NYMEX Natural Gas Futures

$6.49 Levelized Price

8/14/2009

Contract	Prior Settle ($/mmBtu)	High ($/mmBtu)	Low ($/mmBtu)	Settle ($/mmBtu)	Change ($/mmBtu)	Volume
Jan-2010	5.616	5.580	5.570	5.584	-.032	10020
Feb-2010	5.650	-	-	5.623	-.027	1526
Mar-2010	5.602	5.590	5.590	5.581	-.021	2315
Apr-2010	5.550	5.570	5.540	5.531	-.019	2675
May-2010	5.605	-	-	5.591	-.014	573
Jun-2010	5.70	-	-	5.688	-.012	1597
Jul-2010	5.817	5.810	5.320	5.806	-.011	2073
Aug-2010	5.912	5.920	5.915	5.901	-.011	1720
Sep-2010	5.975	-	-	5.964	-.011	653
Oct-2010	6.095	-	-	6.084	-.011	363
Nov-2010	6.480	6.450	6.450	6.474	-.006	127
Dec-2010	6.850	-	-	6.849	-.001	150
Jan-2011	7.075	-	-	7.074	-.001	118
Feb-2011	7.070	-	-	7.069	-.001	49
Mar-2011	6.890	-	-	6.889	-.001	128
Apr-2011	6.405	6.395	6.395	6.404	-.001	15
May-2011	6.375	-	-	6.374	-.001	112
Jun-2011	6.455	-	-	6.454	-.001	2
Jul-2011	6.545	-	-	6.544	-.001	2
Aug-2011	6.615	-	-	6.614	-.001	9
Sep-2011	6.645	-	-	6.644	-.001	6
Oct-2011	6.725	-	-	6.724	-.001	3
Nov-2011	6.970	-	-	6.969	-.001	8
Dec-2011	7.255	-	-	7.254	-.001	8
Jan-2012	7.465	-	-	7.464	-.001	4
Feb-2012	7.460	-	-	7.459	-.001	6
Mar-2012	7.235	7.240	7.240	7.234	-.001	406
Apr-2012	6.535	-	-	6.534	-.001	1
May-2012	6.490	6.50	6.50	6.489	-.001	400
Jun-2012	6.570	-	-	6.569	-.001	4
Jul-2012	6.665	-	-	6.664	-.001	30
Aug-2012	6.730	-	-	6.729	-.001	27
Sep-2012	6.760	-	-	6.759	-.001	3
Oct-2012	6.840	-	-	6.839	-.001	1
Nov-2012	7.065	-	-	7.064	-.001	6
Dec-2012	7.340	-	-	7.339	-.001	2

Changes in settlement price with zero volume mean the settlement price is implied. No actual trading took place for these contracts on the given day. Price is based on delivery at the Henry Hub in Louisiana, which serves markets throughout the US East Coast, the Gulf Coast, the Midwest, and up to the Canadian border.

NYMEX Natural Gas Futures

$6.67 Levelized Price

9/30/2009

Contract	Prior Settle ($/mmBtu)	High ($/mmBtu)	Low ($/mmBtu)	Settle ($/mmBtu)	Change ($/mmBtu)	Volume
Jan-2010	5.954	-	-	5.965	.011	16,549
Feb-2010	5.980	-	-	5.991	.011	4,117
Mar-2010	5.929	-	-	5.937	.008	5,406
Apr-2010	5.894	-	-	5.909	.015	6,455
May-2010	5.928	5.912	5.912	5.944	.016	3,401
Jun-2010	5.996	5.980	5.980	6.012	.016	2,004
Jul-2010	6.081	-	-	6.099	.018	618
Aug-2010	6.158	6.115	6.115	6.179	.021	972
Sep-2010	6.225	-	-	6.239	.014	774
Oct-2010	6.384	6.340	6.340	6.396	.012	2,768
Nov-2010	6.729	-	-	6.741	.012	300
Dec-2010	7.074	-	-	7.084	.010	449
Jan-2011	7.299	-	-	7.311	.012	307
Feb-2011	7.284	-	-	7.291	.007	57
Mar-2011	7.084	7.10	7.10	7.091	.007	84
Apr-2011	6.519	6.530	6.530	6.526	.007	236
May-2011	6.464	6.480	6.480	6.471	.007	2
Jun-2011	6.534	6.540	6.540	6.536	.002	3
Jul-2011	6.614	6.635	6.635	6.616	.002	10
Aug-2011	6.684	6.690	6.690	6.686	.002	8
Sep-2011	6.714	6.720	6.720	6.716	.002	2
Oct-2011	6.809	-	-	6.811	.002	61
Nov-2011	7.069	-	-	7.071	.002	5
Dec-2011	7.344	-	-	7.341	-.003	174
Jan-2012	7.554	-	-	7.551	-.003	15
Feb-2012	7.554	-	-	7.546	-.008	3
Mar-2012	7.334	-	-	7.326	-.008	10
Apr-2012	6.639	-	-	6.626	-.013	60
May-2012	6.599	-	-	6.581	-.018	20
Jun-2012	6.669	-	-	6.651	-.018	19
Jul-2012	6.749	-	-	6.731	-.018	1
Aug-2012	6.809	-	-	6.791	-.018	17
Sep-2012	6.839	-	-	6.821	-.018	29
Oct-2012	6.919	-	-	6.901	-.018	1
Nov-2012	7.139	-	-	7.121	-.018	1
Dec-2012	7.409	-	-	7.391	-.018	100

Changes in settlement price with zero volume mean the settlement price is implied. No actual trading took place for these contracts on the given day.
Price is based on delivery at the Henry Hub in Louisiana, which serves markets throughout the US East Coast, the Gulf Coast, the Midwest, and up to the Canadian border.

AGREEMENT

This Agreement is dated as of May ____, 2007 between Entergy Arkansas, Inc., ("EAI" or "Seller"), and Entergy Louisiana, LLC ("ELL" or "Buyer").

WHEREAS, EAI has agreed to make a unit power sale from the designated unit set forth on Attachment A ("Designated Unit") to ELL; and

WHEREAS, the Agreement among EAI, ELL, and Entergy New Orleans, Inc. ("ENO"), Entergy Mississippi, Inc. ("EMI"), Entergy Gulf States, Inc. ("EGS") and Entergy Services, Inc. ("ESI") (hereinafter referred to as the "System Agreement"), was filed with the FERC on April 30, 1982, and became effective on January 1, 1983, and amended to incorporate EGS in 1993; and

WHEREAS, the System Agreement contains a Service Schedule MSS-4 providing the basis for making a unit power purchase between the Companies that are participants in that Agreement; and

WHEREAS, the parties herein wish to execute this Agreement to provide for a unit power purchase by ELL under Service Schedule MSS-4 from the Designated Unit.

THEREFORE, the parties agree as follows:

1. Designated Unit. The designated generating unit for purposes of this unit power purchase under Service Schedule MSS-4 of the System Agreement shall be the unit set forth on Attachment A.

2. Unit Power Purchase. EAI agrees to sell and ELL agrees to purchase that quantity of generating capacity and associated energy from the Designated Unit equivalent to the percentage (the "Allocated Percentage") of EAI's baseload capacity in such Designated Unit set forth on Attachment A, with such sale and purchase to become effective as of June 1, 2003, or as soon thereafter as deliveries may commence and to

continue thereafter until the retirement date of Designated Unit set forth on Attachment A.

3. Pricing. The pricing of the capacity and energy to be sold and purchased pursuant to paragraph 2 above shall be as specified in Service Schedule MSS-4 of the System Agreement.

4. Energy Entitlement. ELL is entitled to receive on an hourly basis the Allocated Percentage of the energy generated by the Designated Unit.

5. Termination. Neither party shall have the right to terminate the unit power purchase and sale required by this Agreement without the express written consent of the other party.

6. Condition Precedent. This contract shall be conditioned upon Buyer receiving all regulatory approvals required for this Agreement.

7. Notices. Unless specifically stated otherwise herein, any notice to be given hereunder shall be sent by Registered Mail, postage prepaid, to the party to be notified at the address set forth below, and shall be deemed given when so mailed.

To EAI:	Entergy Arkansas, Inc. 425 West Capitol Avenue Little Rock, AR 72201 ATTN: Chief Executive Officer
To ELL:	Entergy Louisiana, LLC 4809 Jefferson Hwy Jefferson, LA 70121 ATTN: Chief Executive Officer

8. Nonwaiver: The failure of either party to insist upon or enforce, in any instance, strict performance by the other of any of the terms of this Agreement or to exercise any rights herein conferred shall not be considered as a waiver or relinquishment

to any extent of its rights to assert or rely upon any such terms or rights on any future occasion.

9. Amendments. No waiver, alteration, amendment or modification of any of the provisions of this Agreement shall be binding unless in writing and signed by a duly authorized representation of both parties.

10. Entire Agreement. This Agreement, which is entered into in accordance with the authority of Service Schedule MSS-4 of the System Agreement, constitutes the entire agreement between the parties with respect to the subject matter hereof and supersedes all previous and collateral agreements of understandings with respect to the subject matter hereof.

11. Severability. It is agreed that if any clause or provision of this Agreement is held by the courts to be illegal or void, the validity of the remaining portions and provisions of the Agreement shall not be affected, and the rights and obligations of the parties shall be enforced as if the Agreement did not contain such illegal or void clauses or provisions.

WITNESS OUR SIGNATURES as of May __, 2007.

WITNESS: ______________________

ENTERGY ARKANSAS, INC.

BY: [signature]

TITLE: President + CEO, EAI

WITNESS: [signature]

ENTERGY LOUISIANA, LLC

BY: E Renae Conley

TITLE: President + CEO, Entergy LA LLC

ATTACHMENT A

SALE OF CAPACITY AND ENERGY

BY ENTERGY ARKANSAS, INC. TO ENTERGY LOUISIANA, LLC

This Attachment A is attached to and forms a part of the Agreement dated on May ____, 2007, between Entergy Louisiana, LLC ("ELL" or "Buyer") and Entergy Arkansas, Inc. ("EAI" or "Seller") pursuant to the Service Schedule MSS-4 of the System Agreement.[1]

During the period, June 1, 2003 through the end of the term, the capacity and energy amount is as follows:

DESIGNATED UNIT	EAI's BASELOAD CAPACITY*	BUYER'S ALLOCATED CAPACITY*	BUYER'S ALLOCATED PERCENTAGE
Grand Gulf Retained Share	91.00	19.00	20.88%

*Expressed in megawatts. To the extent EAI's Baseload Capacity increases or decreases, Buyer's Allocated Capacity shall adjust correspondingly based on Buyer's Allocated Percentage of EAI's Baseload Capacity.

AGREEMENT

This Agreement is dated as of May ____, 2007 between Entergy Arkansas, Inc., ("EAI" or "Seller"), and Entergy Louisiana, LLC ("ELL" or "Buyer").

WHEREAS, EAI has agreed to make a unit power sale from the designated units set forth on Attachment A (individually a "Designated Unit" and collectively "Designated Units") to ELL; and

WHEREAS, the Agreement among EAI, ELL, and Entergy New Orleans, Inc. ("ENO"), Entergy Mississippi, Inc. ("EMI"), Entergy Gulf States, Inc. ("EGS") and Entergy Services, Inc. ("ESI") (hereinafter referred to as the "System Agreement"), was filed with the FERC on April 30, 1982, and became effective on January 1, 1983, and amended to incorporate EGS in 1993; and

WHEREAS, the System Agreement contains a Service Schedule MSS-4 providing the basis for making a unit power purchase between the Companies that are participants in that Agreement; and

WHEREAS, the parties herein wish to execute this Agreement to provide for a unit power purchase by ELL under Service Schedule MSS-4 from the Designated Units.

THEREFORE, the parties agree as follows:

1. <u>Designated Units</u>. The designated generating units for purposes of this unit power purchase under Service Schedule MSS-4 of the System Agreement shall be those units set forth on Attachment A.

2. <u>Unit Power Purchase</u>. EAI agrees to sell and ELL agrees to purchase that quantity of generating capacity and associated energy from the Designated Units equivalent to the percentage (the "Allocated Percentage") of EAI's baseload capacity in each such Designated Unit set forth on Attachment A, with such sale and purchase to

become effective as of June 1, 2003, or as soon thereafter as deliveries may commence and to continue thereafter until the retirement date of Designated Units set forth on Attachment A.

3. Pricing. The pricing of the capacity and energy to be sold and purchased pursuant to paragraph 2 above shall be as specified in Service Schedule MSS-4 of the System Agreement.

4. Energy Entitlement. ELL is entitled to receive on an hourly basis the Allocated Percentage of the energy generated by each of the Designated Units.

5. Termination. Neither party shall have the right to terminate the unit power purchase and sale required by this Agreement without the express written consent of the other party.

6. Condition Precedent. This contract shall be conditioned upon Buyer receiving all regulatory approvals required for this Agreement.

7. Notices. Unless specifically stated otherwise herein, any notice to be given hereunder shall be sent by Registered Mail, postage prepaid, to the party to be notified at the address set forth below, and shall be deemed given when so mailed.

To EAI:
Entergy Arkansas, Inc.
425 West Capitol Avenue
Little Rock, AR 72201
ATTN: Chief Executive Officer

To ELL:
Entergy Louisiana, LLC
4809 Jefferson Hwy
Jefferson, LA 70121
ATTN: Chief Executive Officer

8. Nonwaiver: The failure of either party to insist upon or enforce, in any instance, strict performance by the other of any of the terms of this Agreement or to exercise any rights herein conferred shall not be considered as a waiver or relinquishment

to any extent of its rights to assert or rely upon any such terms or rights on any future occasion.

9. Amendments. No waiver, alteration, amendment or modification of any of the provisions of this Agreement shall be binding unless in writing and signed by a duly authorized representation of both parties.

10. Entire Agreement. This Agreement, which is entered into in accordance with the authority of Service Schedule MSS-4 of the System Agreement, constitutes the entire agreement between the parties with respect to the subject matter hereof and supersedes all previous and collateral agreements of understandings with respect to the subject matter hereof.

11. Severability. It is agreed that if any clause or provision of this Agreement is held by the courts to be illegal or void, the validity of the remaining portions and provisions of the Agreement shall not be affected, and the rights and obligations of the parties shall be enforced as if the Agreement did not contain such illegal or void clauses or provisions.

WITNESS OUR SIGNATURES as of May __, 2007.

WITNESS: ____________________

ENTERGY ARKANSAS, INC.

BY: ____________________

TITLE: President & CEO, EAI

WITNESS: ____________________

ENTERGY LOUISIANA, LLC

BY: E. Renae Conley

TITLE: President & CEO, Entergy LA, LLC

ATTACHMENT A

SALE OF CAPACITY AND ENERGY

BY ENTERGY ARKANSAS, INC. TO ENTERGY LOUISIANA, LLC

This Attachment A is attached to and forms a part of the Agreement dated on May ____, 2007, between Entergy Louisiana, LLC ("ELL" or "Buyer") and Entergy Arkansas, Inc. ("EAI" or "Seller") pursuant to the Service Schedule MSS-4 of the System Agreement.

During the period, June 1, 2003 through the end of the term, the capacity and energy amount is as follows:

	EAI's BASELOAD CAPACITY*	BUYER'S ALLOCATED CAPACITY*	BUYER'S ALLOCATED PERCENTAGE
DESIGNATED UNITS			
ANO Unit 1	846.00	23.00	2.72%
ANO Unit 2	998.00	27.00	2.71%
White Bluff Unit 1	461.70	13.00	2.82%
White Bluff Unit 2	461.70	12.00	2.60%
Independence Unit 1	257.00	7.00	2.72%
Grand Gulf – EAI	324.00	9.00	2.78%
TOTAL	3,348.40	91.00	2.72%

*Expressed in megawatts. To the extent EAI's Baseload Capacity increases or decreases, Buyer's Allocated Capacity shall adjust correspondingly based on Buyer's Allocated Percentage of EAI's Baseload Capacity.

AGREEMENT

This Agreement is dated as of May ____, 2007 between Entergy Arkansas, Inc., ("EAI" or "Seller"), and Entergy New Orleans, Inc. ("ENO" or "Buyer").

WHEREAS, EAI has agreed to make a unit power sale from the designated units set forth on Attachment A (individually a "Designated Unit" and collectively "Designated Units") to ENO; and

WHEREAS, the Agreement among EAI, ENO, and Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), Entergy Gulf States, Inc. ("EGS") and Entergy Services, Inc. ("ESI") (hereinafter referred to as the "System Agreement"), was filed with the FERC on April 30, 1982, and became effective on January 1, 1983, and amended to incorporate EGS in 1993; and

WHEREAS, the System Agreement contains a Service Schedule MSS-4 providing the basis for making a unit power purchase between the Companies that are participants in that Agreement; and

WHEREAS, the parties herein wish to execute this Agreement to provide for a unit power purchase by ENO under Service Schedule MSS-4 from the Designated Units.

THEREFORE, the parties agree as follows:

1. Designated Units. The designated generating units for purposes of this unit power purchase under Service Schedule MSS-4 of the System Agreement shall be those units set forth on Attachment A.

2. Unit Power Purchase. EAI agrees to sell and ENO agrees to purchase that quantity of generating capacity and associated energy from the Designated Units equivalent to the percentage (the "Allocated Percentage") of EAI's baseload capacity in each such Designated Unit set forth on Attachment A, with such sale and purchase to

become effective as of June 1, 2003 and to continue thereafter until the retirement date of Designated Units set forth on Attachment A.

3. Pricing. The pricing of the capacity and energy to be sold and purchased pursuant to paragraph 2 above shall be as specified in Service Schedule MSS-4 of the System Agreement.

4. Energy Entitlement. ENO is entitled to receive on an hourly basis the Allocated Percentage of the energy generated by each of the Designated Units.

5. Termination. Neither party shall have the right to terminate the unit power purchase and sale required by this Agreement without the express written consent of the other party.

6. Condition Precedent. This contract shall be conditioned upon Buyer receiving all regulatory approvals required for this Agreement.

7. Notices. Unless specifically stated otherwise herein, any notice to be given hereunder shall be sent by Registered Mail, postage prepaid, to the party to be notified at the address set forth below, and shall be deemed given when so mailed.

To EAI: Entergy Arkansas, Inc.
425 West Capitol Avenue
Little Rock, AR 72201
ATTN: Chief Executive Officer

To ENO: Entergy New Orleans, Inc.
1600 Perdido Street
Building 529
New Orleans, LA 70112
ATTN: Chief Executive Officer

8. Nonwaiver: The failure of either party to insist upon or enforce, in any instance, strict performance by the other of any of the terms of this Agreement or to exercise any rights herein conferred shall not be considered as a waiver or relinquishment

to any extent of its rights to assert or rely upon any such terms or rights on any future occasion.

9. Amendments. No waiver, alteration, amendment or modification of any of the provisions of this Agreement shall be binding unless in writing and signed by a duly authorized representation of both parties.

10. Entire Agreement. This Agreement, which is entered into in accordance with the authority of Service Schedule MSS-4 of the System Agreement, constitutes the entire agreement between the parties with respect to the subject matter hereof and supersedes all previous and collateral agreements of understandings with respect to the subject matter hereof.

11. Severability. It is agreed that if any clause or provision of this Agreement is held by the courts to be illegal or void, the validity of the remaining portions and provisions of the Agreement shall not be affected, and the rights and obligations of the parties shall be enforced as if the Agreement did not contain such illegal or void clauses or provisions.

WITNESS OUR SIGNATURES as of May __, 2007.

WITNESS: ______________________

ENTERGY ARKANSAS, INC.

BY: ______________________

TITLE: President & CEO, EAI

WITNESS: ______________________

ENTERGY NEW ORLEANS, INC.

BY: ______________________

TITLE: President & CEO

ATTACHMENT A

SALE OF CAPACITY AND ENERGY

BY ENTERGY ARKANSAS, INC. TO ENTERGY NEW ORLEANS, INC.

This Attachment A is attached to and forms a part of the Agreement dated on May ____, 2007, between Entergy New Orleans, Inc. ("ENO" or "Buyer") and Entergy Arkansas, Inc. ("EAI" or "Seller") pursuant to the Service Schedule MSS-4 of the System Agreement.

During the period, June 1, 2003 through the end of the term, the capacity and energy amount is as follows:

	EAI's BASELOAD CAPACITY*	BUYER'S ALLOCATED CAPACITY*	BUYER'S ALLOCATED PERCENTAGE
DESIGNATED UNITS			
ANO Unit 1	846.00	23.00	2.72%
ANO Unit 2	998.00	27.00	2.71%
White Bluff Unit 1	461.70	12.00	2.60%
White Bluff Unit 2	461.70	13.00	2.82%
Independence Unit 1	257.00	7.00	2.72%
Grand Gulf – EAI	324.00	9.00	2.78%
TOTAL	3,348.40	91.00	2.72%

*Expressed in megawatts. To the extent EAI's Baseload Capacity increases or decreases, Buyer's Allocated Capacity shall adjust correspondingly based on Buyer's Allocated Percentage of EAI's Baseload Capacity.

AGREEMENT

This Agreement is dated as of May ____, 2007 between Entergy Arkansas, Inc., ("EAI" or "Seller"), and Entergy New Orleans, Inc. ("ENO" or "Buyer").

WHEREAS, EAI has agreed to make a unit power sale from the designated unit set forth on Attachment A ("Designated Unit") to ENO; and

WHEREAS, the Agreement among EAI, ENO, and Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), Entergy Gulf States, Inc. ("EGS") and Entergy Services, Inc. ("ESI") (hereinafter referred to as the "System Agreement"), was filed with the FERC on April 30, 1982, and became effective on January 1, 1983, and amended to incorporate EGS in 1993; and

WHEREAS, the System Agreement contains a Service Schedule MSS-4 providing the basis for making a unit power purchase between the Companies that are participants in that Agreement; and

WHEREAS, the parties herein wish to execute this Agreement to provide for a unit power purchase by ENO under Service Schedule MSS-4 from the Designated Unit.

THEREFORE, the parties agree as follows:

1. Designated Unit. The designated generating unit for purposes of this unit power purchase under Service Schedule MSS-4 of the System Agreement shall be the unit set forth on Attachment A.

2. Unit Power Purchase. EAI agrees to sell and ENO agrees to purchase that quantity of generating capacity and associated energy from the Designated Unit equivalent to the percentage (the "Allocated Percentage") of EAI's baseload capacity in such Designated Unit set forth on Attachment A, with such sale and purchase to become

effective as of June 1, 2003 and to continue thereafter until the retirement date of Designated Unit set forth on Attachment A.

3. Pricing. The pricing of the capacity and energy to be sold and purchased pursuant to paragraph 2 above shall be as specified in Service Schedule MSS-4 of the System Agreement.

4. Energy Entitlement. ENO is entitled to receive on an hourly basis the Allocated Percentage of the energy generated by the Designated Unit.

5. Termination. Neither party shall have the right to terminate the unit power purchase and sale required by this Agreement without the express written consent of the other party.

6. Condition Precedent. This contract shall be conditioned upon Buyer receiving all regulatory approvals required for this Agreement.

7. Notices. Unless specifically stated otherwise herein, any notice to be given hereunder shall be sent by Registered Mail, postage prepaid, to the party to be notified at the address set forth below, and shall be deemed given when so mailed.

To EAI:
Entergy Arkansas, Inc.
425 West Capitol Avenue
Little Rock, AR 72201
ATTN: Chief Executive Officer

To ENO:
Entergy New Orleans, Inc.
1600 Perdido Street
Building 529
New Orleans, LA 70112
ATTN: Chief Executive Officer

8. Nonwaiver: The failure of either party to insist upon or enforce, in any instance, strict performance by the other of any of the terms of this Agreement or to exercise any rights herein conferred shall not be considered as a waiver or relinquishment

to any extent of its rights to assert or rely upon any such terms or rights on any future occasion.

9. Amendments. No waiver, alteration, amendment or modification of any of the provisions of this Agreement shall be binding unless in writing and signed by a duly authorized representation of both parties.

10. Entire Agreement. This Agreement, which is entered into in accordance with the authority of Service Schedule MSS-4 of the System Agreement, constitutes the entire agreement between the parties with respect to the subject matter hereof and supersedes all previous and collateral agreements of understandings with respect to the subject matter hereof.

11. Severability. It is agreed that if any clause or provision of this Agreement is held by the courts to be illegal or void, the validity of the remaining portions and provisions of the Agreement shall not be affected, and the rights and obligations of the parties shall be enforced as if the Agreement did not contain such illegal or void clauses or provisions.

WITNESS OUR SIGNATURES as of May __, 2007.

WITNESS: ______________________

ENTERGY ARKANSAS, INC.

BY: [signature]

TITLE: President + CEO, EAI

WITNESS: [signature]

ENTERGY NEW ORLEANS, INC.

BY: [signature]

TITLE: President & CEO

ATTACHMENT A

SALE OF CAPACITY AND ENERGY

BY ENTERGY ARKANSAS, INC. TO ENTERGY NEW ORLEANS, INC.

This Attachment A is attached to and forms a part of the Agreement dated on May ____, 2007, between Entergy New Orleans, Inc. ("ENO" or "Buyer") and Entergy Arkansas, Inc. ("EAI" or "Seller") pursuant to the Service Schedule MSS-4 of the System Agreement.

During the period, June 1, 2003 through the end of the term, the capacity and energy amount is as follows:

	EAI's BASELOAD CAPACITY*	BUYER'S ALLOCATED CAPACITY*	BUYER'S ALLOCATED PERCENTAGE
DESIGNATED UNIT			
Grand Gulf Retained Share	91.00	19.00	20.88%

*Expressed in megawatts. To the extent EAI's Baseload Capacity increases or decreases, Buyer's Allocated Capacity shall adjust correspondingly based on Buyer's Allocated Percentage of EAI's Baseload Capacity.

CNRO-2012-00007

SERIES 2 ATTACHMENTS

2 SERI & SMEPA - GGNS Status Report (1 page)

2-A SERI & SMEPA – Calculation of Minimum Amount (1 page)

2-B Schedule of Remaining Principle Payments – GGNS (1 page)

2-C FERC Order in Docket No. ER95-1042 and Availability Agreement (39 pages)

Attachment 2
(1 page)

SYSTEM ENERGY RESOURCES, INC. and
SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION
Status Report of Decommissioning Funding
For Year Ending December 31, 2011 - 10 CFR 50.75(f)(1)

Plant Name: **Grand Gulf Station (Owned & leased 90% by System Energy Resources, Inc (SERI) and 10% by South Mississippi Electric Power Association (SMEPA))**

1. Minimum Financial Assurance (MFA) Estimated per 10 CFR 50.75(b) and (c) (2011$):	
SERI (90% ownership share)	$557.0 million[1]
SMEPA (10% ownership share)	$61.9 million
2. Decommissioning Fund Total as of 12/31/11:	
SERI	$423.4 million
SMEPA	$39.4 million
3. Annual amounts remaining to be collected:	See Attachment 2-B
4. Assumptions used: Rate of Escalation of Decommissioning Costs:	
SERI	See item below
SMEPA	3.0%
Rate of Earnings on Decommissioning Funds:	
SERI	2% real rate of return per 10 CFR 50.75(e)(1)(i)
SMEPA	Approx. 5.91%
Authority for use of Real Earnings Over 2%:	
SERI N/A	
SMEPA SMEPA Board	
5. Contracts upon which licensee is relying For Decommissioning Funding:	See footnote[2]
6. Modifications to Method of Financial Assurance since Last Report:	None
7. Material Changes to Trust Agreements:	None

[1] See Attachment 2-A

[2] See the Unit Power Sales Agreement, a FERC tariff, in Attachment 2-C; and see also the Availability Agreement, in Attachment 2-C, which includes additional provisions related to decommissioning financial assurance. It is the licensee's position that the Unit Power Sales Agreement is not a 10 CFR §50.75(e)(1)(v) "contractual obligation," but rather a cost of service tariff which may appropriately be used to fund the external sinking fund in accordance with 10 CFR §50.75(e)(1)(ii). Out of abundance of caution, the licensee identifies this information here.

Attachment 2-A
(1 page)

SYSTEM ENERGY RESOURCES, INC. and
SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION
Calculation of Minimum Amount
For Year Ending December 31, 2011 - 10 CFR 50.75(f)(1)

System Energy Resources, Inc.: 90% ownership/leasehold interest
South Mississippi Electric Power Association ("SMEPA"): 10% ownership interest
Plant Location: Port Gibson, Mississippi
Reactor Type: Boiling Water Reactor ("BWR")
Power Level: >3,400 MWt
BWR Base Year 1986$: $135,000,000
Labor Region: South
Waste Burial Facility: Generic Disposal Site

10CFR50.75(c)(2) Escalation Factor Formula:
0.65(L) +0.13(E) +0.22(B)

	Factor
L=Labor (South)	2.28[1]
E=Energy (BWR)	2.66[2]
B=Waste Burial-Vendor (BWR)	12.54[3]

BWR Escalation Factor:

0.65(L) +0.13(E) +0.22(B)=	4.58401

1986 BWR Base Year $ Escalated:

$135,000,000 * Factor=	$618,856,935
System Energy interest (90%):	$556,956,813
SMEPA interest (10%):	61,884,090
Total	$618,840,903

1 Bureau of Labor Statistics, Series Report ID: CIU2010000000220i (4th Quarter 2011)
2 Bureau of Labor Statistics, Series Report ID: wpu0543 and wpu0573 (December 2011)
3 Nuclear Regulatory Commission: NUREG-1307 Revision 14, Table 2.1 (2010)

Attachment 2-B
(1 page)

Schedule of Remaining Principal Payments into
Grand Gulf Decommissioning Fund
($ Thousands)

	SERI Share	SMEPA Share	Total
2012	$23,785	$0 Thereafter	$23,785
2013	$23,785		$23,785
2014	$23,785		$23,785
2015	$22,285		$22,285
2016	$24,550		$24,550
2017	$24,550		$24,550
2018	$24,550		$24,550
2019	$24,550		$24,550
2020	$24,550		$24,550
2021	$29,878		$29,878
2022	$17,429		$17,429
2023	$0 Thereafter		$0 Thereafter

Note: Approved in FERC Docket No. ER95-1042-004, see Attachment C in Attachment 2-C.

Attachment 2-C
(39 pages)

FERC Order in Docket No. ER95-1042-004
And
Availability Agreement

FILING PUBLIC UTILITY

System Energy Resources, Inc.

Rate Schedule FERC No. 2

PUBLIC UTILITIES RECEIVING SERVICE
UNDER RATE SCHEDULE

Entergy Arkansas, Inc.
Entergy Louisiana, Inc.
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.

SERVICE TO BE PROVIDED UNDER RATE SCHEDULE

Wholesale Sale of Electric Power

System Energy Resources, Inc.
1st Rev. Rate Schedule FERC No. 2
(SS original Rate Schedule FERC No. 2, as supplemented)

Original Sheet No. 1

-1st Rev.
Docket No.: ER95-1042-004
Company: System Energy Re.
FERC El. Rate Sch. No. 2
Filing Date: 8-29-01
Effective Date: 12-30-94

FILING PUBLIC UTILITY

System Energy Resources, Inc.

Rate Schedule FERC No. 2

PUBLIC UTILITIES RECEIVING SERVICE
UNDER RATE SCHEDULE

Entergy Arkansas, Inc.
Entergy Louisiana, Inc.
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.

SERVICE TO BE PROVIDED UNDER RATE SCHEDULE

Wholesale Sale of Electric Power

Issued by: Kimberly H. Despeaux
Director, Federal Regulatory Affairs
Issued on: August 29, 2001

Effective Date: December 12, 1995

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER95-1042-000, issued July 31, 2000, 92 FERC 61,119, *order denying rehearing*, issued July 30, 2001, 96 FERC 61,165.

011207-0008-1

Unit Power Sales Agreement

THIS AGREEMENT, made, entered into, and effective as of this 10th day of June, 1982, as amended from time to time thereafter, and as revised to comply with Federal Energy Regulatory Commission ("FERC") Opinion Nos. 446 and 446-A and FERC Order No.614, between and among Entergy Arkansas, Inc. ("EAI"), Entergy Louisiana, Inc. ("ELI"), Entergy Mississippi, Inc. ("EMI"), Entergy New Orleans, Inc. ("ENOI") and System Energy Resources, Inc. ("System Energy"),

WITNESSETH THAT:

WHEREAS, System Energy was incorporated on February 11, 1974 under the laws of the State of Arkansas to own certain future generating capacity for the Entergy System, of which EAI, ELI, EMI and ENOI,("System Companies") are members; and

WHEREAS, System Energy has accordingly undertaken the ownership and financing of an undivided interest in, and construction of, the Grand Gulf Generating Station, a one-unit, nuclear-fueled electric generating station on the east bank of the Mississippi River near Port Gibson, Mississippi ("Project"); and

WHEREAS, the System Companies own and operate electric generating, transmission and distribution facilities in Arkansas, Louisiana and Mississippi and generate, transmit and sell electric energy both at retail and wholesale in such states; and

WHEREAS, System Energy has agreed to sell to EAI, ELI, EMI and ENOI ("Purchasers") specified percentages of all of the capacity and energy available to System Energy from the Project, and the System Companies have agreed to join with System Energy, before the date Unit 1 of the Project is placed in service, in executing an agreement which will set forth in detail the terms and conditions for the sale of such capacity and energy by System Energy to the System Companies; and

WHEREAS, Unit 1 is expected to be placed in commercial operation in the first quarter of 1983;

NOW, THEREFORE, System Energy and the System Companies mutually understand and agree as follows:

1.1 System Energy shall, subject to the terms and conditions of this Agreement, make available, or cause to be made available, to the Purchasers all of the capacity and energy which shall be available to System Energy at the Project, including test energy produced during the course of the construction and testing of Unit 1 of the Project ("Power").

1.2 The Purchasers shall, subject to the terms and conditions of this Agreement, be entitled to receive all of the Power which shall be available to System Energy at the Project in accordance with their respective Entitlement Percentages. The Entitlement Percentages are as follows:

	Entitlement Percentages Unit No. 1
EAI	36%
ELI	14%
EMI	33%
ENOI	17%
	100%

1.3 Commencing with the earlier of (a) the date of commercial operation of the Unit or (b) December 31, 1984 and continuing monthly thereafter until this Agreement is terminated pursuant to the provisions of Section 9 hereof, in consideration of the right to receive its Entitlement Percentage of such Power from the unit, each Purchaser will pay System Energy an amount determined pursuant to the Monthly Grand Gulf Power Charge Formula, which is attached hereto as Appendix 1.

2. The performance of the obligations of System Energy hereunder shall be subject to the receipt and continued effectiveness of all authorizations of governmental regulatory authorities at the time necessary to permit System Energy to perform its duties and obligations hereunder, including the receipt and continued effectiveness of all authorizations by governmental regulatory authorities at the time necessary to permit the completion by System Energy of the construction of the Project, the operation of the Project, and for System Energy to make available to the Purchasers all of the Power available to System Energy at the Project. System Energy shall use its best efforts to secure and maintain all such authorizations by governmental regulatory authorities.

3. System Energy shall operate and maintain the Project in accordance with good utility practice. Outages for inspection, maintenance, refueling, repairs and replacements shall be scheduled in accordance with good utility practice and, insofar as practicable, shall be mutually agreed to by System Energy and the Purchasers.

4. Delivery of Power sold to the Purchasers pursuant to this Agreement shall occur at the Project's step-up transformer and shall be made in the form of three-phase, sixty hertz alternating current at a nominal voltage of 500 kilovolts. System Energy will supply and maintain all necessary metering equipment for determining the quantity and conditions of delivery under this Agreement. System Energy will furnish to the Purchasers such summaries of meter reading and other metering information as may reasonably be requested.

5. Monthly bills shall be calculated in accordance with the provisions of the Monthly Grand Gulf Power Charge Formula, attached hereto as Appendix 1.

6. Nothing contained herein shall be construed as affecting in any way the right of System Energy to unilaterally make application to FERC for a change in the rates contained herein or any other term or condition of this Agreement under Section 205 of the Federal Power Act and pursuant to FERC Rules and Regulations promulgated thereunder.

7. No Purchaser shall be entitled to set off against any payment required to be made by it under this Agreement (a) any amounts owed by System Energy to any Purchaser or (b) the amount of any claim by any Purchaser against System Energy. The foregoing, however, shall not affect in any other way the rights and remedies of any Purchaser with respect to any such amounts owed to any Purchaser by System Energy or any such claim by any Purchaser against System Energy.

8. The invalidity and unenforceability of any provision of this Agreement shall not affect the remaining provisions hereof.

9. This Agreement shall continue until terminated by mutual agreement of all parties hereto.

10. This Agreement shall be binding upon the parties hereto and their successors and assigns, but no assignment hereof, or of any right to any funds due or to become due under this Agreement, shall in any event relieve either any Purchaser or System Energy of any of their respective obligations hereunder, or, in the case of the Purchasers, reduce to any extent their entitlement to receive all of the Power available to System Energy from time to time at the Project.

11. The agreements herein set forth have been made for the benefit of the Purchasers and System Energy and their respective successors and assigns and no other person shall acquire or have any right under or by virtue of this Agreement.

12. The Purchasers and System Energy may, subject to the provisions of this Agreement, enter into a further agreement or agreements between the Purchasers and System Energy, setting forth detailed terms and provisions relating to the performance by the Purchasers and System Energy of their respective obligations under this Agreement. No agreement entered into under this Section 12 shall, however, alter to any substantive degree the obligations of any party to this Agreement in any manner inconsistent with any of the foregoing sections of this Agreement.

13. Each of the Purchasers shall, at any time and from time to time, be entitled to assign all of its right, title and interest in and to all of the power to which any of them shall be entitled under this Agreement, but no Purchaser shall, by such assignment, be relieved of any of its obligations and duties under this Agreement except through the payment to System Energy, by or on behalf of such Purchaser, of the amount or amounts which such Purchaser shall be obligated to pay pursuant to the terms of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed as of the day and year first above written

SYSTEM ENERGY RESOURCES, INC., formerly
MIDDLE SOUTH ENERGY, INC.

By: /S/ F W. Lewis

ENTERGY ARKANSAS, INC., formerly
ARKANSAS POWER & LIGHT COMPANY

By: /S/ Jerry Maulden

ENTERGY LOUISIANA, INC., formerly
LOUISIANA POWER & LIGHT COMPANY

By: /S/ J. Wyatt

ENTERGY MISSISSIPPI, INC., formerly
MISSISSIPPI POWER & LIGHT COMPANY

By: /S/ D. C. Lutkin

ENTERGY NEW ORLEANS, INC., formerly
NEW ORLEANS PUBLIC SERVICE INC.

By: /S/ James M. Cain

SYSTEM ENERGY RESOURCES, INC.
MONTHLY GRAND GULF POWER CHARGE FORMULA

1. GENERAL

This Grand Gulf Power Charge Formula ("PCF") sets out the procedures that shall be used to determine the monthly amounts which System Energy Resources, Inc. ("SERI") shall charge Entergy Arkansas, Inc. ("EAI"); Entergy Louisiana, Inc. ("ELI"); Entergy Mississippi, Inc. ("EMI"); and Entergy New Orleans, Inc. ("ENOI") (referred to hereafter, collectively, as "Purchasers", or, individually, as "Purchaser"), for capacity and energy from the Grand Gulf Nuclear Station ("Grand Gulf") pursuant to the Unit Power Sales Agreement ("UPSA") between SERI and the Purchasers to which this document is attached as Appendix 1. The monthly charges for capacity ("Monthly Capacity Charges") shall be determined in accordance with the provisions of Section 2 below. The monthly charges for fuel ("Monthly Fuel Charges") shall be determined in accordance with the provisions of Section 3 below. The Monthly Capacity Charges and the Monthly Fuel Charges determined in accordance with the provisions of this PCF shall be billed to the Purchasers monthly in accordance with the provisions of Section 4 below.

2. MONTHLY CAPACITY CHARGE

The Monthly Capacity Charge to be billed to each of the Purchasers for any service month shall be determined by applying the Monthly Capacity Charge Formula set out in Attachment A to the applicable cost data.

3. MONTHLY FUEL CHARGE

The Monthly Fuel Charge to be billed to each of the Purchasers for any service month shall be determined by applying the Monthly Fuel Charge Formula set out in Attachment B to fuel cost data for the service month.

4. BILLING

On or before the fifth workday of each month SERI shall render a billing to each of the Purchasers reflecting the Purchaser's Monthly Capacity Charge and Monthly Fuel Charge for the immediately preceding service month. In addition, any applicable and appropriate adjustments shall be reflected in each of the monthly billings. The monthly billings shall be payable in immediately available funds on or before the 15th day of such month. After the 15th day of such month, interest shall accrue on any balance due to SERI, or owed by SERI, at the rate required for refunds rendered pursuant to the requirements of Section 35.19.a of the Code of Federal Regulations. Entergy Services Inc., acting as agent for SERI and the Purchasers, may prepare the necessary billings to the Purchasers and arrange for payment in accordance with the above requirements.

5. **EFFECTIVE DATE AND TERM**

This PCF shall be effective for service rendered on and after December 12, 1995 and shall continue in effect until modified or terminated in accordance with the provisions of this PCF or applicable regulations or laws.

SYSTEM ENERGY RESOURCES, INC.
MONTHLY CAPACITY CHARGE FORMULA
DETERMINATION OF MONTHLY CAPACITY CHARGES
MONTH, XXXX

LINE NO	DESCRIPTION	AMOUNT	REFERENCE/SOURCE
1	CAPACITY REVENUE REQUIREMENT		Page 3, Line 1
2	CREDIT, PER STIPULATION AND AGREEMENT IN DOCKET NO. FA89-28		SERI Rate Schedule FERC No. 6
3	ADJUSTED CAPACITY REVENUE REQUIREMENT		Line 1 – Line 2
4	MONTHLY CAPACITY CHARGE FOR EAI		36% * Line 3
5	MONTHLY CAPACITY CHARGE FOR ELI		14% * Line 3
6	MONTHLY CAPACITY CHARGE FOR EMI		33% * Line 3
7	MONTHLY CAPACITY CHARGE FOR ENOI		17% * Line 3

Attachment A
Page 2 of 5

SYSTEM ENERGY RESOURCES, INC.
MONTHLY CAPACITY CHARGE FORMULA
DEVELOPMENT OF RATE BASE (1)
MONTH, XXXX

LINE NO	DESCRIPTION	AMOUNT	REFERENCE/SOURCE
1	PLANT IN SERVICE		FERC Accounts 101, 106
2	ACCUMULATED DEPRECIATION & AMORTIZATION		FERC Accounts 108, 111 (2)
3	NET UTILITY PLANT		Line 1 Plus Line 2
4	NUCLEAR FUEL		FERC Accounts 120.2-120.4
5	AMORTIZATION OF NUCLEAR FUEL		FERC Account 120.5
6	MATERIALS & SUPPLIES		FERC Accounts 154, 163
7	PREPAYMENTS		FERC Account 165
8	DEFERRED REFUELING OUTAGE COSTS		FERC Account 182.3
9	ACCUMULATED DEFERRED INCOME TAXES		FERC Accounts 190, 281, 282, 283
10	RATE BASE		Sum of Lines 3 - 9

NOTES:

(1) TO BE DETERMINED BASED ON DATA AS OF THE END OF THE MONTH IMMEDIATELY PRECEDING THE CURRENT SERVICE MONTH.

(2) THE BALANCE FOR ACCUMULATED DEPRECIATION AND AMORTIZATION IS TO BE REDUCED BY ANY DECOMMISSIONING RESERVE AND RESERVE FOR DISPOSAL OF NUCLEAR FUEL INCLUDED IN FERC ACCOUNTS 108 AND 111 WHICH REPRESENT MONIES HELD BY THIRD PARTIES.

Attachment A
Page 3 of 5

SYSTEM ENERGY RESOURCES, INC.
MONTHLY CAPACITY CHARGE FORMULA
DEVELOPMENT OF CAPACITY REVENUE REQUIREMENT (1)
MONTH, XXXX

LINE NO	DESCRIPTION	AMOUNT	REFERENCE/SOURCE
1	CAPACITY REVENUE REQUIREMENT		Determined as described in Note 2 below.
2	OPERATION & MAINTENANCE EXPENSE (3)		FERC Accounts 517, 519-525, 528-532, 556, 557, 560-573, 901-905, 920-931, 935
3	DEPRECIATION EXPENSE		FERC Account 403-Excluding Decommissioning Exp
4	DECOMMISSIONING EXPENSE (4)		FERC Account 403-Decommissioning Expense
5	AMORTIZATION EXPENSE		FERC Accounts 404, 407.3, 407.4
6	TAXES OTHER THAN INCOME TAXES		FERC Account 408.1
7	CURRENT STATE INCOME TAX		Page 4, Line 18
8	CURRENT FEDERAL INCOME TAX		Page 4, Line 25
9	PROVISION FOR DEFERRED INCOME TAX-STATE		State Portion of FERC Accounts 410.1, 411.1 (5)
10	PROVISION FOR DEFERRED INCOME TAX-FEDERAL		Federal Portion of FERC Accounts 410.1, 411.1 (5)
11	INVESTMENT TAX CREDIT-NET		FERC Account 411.4
12	GAINS/LOSSES ON DISPOSITION OF UTILITY PLANT		FERC Accounts 411.6, 411.7
13	UTILITY OPERATING EXPENSES		Sum of Lines 2 - 12
14	UTILITY OPERATING INCOME		Line 1 minus Line 13
15	VERIFICATION:		
16	RATE BASE		Page 2, Line 10
17	RATE OF RETURN ON RATE BASE		12*(Line 14 / Line 16) (Must equal Line 18)
18	COST OF CAPITAL		Weighted Cost Rate from Page 5, Line 6

NOTES

1) ALL EXPENSES ARE TO BE THOSE FOR THE CURRENT SERVICE MONTH.

2) THE CAPACITY REVENUE REQUIREMENT FOR THE SERVICE MONTH IS THE VALUE THAT RESULTS IN A UTILITY OPERATING INCOME WHICH, WHEN DIVIDED BY THE RATE BASE (DETERMINED IN ACCORDANCE WITH PAGE 2) AND MULTIPLIED BY 12 PRODUCES A RATE OF RETURN ON RATE BASE EQUAL TO THE COST OF CAPITAL (DETERMINED IN ACCORDANCE WITH PAGE 5).

3) EXCLUSIVE OF FUEL EXPENSE IN FERC ACCOUNT 518.

4) SHOULD THE FERC APPROVE A CHANGE IN SYSTEM ENERGY'S SCHEDULE OF ANNUAL DECOMMISSIONING EXPENSES DURING THE SERVICE MONTH, THE MONTHLY LEVEL IN EFFECT AS OF THE END OF THE MONTH SHALL BE UTILIZED. OTHERWISE, THE AMOUNT CHARGED TO FERC ACCOUNT 403 FOR THE SERVICE MONTH SHALL BE UTILIZED, AS SHOWN ON ATTACHMENT C.

5) RESTRICTED TO THOSE ITEMS FOR WHICH CORRESPONDING TIMING DIFFERENCES ARE INCLUDED IN THE ADJUSTMENTS TO NET INCOME BEFORE INCOME TAX (SEE PAGE 4, LINE 10).

SYSTEM ENERGY RESOURCES, INC.
MONTHLY CAPACITY CHARGE FORMULA
DEVELOPMENT OF CURRENT INCOME TAX EXPENSE
MONTH, XXXX

LINE NO	DESCRIPTION	AMOUNT	REFERENCE/SOURCE
1	CAPACITY REVENUE REQUIREMENT		Page 3, Line 1
2	OPERATION & MAINTENANCE EXPENSE		Page 3, Line 2
3	DEPRECIATION EXPENSE		Page 3, Line 3
4	DECOMMISSIONING EXPENSE		Page 3, Line 4
5	AMORTIZATION EXPENSE		Page 3, Line 5
6	TAXES OTHER THAN INCOME		Page 3, Line 6
7	NET INCOME BEFORE INCOME TAXES		Line 1 - (Sum of Lines 2-6)
8	ADJUSTMENTS TO NET INCOME BEFORE INCOME TAX:		
9	INTEREST SYNCHRONIZATION		Rate Base (Page 2, Line 10) * (-1) * Total Debt Rate (Page 5, Line 4)/12
10	OTHER ADJUSTMENTS		See Note 1
11	TOTAL ADJUSTMENTS		Line 9 plus Line 10
12	TAXABLE INCOME		Line 7 plus Line 11
	COMPUTATION OF STATE INCOME TAX		
13	STATE TAXABLE INCOME BEFORE ADJUSTMENTS		Line 12
14	NET ADJUSTMENT TO STATE TAXABLE INCOME		See Note 1
15	STATE TAXABLE INCOME		Line 13 plus Line 14
16	STATE INCOME TAX BEFORE ADJUSTMENTS		Line 15 * Mississippi State Tax Rate(2)
17	ADJUSTMENTS TO STATE TAX		See Note 1
18	CURRENT STATE INCOME TAX		Sum of Lines 16 - 17
	COMPUTATION OF FEDERAL INCOME TAX		
19	FEDERAL TAXABLE INCOME BEFORE ADJUSTMENTS		Line 12
20	CURRENT STATE INCOME TAX DEDUCTION		Line 18 (Shown as deduction)
21	OTHER ADJUSTMENTS TO FEDERAL TAXABLE INCOME		See Note 1
22	FEDERAL TAXABLE INCOME		Sum of Lines 19-21
23	FEDERAL INCOME TAX BEFORE ADJUSTMENTS		Line 22 * Federal Tax Rate(2)
24	ADJUSTMENTS TO FEDERAL TAX		See Note 1
25	CURRENT FEDERAL INCOME TAX		Sum of Lines 23 - 24

NOTES
1) ITEMS FROM MONTHLY TAX DETERMINATION THAT ARE APPROPRIATE FOR RATEMAKING PURPOSES.
2) RATE IN EFFECT AT THE END OF THE SERVICE MONTH.

Attachment A
Page 5 of 5

SYSTEM ENERGY RESOURCES, INC.
MONTHLY CAPACITY CHARGE FORMULA
DEVELOPMENT OF COST OF CAPITAL (1)
MONTH, XXXX

LINE NO	CAPITAL SOURCE	CAPITAL AMOUNT (2) (3)	CAPITALIZATION RATIO (4)	COST RATE	WEIGHTED COST RATE (8)
1	DEBT				
2	LONG TERM	FERC Accts 221, 224, 225, 226, 181, 189		(5)	
3	SHORT TERM			(6)	
4	TOTAL DEBT			(7)	
5	COMMON EQUITY	FERC Accts 201, 208, 216		(SEE NOTE 9)	
6	TOTAL			NA	

NOTES

(1) TO BE DETERMINED BASED ON DATA AS OF THE END OF THE MONTH IMMEDIATELY PRECEDING THE CURRENT SERVICE MONTH.

(2) LONG TERM DEBT SHALL INCLUDE ALL ISSUES AND REFLECT THE PRINCIPAL AMOUNT.

(3) SHORT TERM DEBT SHALL INCLUDE ONLY THAT PORTION NOT REFLECTED IN THE CALCULATION OF SERI'S RATE FOR ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION.

(4) APPLICABLE CAPITAL AMOUNT DIVIDED BY THE TOTAL CAPITAL AMOUNT.

(5) AVERAGE COST RATE FOR ALL OUTSTANDING ISSUES INCLUDING APPLICABLE AMORTIZATION OF DEBT DISCOUNT, PREMIUM, AND EXPENSE TOGETHER WITH AMORTIZATION OF LOSS OR GAIN ON REACQUIRED DEBT.

(6) THE AVERAGE COST RATE FOR ELIGIBLE SHORT TERM DEBT.

(7) WEIGHTED AVERAGE COST RATE FOR LONG TERM DEBT AND SHORT TERM DEBT.

(8) CAPITALIZATION RATIO FOR THE APPLICABLE CAPITAL SOURCE MULTIPLIED BY THE CORRESPONDING COST RATE.

(9) THE COMMON EQUITY COST RATE SHALL BE AS FOLLOWS:

A. FOR SERVICE FROM DECEMBER 12, 1995 THROUGH JULY 30, 2000 THE RATE SHALL BE 10.58%.

B. FOR SERVICE AFTER JULY 30, 2000 THE RATE SHALL BE 10.94%.

Attachment B
Page 1 of 1

SYSTEM ENERGY RESOURCES, INC.
MONTHLY FUEL CHARGE FORMULA
MONTH, XXXX

LINE NO	DESCRIPTION	AMOUNT	REFERENCE/SOURCE
1	FUEL EXPENSE FOR APPLICABLE SERVICE MONTH		FERC Account 518
2	MONTHLY FUEL CHARGE FOR EAI		36% * Line 1
3	MONTHLY FUEL CHARGE FOR ELI		14% * Line 1
4	MONTHLY FUEL CHARGE FOR EMI		33% * Line 1
5	MONTHLY FUEL CHARGE FOR ENOI		17% * Line 1

Issued by: Kimberly H. Despeaux
Director, Federal Regulatory Affairs
Issued on: August 29, 2001

Effective Date: December 12, 1995

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER95-1042-000, issued July 31, 2000, 92 FERC 61,119, order denying rehearing, issued July 30, 2001, 96 FERC 61,165.

Attachment C
Page 1 of 1

System Energy Resources, Inc.
Grand Gulf Decommissioning Model
Revenue Requirements Summary
($000)

		Revenue Requirements		
Line No	Year	Owned Portion	Leased Portion	Total
1	1995	6,813	1,208	8,021
2	1996	11,195	1,997	13,192
3	1997	11,195	1,997	13,192
4	1998	11,195	1,997	13,192
5	1999	11,195	1,997	13,192
6	2000	11,195	1,997	13,192
7	2001	13,624	2,431	16,055
8	2002	13,624	2,431	16,055
9	2003	13,624	2,431	16,055
10	2004	13,624	2,431	16,055
11	2005	13,624	2,431	16,055
12	2006	16,590	2,960	19,550
13	2007	16,590	2,960	19,550
14	2008	16,590	2,960	19,550
15	2009	16,590	2,960	19,550
16	2010	16,590	2,960	19,550
17	2011	20,184	3,601	23,785
18	2012	20,184	3,601	23,785
19	2013	20,184	3,601	23,785
20	2014	20,184	3,601	23,785
21	2015	20,184	2,101	22,285
22	2016	24,550	0	24,550
23	2017	24,550	0	24,550
24	2018	24,550	0	24,550
25	2019	24,550	0	24,550
26	2020	24,550	0	24,550
27	2021	29,878	0	29,878
28	2022	17,429	0	17,429
29	2023	0	0	0
30	2024	0	0	0
31	2025	0	0	0
32	2026	0	0	0
33	2027	0	0	0
34	2028	0	0	0
35	2029	0	0	0
36	2030	0	0	0
37	2031	0	0	0

Issued by: Kimberly H. Despeaux
Director, Federal Regulatory Affairs

Effective Date: December 30, 1994

Issued on: August 29, 2001

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER95-1042-000, issued July 31, 2000, 92 FERC 61,119, order denying rehearing, issued July 30, 2001, 96 FERC 61,165.

AVAILABILITY AGREEMENT

BETWEEN

MIDDLE SOUTH ENERGY, INC.

AND

ARKANSAS POWER & LIGHT COMPANY,
ARKANSAS-MISSOURI POWER COMPANY,
LOUISIANA POWER & LIGHT COMPANY,
MISSISSIPPI POWER & LIGHT COMPANY, and
NEW ORLEANS PUBLIC SERVICE INC.

THIS AGREEMENT, dated as of the 21st day of June, 1974, between MIDDLE SOUTH ENERGY, INC. (MSEI) and ARKANSAS POWER & LIGHT COMPANY (AP&L), ARKANSAS-MISSOURI POWER COMPANY (Ark-Mo), LOUISIANA POWER & LIGHT COMPANY (LP&L), MISSISSIPPI POWER & LIGHT COMPANY (MP&L) and NEW ORLEANS PUBLIC SERVICE INC. (NOPSI), WITNESSETH THAT:

WHEREAS, AP&L, Ark-Mo, LP&L, MP&L and NOPSI (collectively, *System operating companies and, singly, System operating company*), all outstanding shares of whose common stock are wholly owned by Middle South Utilities, Inc., operate electric generating, transmission and distribution facilities in the states of Arkansas, Louisiana, Mississippi and Missouri and comprise the Middle South System; and

WHEREAS, the System operating companies are parties to an agreement dated April 16, 1973 (as presently constituted and as amended in the future, System Agreement), which provides the contractual basis for the continued planning, construction and operation of certain facilities owned by the System operating companies to achieve the purposes set forth therein; and

WHEREAS, other entities may become parties to the System Agreement; and

WHEREAS, MSEI has been organized as a subsidiary of Middle South Utilities, Inc. to finance and own certain generating units for the benefit of the Middle South System, including the Grand Gulf Nuclear Electric Station project (Project), a two unit nuclear-fueled electric generating plant having an expected aggregate capacity of 2,500,000 KW and to be located near Port Gibson, Mississippi; and

WHEREAS, MSEI is, subject to the terms hereof, willing to undertake the construction and operation of the Project, *to become a party to the System Agreement and to make available to the* Parties, as hereinafter defined, all of the power (and the energy associated therewith) available at any MSEI Generating Unit, including the Project, under the terms hereof and of the System Agreement; and

WHEREAS, the Parties, as hereinafter defined, are, subject to the terms hereof, willing to purchase power (and the energy associated therewith) available or to be available at any *MSEI Generating* Unit, including the Project, under the terms hereof and of the System Agreement;

Now, THEREFORE, in consideration of the terms and conditions hereinafter set forth, the parties hereto agree with each other as follows:

1. For the purposes of this Agreement, the following definitions shall apply:

(a) *Party or Parties* shall mean any entity or entities (other than MSEI) now or hereafter a party or parties to this Agreement.

(b) *MSEI Generating Unit* shall be that portion of any electric generator, together with its prime mover and all auxiliary and appurtenant devices and equipment designed to be operated as a unit for the production of electric power and energy and all associated equipment and facilities, which is owned by MSEI and which MSEI and the Parties have designated as being subject to this Agreement.

(c) *Power* shall mean both power and the energy associated therewith, including test power produced during construction or thereafter.

2. MSEI and the Parties hereby designate Unit No. 1 and Unit No. 2 of the Project as being subject to this Agreement and MSEI Generating Units hereunder, and MSEI hereby undertakes to use its best efforts to construct the Project.

3. On or before the date on which Unit No. 1 of the Project is placed in commercial operation, MSEI and the Parties will join in executing such document or documents as may be necessary for MSEI to become a party to the System Agreement. MSEI and the Parties will also join in executing at an appropriate time such document or documents as may be necessary for others who become parties to the System Agreement to join in and become parties to this Agreement. MSEI shall, subject to the provisions of the then applicable requirements of Section 6 of this Agreement and the then applicable provisions of the System Agreement (or any agreement substituted therefor), make available, or cause to be made available, to the Parties all Power available from time to time at any MSEI Generating Unit.

4. The Parties shall, subject to the provisions of the then applicable requirements of Section 7 of this Agreement and the then applicable requirements of the System Agreement (or any agreement substituted therefor) be entitled to receive all Power available from time to time at any MSEI Generating Unit; provided, that (i) should any Party terminate its participation in the System Agreement, then it is agreed that MSEI, such Party and the other Parties shall enter into a separate agreement whereby such Party shall continue to be entitled to receive Power, and obligated to take Power, available at any MSEI Generating Unit which has been designated as being subject to this Agreement at the time such Party shall exercise its right to terminate such participation, in such amounts and for such consideration calculated from time to time as if such Party had remained a party to the System Agreement, and (ii) should the System Agreement be cancelled or terminated, then it is agreed that MSEI and all such Parties shall enter into a separate agreement whereby such Parties shall continue to be entitled to receive Power, and obligated to take Power, available at any MSEI Generating Unit which has been designated as being subject to this Agreement at the time of cancellation or termination of the System Agreement, in such amounts and for such consideration calculated from time to time as if the System Agreement had remained in effect and MSEI and such Parties were parties thereto. Notwithstanding such withdrawal from, or cancellation or termination of, the System Agreement, each Party shall remain bound by the terms of this Agreement with respect to any MSEI Generating Unit which has been designated as being subject to this Agreement at the time of such withdrawal, cancellation or termination. In consideration of MSEI's commitment to undertake construction of the Project and its other obligations hereunder and of the right of the Parties to receive Power available at any MSEI Generating Unit under the terms of the System Agreement (or any separate agreement referred to above), the Parties agree to pay to MSEI, commencing on the date on which a particular MSEI Generating Unit is deemed to be in operation for the purposes of this Agreement, such amounts from time to time as, when added to amounts received by MSEI

from any other source, including, but not limited to, amounts (if any) received by MSEI with respect to such MSEI Generating Unit under the terms of the System Agreement, shall be at least equal to MSEI's total operating expenses and interest charges with respect to such MSEI Generating Unit, including (without limitation), for the purposes of this Agreement, (i) all expenses, deductions, charges and other items properly chargeable to the applicable Income Accounts 400 to 435, inclusive, of the Uniform System of Accounts prescribed by the Federal Power Commission for Class A and Class B Public Utilities and Licensees, as in effect on April 1, 1973, (Uniform System of Accounts) or, if such MSEI Generating Unit is not in service for any reason, all expenses, deductions, charges and other items which would be chargeable to the above Accounts if such MSEI Generating Unit were in service; it being agreed that when a particular generating unit is designated as being subject to this Agreement by MSEI and the Parties, then, solely for the purposes of determining MSEI's total operating expenses under this Section 4, such MSEI Generating Unit shall be deemed to be in operation on the date, and the accrual of depreciation as an operating expense with respect to the MSEI Generating Unit shall be deemed to commence on the date at the rate and in the manner and continue for the duration, as is specified in the document so designating such generating unit as a MSEI Generating Unit subject to this Agreement, whether or not such MSEI Generating Unit is actually in operation on such date, and (ii) such expenses as might be incurred in connection with permanent shut-down of any MSEI Generating Unit which is nuclear-fueled and, in the event of any such shut-down, for perpetual maintenance and surveillance of any such facility in accordance with, and as required by, all applicable regulations established by any governmental authority having jurisdiction. Payments to be made pursuant to this Section 4 shall be made monthly and shall be apportioned among the Parties whose Company Capability is less than its Capability Responsibility, as such terms are defined in the System Agreement and as determined in accordance with Section 10 of the System Agreement, in the ratio of each such Party's deficiency to the sum of the deficiencies of all such deficient Parties; provided, however, that if in any month no Party has such a deficiency then the payments for such month shall be apportioned among the Parties in accordance with the ratio of their then respective Capability Responsibilities, as such term is defined in the System Agreement. For the purpose of this Agreement, the Capability of all MSEI Generating Units shall be included in the System Capability, as such terms are defined in the System Agreement. In the event the System Agreement is not then in effect, or has been amended or interpreted so that at least one or more of the Parties is not obligated to make the entire payment herein provided, then the Parties agree to make payments hereunder in accordance with the ratio of their then respective "Capability Responsibilities", as such term is defined in Appendix A attached hereto and made a part hereof and not as defined in the System Agreement. Payments made by any Party to MSEI pursuant to this Section 4 shall be applied as a credit to such Party's liability for payments to MSEI under the System Agreement.

5. For the purpose of determining MSEI's expenses and the Parties' obligations under Section 4 of this Agreement, it is hereby agreed that both Unit No. 1 and Unit No. 2 of the Project shall be deemed to be in operation on the earlier of December 31, 1982 (whether or not such Units, or either of them, are then completed or in operation) or the date on which either of such Units is first placed in commercial operation as determined under the System Agreement (or any agreement substituted therefor), and the accrual of depreciation and amortization with respect to the Project shall be deemed to commence on the earlier of such dates; that such accrual of depreciation and amortization shall be at the rate of 3.65% per annum of the aggregate amount properly chargeable (prior to the deduction therefrom of any depreciation or amortization) at the time with respect to the Project to Balance Sheet Accounts 101, 102, 103, 104, 105, 106, 107 (the aforementioned accounts being exclusive of land and land rights), 118, 120 (.1 through .5), 121, 123, 123.1, 124, 151, 152, 153, 154, 155, 156, 157, 163, 182, 183, 184, 185, 186, 187 and 188 of the Uniform System of Accounts and such other accounts as are properly subject to depreciation or amortization at the time pursuant to such Uniform System of Accounts; and that such accrual shall continue during each of the first 27.4 years after the date of commencement of such accrual hereunder whether or not such Units, or either of them, shall ever commence operation and/or remain in operation; provided, however, that if Unit No. 1 is placed in commercial operation prior to December 31, 1982 and Unit No. 2 is not completed and ready for

service at such time, then until December 31, 1982 or the date Unit No. 2 is placed in commercial operation, whichever date occurs earlier, expenditures included in Account 107 which are identified exclusively with the construction of Unit No. 2 may be excluded from the calculation of the aggregate amount subject to the accrual of depreciation and amortization pursuant to this paragraph.

6. The performance of the obligations of MSEI hereunder shall be subject to the receipt and continued effectiveness of all authorizations of governmental regulatory authorities at the time necessary to permit MSEI to perform its duties and obligations hereunder, including the receipt and continued effectiveness of all authorizations by governmental regulatory authorities at the time necessary to permit MSEI to finance, to construct or cause to be constructed, to operate or cause to be operated, and/or to make available to the Parties the Power available at any MSEI Generating Unit. MSEI shall use its best efforts to secure and maintain all such authorizations by governmental regulatory authorities.

7. The performance by each Party of its obligations hereunder shall be subject to the receipt and continued effectiveness of all authorizations of governmental regulatory authorities necessary at the time to permit it to perform its duties and obligations hereunder, including the receipt and continued effectiveness of all authorizations by governmental regulatory authorities necessary at the time to permit it to pay to MSEI, in consideration for the right to receive its share of the Power available at any MSEI Generating Unit, the amounts provided for in Section 4 of this Agreement. Each Party shall use its best efforts to secure and maintain all such authorizations by governmental regulatory authorities. Each Party shall, to the extent permitted by law, be obligated to perform its duties and obligations hereunder, subject to the then applicable provisions of this Section 7, (a) whether or not MSEI shall have received all authorizations of governmental regulatory authorities necessary to permit MSEI to perform its duties and obligations hereunder or under the System Agreement, (b) whether or not such authorizations, or any such authorization, shall at any time in question be in effect, (c) whether or not the System Agreement shall, from time to time, be amended, modified or supplemented or shall be cancelled or terminated or such Party shall have withdrawn therefrom and (d) so long as MSEI and such Party shall continue to be subsidiary companies of Middle South Utilities, Inc. (as said term is defined in Section 2(a)(8) of the Public Utility Holding Company Act of 1935) or a successor thereto, whether or not, at any time in question, MSEI shall have performed its duties and obligations under this Agreement or the System Agreement. In the event that MSEI or any Party shall cease to be such a subsidiary company, then and thereafter such Party shall not be relieved of its obligation to make payments pursuant to Section 4 of this Agreement by reason of the failure of MSEI to perform its duties and obligations hereunder or under the System Agreement occasioned by act of God, fire, flood, explosion, strike, civil or military authority, insurrection, riot, act of the elements, failure of equipment, or for any other cause beyond the control of MSEI.

8. To the extent they may legally do so, each Party and MSEI hereby irrevocably waive any defense based on the adequacy of a remedy at law which may be asserted as a bar to the remedy of specific performance in any action brought against it for specific performance of this Agreement by any other party to this Agreement, or by a trustee under any mortgage or other debt instrument which any such party to this Agreement may, subject to requisite regulatory authority, enter into, or by any receiver or trustee appointed for any such party under the bankruptcy or insolvency laws of any jurisdiction to which any such party may be subject; provided, however, that nothing herein contained shall be deemed to constitute a representation or warranty by any party to this Agreement that their respective obligations under this Agreement are, as a matter of law, subject to the equitable remedy of specific performance.

9. No Party shall be entitled to set off against any payment required to be made by such Party under this Agreement (i) any amounts owed by MSEI to such Party or (ii) the amount of any claim by such Party against MSEI. The foregoing, however, shall not affect in any other way

the rights and remedies of any Party with respect to any such amounts owed to such Party by MSEI or any such claim by such Party against MSEI.

10. The invalidity or unenforceability of any provision of this Agreement shall not affect the remaining provisions hereof.

11. This Agreement shall become effective forthwith. This Agreement may be amended, modified or terminated only with the consent of MSEI and of the Parties then having responsibility for two-thirds or more of the amounts to be paid under Section 4 hereof, and upon the receipt and continued effectiveness of all authorizations of governmental regulatory authorities at the time necessary.

12. This Agreement shall be binding upon the Parties and MSEI and their respective successors and assigns, but no assignment hereof, or of any right to any funds due or to become due under this Agreement, shall in any event relieve any Party or MSEI of any of their respective obligations hereunder, or, in the case of the Parties, reduce to any extent their entitlement to receive Power available from time to time at any MSEI Generating Unit.

13. The agreements herein set forth have been made for the benefit of the Parties, MSEI and their respective successors and assigns, and no other person shall acquire or have any right under or by virtue of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed by their respective officers thereunto duly authorized as of the day and year first above written.

ARKANSAS POWER & LIGHT COMPANY

By ....
Title

Witness:

....

ARKANSAS-MISSOURI POWER COMPANY

By ....
Title

Witness:

....

LOUISIANA POWER & LIGHT COMPANY

By ....
Title

Witness:

....

APPENDIX A

Definition of "Capability Responsibility" As Used in Availability Agreement

"Capability Responsibility" shall mean: with respect to any "Company", the "System Capability" multiplied by the "Responsibility Ratio" for that Company.

"Company" shall mean one of the Middle South Utilities, Inc.'s System operating companies, as defined in the Availability Agreement; "System Capability" shall mean the arithmetical sum in megawatts of the individual "Company Capabilities"; "Company Capabilities" shall be the net output in megawatts that can be produced by all of a Company's generating units, each unit of which consists of an electric generator, together with its prime mover and all auxiliary and appurtenant devices and equipment designed to be operated as a unit for the production of electric power and energy, under the conditions specified by the administrative organization then having the authority to so specify, under either the System Agreement or any similar and succeeding agreement to which such Company is a party, or the input in megawatts available under contract to such Company from a supplying source; provided, however, that each Company shall be deemed to have at least one Kilowatt of Capability, whether or not it has any such Capability; "Responsibility Ratio" shall mean the ratio obtained by dividing a "Company Load Responsibility" by the "System Load Responsibility"; "Company Load Responsibility" shall mean (a) the average of the four highest clock-hour demands in megawatts of a Company's system, each on a different day, occurring during the twelve month period ending with the current month, but not less than 90% of the average of the four highest such demands occurring during the twenty-four (24) month period ending with the current month, where each such demand shall represent the simultaneous hourly input from all sources into the system of a company, less the sum of the simultaneous hourly outputs to the system of other interconnected utilities (Company demands shall include firm power supplied to other systems for its own account), (b) less the power supplied to others as sales for the joint account of all Companies, (c) less the contractual amount of firm purchases with reserves available during the month from other systems for its own account; provided, however, that each Company shall be deemed to have a Load Responsibility of at least one kilowatt, whether or not such Company has any such Load Responsibility; "System Load Responsibility" shall be the arithmetical sum in megawatts of the individual Company Load Responsibilities.

FIRST AMENDMENT TO AVAILABILITY AGREEMENT

BETWEEN

MIDDLE SOUTH ENERGY, INC.

AND

ARKANSAS POWER & LIGHT COMPANY,

ARKANSAS-MISSOURI POWER COMPANY,

LOUISIANA POWER & LIGHT COMPANY,

MISSISSIPPI POWER & LIGHT COMPANY, and

NEW ORLEANS PUBLIC SERVICE INC.

THIS FIRST AMENDMENT, dated as of the 30th day of June, 1977, between Middle South Energy, Inc. (MSE), and Arkansas Power & Light Company (AP&L), Arkansas-Missouri Power Company (Ark-Mo), Louisiana Power & Light Company (LP&L), Mississippi Power & Light Company (MP&L) and New Orleans Public Service Inc. (NOPSI), to the Availability Agreement, dated as of the 21st day of June, 1974, between MSE and AP&L, Ark-Mo, LP&L, MP&L and NOPSI (Availability Agreement), WITNESSETH THAT:

WHEREAS, pursuant to the provisions of Section 5 of the Availability Agreement, it has been agreed that Unit No. 2 of the Project shall be deemed to be in operation no later than December 31, 1982 for purposes of calculating the date of commencement of the accrual of depreciation and amortization with respect to Unit No. 2 of the Project; and

WHEREAS, the commencement of commercial operation of Unit No. 2 has been deferred to a date subsequent to December 31, 1982 but is expected to occur not later than December 31, 1986; and

WHEREAS, it is now appropriate and necessary to revise the provisions of Section 5 of the Availability Agreement accordingly.

Now, Therefore, in consideration of the terms and conditions hereinafter set forth, the parties hereto agree with each other as follows:

1. For the purposes of this First Amendment to Availability Agreement, any term used herein which has a defined meaning in the Availability Agreement shall have the same meaning herein.

2. Section 5 of the Availability Agreement is hereby deemed amended so that the last reference in Section 5 to "December 31, 1982" shall be changed to read "December 31, 1986".

3. All other provisions of the Availability Agreement shall be deemed to continue in full force and effect.

In Witness Whereof, the parties hereto have caused this First Amendment to Availability Agreement to be duly executed by their respective officers thereunto duly authorized as of the day and year first above written.

Arkansas Power & Light Company

By ....

President

Mississippi Power & Light Company

By ....

President

Arkansas-Missouri Power Company

By ....

President

New Orleans Public Service Inc.

By ....

President

Louisiana Power & Light Company

By ....

President

Middle South Energy, Inc.

By ....

Vice President, Finance

SECOND AMENDMENT TO AVAILABILITY AGREEMENT BETWEEN MIDDLE SOUTH ENERGY, INC. AND ARKANSAS POWER & LIGHT COMPANY, LOUISIANA POWER & LIGHT COMPANY, MISSISSIPPI POWER & LIGHT COMPANY, and NEW ORLEANS PUBLIC SERVICE INC.

THIS SECOND AMENDMENT, dated as of the 15th day of June, 1981, between Middle South Energy, Inc. (MSE) and Arkansas Power & Light Company (AP&L), Louisiana Power & Light Company (LP&L), Mississippi Power & Light Company (MP&L) and New Orleans Public Service Inc. (NOPSI), to the Availability Agreement, dated as of the 21st day of June, 1974, between MSE and AP&L, Arkansas-Missouri Power Company (Ark-Mo), LP&L, MP&L and NOPSI, as amended by the First Amendment thereto dated as of June 30, 1977 (Availability Agreement), WITNESSETH THAT:

WHEREAS, pursuant to the provisions of Section 3 of the Availability Agreement, it has been agreed that on or before the date on which Unit No. 1 of the Project is placed in commercial operation MSE and the Parties will join in executing such document or documents as may be necessary for MSE to become a party to the System Agreement and that MSE will make available to the Parties under the then applicable provisions of the System Agreement (or any agreement substituted therefor) all Power available from time to time at any MSEI Generating Unit; and

WHEREAS, pursuant to the provisions of Section 4 of the Availability Agreement, it has been agreed that the Parties shall be entitled, subject to the then applicable requirements of the System Agreement (or any agreement substituted therefor), to receive all Power available from time to time at any MSEI Generating Unit and shall be responsible for certain of the operating expenses of such Units apportioned in accordance with the formula set forth in Section 4; and

WHEREAS, Unit No. 1 and Unit No. 2 of the Project are MSEI Generating Units, and MSE and the Parties desire to allocate the Power available to MSE from time to time from these MSEI Generating Units and the operating expenses associated therewith on a fixed percentage basis rather than in accordance with the System Agreement; and

WHEREAS, pursuant to the provisions of Section 5 of the Availability Agreement, it has been agreed that both Unit No. 1 and Unit No. 2 of the Project shall be deemed to be in operation no later than December 31, 1982 for purposes of commencing the accrual of depreciation and amortization with respect to such Units and that, if Unit No. 1 of the Project has been placed in operation on or prior to December 31, 1982, Unit No. 2 of the Project shall be deemed to be in operation no later than December 31, 1986 for purposes of commencing the accrual of depreciation and amortization with respect to such Unit; and

WHEREAS, the commencement of commercial operation of Unit No. 1 has been deferred to a date subsequent to December 31, 1981 but currently is expected to occur not later than December 31, 1982, and the commencement of commercial operation of Unit No. 2 has been deferred to a date subsequent to December 31, 1985 but currently is expected to occur not later than December 31, 1986; and

WHEREAS, MSE and the Parties deem it desirable that there be an approximate two-year interval between the presently expected commercial operation dates of the Units and the dates on which the Units shall be deemed to be in operation under the Availability Agreement for purposes of commencing the accrual of depreciation and amortization with respect to such Units; and

WHEREAS, MSE and the Parties have determined that it would be preferable if Power available from any MSEI Generating Unit could be sold either pursuant to the then applicable provisions of the System Agreement or pursuant to the terms of another or other agreements; and

WHEREAS, effective January 1, 1981, the electric properties of Ark-Mo were consolidated with those of AP&L and Ark-Mo was dissolved, and AP&L assumed all of the obligations of Ark-Mo under the Availability Agreement; and

WHEREAS, MSE, AP&L, Ark-Mo, LP&L, MP&L and NOPSI have entered into (i) a First and Fourth Assignment of Availability Agreement, Consent and Agreement, dated as of June 30, 1977 and March 20, 1980, respectively, with Manufacturers Hanover Trust Company, as agent for certain banks, and (ii) a Second and Third Assignment of Availability Agreement, Consent and Agreement, dated as of June 30, 1977 and January 1, 1980, respectively, with United States Trust Company of New York and Malcolm J. Hood, as trustees; and

WHEREAS, it is now appropriate and necessary to revise the provisions of Sections 3, 4 and 5 of the Availability Agreement accordingly.

NOW, THEREFORE, in consideration of the terms and conditions hereinafter set forth, the parties hereto agree with each other as follows:

1. For the purposes of this Second Amendment to Availability Agreement, any term used herein which has a defined meaning in the Availability Agreement shall have the same meaning herein.

2. Sections 3, 4 and 5 of the Availability Agreement are hereby amended to read as follows:

"3. On or before the date on which Unit No. 1 of the Project is placed in commercial operation, AP&L, LP&L, MP&L and NOPSI (Participating Parties) will (a) join with MSEI in executing an agreement which will set forth in detail the terms and provisions for the sale by MSEI to the Participating Parties of Power available to MSEI from Unit No. 1 and Unit No. 2 of the Project (Power Purchase Agreement), or (b) join (together with all other Parties) in executing such document or documents as may be necessary for MSEI to become a party to the System Agreement in such a manner as will cause the Power from the Project to be sold under the terms thereof. MSEI shall, subject to the provisions of this Agreement and the then applicable provisions of the Power Purchase Agreement (or, if applicable, the System Agreement), make available, or cause to be made available, to the Participating Parties all Power available to MSEI from time to time from the Project. On or before the date on which any MSEI Generating Unit other than Unit No. 1 and Unit No. 2 of the Project (Additional MSEI Generating Unit) is placed in commercial operation, MSEI and the Parties will either (a) join in executing such document or documents as may be necessary for MSEI to become a party to the System Agreement in such a manner as will cause the Power from such Additional MSEI Generating Unit to be sold under the terms thereof or (b) enter into an agreement or agreements which will set forth in detail the terms and provisions for the sale by MSEI to the Parties of Power available to MSEI from such Additional MSEI Generating Unit (Other MSEI Power Agreement). Notwithstanding (a) that MSEI may be a party to the System Agreement at the time it enters into an Other MSEI Power Agreement, or (b) that MSEI may be a party to the Power Purchase Agreement at such time as it joins in the System Agreement, neither MSEI nor the Parties shall have any rights or duties under the System Agreement with respect to the Additional MSEI Generating Units which are subject to any Other MSEI Power Agreement or with respect to Unit No. 1 and Unit No. 2 of the Project if they are then subject to the Power Purchase Agreement. No generating unit or portion thereof owned by MSEI will become an "MSEI Generating Unit" for purposes of this Agreement until it has been designated as such hereunder. MSEI and the Parties will also join in executing at an appropriate time such document or documents as may be necessary for others who become parties to (a) the Power Purchase Agreement, (b) the System Agreement or (c) any Other MSEI Power Agreement to join in and become parties to this Agreement. MSEI shall, subject to the provisions of the then applicable requirements of Section 6 of this Agreement and (a) the Power Purchase Agreement, (b) the System Agreement (or any agreement substituted therefor), or (c) any Other MSEI Power Agreement, make available, or cause to be made available, to the Parties all Power available to MSEI from time to time at any MSEI Generating Unit.

"4. The Parties shall, subject to the provisions of the then applicable requirements of Section 7 of this Agreement and (a) the Power Purchase Agreement, (b) the then applicable requirements of the System Agreement (or any agreement substituted therefor) or (c) any Other MSEI Power Agreement be entitled to receive all Power available to MSEI from time to time at any MSEI Generating Unit: provided, that (i) should any Party terminate its participation in (a) the Power Purchase Agreement, (b) the System Agreement or (c) any Other MSEI Power Agreement, then it is agreed that MSEI, such Party and the other Parties shall enter into a separate agreement whereby such Party shall continue to be entitled to receive Power, and obligated to take Power, available to MSEI at any MSEI Generating Unit which has been designated as being subject to this Agreement at the time such Party shall exercise its right to terminate such participation, in such amounts and for such consideration calculated from time to time as if such Party had remained a party to (a) the Power Purchase Agreement, (b) the System Agreement or (c) any Other MSEI Power Agreement, and (ii) should (a) the Power Purchase Agreement, (b) the System Agreement or (c) any Other MSEI Power Agreement be cancelled or terminated, then it is agreed that MSEI and all such Parties shall enter into a separate agreement whereby such Parties shall continue to be entitled to receive

Power, and obligated to take Power, available to MSEI at any MSEI Generating Unit at the time of cancellation or termination of (a) the Power Purchase Agreement, (b) the System Agreement or (c) any Other MSEI Power Agreement, in such amounts and for such consideration calculated from time to time as if (a) the Power Purchase Agreement, (b) the System Agreement or (c) any Other MSEI Power Agreement had remained in effect and MSEI and such Parties were parties thereto. Notwithstanding such withdrawal from, or cancellation or termination of, (a) the Power Purchase Agreement, (b) the System Agreement or (c) any Other MSEI Power Agreement, each Party shall remain bound by the terms of this Agreement with respect to any MSEI Generating Unit which has been designated as being subject to this Agreement at the time of such withdrawal, cancellation or termination. The Power available to MSEI from both Unit No. 1 and Unit No. 2 of the Project will be allocated to the Participating Parties according to the following percentages:

AP&L	17.1%
LP&L	26.9%
MP&L	31.3%
NOPSI	24.7%

The percentage applicable to any Participating Party is hereinafter called its "Allocable Share". Notwithstanding such fixed allocation, the Participating Parties may, pursuant to the Power Purchase Agreement or otherwise, freely assign and transfer all or any portion of their respective Allocable Shares. No such transfer or assignment will change the percentage Allocable Share of any Participating Party hereunder. In consideration of MSEI's commitment to undertake construction of the Project and its other obligations hereunder and of the right of the Parties to receive Power available to MSEI at any MSEI Generating Unit under the terms of (a) the Power Purchase Agreement, (b) the System Agreement or (c) any Other MSEI Power Agreement, the Parties agree to pay to MSEI, commencing on the date on which a particular MSEI Generating Unit is deemed to be in operation for the purposes of this Agreement, such amounts from time to time as, when added to amounts received by MSEI from any other source, including, but not limited to, amounts (if any) received by MSEI with respect to such MSEI Generating Unit under the terms of (a) the Power Purchase Agreement, (b) the System Agreement or (c) any Other MSEI Power Agreement, shall be at least equal to MSEI's total operating expenses and interest charges with respect to such MSEI Generating Unit, including (without limitation), for the purposes of this Agreement, (i) all expenses, deductions, charges and other items properly chargeable to the applicable Income Accounts 400 to 435, inclusive, of the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission for Class A and Class B Public Utilities and Licensees, as in effect on April 1, 1980 (Uniform System of Accounts), or, if such MSEI Generating Unit is not in service for any reason, all expenses, deductions, charges and other items which would be chargeable to the above Accounts if such MSEI Generating Unit were in service; it being agreed that when a particular generating unit is designated as being subject to this Agreement by MSEI and the Parties, then, solely for the purposes of determining MSEI's total operating expenses under this Section 4, such MSEI Generating Unit shall be deemed to be in operation on the date, and the accrual of depreciation as an operating expense with respect to the MSEI Generating Unit shall be deemed to commence on the date, at the rate and in the manner and continue for the duration, as is specified in the document so designating such generating unit as an MSEI Generating Unit subject to this Agreement, whether or not such MSEI Generating Unit is actually in operation on such date, and (ii) such expenses as might be incurred in connection with permanent shut-down of any MSEI Generating Unit which is nuclear-fueled and, in the event of any such shut-down, for perpetual maintenance and surveillance of any such facility in accordance with, and as required by, all applicable regulations established by any governmental authority having jurisdiction. Payments of all such expenses, deductions, charges, and other items to be made pursuant to this Section 4 shall be made monthly and (a) with respect to Unit No. 1 and Unit No. 2 of the Project shall be apportioned severally and not jointly among the Participating Parties, in accordance with the Allocable Share of each Participating Party, and (b) with respect to any Additional MSEI Generating Unit shall be apportioned among the Parties whose Company Capability is less than their Capability Responsibility, as such terms are defined in the System Agreement and as determined in accordance with Section 10 of the System Agreement, in the ratio of each such Party's deficiency to the sum of the deficiencies of all such deficient Parties; provided, however, that if in any month no Party has such a deficiency then the payments for such month shall be apportioned among the Parties in accordance with the ratio of their then respective Capability Responsibilities, as such term is defined in the System Agreement. For the purpose of this Agreement, the Capability of all MSEI Generating Units shall be included in the System Capability, as such terms are defined in the System Agreement. In the event the System Agreement is not then in effect, or has been amended or interpreted so that at least one or more of the Parties is not obligated to make the entire payment herein provided, then the Parties agree to make payments hereunder with respect to any Additional MSEI Generating Unit in accordance with the ratio of their then respective "Capability Responsibilities", as such term is defined in Appendix A attached hereto and made a part hereof and not as defined in the System Agreement. Payments made by any Participating Party to MSEI pursuant to this Section 4 with respect to Unit No. 1 and Unit No. 2 of the Project shall be applied as a credit to such Participating Party's liability for payments to MSEI under the Power Purchase Agreement or the System Agreement, as the case may be. Payments made by any Party to MSEI pursuant to this Section 4 with respect to any Additional MSEI Generating Unit shall be applied as a credit to such Party's liability for payments to MSEI under (a) the System Agreement or (b) any Other MSEI Power Agreement.

"5. For the purpose of determining MSEI's expenses and the Participating Parties' obligations under Section 4 of this Agreement with respect to Unit No. 1 and Unit No. 2 of the Project, it is hereby agreed that both Unit No. 1 and Unit No. 2 of the Project shall be deemed to be in operation on the earlier of December 31, 1984 (whether or not such Units, or either of them, are then completed or in operation) or the date on which either of such Units is first placed in commercial operation as determined under the Power Purchase Agreement, and the accrual of depreciation and amortization with respect to the Project shall be deemed to commence on the earlier of such dates; that such accrual of depreciation and amortization shall be at the rate of 3.65% per annum of the aggregate amount properly chargeable (prior to the deduction therefrom of any depreciation and amortization) at the time with respect to the Project to Balance Sheet Accounts 101, 102, 103, 104, 105, 106, 107 (the aforementioned accounts being exclusive of land and land rights), 118, 120 (.1 through .5), 121, 123, 123.1, 124, 151, 152, 153, 154, 155, 156, 157, 163, 182, 183, 184, 185, 186, 187, and 188 of the Uniform System of Accounts and such other accounts as are properly subject to depreciation or amortization at the time pursuant to such Uniform System of Accounts; and that such accrual shall continue during each of the first 27.4 years after the date of commencement of such accrual hereunder whether or not such Units, or either of them, shall ever commence operation and/or remain in operation; provided, however, that if Unit No. 1 is placed in commercial operation prior to December 31, 1984 and Unit No. 2 is not completed and ready for service at such time, then until December 31, 1988 or the date Unit No. 2 is placed in commercial operation, whichever date occurs earlier, expenditures included in Account 107 which are identified exclusively with the construction of Unit No. 2 may be excluded from the calculation of the aggregate amount subject to the accrual of depreciation and amortization pursuant to this paragraph."

3. All other provisions of the Availability Agreement shall be deemed to continue in full force and effect.

In Witness Whereof, the parties hereto have caused this Second Amendment to Availability Agreement to be duly executed by their respective officers thereunto duly authorized as of the day and year above written.

MIDDLE SOUTH ENERGY, INC.

By: ______________________
Senior Vice President

LOUISIANA POWER & LIGHT COMPANY

By: ______________________
President and Chief Executive Officer

ARKANSAS POWER & LIGHT COMPANY

By: ______________________
President and Chief Executive Officer

MISSISSIPPI POWER & LIGHT COMPANY

By: ______________________
President and Chief Executive Officer

NEW ORLEANS PUBLIC SERVICE INC.

By: James M. Cain
President and Chief Executive Officer

Exhibit B-13(a)

THIRD AMENDMENT TO
AVAILABILITY AGREEMENT
Between
MIDDLE SOUTH ENERGY, INC.
And
ARKANSAS POWER & LIGHT COMPANY, LOUISIANA POWER & LIGHT COMPANY, MISSISSIPPI POWER & LIGHT COMPANY, and NEW ORLEANS PUBLIC SERVICE INC.

This Third AMENDMENT, dated as of the 28th day of June, 1984, between Middle South Energy, Inc. (MSE), and Arkansas Power & Light Company (AP&L), Louisiana Power & Light Company (LP&L), Mississippi Power & Light Company (MP&L) and New Orleans Public Service Inc. (NOPSI), to the Availability Agreement, dated as of the 21st day of June, 1974, between MSE and AP&L, Arkansas-Missouri Power Company (Ark-Mo), LP&L, MP&L and NOPSI, as amended by the First Amendment thereto dated as of June 30, 1977 and the Second Amendment thereto dated as of June 15, 1981 (Availability Agreement), WITNESSETH THAT:

WHEREAS, pursuant to the provisions of Section 5 of the Availability Agreement, it has been agreed that both Unit No. 1 and Unit No. 2 of the Project shall be deemed to be in operation no later than December 31, 1984 for the purposes of commencing the accrual of depreciation and amortization with respect to such Units and that, if Unit No. 1 of the Project has been placed in operation on or prior to December 31, 1984, Unit No. 2 of the Project shall be deemed to be in operation no later than December 31, 1988 for purposes of commencing the accrual of depreciation and amortization with respect to such Unit; and

WHEREAS, commercial operation of Unit No. 1 is currently scheduled to commence in the first quarter of 1985; and

WHEREAS, MSE and the Parties deem it desirable that there be a reasonable interval between the presently expected commercial operation date of Unit No. 1 and the date on which Unit No. 1 shall be deemed to be in operation under the Availability Agreement for purposes of commencing the accrual of depreciation and amortization with respect to Unit No. 1 and Unit No. 2 of the Project; and

WHEREAS, effective January 1, 1981, the electric properties of Ark-Mo were consolidated with those of AP&L and Ark-Mo was dissolved, and AP&L assumed all of the obligations of Ark-Mo under the Availability Agreement; and

WHEREAS, MSE, AP&L, LP&L, MP&L and NOPSI have entered into (i) a First, Fourth, Fifth and Eighth Assignment of Availability Agreement, Consent and Agreement, dated as of June 30, 1977, March 20, 1980, June 15, 1981 and June 30, 1983, respectively, with Manufacturers Hanover Trust Company, as agent for certain banks, (ii) a Second and Third Assignment of Availability Agreement, Consent and Agreement, dated as of June 30, 1977 and January 1, 1980, respectively, with United States Trust Company of New York and Malcolm J. Hood, as trustees, (iii) a Sixth and Seventh Assignment of Availability Agreement, Consent and Agreement, dated as of February 5, 1982 and February 18, 1983, respectively, with Credit Suisse First Boston Limited, as agent for certain banks, and (iv) a Ninth Assignment of Availability Agreement, Consent and Agreement, dated as of December 1, 1983, with Citibank, N.A. and Deposit Guaranty National Bank, as Trustee; and

WHEREAS, it is now appropriate and necessary to revise Section 5 of the Availability Agreement accordingly.

NOW, THEREFORE: in consideration of the terms and conditions hereinafter set forth, the parties hereto agree with each other as follows:

1. For the purposes of this Third Amendment to Availability Agreement, any term used herein which has a defined meaning in the Availability Agreement shall have the same meaning herein.

2. Section 5 of the Availability Agreement is hereby deemed amended so that the two references in Section 5 to "December 31, 1984" shall be changed to read "December 31, 1985".

3. All other provisions of the Availability Agreement shall be deemed to continue in full force and effect.

IN WITNESS WHEREOF, the parties hereto have caused this Third Amendment to Availability Agreement to be duly executed by their respective officers thereunto duly authorized as of the day and year first above written.

ARKANSAS POWER & LIGHT COMPANY

By: Jerry M Maulden

Jerry L. Maulden,
President

MISSISSIPPI POWER & LIGHT COMPANY

By: D C Lutken

D.C. Lutken, Chairman of the Boar
and Chief Executive Officer

LOUISIANA POWER & LIGHT COMPANY

By: James M. Cain

James M. Cain,
President

NEW ORLEANS PUBLIC SERVICE INC.

By: James M. Cain

James M. Cain,
President

MIDDLE SOUTH ENERGY, INC.

By: F W Lewis

F.W. Lewis, President

8305-0096-04

FOURTH AMENDMENT TO

AVAILABILITY AGREEMENT

Between

SYSTEM ENERGY RESOURCES, INC.

And

ARKANSAS POWER & LIGHT COMPANY,

LOUISIANA POWER & LIGHT COMPANY,

MISSISSIPPI POWER & LIGHT COMPANY, and

NEW ORLEANS PUBLIC SERVICE INC.

This Fourth AMENDMENT, dated as of the 1st day of June, 1989, between System Energy Resources, Inc. (System Energy), and Arkansas Power & Light Company (AP&L), Louisiana Power & Light Company (LP&L), Mississippi Power & Light Company (MP&L) and New Orleans Public Service Inc. (NOPSI), to the Availability Agreement, dated as of the 21st day of June, 1974, between Middle South Energy, Inc. and AP&L, Arkansas-Missouri Power Company, LP&L, MP&L and NOPSI, as amended by the First Amendment thereto dated as of June 30, 1977, the Second Amendment thereto dated as of June 15, 1981 and the Third Amendment thereto dated as of June 28, 1984 (Availability Agreement), WITNESSETH THAT:

WHEREAS, a special group of officials have conducted an evaluation and review of Unit No. 2 of the Project; and

WHEREAS, System Energy and the Parties deem it desirable that, for purposes of the Availability Agreement, any of System Energy's investment associated with Unit No. 2 which it will not be permitted to charge its customers in wholesale rates, and the obligations of the Parties to pay such investment to System Energy, be amortizable at the rate of 3.65% of such investment over a period of 27.4 years; and

WHEREAS, effective December 20, 1986, System Energy's name was changed from Middle South Energy, Inc. to System Energy Resources, Inc.; and

WHEREAS, System Energy, AP&L, LP&L, MP&L and NOPSI have entered into (i) a Sixteenth Assignment of the Availability Agreement, Consent and Agreement, dated as of May 1, 1986, with United States Trust Company of New York and Malcolm J. Hood, as Trustees, (ii) a Fourteenth and Fifteenth Assignment of the Availability Agreement, Consent and Agreement, dated as of June 15, 1985 and May 1, 1986, respectively, with Deposit Guaranty National Bank, United States Trust Company of New York and Malcolm J. Hood, as Trustees, (iii) a Seventeenth, Eighteenth, Nineteenth, Twentieth and Twenty-first Assignment of the Availability Agreement, Consent and Agreement, dated as of September 1, 1986, September 1, 1986, September 1, 1986, November 15, 1987 and December 1, 1987, respectively, with United States Trust Company of New York and Gerard F. Ganey, as Trustees, and (iv) a Twenty-second Assignment of the Availability Agreement, Consent and Agreement, dated as of December 1, 1988, with Chemical Bank as Agent, pursuant to which the following terms of this Fourth Amendment have been consented to; and

WHEREAS, it is now appropriate and necessary to revise Section 4 of the Availability Agreement accordingly.

NOW, THEREFORE, in consideration of the terms and conditions hereinafter set forth, the parties hereto agree with each other as follows:

1. For the purposes of this Fourth Amendment to Availability Agreement, any term used herein which has a defined meaning in the Availability Agreement shall have the same meaning herein.

2. Section 4 of the Availability Agreement is hereby amended to add the following to the end of such Section:

> Notwithstanding anything to the contrary in this Section 4, in the event that any portion of the Project is Abandoned prior to its Completion, the portion of System Energy's investment which it is not permitted to charge to its customers in wholesale rates ("disallowed investment") and the obligations of the Parties to pay such disallowed investment to System Energy, shall be amortizable from the date on which System Energy is obligated by applicable generally accepted accounting principles to

eliminate the disallowed investment from the asset side of its balance sheet no less rapidly than at the rate of 3.65% of the disallowed investment per annum for a period of 27.4 years. Any portion of the Project that is Abandoned shall no longer be subject to this Availability Agreement except that Section 4 and 5 hereof shall remain applicable to System Energy's investment (including the disallowed investment) in the Project.

"Abandoned" shall mean the good faith decision by System Energy to abandon any material portion of the Project as evidenced by a resolution of the Board of Directors of System Energy followed by a cessation of all operations (other than preservative maintenance) of such material portion for a period of ninety (90) days certified to in a certificate signed by the President or a Vice-President and the Treasurer or an Assistant Treasurer of System Energy (Officers' Certificate).

"Completion", when applied to Unit No. 2, shall mean the first date on which all of the following have occurred: the necessary permits and operating licenses have been issued; the critical tests for the major components have been completed; Unit No. 2 has been placed in the control of System Energy by the principal contractor; Unit No. 2 has been synchronized into the power grid of the Parties for its function in the business of generating electric energy for the production of income; Unit No. 2 is available for commercial operation; and an Officers' Certificate to such effect shall have been delivered to all necessary parties.

3. All other provisions of the Availability Agreement shall be deemed to continue in full force and effect.

IN WITNESS WHEREOF, the parties hereto have caused this Fourth Amendment to Availability Agreement to be duly executed by their respective officers thereunto duly authorized as of the day and year first above written.

SYSTEM ENERGY RESOURCES, INC.

By: ______________________
William Cavanaugh, III
President

ARKANSAS POWER & LIGHT COMPANY

By: ______________________

MISSISSIPPI POWER & LIGHT COMPANY

By: ______________________

LOUISIANA POWER & LIGHT COMPANY

By: ______________________

NEW ORLEANS PUBLIC SERVICE INC.

By: ______________________

CNRO-2012-00007

SERIES 3 ATTACHMENTS

3 Entergy Gulf States Louisiana, LLC RBS Status Report – 70% Regulated (1 page)

3-A Entergy Gulf States Louisiana, LLC – Calculation of Minimum Amount (1 page)

3-B Schedule of Remaining Principle Payments – RBS (1 page)

3-C Entergy Gulf States Louisiana, LLC RBS Status Report – 30% Non-Regulated (1 page)

3-D LPSC Order in Docket No.U-31237 (20 pages)

3-E PUCT Order in Docket No. 37744 (16 pages)

3-F FERC Order in Docket Nos. ER86-558-002 (9 pages)

3-G MSS-4 Agreement and FERC's acceptance (13 pages)

Attachment 3
(1 page)

ENTERGY GULF STATES LOUISIANA, L.L.C.
Status Report of Decommissioning Funding
For Year Ending December 31, 2011 - 10 CFR 50.75(f)(1)

Plant Name: **River Bend Station (70% Regulated Interest)**

1. Minimum Financial Assurance (MFA) Estimated per 10 CFR 50.75(b) and (c) (2011$):	$423.0 million[1]
2. Decommissioning Fund Total As of 12/31/11:	$192.3 million
3. Annual amounts remaining to be collected:	See Attachment 3-B
4. Assumptions used: Rate of Escalation of Decommissioning Costs:	See item below
Rate of Earnings on Decommissioning Funds:	2% real rate of return per 10 CFR 50.75(e)(1)(i)
Authority for use of Real Earnings Over 2%:	N/A
5. Contracts upon which licensee is relying For Decommissioning Funding:	See footnote [2]
6. Modifications to Method of Financial Assurance since Last Report:	See footnote [3]
7. Material Changes to Trust Agreements:	None

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1 See Attachment 3-A

2 See the agreement in attachment 3-G for the MSS-4 Agreement which is a unit power purchase agreement under the MSS-4 Agreement, a FERC tariff. The licensee had previously believed this arrangement would qualify as a contractual obligation, but upon further consideration, the licensee believes this arrangement is simply a cost of service recovery mechanism as defined in 10 CFR §50.75(e)(1)(ii)(A). This MSS-4 Agreement is a FERC tariff, part of the larger Entergy System Agreement, which is itself a FERC tariff. The NRC reviewed this arrangement in a license transfer application in 2007 (see ADAMS Accession Nos. ML071560529 and ML072470715). Accordingly, it is the licensee's position that this agreement is not a 10 CFR §50.75(e)(1)(v) "contractual obligation," but rather a cost of service tariff which may appropriately be used to fund the external sinking fund in accordance with 10 CFR §50.75(e)(1)(ii). Out of an abundance of caution, the licensee identifies this information here.

3 Please see footnote 2 above. The MSS-4 Agreement was modified in 2010 in response to certain concerns raised by the NRC Staff. The modifications were accepted by the FERC on February 14, 2011. See attachment 3-G for the changes to the MSS-4 Agreement and the FERC's acceptance thereof.

Attachment 3-A
(1 page)

ENTERGY GULF STATES LOUISIANA, L.L.C.
Calculation of Minimum Amount
For Year Ending December 31, 2011 - 10 CFR 50.75(f)(1)

Entergy Gulf States Louisiana, L.L.C.: Factors below used for all of ownership interests
Plant Location: West Feliciana Parish, Louisiana
Reactor Type: Boiling Water Reactor ("BWR")
Power Level: <3,400 MWt (3,091MWt)
BWR Base Year 1986$: $131,819,000
Labor Region: South
Waste Burial Facility: Generic Disposal Site

10CFR50.75(c)(2) Escalation Factor Formula:
0.65(L) +0.13(E) +0.22(B)

	Factor
L=Labor (South)	2.28[1]
E=Energy (BWR)	2.66[2]
B=Waste Burial-Vendor (BWR)	12.54[3]

BWR Escalation Factor:

0.65(L) +0.13(E) +0.22(B)=	4.58401

1986 BWR Base Year $ Escalated:

$131,819,000 * Factor=	$604,259,178
River Bend 70% Regulated Interest:	$422,981,425
River Bend 30% Non-Regulated Interest:	181,277,753
Total	$604,259,178

1 Bureau of Labor Statistics, Series Report ID: CIU2010000000220i (4th Quarter 2011)
2 Bureau of Labor Statistics, Series Report ID: wpu0543 and wpu0573 (December 2011)
3 Nuclear Regulatory Commission: NUREG-1307 Revision 14, Table 2.1 (2010)

Attachment 3-B
(1 page)

Schedule of Remaining Principal Payments into
River Bend Decommissioning Fund
($ Thousands)

Year	LPSC	PUCT	FERC	Total
2012	$ 7,843	$ 2,019	$ 113	$ 9,975
2013	$ 7,843	$ 2,019	$ 113	$ 9,975
2014	$ 7,843	$ 2,019	$ 113	$ 9,975
2015	$ 8,996	$ 2,019	$ 113	$11,128
2016	$ 8,996	$ 2,019	$ 113	$11,128
2017	$ 8,995	$ 2,019	$ 113	$11,127
2018	$ 8,995	$ 2,019	$ 113	$11,127
2019	$ 8,996	$ 2,019	$ 113	$11,128
2020	$10,195	$ 2,019	$ 113	$12,327
2021	$10,195	$ 2,019	$ 113	$12,327
2022	$10,195	$ 2,019	$ 113	$12,327
2023	$10,195	$ 2,019	$ 113	$12,327
2024	$10,195	$ 2,019	$ 113	$12,327
2025	$11,693	$ 2,019	$ 165	$13,877
2026	$11,693	$ 2,019	$0	$13,712
2027	$11,693	$ 2,019	$0	$13,712
2028	$11,693	$ 2,019	$0	$13,712
2029	$11,693	$ 2,019	$0	$13,712
2030	$13,513	$ 2,019	$0	$15,532
2031	$0	$ 2,019	$0	$ 2,019
2032	$0	$ 2,019	$0	$ 2,019
2033	$0	$ 2,019	$0	$ 2,019
2034	$0	$ 2,019	$0	$ 2,019

Note: Approved in LPSC Docket No.U-31237, see Attachment 3-D; PUCT Order in Docket No. 37744, See Attachment 3-E; FERC Order in Docket Nos. ER86-558-002, see Attachment 3-F.

Attachment 3-C
(1 page)

ENTERGY GULF STATES LOUISIANA, L.L.C.
Status Report of Decommissioning Funding
For Year Ending December 31, 2011 - 10 CFR 50.75(f)(1)

Plant Name: **River Bend Station (30% Non-Regulated Interest)**

1.	Minimum Financial Assurance (MFA) Estimated per 10 CFR 50.75(b) and (c) (2011$):	\$181.3 million[1]
2.	Decommissioning Fund Total As of 12/31/11:	\$228.7 million
3.	Annual amounts remaining to be collected:	None
4.	Assumptions used: Rate of Escalation of Decommissioning Costs:	See next item
	Rate of Earnings on Decommissioning Funds:	2% real rate of return per 10 CFR 50.75(e)(1)(i)
	Authority for use of Real Earnings Over 2%:	N/A
5.	Contracts upon which licensee is relying For Decommissioning Funding:	None
6.	Modifications to Method of Financial Assurance since Last Report:	None
7.	Material Changes to Trust Agreements:	None

[1] See Attachment 3-A

Attachment 3-D
(20 pages)

LPSC Order in Docket No.U-31237

LOUISIANA PUBLIC SERVICE COMMISSION

ORDER NO. U-31237

ENTERGY GULF STATES LOUISIANA, L.L.C.
ENTERGY LOUISIANA, LLC
EX PARTE

Docket No. U-31237 In re: Joint Application of Entergy Gulf States Louisiana, L.L.C. and Entergy Louisiana, LLC for approval of an Increase in Funding for Decommissioning for River Bend and Waterford 3 Nuclear Facilities LPSC Docket No. U-31237.

(Decided at the Commission's July 28, 2010 Business and Executive Session.)

Overview and Procedural History

Entergy Gulf States Louisiana, L.L.C. ("EGSL") and Entergy Louisiana, LLC ("ELL") (collectively "the Companies") filed a joint Application with supporting documentation and testimony on December 29, 2009 seeking approval from the Louisiana Public Service Commission ("LPSC" or "Commission") to provide supplemental funding for the decommissioning trusts maintained for the LPSC-jurisdictional portions of ELL's Waterford 3 and EGSL's River Bend nuclear generation units.[1] The request to increase the amounts is the result of the Nuclear Regulatory Commission ("NRC") notifying the Companies of "a projected shortfall of decommissioning funding assurance" at both Waterford 3 and River Bend. The filings were published in the Commission's Official Bulletin on January 8, 2010. Interventions were filed by the Louisiana Energy Users Group ("LEUG"), Marathon Oil Company ("Marathon"), ArcelorMittal LaPlace, LLC ("ArcelorMittal") and the Alliance for Affordable Energy ("the Alliance").

This matter was assigned to Administrative Law Judge Michelle Finnegan who presided over a status conference on February 22, 2010. At the status conference, Commission Staff requested that establishing a procedural schedule be postponed until after Commission hiring of an outside consultant to assist Staff in this matter. Staff advised that a Request for Proposals had been issued on February 5, 2010, and Staff anticipated the Commission's hiring decision would occur at the Commission's March 2010 Business and Executive ("B&E"). No party opposed Staff's request. A follow up conference was scheduled for April 5. At the Commission's March 10 B&E, the Commission voted to hire the firms of Exeter Associates, Inc. and Henderson Ridge Consulting, who submitted a joint proposal. At a status conference held April 5, the parties established a procedural schedule with hearings set for early August 2010.

On May 24, 2010 the Companies filed an Unopposed Motion to Modify and Amend Procedural Schedule to postpone the schedule while the parties worked to negotiate a possible settlement or narrow issues for hearing; the motion was granted. The Companies and Staff filed, on June 24, an Unopposed Joint Motion to Suspend the Procedural Schedule. The motion was granted, and as requested in the motion, the

1 Waterford 3 is a single-unit 1,152 MW nuclear steam-electric generating station located near Killona, Louisiana that was constructed by ELL's predecessor, Louisiana Power & Light Company, and began commercial operation in September 1985. Waterford 3 employs the pressurized-water-reactor design.

River Bend is a single-unit 967 MW nuclear steam-electric generating station located near St. Francisville, Louisiana that was constructed by EGSL's predecessor, Gulf States Utilities Company, and began commercial operation in June 1986. River Bend employs the boiling-water-reactor design.

parties were directed to file an update on the status of the case or an uncontested stipulation on or before July 9. On July 9, Staff and the Companies advised that a Settlement Term Sheet had been executed by all but one party, and that the parties planned to file the uncontested stipulation and request that a hearing be set so that this matter could be considered at the Commission's July B&E. On July 13, 2010 the parties filed a Joint Motion for the Scheduling of a Stipulation Hearing and Request for Expedited Hearing. The motion was granted and a Stipulation Hearing was convened on July 20, 2010.

Commission Authority

Louisiana Constitution and Statutes:

The Commission exercises jurisdiction in this proceeding pursuant to Article IV, Sec. 21 of the Louisiana Constitution, and La. R.S. 45:1163(A)(1) and La. R.S. 45:1176.

La. Const. Art. IV, Sec. 21 provides in pertinent part:

> The Commission shall regulate all common carriers and public utilities and have such other regulatory authority as provided by law. It shall adopt and enforce reasonable rules, regulations, and procedures necessary for the discharge of its duties, and perform other duties as provided by law.

La. R.S. 45:1163 provides in pertinent part:

> A. (1) The Commission shall exercise all necessary power and authority over any street, railway, gas, electric light, heat, power, waterworks, or other local public utility for the purpose of fixing and regulation the rates charged or to be charged by and service furnished by such public utilities.

La. R.S. 45:1176 provides in pertinent part:

> The Commission...shall investigate the reasonableness and justness of all contracts, agreements and charges entered into or paid by such public utilities with or to other persons, whether affiliated with such public utility or not.

Companies' Application

The Companies December 29, 2009 Joint Application requests an increase in revenues for ELL and EGSL to provide supplemental funding for the decommissioning trusts maintained for the LPSC-jurisdictional portions of ELL's Waterford 3 and EGSL's River Bend nuclear generation units. The request for increase is the result of the NRC's determination of a projected shortfall in the decommissioning funding at both Waterford 3 and River Bend.

The Companies' Application proposes new revenue requirement amounts consistent with their revised decommissioning funding plans using a 40 year license and requests approval to include these revenue requirements in their 2009 Test Year Formula Rate Plan ("FRP") filings. ELL requests approximately $10.336 million per year for its LPSC-jurisdictional revenue requirement in 2010 to meet the NRC minimum funding assurance of $400.2 million, which would be a $7.94 million increase over the $2.396 million in ELL's rates. For EGSL's portion of the regulated 70% share of River Bend, EGSL requests a revenue requirement of \$9.671 million per year to meet its NRC minimum assurance of \$378.8 million. Currently, EGSL has no funding in retail rates for decommissioning.

Staff's Review

Commission Staff conducted a review of the Application, supporting documentation and testimony. Commission Staff issued data requests, reviewed those responses and conducted a series of conferences with the Companies. Staff proposed certain adjustments to the Companies' filed calculations of their revenue requirements to update the trust fund balances, extend the funding period and modify the investment portfolio allocations. Commission Staff and the Companies reached a stipulated agreement, taking into account Commission Staff's adjustments, that resolves all issues in this docket.

Uncontested Stipulated Settlement

The Companies and Staff filed on July 13, pursuant to Rule 6 of the Commission's Rules of Practice and Procedure, a motion for stipulation hearing, Settlement Term Sheet signed by all parties, and supporting testimony from Kenneth Gallagher for the Companies and Thomas S. Catlin and William J. Barta for Commission Staff. A stipulation hearing was held July 20. At the stipulation hearing, the Companies presented the live testimony of Mr. Gallagher and Commission Staff presented the live testimony of Mr. Catlin. In addition to live testimony, the following documents were entered into the record:

> Joint Staff EGSL/ELL Exhibit 1- Settlement Term Sheet;
>
> Staff Exhibit 1- Settlement Testimony of William J. Barta, dated July 2010;
>
> Staff Exhibit 2- Settlement Testimony of Thomas S. Catlin, dated July 2010;
>
> EGSL/ELL Exhibit 1- Settlement Testimony of Kenneth F. Gallagher, dated July 9, 2010;
>
> EGSL/ELL Exhibit 2- Direct Testimony of Kenneth F. Gallagher, redacted public version, dated December 2009; and
>
> EGSL/ELL Exhibit 3- Direct Testimony of Kenneth F. Gallagher, confidential version, dated December 2009.

Conclusion

On motion of Commissioner Campbell, seconded by Commissioner Field, and unanimously adopted, the Commission voted to accept the Staff Recommendation and adopt the uncontested stipulated Settlement Term Sheet filed into the record on July 13, 2010. Therefore,

IT IS ORDERED:

1. The Companies submitted a Joint Application seeking approval to provide supplemental funding for the decommissioning trusts maintained for the LPSC's jurisdictional portions of the Waterford 3 Steam Electric Station ("Waterford 3") owned by ELL and the River Bend Station ("River Bend") owned by EGSL.

The Companies requested increases in their respective revenue requirements to address projected shortfalls found by the Nuclear Regulatory Commission ("NRC") in the decommissioning funding assurance required for each facility.

2. The proposed revised revenue requirement amounts are a result of the NRC notifying the Companies of the referenced projected shortfall of decommissioning funding assurance at both Waterford 3 and River Bend. Under NRC financial assurance requirements regulations found in 10 CFR 50.75(a)-(f), ELL and EGSL, as holders of nuclear operating licenses, must certify through biennial filings that available decommissioning funds are not less than the NRC's prescribed minimum amount required to fund decommissioning costs. The projected shortfalls determined by the NRC are a result of several factors, including the NRC's requirement that only the currently approved license life of forty (40) years for each unit may be used in calculating the minimum financial assurance amount. The LPSC, in prior Orders, used a sixty (60) year license life to determine the appropriate level of funding for the decommissioning trusts, based on possible license extensions that the Companies are expected to apply for in the future.

3. The Companies have proposed new revenue requirement amounts consistent with their revised decommissioning funding plans using a 40 year license and requested approval to include these revenue requirements in their 2009 Test Year Formula Rate Plan ("FRP") filings in the manner provided for in each Company's FRP.[2] ELL has requested approximately $10.336 million per year[3] for its LPSC-jurisdictional revenue requirement in 2010 to meet the NRC minimum funding assurance of $400.2 million, which would be a $7.94 million increase over the $2.396 million in ELL's rates. For EGSL's portion of the regulated 70% share of River Bend[4], EGSL has requested a revenue requirement of $9.671 million per year to meet its NRC minimum assurance of $378.8 million.[5] Currently, EGSL has no funding in retail rates for decommissioning.

4. The Commission has recognized in its prior rate Orders setting decommissioning accruals for both ELL and EGSL that the decommissioning accrual issue would be revisited if the NRC notified the Companies that decommissioning funding was inadequate. Orders addressing both EGSL and ELL contain language substantially as follows: "In the event that the Nuclear Regulatory Commission ("NRC") formally notifies [EGSL or ELL] or [the River Bend or Waterford 3] licensee that the decommissioning funding for [River Bend or Waterford 3] is or would become inadequate, the Company would be permitted recognition in rates of decommissioning expense at a level sufficient to address reasonably the NRC's concern as expressed in the notification."[6]

2 Section 3.A.5 of the EGSL and ELL FRP Riders both contain identical language stating, in pertinent part that: "The effects of the changes in depreciation rates, and/or decommissioning accruals, increases and decreases, ordered by the LPSC, including as a result of changes in the requirement to fund the decommissioning trust that may be ordered by the Nuclear Regulatory Commission during the period that this FRP is in effect, shall be considered separately outside of the FRP mechanism."

3 The retail revenue requirement for ELL is $10.134 million.

4 Thirty percent of the River Bend plant is unregulated and was acquired by EGSL from the former Cajun Electric Power Cooperative, Inc. as part of a bankruptcy reorganization. *See In Re Cajun Electric Power Cooperative, Inc.*, 238 B.R. 319 (M.D. La. 1999) *aff'd* 119 F.3rd 349 (5th Cir. 1997). The decommissioning funding for this 30% share is separately funded and is not subject to the NRC's notice of projected shortfalls in the decommissioning funding assurance and, therefore, not subject to the review being undertaken in this proceeding.

5 The $378.8 million figure represents the combined total for the River Bend regulated plant, including the Louisiana, Texas and wholesale jurisdictions. The Louisiana retail jurisdictional share of River Bend's NRC minimum is $217.76 million.

6 For EGSL and River Bend, the provision comes from Item 8 of settlement term sheet for Consolidated Order Nos. U-22491, U-23358, U-24182, U-24993, U-25687 dated January 8, 2003. For ELL and Waterford 3, the provision comes from Item 4 of the settlement term sheet for Order No. U-20925 RRF 2004 dated May 25, 2005.

5. After incorporating certain adjustments to the Companies' filed calculations of their revenue requirements to update the trust fund balances, extend the funding period and modify the investment portfolio allocations, the Staff and the Companies have agreed upon new decommissioning funding requirements for both Waterford 3 and River Bend. The agreed upon decommissioning funding is intended to serve only to meet the decommissioning funding requirements on an interim basis, and the Staff and Companies agree that both the Waterford 3 and River Bend funding requirements will be re-evaluated based on site specific cost studies after ELL and EGSL, respectively, have filed for and received the NRC's responses to requests for license extensions for the two nuclear facilities. It is recognized that there is no certainty that either ELL or EGSL will receive license extensions for their respective plants and that the LPSC may have to re-evaluate and adjust revenue requirements based on a forty (40) year life for each plant.

6. The initial funding requirement of $5.947 million ($5.831 million on a retail basis) per year is appropriate. This amount will be included in ELL's revenue requirement for the Waterford 3 decommissioning funding plan, with collections to begin with the September 2010 billing cycle rate change scheduled to occur through the implementation of ELL's 2009 Test Year Formula Rate Plan and further finds that these costs are to be treated as "Extraordinary Costs" and recovered outside of the earnings sharing mechanism of the Formula Rate Plan. This calculation is based on the 5-year step funding plan historically used for Waterford 3 and reflects beginning fund balance, the investment portfolio allocations, escalation and earnings rates, 5-year funding increments, and other assumptions set forth in the Attached Exhibit A.

7. For River Bend, an initial funding requirement of $7.843 million per year stepped up on a 5-year basis is appropriate[7]. This amount will be included in EGSL's revenue requirement for the River Bend decommissioning funding plan, with collections to begin with the September 2010 billing cycle rate change scheduled to occur through the implementation of EGSL's 2009 Test Year Formula Rate Plan and further finds that these costs are to be treated as "Extraordinary Costs" and recovered outside of the earnings sharing mechanism of the Formula Rate Plan. This calculation is a 5-year step funding plan recommended by Staff and reflects the beginning fund balances, the investment portfolio allocations, escalation and earnings rates, 5-year funding increments, and other assumptions set forth in the Attached Exhibit B.

8. The NRC financial assurance analysis is not a ratemaking adequacy test but is instead a financial adequacy test devised specifically and solely for that purpose. Thus, the financial adequacy test and the resulting implications for ratemaking can differ. Recognizing this fact, the Commission hereby allows contributions to the decommissioning trust fund during the decommissioning period to be considered for purposes of determining whether NRC financial assurance requirements are met For Waterford 3, funding is assumed to occur for the first seven years of the expected ten-year decommissioning period, consistent with the NRC's own calculation of the Waterford 3 minimum decommissioning amount. Staff also assumed funding of the trust through ratepayer contributions during the first six years of the decommissioning period for River Bend.

9. The Staff's decommissioning revenue requirement developed for the River Bend nuclear facility, which is hereby adopted by the Commission, reflects the amount to fully fund the Louisiana retail jurisdictional share of the regulated 70% portion of the unit, including the portion that comprises what is known as the Deregulated Asset Plan ("DAP"). Under the provisions of LPSC Order Nos.

7 For EGSL the $7.843 million amount is on a retail basis.

U-17282 D (1/26/88) and U-17282 K (1/12/92) establishing and modifying the River Bend DAP, EGSL has the following options: (1) selling the DAP capacity to customers at a rate of 4.6 cents per kWh ($46 per MWh), recovered through the Company's Fuel Adjustment Clause, (2) in response to a bona fide offer approved by the LPSC, selling the capacity into the market and sharing proceeds with customers on a 50/50 basis for amounts in excess of 4.6 cents per kWh, or (3) if EGSL requests approval by the LPSC to sell the capacity into the market in response to a bona fide offer, and the LPSC disapproves such off system sale, the purchase price by which the DAP capacity will be sold to customers and recovered through the Company's Fuel Adjustment Clause will be adjusted to 4.6 cents per kWh plus 50 percent of the increment above 4.6 cents per kWh offered by a third party. Seven years after the DAP was approved, in Order U-19904-C (12/29/94), the Commission determined that nuclear decommissioning costs associated with the DAP capacity should be considered to be part of the 4.6 cents per kWh rate established by the DAP instead of separately recovered from customers. The nuclear decommissioning costs for the DAP portion of River Bend should be returned to EGSL's revenue requirement consistent with the original DAP order and collected separately, and in addition to, the 4.6 cents per kWh. EGSL agrees that as long as the DAP portion of the decommissioning revenue requirement is collected separately, and in addition to, the 4.6 cents per kWh, the Company will not sell the DAP capacity into the market and/or realize any amount in excess of 4.6 cents per kWh in the event it receives a bona fide offer by a third party, for the earlier of 1) a period of 5 years or 2) until EGSL receives a final ruling on its application for River Bend's license extension. The LPSC and its Staff will review and re-examine allocating the DAP into rates within 5 years this Order.

10. The increase in the 2010 decommissioning funding contributions of $3.5518 million for ELL and $7.843 million for EGSL will be allocated to and recovered from each applicable rate schedule, as identified in Statement A of Rider FRP-5 for ELL and Rider FRP-1 for EGSL, in proportion to base revenues before the application of the monthly fuel adjustment.

11. This Commission finds that the Companies have complied with, or are not in conflict with, the provisions of all applicable LPSC Orders governing the Companies Joint Application filed December 29, 2009 in this matter.

12. The proposed funding amounts of this Order must be accepted by the NRC. If for any reason the NRC does not accept the proposed funding amounts set forth, the LPSC will promptly undertake to re-examine and review the funding amounts and the related issues which are the subject of a NRC refusal.

13. This Commission affirms the language of its prior Orders, namely Item 8 of settlement term sheet for Consolidated Order Nos. U-22491, U-23358, U-24182, U-24993, U-25687 dated January, 8 2003 and Item 4 of the settlement term sheet for Order No. U-20925 RRF 2004 dated May 25, 2005 that in the event that the NRC formally notifies EGSL or ELL or the River Bend or Waterford 3 licensee that the decommissioning funding for either River Bend or Waterford 3, individually or collectively, is or would become inadequate, then ELL or EGSL or both would be permitted recognition in rates of decommissioning expense at a level sufficient to address reasonably the NRC's concern as expressed in the notification.

14. For ratemaking purposes the amount of the decommissioning accrual to be reflected in rates shall track, on a prospective basis, for the rate effective period, the specific annual amounts set out in the agreed upon decommissioning funding plan or any subsequent Commission-approved decommission funding plan on a monthly pro rata basis. Such derived amounts shall form the basis for

8 The retail increase is $ 3.482 million.

subsequent rate changes. To the extent that the Companies remain subject to Formula Rate Plans with scheduled rate implementations where rate changes do not occur on January 1, the Companies shall make pro forma adjustments to their Formula Rate Plan Filings reflecting any prospective changes to decommissioning accruals that would occur in the rate effective period, on a monthly pro rata basis. These pro forma adjustments shall be treated as Extraordinary Costs outside of any bandwidth sharing. In the event the Companies are no longer under Formula Rate Plans, the rate treatment of decommissioning costs will be determined by subsequent Commission Order. The Companies and the Staff reserve the right to modify this procedure upon mutual agreement if circumstances warrant.

15. Except as stated herein and as set forth in prior Commission Orders, this Order, including the calculation methodology reflected in the Exhibits to this Order, shall have no precedential effect in any other proceedings involving issues similar to those resolved herein and shall be without prejudice to the right of any party to take any position on any such similar issue in future base rate proceedings, including Formula Rate Plan proceedings, or in other related regulatory proceedings or appeals.

16. This Order is effective immediately.

BY ORDER OF THE COMMISSION
BATON ROUGE, LOUISIANA

August 27, 2010

/S/ LAMBERT C. BOISSIERE, III
DISTRICT III
CHAIRMAN LAMBERT C. BOISSIERE, III

/S/ JAMES M. FIELD
DISTRICT II
VICE CHAIRMAN JAMES M. FIELD

/S/ FOSTER L. CAMPBELL
DISTRICT V
COMMISSIONER FOSTER L. CAMPBELL

/S/ ERIC F. SKRMETTA
DISTRICT I
COMMISSIONER ERIC F. SKRMETTA

EVE KAHAO GONZALEZ
SECRETARY

/S/ CLYDE C. HOLLOWAY
DISTRICT IV
COMMISSIONER CLYDE C. HOLLOWAY

ORDER NO. U-31237

EXHIBIT A

Entergy Louisiana, LLC
Waterford-3 Decommissioning Model
Revenue Requirement Summary
($000)

Line No	Year	Total Company (1)	LPSC Jurisdiction (2)	CNO Jurisdiction (3)
1	2010	5,947	5,831	116
2	2011	5,947	5,831	116
3	2012	5,947	5,831	116
4	2013	5,947	5,831	116
5	2014	5,947	5,831	116
6	2015	6,821	6,688	133
7	2016	6,821	6,688	133
8	2017	6,821	6,688	133
9	2018	6,821	6,688	133
10	2019	6,821	6,688	133
11	2020	7,731	7,580	151
12	2021	7,731	7,580	151
13	2022	7,731	7,580	151
14	2023	7,731	7,580	151
15	2024	7,731	7,580	151

Notes:
(1) See Exhibit A Page 2.
(2) Total Company * LPSC Production Demand Allocation Factor 98.05%.
(3) Total Company - LPSC Jurisdiction.

Entergy Louisiana, LLC
Waterford-3 Decommissioning Model
Revenue Requirement, Fund Balance and Expenditure Summary
($000)

Line No	Year	Total Company Revenue Rqmt. [1]	Tax Qualified [2]	Decomm. Expend. [4]
1	Beginning Balance		215,081	
2	2010	5,947	227,329	0
3	2011	5,947	246,951	0
4	2012	5,947	268,384	0
5	2013	5,947	291,400	0
6	2014	5,947	316,413	0
7	2015	6,821	344,050	0
8	2016	6,821	373,680	0
9	2017	6,821	405,077	0
10	2018	6,821	438,789	0
11	2019	6,821	474,814	0
12	2020	7,731	514,259	0
13	2021	7,731	556,427	0
14	2022	7,731	601,516	0
15	2023	7,731	647,991	0
16	2024	7,731	692,624	3,004
17	2025	8,867	656,328	85,183
18	2026	8,867	509,811	193,388
19	2027	8,867	344,370	203,929
20	2028	8,867	262,117	111,237
21	2029	8,867	170,727	115,850
22	2030	10,248	88,810	100,668
23	2031	-	44,001	49,090
24	2032	-	542	45,584
25	2033	-	0	552

Notes:

[1] The annual Revenue Requirement (5,947) is chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
[2] See Exhibit A Page 2.
[3] See Exhibit A Page 3.
[4] Non-Tax Qualified Trust Balance + Tax Qualified Trust Balance.
[5] See Exhibit A Page 4.

Entergy Louisiana, LLC
Waterford-3 Decommissioning Model
Tax Qualified Trust Detail
($000)

Line No	Year	Revenue Rqmt. [1]	Tax Qualified Trust: Earning Rate [2]	Transfer To Trust [3]	Earnings [4]	Mgmt. Fee [5]	Net Additions [6]	Decomm. Expend. [7]	Balance [8]	Qualifying Percent
1	Beginning Balance at 3/31/10								216,061	
2	2010	5,947	6.71%	3,076	9,407	215	12,268	0	227,329	100.00%
3	2011	5,947	5.95%	5,947	13,904	229	19,622	0	246,951	100.00%
4	2012	5,947	6.20%	5,947	15,733	246	21,433	0	268,384	100.00%
5	2013	5,947	6.29%	5,947	17,334	265	23,016	0	291,400	100.00%
6	2014	5,947	6.47%	5,947	19,351	285	25,013	0	316,413	100.00%
7	2015	6,821	6.50%	6,821	21,123	307	27,637	0	344,050	100.00%
8	2016	6,821	6.52%	6,821	23,020	331	29,510	0	373,560	100.00%
9	2017	6,821	6.54%	6,821	25,053	357	31,518	0	405,077	100.00%
10	2018	6,821	6.57%	6,821	27,275	384	33,712	0	438,789	100.00%
11	2019	6,821	6.59%	6,821	29,617	413	36,025	0	474,814	100.00%
12	2020	7,731	6.61%	7,731	32,159	446	39,446	0	514,259	100.00%
13	2021	7,731	6.63%	7,731	34,917	479	42,168	0	556,427	100.00%
14	2022	7,731	6.65%	7,731	37,876	516	45,089	0	601,516	100.00%
15	2023	7,731	6.39%	7,731	39,298	555	46,474	0	647,991	100.00%
16	2024	7,731	6.12%	7,731	40,500	594	47,637	3,004	692,624	100.00%
17	2025	8,867	5.75%	8,867	40,653	632	48,888	85,186	656,326	100.00%
18	2026	8,867	5.76%	8,867	38,604	601	46,870	193,385	509,811	100.00%
19	2027	8,867	5.77%	8,867	30,096	474	38,489	203,929	344,370	100.00%
20	2028	8,867	5.78%	8,867	20,448	331	28,984	111,237	262,117	100.00%
21	2029	8,867	5.79%	8,867	15,653	260	24,260	115,650	170,727	100.00%
22	2030	10,248	4.88%	10,248	8,683	181	18,749	100,866	88,610	100.00%
23	2031	0	4.88%	0	4,387	106	4,281	48,890	44,001	100.00%
24	2032	0	4.88%	0	2,173	67	2,106	45,564	542	100.00%
25	2033	0	4.88%	0	27	17	10	552	0	100.00%
								0		

Notes:

[1] The annual Revenue Requirement (5,947) is chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
[2] Projected after-tax earning rate.
[3] Revenue Requirement * Qualifying Percentage (100%).
[4] Prior Year Balance Compounded Semiannually At Current Year Earnings Rate + ½ Current Year Transfer * Current Year Earnings Rate.
[5] Calculated in accordance with fee schedules for manager and trustee fees and applicable tax rates. See Exhibit A Page 4.
[6] Transfer + Earnings - Management Fee.
[7] Assumes that decommissioning expenditures are made at year end. See Exhibit A Page 3.
[8] Prior Year Balance + Net Additions - Decommissioning Expenditures.

Entergy Louisiana, LLC
Waterford-3 Decommissioning Model
Decommissioning Expenditures
($000)

Line No	Year	CPIU [1]	Cum. CPIU	Cum. Nuclear Cost Esc. [2]	Decommissioning Expenditures Estimate [3]	Escalation. [4]
1	2008	N/A	N/A	1.0000	0	0
2	2009	N/A	1.000	1.0425	0	0
3	2010	1.0217	1.022	1.0868	0	0
4	2011	1.0222	1.045	1.1330	0	0
5	2012	1.0226	1.069	1.1812	0	0
6	2013	1.0231	1.094	1.2314	0	0
7	2014	1.0235	1.120	1.2837	0	0
8	2015	1.0240	1.147	1.3383	0	0
9	2016	1.0244	1.175	1.3952	0	0
10	2017	1.0249	1.204	1.4545	0	0
11	2018	1.0254	1.235	1.5163	0	0
12	2019	1.0258	1.267	1.5807	0	0
13	2020	1.0263	1.300	1.6479	0	0
14	2021	1.0267	1.335	1.7179	0	0
15	2022	1.0272	1.371	1.7909	0	0
16	2023	1.0277	1.409	1.8670	0	0
17	2024	1.0282	1.449	1.9463	1,543	3,004
18	2025	1.0287	1.491	2.0290	41,983	85,183
19	2026	1.0293	1.535	2.1152	91,428	193,388
20	2027	1.0298	1.581	2.2051	92,481	203,929
21	2028	1.0304	1.629	2.2988	48,389	111,237
22	2029	1.0310	1.679	2.3965	48,258	115,650
23	2030	1.0261	1.723	2.4984	40,292	100,666
24	2031	1.0261	1.768	2.6045	18,847	49,090
25	2032	1.0261	1.814	2.7153	16,781	45,564
26	2033	1.0261	1.861	2.8307	195	552
27	Total Expenditures				400,197	908,264

Notes:

[1] CPIU per Global Insight Forecast for 2010 - 2029; the 2.61% for 2030-2034 is the average for 2010 to 2029.

[2] Cumulative Nuclear Cost Escalator at 4.25% per year.

[3] Decommissioning Cost Estimate per 2008 NRC Minimum (2008 dollars).

[4] Decommissioning Cost Estimate * Cumulative Nuclear Cost Escalator.

Entergy Louisiana, LLC
Waterford-3 Decommissioning Model
Fees and Other Data ($ in Thousands)

Tax Qualified Trustee and Investment Manager Fee Schedules

TQ Annual Fees 19.500

	Breakpoints ($000)	Basis Points	Adder ($ 000) Fixed [1]	Adder ($ 000) Cumulative
TQ Trustee Fees	0	1.00		
TQ Manager Fee	0	22.70		
	5,000	17.70	11.350	11.350
	8,000	16.90	5.310	16.660
	16,000	15.70	13.520	30.180
	20,000	9.50	6.280	36.460

Miscellaneous Input Data

Bad Debt Rate [2]	0.00%	Nuclear Cost Escalator [7]	4.25%
Revision Year [3]	2010	Jurisdictional Allocation Factor [8]	100.00%
Cost Estimate Year [4]	2008	TQ Fund Federal Tax Rate [5]	20.00%
Composite Tax Rate [5]	38.48%	End of Funding Period	12/31/2030
ELL Funding Interest [6]	100.00%		

Notes:

[1] Calculated as in the following example: 6.280 = 15.70bp * (20,000 - 16,000) / 10,000
For balance of $25M: TQ Management Fee = 41.210 = 36.460 + (9.50bp * (25,000 - 20,000)) / 10,000.
[2] Bad Debts are assumed to be zero.
[3] First year showing impact of revised decommissioning revenue requirements.
[4] Year upon which the decommissioning cost estimate is based.
[5] State Income Tax Rate is 8.00%, effective rate is 5.35%.
[6] Entergy Louisiana, LLC, funding interest in Waterford-3 is 100%.
[7] Nuclear Cost Escalator is 4 25%
[8] Production demand allocator for Louisiana Retail.

ORDER NO. U-31237

EXHIBIT B

5-Year Step

Entergy Gulf States Louisiana, LLC
River Bend Decommissioning Model
Louisiana Retail
Non-Tax Qualified Trust Detail
($000)

			Non-Tax Qualified Trust							
Line No	Year	Revenue Rqmt. [1]	Earning Rate [2]	Transfer To Trust [3]	Earnings [4]	Mgmt. Fee [5]	Net Additions [6]	Decomm. Expend. [7]	Balance [8]	NTQ % to contribute
1	Beginning Balance at 3/31/10								14,886	
2	2010	7,843	6.45%	0	822	17	805	0	15,691	0.00%
3	2011	7,843	5.54%	0	881	18	864	0	16,556	0.00%
4	2012	7,843	5.80%	0	974	19	956	0	17,511	0.00%
5	2013	7,843	5.87%	0	1,043	19	1,024	0	18,534	0.00%
6	2014	7,843	5.97%	0	1,123	20	1,103	0	19,637	0.00%
7	2015	8,996	5.99%	0	1,194	21	1,173	0	20,809	0.00%
8	2016	8,996	6.01%	0	1,269	22	1,247	0	22,057	0.00%
9	2017	8,996	6.02%	0	1,348	23	1,324	0	23,381	0.00%
10	2018	8,996	6.04%	0	1,434	25	1,409	0	24,790	0.00%
11	2019	8,996	6.06%	0	1,526	28	1,499	0	26,289	0.00%
12	2020	10,195	6.08%	0	1,623	27	1,595	0	27,884	0.00%
13	2021	10,195	6.09%	0	1,724	29	1,695	0	29,579	0.00%
14	2022	10,195	6.02%	0	1,807	30	1,777	0	31,356	0.00%
15	2023	10,195	5.97%	0	1,900	32	1,868	0	33,225	0.00%
16	2024	10,195	5.25%	0	1,767	33	1,734	0	34,958	0.00%
17	2025	11,693	5.10%	0	1,806	35	1,771	12,408	24,321	0.00%
18	2026	11,693	4.89%	0	1,204	25	1,178	25,499	0	0.00%
19	2027	11,693	4.89%	0	0	0	0	0	0	0.00%
20	2028	11,693	4.89%	0	0	0	0	0	0	0.00%
21	2029	11,693	4.89%	0	0	0	0	0	0	0.00%
22	2030	13,513	4.89%	0	0	0	0	0	0	0.00%
23	2031	0	4.51%	0	0	0	0	0	0	0.00%
24	2032	0	4.51%	0	0	0	0	0	0	0.00%
25	2033	0	4.51%	0	0	0	0	0	0	0.00%
26	2034	0	4.51%	0	0	0	0	0	0	0.00%

Notes:

[1] See Exhibit B Page 1.
[2] Projected after-tax earning rate.
[3] Revenue Requirement * (1 - Qualifying Percentage).
[4] Prior Year Balance Compounded Semiannually at Current Year Earnings Rate + ½ Current Year Transfer * Current Year Earnings Rate.
[5] Calculated on average balance (Avg. Bal = Prior Yr. Bal. + ½ (Transfers + Earnings)) in accordance with the fee schedules for trustees and managers and applicable tax rates. See Exhibit B Page 5.
[6] Transfer + Earnings - Management Fee.
[7] Assumes that the Non-Tax Qualified Balance is utilized to pay the decommissioning costs before the TQ Balance. See Exhibit B Page 4 for the total.
[8] Prior Year Balance + Net Additions - Decommissioning Expenditures.

Entergy Gulf States Louisiana, LLC
River Bend Decommissioning Model
Louisiana Retail
Tax Qualified Trust Detail
($000)

			Tax Qualified Trust							
Line No	Year	Revenue Rqmt. [1]	Earning Rate [2]	Transfer To Trust [3]	Earnings [4]	Mgmt. Fee [5]	Net Additions [6]	Decomm. Expend. [7]	Balance [8]	Qualifying Percent
1	Beginning Balance at 3/31/10								32,940	
2	2010	7,843	5.50%	2,614	1,431	31	4,014	0	36,954	100.00%
3	2011	7,843	5.83%	7,843	2,414	36	10,221	0	47,176	100.00%
4	2012	7,843	6.20%	7,843	3,213	42	11,014	0	58,189	100.00%
5	2013	7,843	6.29%	7,843	3,964	49	11,758	0	69,947	100.00%
6	2014	7,843	6.47%	7,843	4,852	57	12,638	0	82,585	100.00%
7	2015	8,998	6.50%	8,998	5,748	65	14,678	0	97,263	100.00%
8	2016	8,998	6.52%	8,998	6,738	75	15,659	0	112,922	100.00%
9	2017	8,998	6.54%	8,998	7,800	86	16,711	0	129,633	100.00%
10	2018	8,998	6.57%	8,998	8,952	98	17,852	0	147,485	100.00%
11	2019	8,998	6.59%	8,998	10,178	107	19,064	0	166,549	100.00%
12	2020	10,195	6.61%	10,195	11,528	120	21,604	0	188,153	100.00%
13	2021	10,195	6.63%	10,195	13,019	133	23,081	0	211,234	100.00%
14	2022	10,195	6.65%	10,195	14,620	148	24,667	0	235,901	100.00%
15	2023	10,195	6.39%	10,195	15,641	164	25,672	0	261,573	100.00%
16	2024	10,195	6.12%	10,195	16,565	180	26,581	0	288,154	100.00%
17	2025	11,693	5.75%	11,693	17,143	197	28,639	0	316,793	100.00%
18	2026	11,693	5.76%	11,693	18,847	215	30,325	23,543	323,575	100.00%
19	2027	11,693	5.76%	11,693	19,243	220	30,717	103,721	250,570	100.00%
20	2028	11,693	5.76%	11,693	14,977	173	26,498	97,774	179,294	100.00%
21	2029	11,693	5.76%	11,693	10,813	128	22,378	67,507	134,166	100.00%
22	2030	13,513	5.76%	13,513	8,228	100	21,642	70,378	85,430	100.00%
23	2031	0	4.88%	0	4,220	64	4,156	50,108	39,478	100.00%
24	2032	0	4.88%	0	1,950	35	1,916	24,761	16,632	100.00%
25	2033	0	4.88%	0	822	20	801	15,917	1,516	100.00%
26	2034	0	4.88%	0	75	7	67	1,584	0	100.00%

Notes:

[1] See Exhibit B Page 1.
[2] Projected after-tax earning rate.
[3] Revenue Requirement * Qualifying Percentage.
[4] Prior Year Balance Compounded Semiannually at Current Year Earnings Rate + ½ Current Year Transfer * Current Year Earnings Rate.
[5] Calculated on average balance (Avg. Bal = Prior Yr. Bal. + ½ (Transfers + Earnings)) in accordance with the fee schedules for trustees and managers and applicable tax rates. See Exhibit B Page 5.
[6] Transfer + Earnings - Management Fee.
[7] Assumes that the Non-Tax Qualified Balance is utilized to pay the decommissioning costs before the TQ Balance. See Exhibit B Page 4.
[8] Prior Year Balance + Net Additions - Decommissioning Expenditures.

Entergy Gulf States Louisiana, LLC
River Bend Decommissioning Model -
Louisiana Retail
Decommissioning Expenditures
($000)

					Decommissioning Expenditures			
Line No	Year	CPIU [1]	Cum. CPIU	Cum. Nuclear Cost Esc. [2]	Regulated 70% [3]	EGSL Portion of Regulated 70% [4]	LA Retail [5]	LA Retail - Escalated [6]
1	2008	N/A	N/A	1.0000	0	0	0	0
2	2009	N/A	1.000	1.0425	0	0	0	0
3	2010	1.0217	1.022	1.0868	0	0	0	0
4	2011	1.0222	1.045	1.1330	0	0	0	0
5	2012	1.0228	1.069	1.1812	0	0	0	0
6	2013	1.0231	1.094	1.2314	0	0	0	0
7	2014	1.0238	1.120	1.2837	0	0	0	0
8	2015	1.0240	1.147	1.3383	0	0	0	0
9	2016	1.0244	1.175	1.3952	0	0	0	0
10	2017	1.0249	1.204	1.4545	0	0	0	0
11	2018	1.0254	1.235	1.5163	0	0	0	0
12	2019	1.0258	1.267	1.5807	0	0	0	0
13	2020	1.0263	1.300	1.6479	0	0	0	0
14	2021	1.0267	1.336	1.7179	0	0	0	0
15	2022	1.0272	1.371	1.7909	0	0	0	0
16	2023	1.0277	1.409	1.8670	0	0	0	0
17	2024	1.0282	1.449	1.9463	0	0	0	0
18	2025	1.0287	1.491	2.0290	11,043	6,350	6,115	12,408
19	2026	1.0293	1.535	2.1152	41,868	24,074	23,186	49,042
20	2027	1.0298	1.581	2.2051	84,938	48,839	47,037	103,721
21	2028	1.0304	1.629	2.2988	76,804	44,162	42,532	97,774
22	2029	1.0310	1.679	2.3965	50,867	29,249	28,169	67,507
23	2030	1.0261	1.723	2.4984	50,867	29,249	28,169	70,378
24	2031	1.0261	1.768	2.6046	34,740	19,976	19,238	50,108
25	2032	1.0261	1.814	2.7163	16,467	9,469	9,119	24,781
26	2033	1.0261	1.861	2.8307	10,154	5,839	5,623	15,917
27	2034	1.0261	1.910	2.9510	969	557	537	1,584
28	Total Expenditures				378,717	217,762	209,726	493,200

Notes:

[1] CPIU per Global Insight Forecast for 2010 - 2029; the 2.61% for 2030-2034 is the average for 2010 to 2029.

[2] Cumulative Nuclear Cost Escalator at 4.25% per year.

[3] Decommissioning Cost Estimate per 2008 NRC Minimum (2008 dollars).

*[4] Decommissioning Cost Estimate * Entergy Gulf States Funding Interest (100%) * 1-TX Retail Allocation per PPA with ETI (42.5%).*

*[5] EGSL Funding Share of Cost Estimate * (Louisiana Retail Production Demand Allocator (96.3094%)*

*[6] Louisiana Retail * Cumulative Nuclear Cost Escalator.*

Entergy Gulf States Louisiana, LLC
River Bend Decommissioning Model - Louisiana
Fees and Other Data ($ in Thousands)

Tax Qualified Trustee and Investment Manager Fee Schedules (1)

TQ Annual Fees 6,328

	Breakpoints ($000)	Basis Points	Adder ($ 000) Fixed [1]	Adder ($ 000) Cumulative
TQ Manager & Asset Based Trustee Fee	0	18.50		
	1,333	17.50	2.467	2.467
	2,083	15.00	1.313	3.779
	2,667	13.50	0.875	4.654
	3,333	12.00	0.900	5.554
	4,167	9.50	1.000	6.554
	12,333	7.00	7.758	14.312

Non-Tax Qualified Trustee and Investment Manager Fee Schedules

NTQ Annual Fees 5.000

	Breakpoints ($000)	Basis Points	Adder ($ 000) Fixed [1]	Adder ($ 000) Cumulative
NTQ Manager & Asset Based Trustee Fee	0	18.50		
	1,000	17.50	1.850	1.850
	1,560	15.00	0.980	2.830
	2,000	13.50	0.660	3.490
	2,500	12.00	0.675	4.165
	3,130	9.50	0.756	4.921
	9,250	7.00	5.814	10.735

Miscellaneous Input Data

Bad Debt Rate [2]	0.00%	Nuclear Cost Escalator [7]	4.25%
Revision Year [3]	2010	EGSL - LA Retail [8]	98.3094%
Cost Estimate Year [4]	2008	TQ Fund Federal Tax Rate 96 & After [9]	20.00%
Composite Effective Tax Rate [5]	38.48%	End of Funding Period	12/31/2030
Entergy Gulf States Ownership Share [6]	100.00%		

Notes:

[1] Calculated as in the following example:
For balance of $10M: TQ Management Fee = 9.837 = 6.554 + (7.0bp * (10,000 - 4,167)) / 10,000.
[2] Bad Debts handled in Cost of Service Study.
[3] First year showing impact of revised decommissioning revenue requirements
[4] Year upon which the decommissioning cost estimate is based.
[5] Louisiana Income Tax Rate is 8.0%, however, in Louisiana Federal Income taxes are deductible, therefore the effective Louisiana rate is 5.35%. The effective Federal Rate is 33.13% resulting in a Composite Rate of 38.48%.
[6] Cost Estimate provided for Regulated Portion (70%) so EGSL funding interest is 100%.
[7] Nuclear Cost Escalator is 4.25%
[8] Per the 2009 FRP based on 12/31/08 Test Year. This is LA Retail portion of EGSL.
[9] Effective Federal Tax Rates for Qualified Trusts. These trusts do not pay state taxes.

Attachment 3-E
(16 pages)

PUCT Order in Docket No. 37744

PUC DOCKET NO. 37744
SOAH DOCKET NO. 473-10-1962

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES AND RECONCILE FUEL COSTS	**§ § § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the application of Entergy Texas, Inc. (ETI) for authority to change rates and reconcile fuel costs. ETI, Commission Staff, the Office of Public Utility Counsel (OPUC), the Steering Committee of Cities Served by ETI (Cities),[1] Texas Industrial Energy Consumers (TIEC), The Kroger Company (Kroger), and Wal-Mart Stores Texas, LLC and Sam's East, Inc. (collectively Wal-Mart), through their duly authorized representatives entered into and filed a stipulation and settlement agreement that resolves all of the issues in this proceeding except the issues related to ETI's proposal for competitive generation service. Cottonwood Energy, L.P. and the State of Texas agencies and institutions of higher education (State Agencies) did not join but do not oppose the stipulation.

The Commission severed the competitive generation service issues into Docket No. 38951[2] in Order No. 14.

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

[1] Steering Committee of Cities is comprised of the Cities of Anahuac, Beaumont, Bridge City, Cleveland, Conroe, Groves, Houston, Huntsville, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Pinehurst, Port Arthur, Port Neches, Rose City, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, and West Orange.

[2] *Application of Entergy Texas, Inc. for Approval of Competitive Generation Service Tariff (Issues Severed From Docket No. 37744)*, Docket No. 38951.

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I. Findings of Fact

Procedural History

1. On December 30, 2009, ETI filed an application requesting approval of (1) base rate tariffs and riders designed to collect an overall revenue requirement of $1,758.4 million, which includes a total non-fuel retail revenue requirement of $838.3 million (base rate revenues of $486 million plus revenue from riders of $352.3 million); (2) a set of proposed tariff schedules presented in the Electric Utility Rate Filing Package for Generating Utilities (RFP) accompanying ETI's application; (3) a request for final reconciliation of ETI's fuel and purchased power costs for the reconciliation period from April 1, 2007 to June 30, 2009; and (4) certain waivers to the instructions in RFP Schedule V accompanying ETI's application.

2. The 12-month test year employed in ETI's filing ended on June 30, 2009.

3. ETI provided notice by publication for four consecutive weeks before the effective date of the proposed rate change in newspapers having general circulation in each county of ETI's Texas service territory. ETI also mailed notice of its proposed rate change to all of its customers. Additionally, ETI timely served notice of its statement of intent to change rates on all municipalities retaining original jurisdiction over its rates and services. ETI also published one-time supplemental notice by publication in newspapers and by bill insert.

4. The following parties were granted intervenor status in this docket: OPUC, Cities, Cottonwood, Kroger, State Agencies, TIEC, and Wal-Mart. Commission Staff was also a participant in this docket.

5. On January 4, 2010, the Commission referred this case to the State Office of Administrative Hearings (SOAH) for processing.

6. On February 19, 2010, the ALJs issued Order No. 3, which approved an agreement between ETI, Staff, Cities, State Agencies, OPUC, TIEC, Kroger, and Wal-Mart, to (1) establish an interim rate increase of $17.5 million annually above ETI's then-existing base rates commencing with service rendered on and after May 1, 2010 subject to true-up and refund for service rendered prior to September 13, 2010 to the extent final

overall rates established by the Commission amounted to less than a $17.5 million rate increase; (2) extend the jurisdictional deadline by which the Commission must issue a final order on the Company's rate request from July 5, 2010 to November 1, 2010; (3) establish a September 13, 2010 effective date for rates such that, notwithstanding the extension of the jurisdictional deadline, the final overall rates established by the Commission would relate back to service rendered on and after September 13, 2010; (4) require ETI to publish supplemental notice, once in newspapers and by a bill insert, setting forth the effect of its proposed rate change in terms of the percentage increase in non-fuel revenues; and (5) establish a procedural schedule and discovery deadlines for this proceeding. Order No. 3 also granted Mr. Kurt Boehm's motion for admission pro hac vice as counsel for Kroger and ETI's February 3 and February 11, 2010 petitions for review of cities' ordinances and motions to consolidate with respect to the rate decisions adopted by the Cities of Ames, Anderson, Bedias, Bevil Oaks, Bremond, Caldwell, Calvert, Chester, China, Colmesneil, Corrigan, Cut and Shoot, Daisetta, Dayton, Devers, Franklin, Groveton, Hardin, Hearne, Iola, Kosse, Kountze, Liberty, Lumberton, Madisonville, Midway, New Waverly, Normangee, Nome, Patton Village, Plum Grove, Riverside, Rose Hill Acres, Somerville, Taylor Landing, Todd Mission, Trinity, and Woodville.

7. On June 14, 2010, the ALJs issued Order No. 6 granting Staff's June 1, 2010 motion and severing rate case expense issues to Docket No. 38346.[3] Through Order No. 6, the ALJs also granted ETI's March 12, April 29, and May 17 petitions for review and motions to consolidate with respect to the rate decisions adopted by the Cities of Anahuac, Beaumont, Bridge City, Cleveland, Conroe, Groves, Houston, Huntsville, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Panorama Village, Pine Forest, Pinehurst, Port Arthur, Port Neches, Roman Forest, Rose City, Shenandoah, Shepard, Silsbee, Sour Lake, Splendora, Vidor, West Orange, Willis, Woodbranch Village, and Woodloch.

[3] *Application of Entergy Texas, Inc. for Rate Case Expenses Severed from PUC Docket No. 37744*, Docket No. 38346.

8. The hearing on the merits commenced on July 13, 2010 and was immediately recessed in order to facilitate settlement negotiations. The hearing was again convened on July 15, 2010, at which time the signatories announced their intent to continue settlement discussions to resolve all issues related to the Company's application with the exception of those related to ETI's proposal for competitive generation service (CGS) and associated riders.

9. On August 6, 2010, the signatories submitted the stipulation resolving all outstanding issues regarding the Company's application with the exception of those related to ETI's CGS proposal. Under the stipulation, ETI will be allowed to implement base rate tariffs and riders designed to collect an overall revenue requirement of $1,614.9 million,[4] which includes a total non-fuel retail revenue requirement of $694.9 million (base rate revenues of $599 million plus revenue from riders of $95.9 million). The signatories also submitted, on August 6, 2010, an agreed motion to revise interim rates and to consolidate the severed rate-case expense docket. The interim rates requested in the agreed motion mirrored the final rates proposed for Commission approval in the stipulation. The agreed motion further requested that the ALJs consolidate with the instant proceeding Docket No. 38346, related to severed Docket No. 37744 rate case expense issues, and admit the parties' pre-filed exhibits into evidence.

10. On July 16 and July 20, 2010, the ALJs held the hearing on the merits with respect to ETI's CGS proposal.

11. On August 9, 2010, the ALJs issued Order No. 12, granting approval of revised interim rates for usage on and after August 15, 2010.

12. On October 5, 2010, the ALJs issued a proposal for decision regarding issues related to ETI's CGS proposal.

13. On October 5, 2010, the ALJs issued Order No. 13, ordering the consolidation of Docket No. 38346, related to severed rate-case expense issues, into the instant proceeding,

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[4] This figure includes fuel at test year prices. If current fuel prices are substituted for test year fuel prices, the overall revenue requirement figure would be $1,504.0 million.

admitting evidence, and returning this docket to the Commission consistent with the agreed motion filed on August 6, 2010.

14. The Commission considered this Docket at the November 10, 2010 and December 1, 2010 open meetings.

15. On November 30, 2010 ETI filed an unopposed motion to sever the competitive CGS issues from the settled issues in this docket. The Commission granted the motion at the December 1, 2010 open meeting and the Commission's decision was memorialized in Order No. 14 issued on December 3, 2010. The CGS issues were severed into Docket No. 38951 in Order No. 14.

Description of the stipulation and Settlement Agreement

16. The signatories to the settlement stipulated that ETI should be allowed to implement an initial overall increase in base-rate revenues of $59 million for usage on and after August 15, 2010. The signatories further stipulated that they would request approval of interim rates by the ALJs presiding or by the Commission, as necessary, to ensure timely implementation of this initial rate increase. The signatories further stipulated that ETI should be allowed to implement an additional overall increase in base-rate revenues of $9 million on an annualized basis effective for bills rendered on and after May 2, 2011, the first billing cycle for the revenue month of May.

17. The signatories agreed that ETI's authorized return on equity shall be 10.125% and its weighted average cost of capital shall be 8.5209%.

18. The signatories stipulated that the amount of rate increase authorized under finding of fact 16 includes rate-case expenses and contemplates their full amortization in 2010, and that this amount constitutes the full and final recovery of all rate-case expenses relating to Docket No. 37744.

19. The signatories stipulated to the amount of transmission and distribution invested capital by function as of June 30, 2009 as set out in attachment 1 to the stipulation.

20. The signatories stipulated that the Company's proposed purchased-power recovery rider will not be approved in this docket, and purchased capacity costs will be included in base rates.

21. The signatories stipulated that the Company's proposed transmission cost recovery factor (TCRF) will not be approved in this docket. The signatories stipulated to the baseline values as shown in attachment 2 to the stipulation to be used in the Company's request, if any, for a TCRF in a separate proceeding.

22. The signatories agreed that ETI's proposed cost-of-service adjustment rider and formula rate plan will not be approved in this docket.

23. The signatories stipulated that the Company's proposed renewable-energy-credit rider will not be approved in this docket, and the Company's renewable-energy-credit costs shall be recovered in base rates. The signatories further stipulated that a transmission customer that opts out pursuant to P.U.C. SUBST. R. 25.173(j) shall receive a credit that offsets the amount of renewable-energy-credit costs that are recovered in base rates from the transmission customer.

24. The signatories agreed that ETI's proposed remote-communications-link rider should be approved as filed by the Company.

25. The signatories agreed that ETI's proposed market-valued-energy-reduction service rider will not be approved in this docket.

26. The signatories reached the following specific agreements regarding rate design as a part of the overall resolution of this docket:

    a. Rate Schedule IS. Rate Schedule IS will be opened to new business. In the Company's next base-rate case, the amount of interruptible credits recoverable from Texas retail customers shall be limited to an increase of $1 million more than the amount requested in this docket (or a total of $6.8 million); provided, however, that in the next rate case, the Company may request an exception to this limitation upon a showing that the test-year credit amount in excess of the $6.8 million cap is both cost effective and necessary to meet the Company's generation reserve margin requirement. The signatories further agreed that the

Company will not offer additional interruptible service if the availability of total interruptible service supplied by the Company under all interruptible service riders exceeds 5% of the projected aggregate Company peak demand unless the additional level of interruptible service offered in excess of the 5% cap is both cost effective and necessary to meet the Company's generation reserve margin requirement. To the extent that the credit amount or participation level exceeds the limitations described in this paragraph and the Company includes test-year credits over the $6.8 million credit-amount cap or additional participation in excess of the 5% participation-level cap in its next rate case, the Company shall have the burden to prove whether those test-year credits or participation levels meet the standards established in this paragraph for inclusion in the test year. The standards in this paragraph are in addition to any requirements in PURA for inclusion of costs in rates. The signatories further agreed to the Schedule IS revisions shown on attachment 3 to the stipulation.

b. Rate Schedule IHE. The signatories agreed that no change shall be made to rate schedule IHE in this docket.

c. Lighting Class Rates. The signatories stipulated that the language under the paragraph relating to rate group C in rate schedule SHL will be revised to reflect that, where the Company agrees to install facilities other than its standard street light fixture and lamp as provided under Rate Group A, a lump sum payment will be required, based upon the installed cost of all facilities excluding the cost of the standard street light fixture and lamp, and the customer will be billed under rate group A.

e. Electric Extension Policy. The signatories agreed to the line-extension terms and conditions as reflected in attachment 4 to the stipulation.

f. Life-of-Contract Demand Ratchet. The signatories agreed that the life-of-contract demand ratchet provision in rate schedules Large Industrial Power Service, Large Industrial Power Service-Time of Day, General Service, General Service-Time of Day, Large General Service, and Large General Service-Time of

Day shall be excluded from rate schedules in ETI's next rate case. The signatories further stipulated that the foregoing rate schedules will be revised so that the life-of-contract demand ratchet provision shall not be applicable to new customers and shall not exceed the level in effect on August 15, 2010 for existing customers.

g. Residential Customer Charge. The signatories agreed that the residential customer charge shall be increased to $5.00.

h. Non-Sufficient Funds Charge. The signatories agreed that the non-sufficient funds charge shall be increased to $15.00.

27. The signatories agreed to the class cost allocation set forth in attachment 5 to the stipulation.

28. The signatories stipulated that the appropriate allocation between ETI's wholesale and retail jurisdictions of baseline values and costs to be included in a TCRF is to be addressed in the proceeding, if any, in which ETI seeks approval of a TCRF.

29. The signatories stipulated that no party waives its right to address in any subsequent proceeding the appropriate treatment for Texas retail ratemaking purposes of power sales between ETI and Entergy Gulf States Louisiana, L.L.C.

30. The signatories reached the following specific agreements regarding fuel-related issues as part of the overall resolution of this docket:

a. Agreed Fuel Disallowance. The Company stipulated to a fuel disallowance of $3.25 million not associated with any particular issue raised by the signatories. The disallowance will be allocated pro rata with interest over each month of the reconciliation period and reflected in the refund in Docket No. 38403.[5] The signatories stipulated that the Company's fuel costs shall be finally reconciled for the reconciliation period of April 1, 2007 through June 30, 2009.

b. Rider IPCR. The signatories agreed that ETI's eligible Rider IPCR costs for the

[5] *Application of Entergy Texas, Inc. to Implement an Interim Fuel Refund*, Docket No. 38403, Order (Sept. 16, 2010).

period April 1, 2007 through the date the rider terminated shall be finally reconciled with a disallowance of $300,000. The signatories further agreed that the under-recovered balance of Rider IPCR costs shall be booked as fuel expense in the month in which the Commission issues an order adopting the stipulation; provided, however, that the under-recovered balance shall be allocated to customer classes using A&E4CP.

c. Rough Production Cost Equalization (RPCE) Payments. The signatories agreed that ETI will credit an additional $18.6 million to Texas fuel-factor customers, which the signatories stipulated represents the remaining portion of RPCE payments ETI received in 2007 that were at issue in Docket No. 35269.[6] The RPCE credit shall be allocated to rate classes based on loss-adjusted kilowatt hours at plant for calendar year 2006. For customers in the Large Industrial Power Service rate class, the credit will be refunded based on the customer's actual kWh usage during the billing months of January 2006 through December 2006. Upon issuance of a final order approving the stipulation, the RPCEs shall be credited to customers as a separate one-month bill credit in the same form as the RPCEA Rider last approved in Docket No. 38098.[7] ETI agreed that it will terminate all appeals related to Docket No. 35269.

31. The signatories agreed that ETI will continue its accrual of storm-cost reserves at the level of $3.65 million annually and that this amount shall be subsumed in the base-rate revenue increase described in finding of fact 16 above.

32. The signatories agreed that ETI shall maintain River Bend depreciation rates at current levels, *i.e.*, based on a 60-year life. River Bend decommissioning costs will be set at $2,019,000 annually, which is based upon a labor-factor escalation rate of 1.67%, an energy-factor escalation rate of 0.25%, and a waste-burial-factor-escalation rate of

[6] *Compliance Filing of Entergy Texas, Inc. Regarding Jurisdictional Allocation of 2007 System Agreement Payments*, Docket No. 35269, Order (Jan. 7, 2009).

[7] *Application of Entergy Texas, Inc. for Authority to Implement New RPCEA Rate*, Docket No. 38098, Order (July 1, 2010).

1.71%, resulting in an overall escalation rate of 3.62%, and net investment yields as follows:

Nuclear-Decommissioning-Trust Projected Returns

	Tax-Qualified Investments	Non-Tax-Qualified Investment
2010	5.475%	5.057%
2011	5.837%	5.236%
2012	6.306%	5.567%
2013	6.304%	5.607%
2014	6.481%	5.896%
2015	6.493%	5.909%
2016	6.412%	5.826%
2017	6.412%	5.830%
2018	6.364%	5.790%
2019	6.316%	5.748%
2020	6.268%	5.712%
2021	6.220%	5.670%
2022	2.503%	5.458%
2023	5.817%	5.055%
2024	5.382%	4.628%
2025	5.036%	4.516%
2026-2034	4.920%	4.409%

33. The signatories stipulated that the Company's depreciation rates for non-River Bend production plant, transmission, distribution, and general plant will remain at current levels and the Company will maintain its accounting records on a prospective basis for purposes of depreciation accrual, depreciation reserve, retirements, additions, salvage, and cost of removal by FERC account.

Consistency of the Agreement with PURA and the Commission Requirements

34. Considered in light of (1) the pre-filed testimony by the parties entered into evidence and (2) the additional evidence and testimony admitted during the course of the hearing on the merits on the Company's application, the stipulation is the result of compromise from each signatory, and these efforts, as well as the overall result of the stipulation viewed in light of the record evidence as a whole, support the reasonableness and benefits of the terms of the stipulation.

35. The evidence addressed in finding of fact 34 demonstrates that the rates, terms, and conditions resulting from the stipulation are just and reasonable and consistent with the public interest.

36. The total level of the Texas retail revenue requirement contemplated by the stipulation will allow ETI the opportunity to earn a reasonable return over and above its reasonable and necessary operating expense.

37. The stipulated revenue requirement is consistent with applicable provisions of PURA chapter 36 and the Commission's rules.

38. To the extent that affiliate costs are included in the stipulated revenue requirement and fuel expense, they are reasonable and necessary for each class of affiliate costs presented in ETI's application.

39. To the extent that affiliate costs are included in the stipulated revenue requirement and fuel expense, the price charged to ETI is not higher than the prices charged by the supplying affiliate for the same item or class of items to its other affiliates or divisions, or a non-affiliated person within the same market area or having the same market conditions.

40. The retail revenue requirement in the stipulation does not include any expenses prohibited from recovery under PURA.

41. A return on equity of 10.125% and a weighted average cost of capital of 8.5209% for ETI should be adopted consistent with the stipulation.

42. The agreed rate-design provisions and terms and conditions of service included in the stipulation are just and reasonable.

43. The treatment of rate-case expenses described in the stipulation is reasonable.

44. The Company's proposed remote-communications-link rider as filed by the Company is reasonable.

45. The depreciation rates agreed to in the stipulation are just and reasonable.

46. The recovery of $2,019,000 annually for decommissioning costs of nuclear production assets based on the factors agreed to in the stipulation is reasonable.

47. A $3.65 million annual storm cost accrual is reasonable.

48. The class allocation methodologies described in the stipulation are just and reasonable.

49. The fuel and IPCR-related provisions of the stipulation are reasonable.

II. Conclusions of Law

1. ETI is a public utility as that term is defined in PURA § 11.004(1) and an electric utility as that term is defined in PURA § 31.002(6).

2. The Commission exercises regulatory authority over ETI and jurisdiction over the subject matter of this application pursuant to PURA §§ 14.001, 32.001, 32.101, 33.002, 33.051, 36.001–.111, 36.203, 39.452, and 39.455.

3. SOAH has jurisdiction over matters related to the conduct of the hearing and the preparation of a proposal for decision in this docket, pursuant to PURA § 14.053 and TEX. GOV'T CODE ANN. § 2003.049.

4. This docket was processed in accordance with the requirements of PURA, the Texas Administrative Procedure Act,[8] and Commission rules.

5. ETI provided notice of its application in compliance with PURA § 36.103, P.U.C. PROC. R. 22.51(a), and P.U.C. SUBST. R. 25.235(b)(1)-(3).

6. This docket contains no remaining contested issues of fact or law.

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

8. ETI has properly accounted for the amount of fuel and IPCR-related revenues collected pursuant to the fuel factor and Rider IPCR.

[8] TEX. GOV'T CODE ANN. Chapter 2001 (Vernon 2007 and Supp. 2009).

9. The revenue requirement, cost allocation, revenue distribution, and rate design implementing the stipulation result in rates that are just and reasonable, comply with the ratemaking provisions in PURA, and are not unreasonably discriminatory, preferential, or prejudicial.

10. Based on the evidence in this docket, the overall total invested capital through the end of the test year meets the requirement in PURA § 36.053(a) that electric utility rates be based on the original cost, less depreciation, of property used by and useful to the utility in providing service.

11. ETI has met its burden of proof in demonstrating that it is entitled to the level of retail base rate and rider revenue set out in the stipulation.

12. ETI has met its burden of proof in demonstrating that the rates resulting from the stipulation are just and reasonable, and consistent with PURA.

III. Ordering Paragraphs

1. ETI's application seeking authority to change its rates; reconcile its fuel and purchased power costs for the Reconciliation Period from April 1, 2007 to June 30, 2009; and for other related relief is approved consistent with the above findings of fact and conclusions of law.

2. Rates, terms, and conditions consistent with the stipulation are approved.

3. The tariffs and riders consistent with the stipulation are approved for the initial and second step rate increases.

4. ETI's request for waivers of RFP instructions (RFP Schedule V) is granted.

5. ETI shall adjust decommissioning expense related to the River Bend Nuclear Generating Station consistent with the terms of this Order.

6. Neither the stipulation and settlement agreement nor this Order constitutes the Commission's agreement with, or consent to, the manner in which ETI, or any entity affiliated with ETI, has interacted with any decommissioning trust to which ETI or its ratepayers have made contributions or provided funds. Furthermore, this Order in no

way constitutes a waiver or release of any conduct, whether or not such conduct occurred before the date of this Order, that may constitute a violation of any provision of state law, including, without limitation, the rules and regulations of this Commission relating to nuclear decommissioning trust funds; or prevents the Staff of the Commission from opening an investigation and taking enforcement action relating to violations of such rules and regulations.

7. Nothing contained in this Order constitutes the consent or approval, explicit or implied, of any modification, amendment or clarification of any power purchase agreement between ETI and any other Entergy entity relating to the River Bend Station. Without limiting the foregoing, nothing contained in this Order shall constitute the consent or approval of any modification, amendment, or clarification of any power purchase agreement between ETI and any other Entergy entity relating to the River Bend Station, which is made to address any concerns raised by the NRC in its Request for Additional Information regarding the River Bend Station dated March 11, 2010.

8. The Rider IPCR costs and eligible fuel costs requested by ETI are, consistent with this Order, reconciled through June 30, 2009, and are approved consistent with the stipulation.

9. ETI shall adjust its fuel over/under recovery balance consistent with the findings in this Order.

10. ETI shall file an RPCEA Rider consistent with the above findings of fact and conclusions of law to be effective with the first billing cycle of the billing month immediately following the effective date of this Order..

11. Because the final approved rates are equal to or higher than the interim rates adopted in Order No. 3, no refund of the interim rates authorized by Order No. 3 is necessary.

12. The interim rates approved in Order No. 12 are herby approved for the initial step rate increase contemplated by the stipulation, and ETI shall implement the second step rates for bills rendered on and after May 2, 2011, the first billing cycle for the revenue month of May.

13. Within 30 days of the date of this Order, ETI shall file a clean copy of all of the tariffs and schedules approved in this docket and a clean copy of the attachments to the stipulation.

14. The entry of this Order consistent with the stipulation does not indicate the Commission's endorsement of any principle or method that may underlie the stipulation. Neither should entry of this Order be regarded as a precedent as to the appropriateness of any principle or methodology underlying the stipulation.

15. All other motions, requests for entry of specific findings of fact, conclusions of law, and ordering paragraphs, and any other requests for general or specific relief, if not expressly granted in this order, are hereby denied.

SIGNED AT AUSTIN, TEXAS the 13th day of December 2010

PUBLIC UTILITY COMMISSION OF TEXAS

BARRY T. SMITHERMAN, CHAIRMAN

DONNA L. NELSON, COMMISSIONER

KENNETH W. ANDERSON, JR., COMMISSIONER

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Attachment 3-F
(9 pages)

FERC Order in Docket Nos. ER86-558-002

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Martha O. Hesse, Chairman;
Anthony G. Sousa, Charles G. Stalon
and Charles A. Trabandt.

Gulf States Utilities Company) Docket Nos. ER86-558-002, ER86-558-011 and ER86-558-013

ORDER CLARIFYING PREVIOUS ORDERS

(Issued May 18, 1988)

On February 16, 1988, Gulf States Utilities Company (Gulf States) filed a petition for clarification of certain letter orders approving settlements in this proceeding. 1/ The letter orders approved settlement rates reflecting decommissioning expenses funded through an external fund (River Bend Nuclear Decommissioning Fund) adjusted for a forty-year funding period.

On March 2, 1988, Cajun Electric Power Cooperative, Inc. (Cajun) requested that the Commission explicitly recognize that its contributions to Gulf States' decommissioning fund are, and have been, on the basis of unadjusted decommissioning expenses, and that the instant order will have no application to the rates being charged to Cajun.

Discussion

Gulf States requests that the Commission expressly recognize the amount of yearly decommissioning costs which it is entitled to collect. Gulf States asserts that absent such express recognition, the Internal Revenue Service (IRS) will not permit its deduction of yearly cash contributions to the River Bend Nuclear Decommissioning Fund.

Gulf States contends that it must first receive a "schedule of ruling amounts" from the IRS in order to take this deduction. Gulf States further maintains that the IRS will not provide a taxpayer with a schedule of ruling amounts "unless a public utility commission that establishes or approves rates for electric energy generated by the nuclear power plant to which the

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1/ See Gulf States Utilities Company, 40 FERC ¶ 61,081 (1987); Gulf States Utilities Company, 40 FERC ¶ 61,380 (1987); and Gulf States Utilities Company, 42 FERC ¶ 61,098 (1988).

nuclear decommissioning fund relates has determined the amount of decommissioning costs of such nuclear power plant to be included in the taxpayer's cost of service for ratemaking purposes." 2/ Gulf States maintains that the Commission's letter orders approving the settlements do not expressly address decommissioning costs, although the settlement rates which the Commission has approved are expressly based upon specified decommissioning costs. Gulf States also claims that the IRS has determined that the Commission's letter orders approving the settlements do not satisfy the requirements of its regulations.

We are not convinced that the instant clarifications are necessary. It appears that Gulf States has never submitted to the IRS the letter orders approving the settlements that specified the amount of decommissioning costs that will be reflected in Gulf States' wholesale rates. Based on Gulf States' filing it appears that they requested approval from the IRS on June 24, 1987. 3/ The letter orders were not issued until July 22 and September 25, 1987 and January 31, 1988, respectively. We believe that had Gulf States properly submitted the letter orders that are the subject of our order today to the IRS that no clarification of these orders would be necessary.

We shall nevertheless grant the requests of Gulf States and Cajun. In approving the settlements reached in this docket the Commission has authorized Gulf States to reflect in its wholesale rates yearly decommissioning costs of $112,914. We believe such action to be in the public interest to allow Gulf States to receive the proper tax deduction for its yearly cash contributions to the River Bend Nuclear Decommissioning Fund. This order will also have no application to the rates being charged to Cajun.

The Commission orders:

The Gulf States' and Cajun's requests for clarification are hereby granted.

By the Commission.

(S E A L)

Lois D. Cashell

Lois D. Cashell,
Acting Secretary.

2/ See Petition for Clarification at 3-4, quoting Temp. Treas. Reg. § 1.463A-3T(g) (1986).

3/ See letter of September 22, 1987 of William J. Dwyer, Chief, Branch 6 Corporation Tax Division, IRS at 1.

BEFORE THE FEDERAL ENERGY
REGULATORY COMMISSION

Gulf States Utilities Company	)	Docket Nos.
	)	ER86-558-000,
	)	ER86-558-002,
	)	ER86-558-011,
	)	ER86-558-013,
	)	ER86-558-015

PETITION FOR CLARIFICATION OF ORDERS OF APPROVAL

I. INTRODUCTION

By this petition pursuant to Rule 207(a)(2) of the Commission's Rules of Practice and Procedure, Gulf States Utilities Company ("Gulf States" or the "Company") requests the Commission to clarify certain letter orders approving settlements which have been reached in this docket. The purpose of the clarification is to recognize expressly the amount of decommissioning costs reflected in the rates established by the settlements. Absent this express recognition, Gulf States will be unable to deduct from its taxable income its yearly cash contributions to its decommissioning fund.

II. BACKGROUND OF THE SETTLEMENT RATES

On June 24, 1986, Gulf States filed a proposed three-phase increase in rates and charges to fourteen wholesale customers. The primary purpose of the filing was to establish rates reflecting the impact of the River Bend Unit I nuclear generating plant ("River Bend"), which went into commercial operation in June, 1986.

On March 20, 1987, Gulf States filed a settlement agreement with seven settling customers (the "Towns Agreement"). The Commission approved the Towns Agreement by a letter order dated July 22, 1987. On July 15, 1987, Gulf States filed a substantially similar settlement agreement with the Town of Welsh, Louisiana (the "Welsh Agreement"). The Commission approved the Welsh Agreement by a letter order dated September 25, 1987. On October 7, 1987, Gulf States filed a settlement agreement with Sam Rayburn Dam Electric Cooperative, Inc., Sam Rayburn G&T, Inc., and Sam Rayburn Municipal Power Agency (the "Sam Rayburn Agreement"). The Commission approved the Sam Rayburn Agreement by a letter order dated January 21, 1988. Also pending before the Commission is Gulf States' December 11, 1987, settlement agreement with Deep East Texas Electric Cooperative, Inc. ("Deep East Agreement") and Gulf States' January 22, 1988, settlement agreement with Brazos Electric Power Cooperative, Inc. ("Brazos Agreement").

With respect to decommissioning costs, the settlement rates (which are the same for all customers) reflect the decommissioning expenses set forth in the Company's filing, adjusted for a 40-year funding period. The Sam Rayburn Agreement, for example, expressly provides:

> The settlement rates reflect the decommissioning expenses set forth in the Company's filing, adjusted for a 40-year funding period, which expenses are funded through an external fund.

Sam Rayburn Agreement, Art. III(H)(3); Deep East Agreement, Art. III (G)(4); Brazos Agreement, Art. III (F)(4). Similarly, the Towns Agreement and the Welsh Agreement provide for settlement rates which incorporate the decommissioning expenses set forth in the Company's filing, funded over a 40-year period. See Towns Agreement, Art. III(K)(4) and Art. III(K)(1) (40-year life); Welsh Agreement, Art. III(E)(4) and Art. III(E)(1) (40-year life).

The Deep East Agreement and Brazos Agreement specifically include a schedule reflecting the yearly decommissioning costs included in the settlement rates. Deep East Agreement, Exhibit D; Brazos Agreement, Exhibit C. As shown in the schedule, the settlement rates are based on a yearly decommissioning cost of $112,914. While the other settlement agreements provided for the same specific decommissioning expenses, they did not include a separate schedule of the Company's actual yearly costs. Gulf States is attaching to this pleading as Attachment 1 the schedule reflecting the yearly decommissioning costs included in the settlement rates.

III. THE IRS WILL NOT PERMIT GULF STATES TO DEDUCT ITS CONTRIBUTIONS TO ITS DECOMMISSIONING FUND UNLESS THE COMMISSION EXPRESSLY DETERMINES THE AMOUNT OF THE RIVER BEND DECOMMISSIONING COSTS TO BE REFLECTED IN RATES

Section 468A of the Internal Revenue Code permits eligible taxpayers to deduct a portion of their cash contributions to a nuclear decommissioning fund. To take this deduction, the taxpayer must first obtain a "schedule of ruling amounts" from the Internal Revenue Service. Temp. Treas. Reg. §1.468A-3T(a)(1)(1986). The Internal Revenue Service will not provide a taxpayer with a schedule of ruling amounts "unless a public utility commission that establishes or approves rates for electric energy generated by the nuclear power plant to which the nuclear decommissioning fund relates has determined the amount of decommissioning costs of such nuclear power plant to be included in the taxpayer's cost of service for ratemaking purposes." Temp. Treas. Reg. §1.468A-3T(g)(1986). A copy of the commission's most recent determination must be included in the request for a schedule of ruling amounts. Temp. Treas. Reg. §1.468A-3T(h)(2)(vi)(C)(1986).

The Commission's letter orders approving the settlements in this docket do not expressly address decommissioning costs. Although the settlement rates which the Commission has approved are expressly based upon specified decommissioning costs, <u>see</u> <u>supra</u> pp. 2-3, the Internal Revenue Service has determined that the Commission's letter orders approving the settlements do not satisfy the requirements of its regulations. <u>See</u> letter from William J. Dwyer, Internal Revenue Service, to William A. Pinkerton, Manager -- Tax Services, Gulf States Utilities Company, September 22, 1987 (Attachment 2). According to the IRS, "a determination of the decommissioning cost to be included in the cost of service must be made by [the Commission] before the IRS can provide a schedule of ruling amounts." <u>Id</u>. at 2.

As a result, absent clarification by the Commission, Gulf States will be unable to obtain the schedule of ruling amounts it needs to take its tax deduction for decommissioning expenses. That result would be detrimental both to Gulf States and its customers. A simple order clarifying the Commission's earlier letter orders, however, will enable Gulf States to take the deduction.

IV. CONCLUSION

For the foregoing reasons, Gulf States respectfully asks the Commission (1) to amend each of its earlier letter orders in this docket to state expressly that yearly decommissioning costs of $112,914 are included in the settlement cost of service and (2) to include similar language in any future orders approving settlement agreements in this docket.

Respectfully submitted,

Cecil L. Johnson / BSS

Cecil L. Johnson

GULF STATES UTILITIES COMPANY
350 Pine Street
Beaumont, Texas 77701
(409) 838-6631

George A. Avery / BSS

George A. Avery
Barry S. Spector

CADWALADER, WICKERSHAM & TAFT
1333 New Hampshire Ave., N.W.
Washington, D.C. 20036
(202) 862-2200

Counsel for
Gulf States Utilities Company

Dated: February 16, 1988

GULF STATES UTILITIES COMPANY
RIVER BEND NUCLEAR DECOMMISSIONING FUND
FOR 70% CO-OWNERSHIP

YEAR	BEGINNING BALANCE	ANNUAL EARNINGS	CUMULATIVE EARNINGS	ANNUAL CONTRIBUTIONS	CUMULATIVE CONTRIBUTIONS	ENDING BALANCE
1986	$	$	$	$ 60974	$ 60974	$ 60974
1987	60974	5487	5487	112914	173888	179375
1988	179375	16144	21631	112914	286802	308433
1989	308433	27759	49390	112914	399716	449106
1990	449106	40419	89809	112914	512630	602439
1991	602439	54220	144029	112914	625544	769573
1992	769573	69261	213290	112914	738458	951748
1993	951748	85658	298948	112914	851372	1150320
1994	1150320	103529	402477	112914	964286	1366763
1995	1366763	123008	525485	112914	1077200	1602685
1996	1602685	144242	669727	112914	1190114	1859841
1997	1859841	167386	837113	112914	1303028	2140141
1998	2140141	192612	1029725	112914	1415942	2445667
1999	2445667	220110	1249835	112914	1528856	2778691
2000	2778691	250083	1499918	112914	1641770	3141688
2001	3141688	282751	1782669	112914	1754684	3537353
2002	3537353	318362	2101031	112914	1867598	3968629
2003	3968629	357177	2458208	112914	1980512	4430720
2004	4430720	399485	2857693	112914	2093426	4951119
2005	4951119	445600	3303293	112914	2206340	5509633
2006	5509633	495867	3799160	112914	2319254	6118414
2007	6118414	550658	4349818	112914	2432168	6781986
2008	6781986	610378	4960196	112914	2545082	7505278
2009	7505278	675475	5635671	112914	2657996	8293667
2010	8293667	746430	6382101	112914	2770910	9153011
2011	9153011	823771	7205872	112914	2883824	10089696
2012	10089696	908073	8113945	112914	2996738	11110683
2013	11110683	999961	9113906	112914	3109652	12223558
2014	12223558	1100121	10214027	112914	3222566	13436593
2015	13436593	1209293	11423320	112914	3335480	14758800
2016	14758800	1328292	12751612	112914	3448394	16200006
2017	16200006	1458001	14209613	112914	3561308	17770921
2018	17770921	1599382	15808995	112914	3674222	19483217
2019	19483217	1753490	17562485	112914	3787136	21349621
2020	21349621	1921466	19483951	112914	3900050	23384001
2021	23384001	2104560	21588511	112914	4012964	25601475
2022	25601475	2304133	23892644	112914	4125878	28018522
2023	28018522	2521667	26414311	112914	4238792	30653103
2024	30653103	2758779	29173090	112914	4351706	33524796
2025	$ 33524796	$ 3017232	$ 32190322	$ 164854	$ 4516560	$ 36706882

THE ANNUAL EARNINGS RATE IS 9.00 PERCENT

This schedule is on a FERC jurisdictional basis.

TACHMENT 1

Attachment 3-G
(13 pages)

MSS-4 Agreement and FERC's acceptance

Entergy

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101 Constitution Avenue, N.W.
Suite 200 East
Washington, DC 20001
Tel: 202 530 7342
Fax: 202 530 7350
e-mail: aweinst@entergy.com

Andrea J. Weinstein
Assistant General Counsel
Federal Energy Regulatory Affairs

December 29, 2010

The Honorable Kimberly Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Entergy Services, Inc. Docket Nos. ER03-753- and ER11- -000

Dear Secretary Bose:

Pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d (2004), and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission") 18 C.F.R. Part 35 (2007), Entergy Services, Inc. ("ESI"), on behalf of Entergy Gulf States Louisiana, L.L.C. ("EGSL"), and Entergy Texas, Inc. ("ETI")[1] hereby submit for filing a revision to the currently-effective Service Schedule MSS-4 Agreement relating to the River Bend nuclear generating station ("River Bend").

I. BACKGROUND AND INTRODUCTION

Service Schedule MSS-4 of the Entergy System Agreement relates to a unit power purchase between Entergy Operating Companies[2] and/or a sale of power purchased by an Operating Company. In an order issued on April 14, 2005, the Commission approved the current version of MSS-4.[3] As a condition in its order, the Commission required ESI to file a notice with

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1 As described below, EGS-LA and ETI are expected to become public utilities on January 1, 2008 pursuant to EGS's proposed jurisdictional separation plan.

2 The Operating Companies are Entergy Arkansas, Inc. ("EAI"), Entergy Gulf States Louisiana, L.L.C. ("EGSL"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), Entergy Texas, Inc. ("ETI") and Entergy New Orleans, Inc. ("ENO"). The generation and bulk transmission system of all of the Operating Companies is collectively referred to as the "Entergy System."

3 *Entergy Services, Inc.*, 111 FERC ¶ 61,035 (2005).

the Commission within 30 days of any Operating Company's entering into any long-term transaction pursuant to Service Schedule MSS-4."[4] The Commission defined "long-term" transactions as "one year or more."[5] According to the Commission, such a notice condition "will provide interested parties with the ability to identify and the opportunity to challenge the transaction under section 206 of the FPA," and is therefore a reasonable resolution of the MSS-4 settlement.[6]

On March 13, 2007, in Docket Nos. EC07-66, ES07-26 and EL07-45, ESI, on behalf of Entergy Gulf States, Inc. ("EGS"), EGSL, and ETI requested authorization for EGS to implement a proposed jurisdictional separation plan ("JSP"). As a result of the JSP, EGS, a FERC-jurisdictional public utility, was restructured into two separate utilities, EGSL and ETI. By order dated July 20, 2007, the Commission authorized the JSP as consistent with the public interest under Section 203 of the Federal Power Act. *See Entergy Gulf States, Inc.*, 120 FERC ¶ 61,079 (2007).

River Bend was previously owned by EGS. As a result of the JSP, EGSL now owns the 70%[7] regulated portion of the River Bend Station. EGSL sells a portion of this 70% regulated portion of River Bend to ETI pursuant to a MSS-4 Agreement ("River Bend MSS-4"). On October 5, 2007, in Docket No. ER08-31, ESI filed the River Bend MSS-4 at the Commission. ESI originally filed the River Bend MSS-4 out of an abundance of caution because certain adjustments to the inputs into the Service Schedule MSS-4 rate were necessary to reflect the historical retail ratemaking treatment for River Bend. By unpublished letter order dated December 19, 2007, the Commission accepted the River Bend MSS-4 for filing.

II. INSTANT FILING

As described above, the Commission has previously held that MSS-4 transactions need not be filed at the FERC prior to the commencement of such transactions.[8] Instead, "long-term" MSS-4 transactions must be filed at the Commission on an informational basis within 30 days of the commencement of such transactions. In this instance, however, ESI is submitting the amended MSS-4 Agreement for River Bend between EGSL and ETI out of an abundance of

4 *Id.* at PP 1, 20.

5 *Id.* at P 20.

6 *Id.* at PP 20, 21.

7 The remaining 30% share of the River Bend is not in retail rate base. This 30% share was formerly owned by Cajun Electric Power Cooperative ("Cajun"). EGSL owns this 30% share and currently sells the power associated with this share of River Bend to ELL and ENO in accordance with the Commission's order in Docket Nos. ER03-583, *et al* (Opinion No. 485 and 485-A).

8 *Entergy Services, Inc.*, 111 FERC ¶ 61,035 at P 31; *Louisiana Pub. Serv. Comm'n v. Arkansas Power & Light Co.*, 44 FERC ¶ 61,392, at 62,270 (1988).

caution because the existing MSS-4 Agreement for River Bend is currently on file at the Commission.

On September 23, 2010, the U.S. Nuclear Regulatory Commission ("NRC") notified the operator of River Bend that it believed that certain language in the MSS-4 Agreement was not in compliance with NRC regulatory requirements. Specifically, the NRC believed that the MSS-4 Agreement should contain express language that (1) payments for River Bend decommissioning costs should be made notwithstanding the operational status of River Bend, (2) payments for River Bend decommissioning costs should be made notwithstanding any force majeure provisions, and that (3) proceeds from decommissioning collections should be deposited into the external sinking fund. EGSL believes that items (1) and (2) are already addressed by the contract; and that item (3) is not an NRC regulatory requirement for the contract, and in any event is the intention of the contract and the current practice. Nevertheless, in order to cooperate fully with the NRC, EGSL and ETI have revised the MSS-4 Agreement to incorporate provisions as suggested by the NRC.

III. COMMUNICATIONS

The following persons are authorized to receive notices and communications with respect to the instant filing:

Andrea Weinstein
Assistant General Counsel
Entergy Services, Inc.
101 Constitution Ave., N.W.
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Richard Armstrong
Director, Federal Regulatory Affairs
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IV. EFFECTIVE DATE

To the extent the Commission determines it necessary to submit the revised River Bend MSS-4 Agreement between EGSL and ETI pursuant to FPA Section 205, ESI requests that the Commission grant an effective date of January 1, 2011. ESI requests waiver of the Commission's sixty day notice requirement to allow a January 1, 2011 effective date. ESI believes that such waiver is appropriate because the River Bend MSS-4 Agreement is already on file, and because the revised River Bend MSS-4 Agreement only amends that agreement to reflect minor revisions requested by the NRC.

V. OTHER FILING REQUIREMENTS

ESI knows of no costs included in the cost of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are the product of discriminatory practices. The cost of service specifically is made subject to the Commission-approved Service Schedule MSS-4.

VI. CONCLUSION

Accordingly, to the extent necessary, ESI requests that the Commission accept the revised River Bend MSS-4 between EGSL and ETI for filing, and grant any waivers of the requirements in 18 C.F.R. Part 35 necessary to allow the agreement to go into effect on January 1, 2011.

If you have any questions concerning this filing, please feel free to contact the undersigned.

Very truly yours,

/s/ Andrea Weinstein

Andrea J. Weinstein

Attorney for
Entergy Services, Inc.

Entergy Operating Companies First Revised Service Agreement No. 472

Service Schedule MSS-4 Agreement by and between
Entergy Texas, Inc. (Buyer) and
Entergy Gulf States Louisiana, LLC (Seller)

MSS-4 AGREEMENT

This Agreement is dated as of January 1, 2008, between Entergy Texas, Inc. ("EGS-TX" or "Buyer"), and Entergy Gulf States Louisiana, LLC. ("EGS-LA" or "Seller").

WHEREAS, Seller has agreed to make a unit power sale from the designated units set forth on Attachment A (individually a "Designated Unit" and collectively "Designated Units") to Buyer; and

WHEREAS, the agreement among Entergy Gulf States, Inc., Entergy Louisiana, LLC, Entergy Mississippi, Inc., Entergy New Orleans, Inc., and Entergy Arkansas, Inc., (collectively the "Companies"), and Entergy Services, Inc. ("ESI") was filed with the FERC on April 30, 1982, and became effective on January 1, 1983, and amended to incorporate Entergy Gulf States, Inc. in 1993 and its successor, EGS-LA in 2008 (hereinafter referred to as the "System Agreement"); and

WHEREAS, the System Agreement contains a Service Schedule MSS-4 providing the basis for making a unit power purchase and sale between the Companies that are participants in that Agreement; and

WHEREAS, the parties herein wish to execute this Agreement to provide for a unit power purchase by Buyer under Service Schedule MSS-4 from the Designated Units.

THEREFORE, the parties agree as follows:

1. <u>Designated Units</u>. The designated generating units for purposes of this unit power sale under Service Schedule MSS-4 of the System Agreement shall be those units set forth on Attachment A.

2. <u>Unit Power Purchase</u>. Seller agrees to sell and Buyer agrees to purchase that quantity of generating capacity and associated energy from the Designated Units

equivalent to the percentage (the "Allocated Percentage") of Seller's capacity in each such Designated Unit set forth on Attachment A.

3. Pricing. The pricing of the capacity and energy to be sold and purchased pursuant to paragraph 2 above shall be as specified in Service Schedule MSS-4 of the System Agreement, as clarified in the accompanying transmittal letter dated October 5, 2007. Should the trust funds set aside for Buyer's share of the responsibility for River Bend Station decommissioning be found to be insufficient to cover the aforesaid Buyer's share of the cost for such decommissioning, Buyer will promptly pay to Seller such deficit. The Buyer will fully pay for the Buyer's share of the decommissioning responsibility for River Bend notwithstanding the operational status of River Bend or any force majeure provisions. All proceeds from decommissioning collections under Service Schedule MSS-4 pursuant to this Agreement will be deposited to the external sinking fund(s) that collect(s) Buyer's decommissioning funding.

4. Energy Entitlement. Buyer is entitled to receive on an hourly basis the Allocated Percentage of the energy generated by each of the Designated Units.

5. Term. The term of this Agreement shall be the operating life of the Designated Units, plus any time required to decommission the Designated Units.

6. Termination. Neither party shall have the right to terminate the unit power purchase and sale required by this Agreement without the express written consent of the other party.

7. Assignment. This Agreement is not assignable by Buyer without the consent of Seller, and Seller must consent to any transfer or assignment to any new or restructured entity resulting from any restructuring or business combination of Buyer, the

effect of which would cause a successor to become a party hereto. Any assignment approved by Seller shall be on terms as then agreed.

8. Condition Precedent. This contract shall be conditioned upon Buyer receiving all regulatory approvals required for this Agreement.

9. Notices. Unless specifically stated otherwise herein, any notice to be given hereunder shall be sent by Registered Mail, postage prepaid, to the party to be notified at the address set forth below, and shall be deemed given when so mailed.

To EGS-TX:	Entergy Texas, Inc. 350 Pine Street Beaumont, TX 77701 ATTN: Chief Executive Officer
To EGS-LA:	Entergy Gulf States Louisiana, L.L.C. 4809 Jefferson Hwy Jefferson, LA 70121 ATTN: Chief Executive Officer

10. Nonwaiver: The failure of either party to insist upon or enforce, in any instance, strict performance by the other of any of the terms of this Agreement or to exercise any rights herein conferred shall not be considered as a waiver or relinquishment to any extent of its rights to assert or rely upon any such terms or rights on any future occasion.

11. Amendments. No waiver, alteration, amendment or modification of any of the provisions of this Agreement shall be binding unless in writing and signed by a duly authorized representation of both parties.

12. Entire Agreement. This Agreement, which is entered into in accordance with the authority of Service Schedule MSS-4 of the System Agreement, constitutes the entire agreement between the parties with respect to the subject matter hereof and

supersedes all previous and collateral agreements of understandings with respect to the subject matter hereof.

13. Severability. It is agreed that if any clause or provision of this Agreement is held by the courts to be illegal or void, the validity of the remaining portions and provisions of the Agreement shall not be affected, and the rights and obligations of the parties shall be enforced as if the Agreement did not contain such illegal or void clauses or provisions.

ENTERGY TEXAS, INC.

BY: ________________________

TITLE: ______________________

ENTERGY GULF STATES LOUISIANA, L.L.C.

BY: ________________________

TITLE: ______________________

ATTACHMENT A

SALE OF CAPACITY AND ENERGY

BY ENTERGY GULF STATES LOUISIANA, L.L.C. TO ENTERGY TEXAS, INC.

This Attachment A is attached to and forms a part of the Agreement dated January 1, 2008, between Entergy Gulf States Louisiana, L.L.C. ("Seller") and Entergy Texas, Inc. ("Buyer") pursuant to the Service Schedule MSS-4 of the System Agreement.

DESIGNATED UNITS	SELLER'S CAPACITY*	BUYER'S ALLOCATED CAPACITY*	BUYER'S ALLOCATED PERCENTAGE
River Bend Station	689	292.83	42.5%
TOTAL	689	292.83	42.5%

* Expressed in megawatts. To the extent Seller's Capacity increases or decreases as determined by the Entergy Operating Committee from time to time, Buyer's Allocated Capacity shall adjust correspondingly based on Buyer's Allocated Percentage of Seller's Capacity.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
Entergy Gulf States
Louisiana, L.L.C.
Docket No. ER11-2562-000

February 14, 2011

Entergy Services, Inc.
101 Constitution Avenue, N.W.
Suite 200 East
Washington, D.C. 20001

Attention: Andrea J. Weinstein, Assistant General Counsel

Reference: Filing of Revised Service Schedule MSS-4 Agreement Relating to River Bend Nuclear Generating Station

Dear Ms. Weinstein:

On December 29, 2010, Entergy Services, Inc. (Entergy) submitted for filing a revised Service Schedule MSS-4 Agreement between Entergy Gulf States Louisiana, L.L.C. (Entergy Gulf States) and Entergy Texas, Inc. (Entergy Texas). The agreement, First Revised Service Agreement No. 472, covers the sale of energy and capacity from the River Bend nuclear generator by Entergy Gulf States to Entergy Texas. Entergy explains that the agreement is being revised to incorporate new language requested by the Nuclear Regulatory Commission. Waiver of the Commission's 60-day notice requirement is granted pursuant to section 35.11 of the Commission's regulations (18 C.F.R. § 35.11) and First Revised Service Agreement No. 472 is accepted for filing effective January 1, 2011, as requested.

This filing was noticed on December 29, 2010 with comments, protests, or motions to intervene due on or before January 19, 2011. No protests or adverse comments were filed. Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214). Any opposed or untimely filed motion to intervene is governed by the provisions of Rule 214.

This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents; nor shall such action be deemed as recognition of any claimed contractual right or obligation affecting or relating to such service or rate; and such action is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against your Company.

This action is taken pursuant to the authority delegated to the Director, Division of Electric Power Regulation -- Central, under 18 C.F.R. § 375.307 of the Commission's Regulations. This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Penny S. Murrell, Director
Division of Electric Power
Regulation -- Central

CNRO-2012-00007

SERIES 4 ATTACHMENTS

4	Entergy Louisiana, LLC – WF3 Status Report (1 page)
4-A	Entergy Louisiana, LLC - Calculation of Minimum Amount (1 page)
4-B	Schedule of Remaining Principle Payments – WF3 (1 page)
4-C	LPSC Order in Docket No. U-31237 (20 pages)
4-D	CNO Resolution R-95-1081 in Docket UD-95-1 and IRS Schedule of Ruling Amounts (6 pgs)

Attachment 4
(1 page)

ENTERGY LOUISIANA, LLC
Status Report of Decommissioning Funding
For Year Ending December 31, 2011 - 10 CFR 50.75(f)(1)

Plant Name: **Waterford 3 Steam Electric Station**

1.	Minimum Financial Assurance (MFA) Estimated per 10 CFR 50.75(b) and (c) (2011$):	$474.3 million[1]
2.	Decommissioning Fund Total As of 12/31/11:	$254.0 million
3.	Annual amounts remaining to be collected:	See Attachment 4-B
4.	Assumptions used: Rate of Escalation of Decommissioning Costs:	See item below
	Rate of Earnings on Decommissioning Funds:	2% real rate of return per 10 CFR 50.75(e)(1)(i)
	Authority for use of Real Earnings Over 2%:	N/A
5.	Contracts upon which licensee is relying For Decommissioning Funding:	None
6.	Modifications to Method of Financial Assurance since Last Report:	None
7.	Material Changes to Trust Agreements:	None

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1 See Attachment 4-A

Attachment 4-A
(1 page)

ENTERGY LOUISIANA, LLC
Calculation of Minimum Amount
For Year Ending December 31, 2011 - 10 CFR 50.75(f)(1)

Entergy Louisiana, LLC: 100% ownership interest
Plant Location: Taft, Louisiana
Reactor Type: Pressurized Water Reactor ("PWR")
Power Level: >3,400 MWt
PWR Base Year 1986$: $105,000,000
Labor Region: South
Waste Burial Facility: Generic Disposal Site

10CFR50.75(c)(2) Escalation Factor Formula:
0.65(L) +0.13(E) +0.22(B)

	Factor
L=Labor (South)	2.28[1]
E=Energy (PWR)	2.58[2]
B=Waste Burial-Vendor (PWR)	12.28[3]

PWR Escalation Factor:

0.65(L) +0.13(E) +0.22(B)=	4.51703

1986 PWR Base Year $ Escalated:

$105,000,000 * Factor=	$474,287,737

1 Bureau of Labor Statistics, Series Report ID: CIU2010000000220i (4th Quarter 2011)
2 Bureau of Labor Statistics, Series Report ID: wpu0543 and wpu0573 (December 2011)
3 Nuclear Regulatory Commission: NUREG-1307 Revision 14, Table 2.1 (2010)

Attachment 4-B
(1 page)

Schedule of Remaining Principal Payments into
Waterford 3 Decommissioning Fund
($ Thousands)

Year	LPSC	City of New Orleans	Total
2012	$5,831	$189	$6,020
2013	$5,831	$189	$6,020
2014	$5,831	$189	$6,020
2015	$6,688	$189	$6,877
2016	$6,688	$189	$6,877
2017	$6,688	$189	$6,877
2018	$6,688	$189	$6,877
2019	$6,688	$189	$6,877
2020	$7,580	$189	$7,769
2021	$7,580	$189	$7,769
2022	$7,580	$189	$7,769
2023	$7,580	$189	$7,769
2024	$7,580	$189	$7,769
2025	$8,694		$8,694
2026	$8,694		$8,694
2027	$8,694		$8,694
2028	$8,694		$8,694
2029	$8,694		$8,694
2030	$10,047		$10,047

Note: Approved in LPSC Docket No. U-31237 and CNO Resolution R-95-1081 in Docket UD-95-1, see Attachments 4-C and 4-D.

Attachment 4-C
(20 pages)

LPSC Order in Docket No. U-31237

LOUISIANA PUBLIC SERVICE COMMISSION

ORDER NO. U-31237

ENTERGY GULF STATES LOUISIANA, L.L.C.
ENTERGY LOUISIANA, LLC
EX PARTE

Docket No. U-31237 In re: Joint Application of Entergy Gulf States Louisiana, L.L.C. and Entergy Louisiana, LLC for approval of an Increase in Funding for Decommissioning for River Bend and Waterford 3 Nuclear Facilities LPSC Docket No. U-31237.

(Decided at the Commission's July 28, 2010 Business and Executive Session.)

Overview and Procedural History

Entergy Gulf States Louisiana, L.L.C. ("EGSL") and Entergy Louisiana, LLC ("ELL") (collectively "the Companies") filed a joint Application with supporting documentation and testimony on December 29, 2009 seeking approval from the Louisiana Public Service Commission ("LPSC" or "Commission") to provide supplemental funding for the decommissioning trusts maintained for the LPSC-jurisdictional portions of ELL's Waterford 3 and EGSL's River Bend nuclear generation units.[1] The request to increase the amounts is the result of the Nuclear Regulatory Commission ("NRC") notifying the Companies of "a projected shortfall of decommissioning funding assurance" at both Waterford 3 and River Bend. The filings were published in the Commission's Official Bulletin on January 8, 2010. Interventions were filed by the Louisiana Energy Users Group ("LEUG"), Marathon Oil Company ("Marathon"), ArcelorMittal LaPlace, LLC ("ArcelorMittal") and the Alliance for Affordable Energy ("the Alliance").

This matter was assigned to Administrative Law Judge Michelle Finnegan who presided over a status conference on February 22, 2010. At the status conference, Commission Staff requested that establishing a procedural schedule be postponed until after Commission hiring of an outside consultant to assist Staff in this matter. Staff advised that a Request for Proposals had been issued on February 5, 2010, and Staff anticipated the Commission's hiring decision would occur at the Commission's March 2010 Business and Executive ("B&E"). No party opposed Staff's request. A follow up conference was scheduled for April 5. At the Commission's March 10 B&E, the Commission voted to hire the firms of Exeter Associates, Inc. and Henderson Ridge Consulting, who submitted a joint proposal. At a status conference held April 5, the parties established a procedural schedule with hearings set for early August 2010.

On May 24, 2010 the Companies filed an Unopposed Motion to Modify and Amend Procedural Schedule to postpone the schedule while the parties worked to negotiate a possible settlement or narrow issues for hearing; the motion was granted. The Companies and Staff filed, on June 24, an Unopposed Joint Motion to Suspend the Procedural Schedule. The motion was granted, and as requested in the motion, the

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1 Waterford 3 is a single-unit 1,152 MW nuclear steam-electric generating station located near Killona, Louisiana that was constructed by ELL's predecessor, Louisiana Power & Light Company, and began commercial operation in September 1985. Waterford 3 employs the pressurized-water-reactor design.

River Bend is a single-unit 967 MW nuclear steam-electric generating station located near St. Francisville, Louisiana that was constructed by EGSL's predecessor, Gulf States Utilities Company, and began commercial operation in June 1986. River Bend employs the boiling-water-reactor design.

parties were directed to file an update on the status of the case or an uncontested stipulation on or before July 9. On July 9, Staff and the Companies advised that a Settlement Term Sheet had been executed by all but one party, and that the parties planned to file the uncontested stipulation and request that a hearing be set so that this matter could be considered at the Commission's July B&E. On July 13, 2010 the parties filed a Joint Motion for the Scheduling of a Stipulation Hearing and Request for Expedited Hearing. The motion was granted and a Stipulation Hearing was convened on July 20, 2010.

Commission Authority

Louisiana Constitution and Statutes:

The Commission exercises jurisdiction in this proceeding pursuant to Article IV, Sec. 21 of the Louisiana Constitution, and La. R.S. 45:1163(A)(1) and La. R.S. 45:1176.

> La. Const. Art. IV, Sec. 21 provides in pertinent part:
>
> The Commission shall regulate all common carriers and public utilities and have such other regulatory authority as provided by law. It shall adopt and enforce reasonable rules, regulations, and procedures necessary for the discharge of its duties, and perform other duties as provided by law.
>
> La. R.S. 45:1163 provides in pertinent part:
>
> A. (1) The Commission shall exercise all necessary power and authority over any street, railway, gas, electric light, heat, power, waterworks, or other local public utility for the purpose of fixing and regulation the rates charged or to be charged by and service furnished by such public utilities.
>
> La. R.S. 45:1176 provides in pertinent part:
>
> The Commission...shall investigate the reasonableness and justness of all contracts, agreements and charges entered into or paid by such public utilities with or to other persons, whether affiliated with such public utility or not.

Companies' Application

The Companies December 29, 2009 Joint Application requests an increase in revenues for ELL and EGSL to provide supplemental funding for the decommissioning trusts maintained for the LPSC-jurisdictional portions of ELL's Waterford 3 and EGSL's River Bend nuclear generation units. The request for increase is the result of the NRC's determination of a projected shortfall in the decommissioning funding at both Waterford 3 and River Bend.

The Companies' Application proposes new revenue requirement amounts consistent with their revised decommissioning funding plans using a 40 year license and requests approval to include these revenue requirements in their 2009 Test Year Formula Rate Plan ("FRP") filings. ELL requests approximately $10.336 million per year for its LPSC-jurisdictional revenue requirement in 2010 to meet the NRC minimum funding assurance of $400.2 million, which would be a $7.94 million increase over the $2.396 million in ELL's rates. For EGSL's portion of the regulated 70% share of River Bend, EGSL requests a revenue requirement of $9.671 million per year to meet its NRC minimum assurance of $378.8 million. Currently, EGSL has no funding in retail rates for decommissioning.

Staff's Review

Commission Staff conducted a review of the Application, supporting documentation and testimony. Commission Staff issued data requests, reviewed those responses and conducted a series of conferences with the Companies. Staff proposed certain adjustments to the Companies' filed calculations of their revenue requirements to update the trust fund balances, extend the funding period and modify the investment portfolio allocations. Commission Staff and the Companies reached a stipulated agreement, taking into account Commission Staff's adjustments, that resolves all issues in this docket.

Uncontested Stipulated Settlement

The Companies and Staff filed on July 13, pursuant to Rule 6 of the Commission's Rules of Practice and Procedure, a motion for stipulation hearing, Settlement Term Sheet signed by all parties, and supporting testimony from Kenneth Gallagher for the Companies and Thomas S. Catlin and William J. Barta for Commission Staff. A stipulation hearing was held July 20. At the stipulation hearing, the Companies presented the live testimony of Mr. Gallagher and Commission Staff presented the live testimony of Mr. Catlin. In addition to live testimony, the following documents were entered into the record:

> Joint Staff EGSL/ELL Exhibit 1- Settlement Term Sheet;
>
> Staff Exhibit 1- Settlement Testimony of William J. Barta, dated July 2010;
>
> Staff Exhibit 2- Settlement Testimony of Thomas S. Catlin, dated July 2010;
>
> EGSL/ELL Exhibit 1- Settlement Testimony of Kenneth F. Gallagher, dated July 9, 2010;
>
> EGSL/ELL Exhibit 2- Direct Testimony of Kenneth F. Gallagher, redacted public version, dated December 2009; and
>
> EGSL/ELL Exhibit 3- Direct Testimony of Kenneth F. Gallagher, confidential version, dated December 2009.

Conclusion

On motion of Commissioner Campbell, seconded by Commissioner Field, and unanimously adopted, the Commission voted to accept the Staff Recommendation and adopt the uncontested stipulated Settlement Term Sheet filed into the record on July 13, 2010. Therefore,

IT IS ORDERED:

1. The Companies submitted a Joint Application seeking approval to provide supplemental funding for the decommissioning trusts maintained for the LPSC's jurisdictional portions of the Waterford 3 Steam Electric Station ("Waterford 3") owned by ELL and the River Bend Station ("River Bend") owned by EGSL.

The Companies requested increases in their respective revenue requirements to address projected shortfalls found by the Nuclear Regulatory Commission ("NRC") in the decommissioning funding assurance required for each facility.

2. The proposed revised revenue requirement amounts are a result of the NRC notifying the Companies of the referenced projected shortfall of decommissioning funding assurance at both Waterford 3 and River Bend. Under NRC financial assurance requirements regulations found in 10 CFR 50.75(a)-(f), ELL and EGSL, as holders of nuclear operating licenses, must certify through biennial filings that available decommissioning funds are not less than the NRC's prescribed minimum amount required to fund decommissioning costs. The projected shortfalls determined by the NRC are a result of several factors, including the NRC's requirement that only the currently approved license life of forty (40) years for each unit may be used in calculating the minimum financial assurance amount. The LPSC, in prior Orders, used a sixty (60) year license life to determine the appropriate level of funding for the decommissioning trusts, based on possible license extensions that the Companies are expected to apply for in the future.

3. The Companies have proposed new revenue requirement amounts consistent with their revised decommissioning funding plans using a 40 year license and requested approval to include these revenue requirements in their 2009 Test Year Formula Rate Plan ("FRP") filings in the manner provided for in each Company's FRP.[2] ELL has requested approximately $10.336 million per year[3] for its LPSC-jurisdictional revenue requirement in 2010 to meet the NRC minimum funding assurance of $400.2 million, which would be a $7.94 million increase over the $2.396 million in ELL's rates. For EGSL's portion of the regulated 70% share of River Bend[4], EGSL has requested a revenue requirement of $9.671 million per year to meet its NRC minimum assurance of $378.8 million.[5] Currently, EGSL has no funding in retail rates for decommissioning.

4. The Commission has recognized in its prior rate Orders setting decommissioning accruals for both ELL and EGSL that the decommissioning accrual issue would be revisited if the NRC notified the Companies that decommissioning funding was inadequate. Orders addressing both EGSL and ELL contain language substantially as follows: "In the event that the Nuclear Regulatory Commission ("NRC") formally notifies [EGSL or ELL] or [the River Bend or Waterford 3] licensee that the decommissioning funding for [River Bend or Waterford 3] is or would become inadequate, the Company would be permitted recognition in rates of decommissioning expense at a level sufficient to address reasonably the NRC's concern as expressed in the notification."[6]

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2 Section 3.A.5 of the EGSL and ELL FRP Riders both contain identical language stating, in pertinent part that: "The effects of the changes in depreciation rates, and/or decommissioning accruals, increases and decreases, ordered by the LPSC, including as a result of changes in the requirement to fund the decommissioning trust that may be ordered by the Nuclear Regulatory Commission during the period that this FRP is in effect, shall be considered separately outside of the FRP mechanism."

3 The retail revenue requirement for ELL is $10.134 million.

4 Thirty percent of the River Bend plant is unregulated and was acquired by EGSL from the former Cajun Electric Power Cooperative, Inc. as part of a bankruptcy reorganization. *See In Re Cajun Electric Power Cooperative, Inc.*, 238 B.R. 319 (M.D. La. 1999) *aff'd* 119 F.3[rd] 349 (5[th] Cir. 1997). The decommissioning funding for this 30% share is separately funded and is not subject to the NRC's notice of projected shortfalls in the decommissioning funding assurance and, therefore, not subject to the review being undertaken in this proceeding.

5 The $378.8 million figure represents the combined total for the River Bend regulated plant, including the Louisiana, Texas and wholesale jurisdictions. The Louisiana retail jurisdictional share of River Bend's NRC minimum is $217.76 million.

6 For EGSL and River Bend, the provision comes from Item 8 of settlement term sheet for Consolidated Order Nos. U-22491, U-23358, U-24182, U-24993, U-25687 dated January 8, 2003. For ELL and Waterford 3, the provision comes from Item 4 of the settlement term sheet for Order No. U-20925 RRF 2004 dated May 25, 2005.

5. After incorporating certain adjustments to the Companies' filed calculations of their revenue requirements to update the trust fund balances, extend the funding period and modify the investment portfolio allocations, the Staff and the Companies have agreed upon new decommissioning funding requirements for both Waterford 3 and River Bend. The agreed upon decommissioning funding is intended to serve only to meet the decommissioning funding requirements on an interim basis, and the Staff and Companies agree that both the Waterford 3 and River Bend funding requirements will be re-evaluated based on site specific cost studies after ELL and EGSL, respectively, have filed for and received the NRC's responses to requests for license extensions for the two nuclear facilities. It is recognized that there is no certainty that either ELL or EGSL will receive license extensions for their respective plants and that the LPSC may have to re-evaluate and adjust revenue requirements based on a forty (40) year life for each plant.

6. The initial funding requirement of $5.947 million ($5.831 million on a retail basis) per year is appropriate. This amount will be included in ELL's revenue requirement for the Waterford 3 decommissioning funding plan, with collections to begin with the September 2010 billing cycle rate change scheduled to occur through the implementation of ELL's 2009 Test Year Formula Rate Plan and further finds that these costs are to be treated as "Extraordinary Costs" and recovered outside of the earnings sharing mechanism of the Formula Rate Plan. This calculation is based on the 5-year step funding plan historically used for Waterford 3 and reflects beginning fund balance, the investment portfolio allocations, escalation and earnings rates, 5-year funding increments, and other assumptions set forth in the Attached Exhibit A.

7. For River Bend, an initial funding requirement of $7.843 million per year stepped up on a 5-year basis is appropriate[7]. This amount will be included in EGSL's revenue requirement for the River Bend decommissioning funding plan, with collections to begin with the September 2010 billing cycle rate change scheduled to occur through the implementation of EGSL's 2009 Test Year Formula Rate Plan and further finds that these costs are to be treated as "Extraordinary Costs" and recovered outside of the earnings sharing mechanism of the Formula Rate Plan. This calculation is a 5-year step funding plan recommended by Staff and reflects the beginning fund balances, the investment portfolio allocations, escalation and earnings rates, 5-year funding increments, and other assumptions set forth in the Attached Exhibit B.

8. The NRC financial assurance analysis is not a ratemaking adequacy test but is instead a financial adequacy test devised specifically and solely for that purpose. Thus, the financial adequacy test and the resulting implications for ratemaking can differ. Recognizing this fact, the Commission hereby allows contributions to the decommissioning trust fund during the decommissioning period to be considered for purposes of determining whether NRC financial assurance requirements are met For Waterford 3, funding is assumed to occur for the first seven years of the expected ten-year decommissioning period, consistent with the NRC's own calculation of the Waterford 3 minimum decommissioning amount. Staff also assumed funding of the trust through ratepayer contributions during the first six years of the decommissioning period for River Bend.

9. The Staff's decommissioning revenue requirement developed for the River Bend nuclear facility, which is hereby adopted by the Commission, reflects the amount to fully fund the Louisiana retail jurisdictional share of the regulated 70% portion of the unit, including the portion that comprises what is known as the Deregulated Asset Plan ("DAP"). Under the provisions of LPSC Order Nos.

7 For EGSL the $7.843 million amount is on a retail basis.

U-17282 D (1/26/88) and U-17282 K (1/12/92) establishing and modifying the River Bend DAP, EGSL has the following options: (1) selling the DAP capacity to customers at a rate of 4.6 cents per kWh ($46 per MWh), recovered through the Company's Fuel Adjustment Clause, (2) in response to a bona fide offer approved by the LPSC, selling the capacity into the market and sharing proceeds with customers on a 50/50 basis for amounts in excess of 4.6 cents per kWh, or (3) if EGSL requests approval by the LPSC to sell the capacity into the market in response to a bona fide offer, and the LPSC disapproves such off system sale, the purchase price by which the DAP capacity will be sold to customers and recovered through the Company's Fuel Adjustment Clause will be adjusted to 4.6 cents per kWh plus 50 percent of the increment above 4.6 cents per kWh offered by a third party. Seven years after the DAP was approved, in Order U-19904-C (12/29/94), the Commission determined that nuclear decommissioning costs associated with the DAP capacity should be considered to be part of the 4.6 cents per kWh rate established by the DAP instead of separately recovered from customers. The nuclear decommissioning costs for the DAP portion of River Bend should be returned to EGSL's revenue requirement consistent with the original DAP order and collected separately, and in addition to, the 4.6 cents per kWh. EGSL agrees that as long as the DAP portion of the decommissioning revenue requirement is collected separately, and in addition to, the 4.6 cents per kWh, the Company will not sell the DAP capacity into the market and/or realize any amount in excess of 4.6 cents per kWh in the event it receives a bona fide offer by a third party, for the earlier of 1) a period of 5 years or 2) until EGSL receives a final ruling on its application for River Bend's license extension. The LPSC and its Staff will review and re-examine allocating the DAP into rates within 5 years this Order.

10. The increase in the 2010 decommissioning funding contributions of $3.5518 million for ELL and $7.843 million for EGSL will be allocated to and recovered from each applicable rate schedule, as identified in Statement A of Rider FRP-5 for ELL and Rider FRP-1 for EGSL, in proportion to base revenues before the application of the monthly fuel adjustment.

11. This Commission finds that the Companies have complied with, or are not in conflict with, the provisions of all applicable LPSC Orders governing the Companies Joint Application filed December 29, 2009 in this matter.

12. The proposed funding amounts of this Order must be accepted by the NRC. If for any reason the NRC does not accept the proposed funding amounts set forth, the LPSC will promptly undertake to re-examine and review the funding amounts and the related issues which are the subject of a NRC refusal.

13. This Commission affirms the language of its prior Orders, namely Item 8 of settlement term sheet for Consolidated Order Nos. U-22491, U-23358, U-24182, U-24993, U-25687 dated January, 8 2003 and Item 4 of the settlement term sheet for Order No. U-20925 RRF 2004 dated May 25, 2005 that in the event that the NRC formally notifies EGSL or ELL or the River Bend or Waterford 3 licensee that the decommissioning funding for either River Bend or Waterford 3, individually or collectively, is or would become inadequate, then ELL or EGSL or both would be permitted recognition in rates of decommissioning expense at a level sufficient to address reasonably the NRC's concern as expressed in the notification.

14. For ratemaking purposes the amount of the decommissioning accrual to be reflected in rates shall track, on a prospective basis, for the rate effective period, the specific annual amounts set out in the agreed upon decommissioning funding plan or any subsequent Commission-approved decommission funding plan on a monthly pro rata basis. Such derived amounts shall form the basis for

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8 The retail increase is $ 3.482 million.

subsequent rate changes. To the extent that the Companies remain subject to Formula Rate Plans with scheduled rate implementations where rate changes do not occur on January 1, the Companies shall make pro forma adjustments to their Formula Rate Plan Filings reflecting any prospective changes to decommissioning accruals that would occur in the rate effective period, on a monthly pro rata basis. These pro forma adjustments shall be treated as Extraordinary Costs outside of any bandwidth sharing. In the event the Companies are no longer under Formula Rate Plans, the rate treatment of decommissioning costs will be determined by subsequent Commission Order. The Companies and the Staff reserve the right to modify this procedure upon mutual agreement if circumstances warrant.

15. Except as stated herein and as set forth in prior Commission Orders, this Order, including the calculation methodology reflected in the Exhibits to this Order, shall have no precedential effect in any other proceedings involving issues similar to those resolved herein and shall be without prejudice to the right of any party to take any position on any such similar issue in future base rate proceedings, including Formula Rate Plan proceedings, or in other related regulatory proceedings or appeals.

16. This Order is effective immediately.

BY ORDER OF THE COMMISSION
BATON ROUGE, LOUISIANA

August 27, 2010

/S/ LAMBERT C. BOISSIERE, III
DISTRICT III
CHAIRMAN LAMBERT C. BOISSIERE, III

/S/ JAMES M. FIELD
DISTRICT II
VICE CHAIRMAN JAMES M. FIELD

/S/ FOSTER L. CAMPBELL
DISTRICT V
COMMISSIONER FOSTER L. CAMPBELL

/S/ ERIC F. SKRMETTA
DISTRICT I
COMMISSIONER ERIC F. SKRMETTA

EVE KAHAO GONZALEZ
SECRETARY

/S/ CLYDE C. HOLLOWAY
DISTRICT IV
COMMISSIONER CLYDE C. HOLLOWAY

ORDER NO. U-31237

EXHIBIT A

Entergy Louisiana, LLC
Waterford-3 Decommissioning Model
Revenue Requirement Summary
($000)

Line No	Year	Total Company (1)	LPSC Jurisdiction (2)	CNO Jurisdiction (3)
1	2010	5,947	5,831	116
2	2011	5,947	5,831	116
3	2012	5,947	5,831	116
4	2013	5,947	5,831	116
5	2014	5,947	5,831	116
6	2015	6,821	6,688	133
7	2016	6,821	6,688	133
8	2017	6,821	6,688	133
9	2018	6,821	6,688	133
10	2019	6,821	6,688	133
11	2020	7,731	7,580	151
12	2021	7,731	7,580	151
13	2022	7,731	7,580	151
14	2023	7,731	7,580	151
15	2024	7,731	7,580	151

Notes:
(1) See Exhibit A Page 2.
(2) Total Company * LPSC Production Demand Allocation Factor 98.05%.
(3) Total Company - LPSC Jurisdiction.

Entergy Louisiana, LLC
Waterford-3 Decommissioning Model
Revenue Requirement, Fund Balance and Expenditure Summary
($000)

Line No	Year	Total Company Revenue Rqmt. [1]	Tax Qualified [2]	Decomm. Expend. [4]
1	Beginning Balance		215,081	
2	2010	5,947	227,329	0
3	2011	5,947	246,951	0
4	2012	5,947	268,384	0
5	2013	5,947	291,400	0
6	2014	5,947	316,413	0
7	2015	6,821	344,050	0
8	2016	6,821	373,580	0
9	2017	6,821	405,077	0
10	2018	6,821	438,789	0
11	2019	6,821	474,814	0
12	2020	7,731	514,259	0
13	2021	7,731	556,427	0
14	2022	7,731	601,516	0
15	2023	7,731	647,991	0
16	2024	7,731	692,624	3,004
17	2025	8,887	658,328	85,183
18	2026	8,887	509,811	193,388
19	2027	8,887	344,370	203,929
20	2028	8,887	262,117	111,237
21	2029	8,887	170,727	115,650
22	2030	10,248	88,810	100,668
23	2031	-	44,001	49,090
24	2032	-	542	45,564
25	2033	-	0	552

Notes:

[1] The annual Revenue Requirement (5,947) is chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
[2] See Exhibit A Page 2.
[3] See Exhibit A Page 3.
[4] Non-Tax Qualified Trust Balance + Tax Qualified Trust Balance.
[5] See Exhibit A Page 4.

Entergy Louisiana, LLC
Waterford-3 Decommissioning Model
Tax Qualified Trust Detail
($000)

Line No	Year	Revenue Rqmt. [1]	Tax Qualified Trust: Earning Rate [2]	Transfer To Trust [3]	Earnings [4]	Mgmt. Fee [5]	Net Additions [6]	Decomm. Expend. [7]	Balance [8]	Qualifying Percent
1	Beginning Balance at 3/31/10								215,061	
2	2010	5,947	6.71%	3,076	9,407	215	12,268	0	227,329	100.00%
3	2011	5,947	6.95%	5,947	13,904	229	19,622	0	246,951	100.00%
4	2012	5,947	6.20%	5,947	15,733	248	21,433	0	268,384	100.00%
5	2013	5,947	6.29%	5,947	17,334	265	23,016	0	291,400	100.00%
6	2014	5,947	6.47%	5,947	19,351	285	25,013	0	316,413	100.00%
7	2015	6,821	6.50%	6,821	21,123	307	27,637	0	344,050	100.00%
8	2016	6,821	6.52%	6,821	23,020	331	29,510	0	373,560	100.00%
9	2017	6,821	6.54%	6,821	25,053	357	31,518	0	405,077	100.00%
10	2018	6,821	6.57%	6,821	27,275	384	33,712	0	438,789	100.00%
11	2019	6,821	6.59%	6,821	29,617	413	36,025	0	474,814	100.00%
12	2020	7,731	6.61%	7,731	32,159	446	39,445	0	514,259	100.00%
13	2021	7,731	6.63%	7,731	34,917	479	42,168	0	556,427	100.00%
14	2022	7,731	6.65%	7,731	37,876	516	45,089	0	601,516	100.00%
15	2023	7,731	6.38%	7,731	39,298	555	46,474	0	647,991	100.00%
16	2024	7,731	6.12%	7,731	40,500	594	47,637	3,004	692,624	100.00%
17	2025	8,867	5.75%	8,867	40,653	632	48,888	85,183	656,328	100.00%
18	2026	8,867	5.76%	8,867	38,604	601	46,870	193,388	509,811	100.00%
19	2027	8,867	5.77%	8,867	30,096	474	38,489	203,929	344,370	100.00%
20	2028	8,867	5.78%	8,867	20,448	331	28,984	111,237	262,117	100.00%
21	2029	8,867	5.79%	8,867	15,653	260	24,260	115,650	170,727	100.00%
22	2030	10,248	4.88%	10,248	8,683	181	18,749	100,666	88,810	100.00%
23	2031	0	4.88%	0	4,387	106	4,281	49,090	44,001	100.00%
24	2032	0	4.88%	0	2,173	67	2,106	45,564	542	100.00%
25	2033	0	4.88%	0	27	17	10	552	0	100.00%
								0		

Notes:

[1] The annual Revenue Requirement (5,947) is chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
[2] Projected after-tax earning rate.
[3] Revenue Requirement * Qualifying Percentage (100%).
[4] Prior Year Balance Compounded Semiannually At Current Year Earnings Rate + ½ Current Year Transfer * Current Year Earnings Rate.
[5] Calculated in accordance with fee schedules for manager and trustee fees and applicable tax rates. See Exhibit A Page 4.
[6] Transfer + Earnings - Management Fee.
[7] Assumes that decommissioning expenditures are made at year end. See Exhibit A Page 3.
[8] Prior Year Balance + Net Additions - Decommissioning Expenditures.

Entergy Louisiana, LLC
Waterford-3 Decommissioning Model
Decommissioning Expenditures
($000)

Line No	Year	CPIU [1]	Cum. CPIU	Cum. Nuclear Cost Esc. [2]	Decommissioning Expenditures Estimate [3]	Decommissioning Expenditures Escalation. [4]
1	2008	N/A	N/A	1.0000	0	0
2	2009	N/A	1.000	1.0425	0	0
3	2010	1.0217	1.022	1.0868	0	0
4	2011	1.0222	1,045	1.1330	0	0
5	2012	1.0228	1.069	1.1812	0	0
6	2013	1.0231	1.094	1.2314	0	0
7	2014	1.0235	1 120	1.2837	0	0
8	2015	1.0240	1,147	1.3383	0	0
9	2016	1.0244	1,175	1.3952	0	0
10	2017	1.0249	1.204	1.4545	0	0
11	2018	1.0254	1.235	1.5163	0	0
12	2019	1.0258	1.267	1.5807	0	0
13	2020	1.0263	1.300	1.6479	0	0
14	2021	1.0267	1.335	1.7179	0	0
15	2022	1.0272	1.371	1.7909	0	0
16	2023	1.0277	1.409	1.8670	0	0
17	2024	1.0282	1.449	1.9463	1,543	3.004
18	2025	1,0287	1.491	2.0290	41,983	85,183
19	2026	1,0293	1.535	2.1152	91,428	193,388
20	2027	1,0298	1.581	2.2051	92,481	203,929
21	2028	1.0304	1.629	2.2988	48,389	111.237
22	2029	1.0310	1.679	2.3965	48,258	115.650
23	2030	1.0261	1.723	2.4984	40,292	100,668
24	2031	1,0261	1.768	2.6046	18,847	49,090
25	2032	1.0261	1.814	2.7153	16,781	45,564
26	2033	1.0261	1.861	2.8307	195	552
27	Total Expenditures				400,197	908,264

Notes:

[1] CPIU per Global Insight Forecast for 2010 - 2029; the 2.61% for 2030-2034 is the average for 2010 to 2029.

[2] Cumulative Nuclear Cost Escalator at 4.25% per year.

[3] Decommissioning Cost Estimate per 2008 NRC Minimum (2008 dollars).

[4] Decommissioning Cost Estimate * Cumulative Nuclear Cost Escalator.

Entergy Louisiana, LLC
Waterford-3 Decommissioning Model
Fees and Other Data ($ in Thousands)

Tax Qualified Trustee and Investment Manager Fee Schedules

TQ Annual Fees 19.500

	Breakpoints ($000)	Basis Points	Adder ($ 000) Fixed [1]	Adder ($ 000) Cumulative
TQ Trustee Fees	0	1.00		
TQ Manager Fee	0	22.70		
	5,000	17.70	11.350	11.350
	8,000	16.90	5.310	16.660
	16,000	15.70	13.520	30.180
	20,000	9.50	6.280	36.460

Miscellaneous Input Data

Bad Debt Rate [2]	0.00%	Nuclear Cost Escalator [7]	4.25%
Revision Year [3]	2010	Jurisdictional Allocation Factor [8]	100.00%
Cost Estimate Year [4]	2008	TQ Fund Federal Tax Rate [5]	20.00%
Composite Tax Rate [5]	38.48%	End of Funding Period	12/31/2030
ELL Funding Interest [6]	100.00%		

Notes:

[1] Calculated as in the following example: 6.280 = 15.70bp * (20,000 - 16,000) / 10,000
For balance of $25M: TQ Management Fee = 41.210 = 36.460 + (9.50bp * (25,000 - 20,000)) / 10,000.
[2] Bad Debts are assumed to be zero.
[3] First year showing impact of revised decommissioning revenue requirements.
[4] Year upon which the decommissioning cost estimate is based.
[5] State Income Tax Rate is 8.00%, effective rate is 5.35%.
[6] Entergy Louisiana, LLC, funding interest in Waterford-3 is 100%.
[7] Nuclear Cost Escalator is 4.25%
[8] Production demand allocator for Louisiana Retail.

ORDER NO. U-31237

EXHIBIT B

5-Year Step

Entergy Gulf States Louisiana, LLC
River Bend Decommissioning Model
Louisiana Retail
Non-Tax Qualified Trust Detail
($000)

Line No	Year	Revenue Rqmt. [1]	Non-Tax Qualified Trust: Earning Rate [2]	Transfer To Trust [3]	Earnings [4]	Mgmt. Fee [5]	Net Additions [6]	Decomm. Expend. [7]	Balance [8]	NTQ % to contribute
1	Beginning Balance at 3/31/10								14,888	
2	2010	7,843	5.45%	0	822	17	805	0	15,691	0.00%
3	2011	7,843	5.54%	0	881	18	864	0	16,555	0.00%
4	2012	7,843	5.80%	0	974	19	956	0	17,511	0.00%
5	2013	7,843	5.87%	0	1,043	19	1,024	0	18,534	0.00%
6	2014	7,843	5.97%	0	1,123	20	1,103	0	19,637	0.00%
7	2015	8,998	5.99%	0	1,194	21	1,173	0	20,809	0.00%
8	2016	8,998	6.01%	0	1,269	22	1,247	0	22,057	0.00%
9	2017	8,998	6.02%	0	1,348	23	1,324	0	23,381	0.00%
10	2018	8,998	6.04%	0	1,434	25	1,409	0	24,790	0.00%
11	2019	8,998	6.06%	0	1,525	26	1,499	0	26,289	0.00%
12	2020	10,195	6.08%	0	1,623	27	1,595	0	27,884	0.00%
13	2021	10,195	6.09%	0	1,724	29	1,695	0	29,579	0.00%
14	2022	10,195	6.02%	0	1,807	30	1,777	0	31,356	0.00%
15	2023	10,195	5.97%	0	1,900	32	1,868	0	33,225	0.00%
16	2024	10,195	5.25%	0	1,767	33	1,734	0	34,958	0.00%
17	2025	11,693	5.10%	0	1,806	35	1,771	12,408	24,321	0.00%
18	2026	11,693	4.89%	0	1,204	25	1,178	25,499	0	0.00%
19	2027	11,693	4.89%	0	0	0	0	0	0	0.00%
20	2028	11,693	4.89%	0	0	0	0	0	0	0.00%
21	2029	11,693	4.89%	0	0	0	0	0	0	0.00%
22	2030	13,513	4.89%	0	0	0	0	0	0	0.00%
23	2031	0	4.51%	0	0	0	0	0	0	0.00%
24	2032	0	4.51%	0	0	0	0	0	0	0.00%
25	2033	0	4.51%	0	0	0	0	0	0	0.00%
26	2034	0	4.51%	0	0	0	0	0	0	0.00%

Notes:

[1] See Exhibit B Page 1.
[2] Projected after-tax earning rate.
[3] Revenue Requirement * (1 - Qualifying Percentage).
[4] Prior Year Balance Compounded Semiannually at Current Year Earnings Rate + ½ Current Year Transfer * Current Year Earnings Rate.
[5] Calculated on average balance (Avg. Bal = Prior Yr. Bal. + ½ (Transfers + Earnings) in accordance with the fee schedules for trustees and managers and applicable tax rates. See Exhibit B Page 5.
[6] Transfer + Earnings - Management Fee.
[7] Assumes that the Non-Tax Qualified Balance is utilized to pay the decommissioning costs before the TQ Balance. See Exhibit B Page 4 for the total.
[8] Prior Year Balance + Net Additions - Decommissioning Expenditures.

Entergy Gulf States Louisiana, LLC
River Bend Decommissioning Model
Louisiana Retail
Tax Qualified Trust Detail
($000)

			Tax Qualified Trust							
Line No	Year	Revenue Rqmt. [1]	Earning Rate [2]	Transfer To Trust [3]	Earnings [4]	Mgmt. Fee [5]	Net Additions [6]	Decomm. Expend. [7]	Balance [8]	Qualifying Percent
1	Beginning Balance at 3/31/10								32,940	
2	2010	7,843	5.50%	2,614	1,431	31	4,014	0	36,954	100.00%
3	2011	7,843	5.83%	7,843	2,414	36	10,221	0	47,176	100.00%
4	2012	7,843	6.20%	7,843	3,213	42	11,014	0	58,189	100.00%
5	2013	7,843	6.29%	7,843	3,964	49	11,758	0	69,947	100.00%
6	2014	7,843	6.47%	7,843	4,852	57	12,638	0	82,585	100.00%
7	2015	8,996	6.50%	8,996	5,748	65	14,678	0	97,263	100.00%
8	2016	8,996	6.52%	8,996	6,738	75	15,659	0	112,922	100.00%
9	2017	8,996	6.54%	8,996	7,800	85	16,711	0	129,633	100.00%
10	2018	8,996	6.57%	8,996	8,952	96	17,852	0	147,485	100.00%
11	2019	8,996	6.59%	8,996	10,176	107	19,064	0	166,549	100.00%
12	2020	10,195	6.61%	10,195	11,528	120	21,604	0	188,153	100.00%
13	2021	10,195	6.63%	10,195	13,019	133	23,081	0	211,234	100.00%
14	2022	10,195	6.65%	10,195	14,620	148	24,667	0	235,901	100.00%
15	2023	10,195	6.39%	10,195	15,641	164	25,672	0	261,573	100.00%
16	2024	10,195	6.12%	10,195	16,565	180	26,581	0	288,154	100.00%
17	2025	11,693	5.75%	11,693	17,143	197	28,639	0	316,793	100.00%
18	2026	11,693	5.76%	11,693	18,847	215	30,325	23,543	323,575	100.00%
19	2027	11,693	5.76%	11,693	19,243	220	30,717	103,721	250,570	100.00%
20	2028	11,693	5.76%	11,693	14,977	173	26,498	97,774	179,294	100.00%
21	2029	11,693	5.76%	11,693	10,813	128	22,378	67,507	134,166	100.00%
22	2030	13,513	5.76%	13,513	8,228	100	21,642	70,378	85,430	100.00%
23	2031	0	4.88%	0	4,220	64	4,156	50,108	39,478	100.00%
24	2032	0	4.88%	0	1,950	35	1,915	24,761	16,632	100.00%
25	2033	0	4.88%	0	822	20	801	15,917	1,516	100.00%
26	2034	0	4.88%	0	75	7	67	1,584	0	100.00%

Notes:

[1] See Exhibit B Page 1.
[2] Projected after-tax earning rate.
[3] Revenue Requirement * Qualifying Percentage.
[4] Prior Year Balance Compounded Semiannually at Current Year Earnings Rate + ½ Current Year Transfer * Current Year Earnings Rate.
[5] Calculated on average balance (Avg. Bal = Prior Yr. Bal. + ½ (Transfers + Earnings) in accordance with the fee schedules for trustees and managers and applicable tax rates. See Exhibit B Page 5.
[6] Transfer + Earnings - Management Fee.
[7] Assumes that the Non-Tax Qualified Balance is utilized to pay the decommissioning costs before the TQ Balance. See Exhibit B Page 4.
[8] Prior Year Balance + Net Additions - Decommissioning Expenditures.

Entergy Gulf States Louisiana, LLC
River Bend Decommissioning Model -
Louisiana Retail
Decommissioning Expenditures
($000)

					Decommissioning Expenditures			
Line No	Year	CPIU [1]	Cum. CPIU	Cum. Nuclear Cost Esc. [2]	Regulated 70% [3]	EGSL Portion of Regulated 70% [4]	LA Retail [5]	LA Retail - Escalated [6]
1	2008	N/A	N/A	1.0000	0	0	0	0
2	2009	N/A	1.000	1.0425	0	0	0	0
3	2010	1.0217	1.022	1.0868	0	0	0	0
4	2011	1.0222	1.045	1.1330	0	0	0	0
5	2012	1.0226	1.069	1.1812	0	0	0	0
6	2013	1.0231	1.094	1.2314	0	0	0	0
7	2014	1.0236	1.120	1.2837	0	0	0	0
8	2015	1.0240	1.147	1.3383	0	0	0	0
9	2016	1.0244	1.175	1.3952	0	0	0	0
10	2017	1.0249	1.204	1.4545	0	0	0	0
11	2018	1.0254	1.235	1.5163	0	0	0	0
12	2019	1.0258	1.267	1.5807	0	0	0	0
13	2020	1.0263	1.300	1.6479	0	0	0	0
14	2021	1.0267	1.335	1.7179	0	0	0	0
15	2022	1.0272	1.371	1.7909	0	0	0	0
16	2023	1.0277	1.409	1.8670	0	0	0	0
17	2024	1.0282	1.449	1.9463	0	0	0	0
18	2025	1.0287	1.491	2.0290	11,043	6,350	6,116	12,408
19	2026	1.0293	1.535	2.1152	41,868	24,074	23,186	49,042
20	2027	1.0298	1.581	2.2051	84,938	48,839	47,037	103,721
21	2028	1.0304	1.629	2.2988	76,804	44,162	42,532	97,774
22	2029	1.0310	1.679	2.3965	50,867	29,249	28,169	67,507
23	2030	1.0261	1.723	2.4984	50,867	29,249	28,169	70,378
24	2031	1.0261	1.768	2.6046	34,740	19,976	19,238	50,108
25	2032	1.0261	1.814	2.7163	16,467	9,469	9,119	24,781
26	2033	1.0261	1.861	2.8307	10,154	5,839	5,623	15,917
27	2034	1.0261	1.910	2.9510	969	557	537	1,584
28	Total Expenditures				378,717	217,762	209,726	493,200

Notes:

[1] CPIU per Global Insight Forecast for 2010 - 2029; the 2.61% for 2030-2034 is the average for 2010 to 2029.

[2] Cumulative Nuclear Cost Escalator at 4.25% per year.

[3] Decommissioning Cost Estimate per 2008 NRC Minimum (2008 dollars).

*[4] Decommissioning Cost Estimate * Entergy Gulf States Funding Interest (100%) * 1-TX Retail Allocation per PPA with ETI (42.5%).*

*[5] EGSL Funding Share of Cost Estimate * (Louisiana Retail Production Demand Allocator (96.3094%)*

*[6] Louisiana Retail * Cumulative Nuclear Cost Escalator.*

Entergy Gulf States Louisiana, LLC
River Bend Decommissioning Model - Louisiana
Fees and Other Data ($ in Thousands)

Tax Qualified Trustee and Investment Manager Fee Schedules [1]

TQ Annual Fees 6.328

	Breakpoints ($000)	Basis Points	Adder ($ 000) Fixed [1]	Adder ($ 000) Cumulative
TQ Manager & Asset Based Trustee Fee	0	18.50		
	1,333	17.50	2.467	2.467
	2,083	15.00	1.313	3.779
	2,667	13.50	0.875	4.654
	3,333	12.00	0.900	5.554
	4,167	9.50	1.000	6.554
	12,333	7.00	7.758	14.312

Non-Tax Qualified Trustee and Investment Manager Fee Schedules

NTQ Annual Fees 5.000

	Breakpoints ($000)	Basis Points	Adder ($ 000) Fixed [1]	Adder ($ 000) Cumulative
NTQ Manager & Asset Based Trustee Fee	0	18.50		
	1,000	17.50	1.850	1.850
	1,560	15.00	0.980	2.830
	2,000	13.50	0.660	3.490
	2,500	12.00	0.675	4.165
	3,130	9.50	0.756	4.921
	9,250	7.00	5.814	10.735

Miscellaneous Input Data

Bad Debt Rate [2]	0.00%	Nuclear Cost Escalator [7]	4.25%
Revision Year [3]	2010	EGSL - LA Retail [8]	98.3094%
Cost Estimate Year [4]	2008	TQ Fund Federal Tax Rate 98 & After [9]	20.00%
Composite Effective Tax Rate [5]	38.48%	End of Funding Period	12/31/2030
Entergy Gulf States Ownership Share [6]	100.00%		

Notes:

[1] Calculated as in the following example:
For balance of $10M: TQ Management Fee = 9.637 = 6.554 + (7.0bp * (10,000 - 4,167)) / 10,000.

[2] Bad Debts handled in Cost of Service Study.

[3] First year showing impact of revised decommissioning revenue requirements

[4] Year upon which the decommissioning cost estimate is based.

[5] Louisiana Income Tax Rate is 8.0%, however, in Louisiana Federal Income taxes are deductible, therefore the effective Louisiana rate is 5.35%. The effective Federal Rate is 33.13% resulting in a Composite Rate of 38.48%.

[6] Cost Estimate provided for Regulated Portion (70%) so EGSL funding interest is 100%.

[7] Nuclear Cost Escalator is 4.25%

[8] Per the 2009 FRP based on 12/31/08 Test Year. This is LA Retail portion of EGSL.

[9] Effective Federal Tax Rates for Qualified Trusts. These trusts do not pay state taxes.

Attachment 4-D
(6 pages)

CNO Resolution R-95-1081 in Docket UD-95-1
and
IRS Schedule of Ruling Amounts

E

RESOLUTION
R-95-1061

CITY HALL: August 8, 1995

TKC

BY: COUNCILMEMBERS CARTER, SINGLETON, GLAPION, HAZEUR-DISTANCE, TERRELL, THOMAS AND WILSON

RESOLUTION AND ORDER DIRECTING INVESTIGATION OF LOUISIANA POWER AND LIGHT COMPANY'S (LP&L) RATES AND CHARGES RELATIVE TO ALGIERS AND ESTABLISHING COUNCIL DOCKET NO. UD-95-1

WHEREAS, pursuant to Section 4-1604 of the Home Rule Charter for the City of New Orleans ("City"), the Council of the City of New Orleans ("Council") has vested in it all powers of supervision, regulation, and control over the rates of electric, gas, heat, power ... and other public utilities within the City, including the New Orleans Public Service, Inc. ("NOPSI") and the Louisiana Power and Light Company ("LP&L"); and

WHEREAS, in 1986 LP&L applied to the Council for a rate increase related primarily to the construction costs associated with its Waterford 3 Nuclear Power Plant and LP&L's 14% share of Grand Gulf Unit No. I, which application was considered in Docket No. CD-86-1; and

WHEREAS, in 1989, during the pendency of the Council's decision with respect to LP&L's rate increase application, the Council passed Resolution R-89-03 establishing Docket No. CD-89-I to investigate the allocation and appropriate disposition of the proceeds received by LP&L incident to litigation with United Gas Pipeline Company ("United"); and

WHEREAS, after considering all of the evidence in Dockets No. CD-86-1 and CD-89-I, which dockets were consolidated for the purpose of procedurally expediting the disposition of the dockets, the Council determined that LP&L should be allowed to increase its base electric rates applicable to customers in Algiers on a phase-in basis provided it amortized $3,940,000 dollars of United proceeds allocable to Algiers over the same period; and

WHEREAS, the rate increase was further conditioned on LP&L's agreement to not seek a base rate increase to be effective through May 14, 1994, i.e., rates were to be "capped"; and

WHEREAS, a similar rate cap was in place on that portion (approximately 98%) of the LP&L system that is subject to the jurisdiction of the Louisiana Public Service Commission ("LPSC"), which also ended on May 14, 1994; and

WHEREAS, in 1994 a rate making investigation was initiated by the LPSC to review the rates and operations of LP&L, and hearings were held by the LPSC in March, 1995; and

WHEREAS, following the hearings, the LPSC ordered that LP&L's base rates should be reduced by $49.4 million; and

WHEREAS, on July 5, 1995, LP&L filed rates with the LPSC, which filing will decrease the electric rates charged by LP&L outside Algiers (hereinafter, State level), which filing implemented $34.7 million of an ordered $49.4 million decrease ($14.7 million is subject to a temporary restraining order) mandated by LPSC Order No. U-20925; and

WHEREAS, LP&L's filing of July 19, 1995 with the Council, seeks to decrease the current Algiers rates to the State level rates as filed by LP&L with the LPSC on July 5, 1995, to expedite implementation of reduced rates for the benefit of Algiers customers (additionally, LP&L indicates that after the issue relating to the temporary restraining order is resolved, a filing for a revision to the Algiers rates will be made at the then resolved State pricing level); and

WHEREAS, that portion of the LP&L system regulated by the Council is approximately 2%; and

WHEREAS, as detailed in the LP&L filing, the typical summer residential bill for 1,000 kWh will decrease from $78.58 to $76.78, a decrease of $1.80, a typical commercial bill for 10 kW and 1,825 kWh will decrease from $207.88 to

$202.52, a decrease of $5.36, and a typical industrial bill for 1,000 kW and 182,500 kWh will decrease from $12,988.65 to $12,709.40, a decrease of $279.25; and

WHEREAS, the Council finds it in the Public Interest to establish an expedited schedule to consider the implementation of reduced rates for Algiers Ratepayers; now, therefore

BE IT RESOLVED BY THE COUNCIL OF THE CITY OF NEW ORLEANS that LP&L's filing for decrease of electric rates in the 15th Ward of the City ("Algiers") is accepted for filing by the Council and the rates are hereby adopted and shall be placed into effect by LP&L for bills rendered on or after July 19, 1995.

BE IT FURTHER RESOLVED that the Council is hereby initiating an investigation into the reasonableness of LP&L's rates and charges relative to Algiers under Docket No. UD 95-1 which Docket is hereby established.

BE IT FURTHER RESOLVED that the following Procedural Schedule and Rules governing this proceeding are hereby established:

August 8, 1995 -	Discovery commences by the Council's Advisors.
August 11, 1995 -	Publication of the Public Notice For Interventions.
August 21, 1995 -	Closing Date for the filing of Interventions. Interventions and all service shall be filed in accordance with the Official Service List established for this proceeding by the City Council Utilities Regulatory Office.
August 28, 1995 -	Deadline for opposing interventions.
September 7, 1995 -	City Council Action on any oppositions to interventions.
September 18, 1995 -	Last Date for submission of Discovery Requests by any party. All Discovery in this Docket is to be considered 15 Day "Rolling Discovery" (i.e. All Discovery responses are due within 15 days of the receipt of the Request) and all parties are encouraged to commence discovery as soon as possible to expedite the Discovery process.
October 3, 1995 -	Discovery Closes.
October 18, 1995 -	Submission of statements of position with regard to the justness and reasonableness of the then effective rates by all parties to the proceeding other than the Council's advisors.

Entergy Louisiana, LLC
Waterford-3 Decommissioning Model
Revenue Requirement Summary
($000)

Line No	Year	Total Company (1)	LPSC Jurisdiction (2)	CNO Jurisdiction (3)
1	2010	5,947	5,831	116
2	2011	5,947	5,831	116
3	2012	5,947	5,831	116
4	2013	5,947	5,831	116
5	2014	5,947	5,831	116
6	2015	6,821	6,688	133
7	2016	6,821	6,688	133
8	2017	6,821	6,688	133
9	2018	6,821	6,688	133
10	2019	6,821	6,688	133
11	2020	7,731	7,580	151
12	2021	7,731	7,580	151
13	2022	7,731	7,580	151
14	2023	7,731	7,580	151
15	2024	7,731	7,580	151
16	2025	8,867	8,694	173
17	2026	8,867	8,694	173
18	2027	8,867	8,694	173
19	2028	8,867	8,694	173
20	2029	8,867	8,694	173
21	2030	10,246	10,047	200

Notes:
(1) See Exhibit A Page 2.
(2) Total Company * LPSC Production Demand Allocation Factor 98.05%.
(3) Total Company - LPSC Jurisdiction.

Entergy Louisiana, LLC
Nuclear Decommissioning Payment Schedule
As of 11/15/2006

Per Sub.Sec. 468A(b) of the Internal Revenue Code
The amount paid into decommisioning funds for any taxable year is limited to the lesser of the amount of nuclear decommissioning costs allocable to this fund which is included in the the taxpayers cost of service for ratemaking purposes for the tax year OR the ruling amounts applicable to this year.

	Payment Schedule		
	LPSC	Council	Total
2005	4,231,513	188,638	4,420,151
2006	2,230,896	188,638	2,419,534
2007	2,230,896	188,638	2,419,534
2008	2,230,896	188,638	2,419,534
2009	2,230,896	188,638	2,419,534
2010	2,566,521	188,638	2,755,159
2011	2,566,521	188,638	2,755,159
2012	2,566,521	188,638	2,755,159
2013	2,566,521	188,638	2,755,159
2014	2,566,521	188,638	2,755,159
2015	2,863,777	188,638	3,052,415
2016	2,863,777	188,638	3,052,415
2017	2,863,777	188,638	3,052,415
2018	2,863,777	188,638	3,052,415
2019	2,863,777	188,638	3,052,415
2020	3,194,524	188,638	3,383,162
2021	3,194,524	188,638	3,383,162
2022	3,194,524	188,638	3,383,162
2023	3,194,524	188,638	3,383,162
2024	3,194,524	188,638	3,383,162
2025	3,315,029	0	3,315,029
2026	3,315,029	0	3,315,029
2027	3,315,029	0	3,315,029
2028	3,315,029	0	3,315,029
2029	3,315,029	0	3,315,029
2030	3,315,029	0	3,315,029
2031	3,315,029	0	3,315,029
2032	3,315,029	0	3,315,029
2033	3,315,029	0	3,315,029
2034	3,315,029	0	3,315,029
2035	3,315,029	0	3,315,029
2036	3,315,029	0	3,315,029
2037	3,315,029	0	3,315,029
2038	3,315,029	0	3,315,029
2039	3,315,029	0	3,315,029
2040	3,315,029	0	3,315,029
2041	3,315,029	0	3,315,029
2042	3,315,029	0	3,315,029
2043	3,315,029	0	3,315,029
2044	3,315,029	0	3,315,029

07 payment schedule	
1/2/2007	604,883.00
04/02/07	604,883.00
07/02/07	604,884.00
10/01/07	604,884.00
	2,419,534.00

CNRO-2012-00007

SERIES 5 ATTACHMENTS

5. Minimum Funding Assurance Calculation Worksheets (9 pages)

Attachment 5
Minimum Funding Assurance Calculation Worksheets

Plant name: **Arkansas Nuclear One 1**

	Month:	Day	Year:
Date of Operation:	1	1	2012
Termination of Operations:	5	20	2034

	MWth	1986$	ECI	Base Lx		Lx	Px	Fx		Ex		Bx-Vendor
PWR	2568	$97,598,400	115.0	1.98	0.65	2.28	1.790	3.671	0.13	2.58	0.22	12.28

NRC Minimum: **$440,854,517**

Licensee:	% Owned:	Amount of NRC Minimum/Site Specific:	Amount in Trust Fund:
Entergy	100.00%	$440,854,517	$303,928,142

Step 1:
Earnings Credit:

Trust Fund Balance:	Real Rate of Return per year	Years Left in License	Total Real Rate of	Total Earnings:	
$303,928,142	3.12%	22.39	1.989235003	**$604,584,498**	**Total Earnings = Trust Fund balance x (1+RRR)^Years left in license**

Step 2:
Accumulation:

Value of Annuity per year	Real Rate of Return per year	Years of Annuity:	Total Annuity:
$0	3.12%	0	$0

Total Step 2
$0

Total Step 1 + Step 2
$604,584,498

Step 3:
Decom Period:

Total Earnings:	Real Rate of Return per year	Decom Period:	Total Real Rate of	Total Earnings for Decom:	
$604,584,498	2.00%	7	0.148685668	$44,946,525	**Total Earnings for Decom = (1/2) x Total Step 4+5 x [(1+RRR)^Decom period - 1]**

Accumulation during Decon	Total of Steps 1 - 3:	
	$649,531,023	**Total = Total Earnings + Accumulation + Total Earnings for Decom**

Excess (Shortfall)	**$208,676,506**

Attachment 5
Minimum Funding Assurance Calculation Worksheets

Plant name: **Arkansas Nuclear One 2**

	Month:	Day	Year:
Date of Operation:	1	1	2012
Termination of Operations:	7	17	2038

	MWth	1986$	ECI	Base Lx		Lx	Px	Fx		Ex		Bx-Vendor
PWR	3026	$101,628,800	115.0	1.98	0.65	2.28	1.790	3.671	0.13	2.58	0.22	12.28

NRC Minimum: **$459,059,939**

Licensee:	% Owned:	Amount of NRC Minimum/Site Specific:	Amount in Trust Fund:
Entergy	100.00%	$459,059,939	$237,729,232

Step 1:
Earnings Credit:

Trust Fund Balance:	Real Rate of Return per year	Years Left in License	Total Real Rate of	Total Earnings:	
$237,729,232	3.40%	26.54	2.42901834	**$577,448,664**	**Total Earnings = Trust Fund balance x (1+RRR)^Years left in license**

Step 2:
Accumulation:

Value of Annuity per year	Real Rate of Return per year	Years of Annuity:	Total Annuity:
$0	3.40%	0	$0

Total Step 2
$0

Total Step 1 + Step 2
$577,448,664

Step 3:
Decom Period:

Total Earnings:	Real Rate of Return per year	Decom Period:	Total Real Rate of	Total Earnings for Decom:	
$577,448,664	2.00%	7	0.148685668	$42,929,170	**Total Earnings for Decom = (1/2) x Total Step 4+5 x [(1+RRR)^Decom period - 1]**

Accumulation during Decon	Total of Steps 1 - 3:	
	$620,377,835	**Total = Total Earnings + Accumulation + Total Earnings for Decom**

Excess (Shortfall)	**$161,317,896**

Attachment 5
Minimum Funding Assurance Calculation Worksheets

Plant name: **Grand Gulf**

	Month:	Day	Year:
Date of Operation:	1	1	2012
Termination of Operations:	11	1	2024

	MWth	1986$	ECI	Base Lx		Lx	Px	Fx		Ex		Bx-Vendor
BWR	3898	$135,000,000	115.0	1.98	0.65	2.28	1.790	3.671	0.13	2.66	0.22	12.54

NRC Minimum: **$618,840,903**

Licensee:	% Owned:	Amount of NRC Minimum/Site Specific:	Amount in Trust Fund:
Entergy	90.00%	$556,956,813	$423,409,202

Step 1:
Earnings Credit:

Trust Fund Balance:	Real Rate of Return per year	Years Left in License	Total Real Rate of	Total Earnings:	
$423,409,202	2.00%	12.83	1.2893442	**$545,920,199**	**Total Earnings = Trust Fund balance x (1+RRR)^Years left in license**

Step 2:
Accumulation:

Value of Annuity per year	Real Rate of Return per year	Years of Annuity:	Total Annuity:
See Annuity Sheet	2.00%	15	$0

Total Step 2	
$309,565,680	**Comes from Annuity Sheet**

Total Step 1 + Step 2
$855,485,879

Step 3:
Decom Period:

Total Earnings:	Real Rate of Return per year	Decom Period:	Total Real Rate of	Total Earnings for Decom:	
$855,485,879	2.00%	7	0.148685668	$63,599,245	**Total Earnings for Decom = (1/2) x Total Step 4+5 x [(1+RRR)^Decom period - 1]**

Accumulation during Decon	Total of Steps 1 - 3:	
	$919,085,124	**Total = Total Earnings + Accumulation + Total Earnings for Decom**

Excess (Shortfall)	**$362,128,311**

Attachment 5
Minimum Funding Assurance Calculation Worksheets

Plant name: Grand Gulf

Termination of Operations: 2025

Year	Annuity:	*Real* Rate of	*Total* Accumulatio
2009	$0	2.00%	$0
2010	$0	2.00%	$0
2011	$0	2.00%	$0
2012	$23,785,000	2.00%	$30,768,434
2013	$23,785,000	2.00%	$30,165,131
2014	$23,785,000	2.00%	$29,573,658
2015	$22,285,000	2.00%	$27,165,291
2016	$24,550,000	2.00%	$29,339,523
2017	$24,550,000	2.00%	$28,764,238
2018	$24,550,000	2.00%	$28,200,233
2019	$24,550,000	2.00%	$27,647,287
2020	$24,550,000	2.00%	$27,105,184
2021	$29,878,000	2.00%	$32,340,908
2022	$17,429,000	2.00%	$18,495,794
2023	$0	2.00%	$0
2024	$0	2.00%	$0
2025	$0	2.00%	$0
		Total:	**$309,565,680**

Total Accumulation = Annuity x (1+RRR)^Years left from Accum

Attachment 5
Minimum Funding Assurance Calculation Worksheets

Plant name: **River Bend Station (Regulated 70%)**

	Month	Day	Year
Year of Biennial:	1	1	2012
Termination of Operation:	8	29	2025

	MWth	1986$	ECI	Base Lx		Lx	Px	Fx		Ex		Bx-Vendor
BWR	3091	$131,819,000	115.0	1.98	0.65	2.28	1.790	3.671	0.13	2.66	0.22	12.54

NRC Minimum: **$604,259,178**

Licensee:	% Owned:	Amount of NRC Minimum/Site Specific:	Amount in Trust Fund:
Entergy	70.00%	$422,981,425	$192,264,458

Step 1:
Earnings Credit:

Trust Fund Balance:	Real Rate of Return per	Years Left in License	Total Real Rate of	Total Earnings:	
$192,264,458	2.0%	13.66	1.31063	**$251,986,774**	**Total Earnings = Trust Fund balance x (1+RRR)^Years left in license**

Step 2:
Accumulation:

Value of Annuity per year	Real Rate of Return per	Years of Annuity:	Total Annuity:
See Annuity Sheet	2.0%	15	$0

Total Step 2	
$182,481,679	**Comes from Annuity Sheet**

Total Step 1 + Step 2
$434,468,453

Step 3:
Decom Period:

Total Earnings:	Real Rate of Return per	Decom Period:	Total Real Rate of	Total Earnings for Decom:	
$434,468,453	2.0%	7	0.14869	$32,299,616	**Total Earnings for Decom = (1/2) x Total Step 4+5 x [(1+RRR)^Decom period - 1]**

Accumulation during Decon	Total of Steps 1 - 3:	
$78,456,000	**$545,224,069**	**Total = Total Earnings + Accumulation + Total Earnings for Decom**

Excess (Shortfall)	**$122,242,644**

Attachment 5
Minimum Funding Assurance Calculation Worksheets

Plant name: River Bend Station (Regulated 70%)

Termination of Operations: 2025

Year	LPSC	PUCT	FERC	Annuity:	Real Rate of	Total Accumulation
2009	$ -	$ -	$ -	$ -		
2010	$ -	$ -	$ -	$ -	2.0%	$0
2011	$ -	$ -	$ -	$ -	2.0%	$0
2012	$7,843,000	$2,019,000	$113,000	$9,975,000	2.0%	$12,903,726
2013	$7,843,000	$2,019,000	$113,000	$9,975,000	2.0%	$12,650,712
2014	$7,843,000	$2,019,000	$113,000	$9,975,000	2.0%	$12,402,659
2015	$8,996,000	$2,019,000	$113,000	$11,128,000	2.0%	$13,564,970
2016	$8,996,000	$2,019,000	$113,000	$11,128,000	2.0%	$13,298,990
2017	$8,995,000	$2,019,000	$113,000	$11,127,000	2.0%	$13,037,054
2018	$8,995,000	$2,019,000	$113,000	$11,127,000	2.0%	$12,781,425
2019	$8,996,000	$2,019,000	$113,000	$11,128,000	2.0%	$12,531,935
2020	$10,195,000	$2,019,000	$113,000	$12,327,000	2.0%	$13,610,004
2021	$10,195,000	$2,019,000	$113,000	$12,327,000	2.0%	$13,343,141
2022	$10,195,000	$2,019,000	$113,000	$12,327,000	2.0%	$13,081,511
2023	$10,195,000	$2,019,000	$113,000	$12,327,000	2.0%	$12,825,011
2024	$10,195,000	$2,019,000	$113,000	$12,327,000	2.0%	$12,573,540
2025	$11,693,000	$2,019,000	$165,000	$13,877,000	2.0%	$13,877,000
					Total:	**$182,481,679**
Accumulation During Decomm Period						
2026	$11,693,000	$2,019,000	$0	$13,712,000		$13,712,000
2027	$11,693,000	$2,019,000	$0	$13,712,000		$13,712,000
2028	$11,693,000	$2,019,000	$0	$13,712,000		$13,712,000
2029	$11,693,000	$2,019,000	$0	$13,712,000		$13,712,000
2030	$13,513,000	$2,019,000	$0	$15,532,000		$15,532,000
2031	$0	$2,019,000	$0	$2,019,000		$2,019,000
2032	$0	$2,019,000	$0	$2,019,000		$2,019,000
2033	$0	$2,019,000	$0	$2,019,000		$2,019,000
2034	$0	$2,019,000	$0	$2,019,000		$2,019,000
					Total:	**$78,456,000**

Total Accumulation = Annuity x (1+RRR)^Years left from Accum

Attachment 5
Minimum Funding Assurance Calculation Worksheets

Plant name: River Bend Station (Regulated 30%)

	Month	Day	Year
Year of Biennial:	1	1	2012
Termination of Operation:	8	29	2025

	MWth	1986$	ECI	Base Lx		Lx	Px	Fx		Ex		Bx-Vendor
BWR	3091	$131,819,000	115.0	1.98	0.65	2.28	1.790	3.671	0.13	2.66	0.22	12.54

NRC Minimum: **$604,259,178**

Licensee:	% Owned:	Amount of NRC Minimum/Site Specific:	Amount in Trust Fund:
Entergy	30.00%	$181,277,753	$228,652,703

Step 1:
Earnings Credit:

Trust Fund Balance:	Real Rate of Return per	Years Left in License	Total Real Rate of	Total Earnings:	
$228,652,703	2.0%	13.66	1.31063	**$299,678,150**	**Total Earnings = Trust Fund balance x (1+RRR)^Years left in license**

Step 2:
Accumulation:

Value of Annuity per year	Real Rate of Return per	Years of Annuity:	Total Annuity:
$0	2.0%	0	$0

Total Step 2
$0

Total Step 1 + Step 2
$299,678,150

Step 3:
Decom Period:

Total Earnings:	Real Rate of Return per	Decom Period:	Total Real Rate of	Total Earnings for Decom:	
$299,678,150	2.0%	7	0.14869	$22,278,923	**Total Earnings for Decom = (1/2) x Total Step 4+5 x [(1+RRR)^Decom period - 1]**

Total of Steps 1 - 3:	
$321,957,073	**Total = Total Earnings + Accumulation + Total Earnings for Decom**

Excess (Shortfall) **$140,679,319**

Attachment 5
Minimum Funding Assurance Calculation Worksheets

Plant name: **Waterford Generating Station, Unit 3**

	Month:	Day	Year:
Date of Operation:	1	1	2012
Termination of Operations:	12	18	2024

	MWth	1986$	ECI	Base Lx		Lx	Px	Fx		Ex		Bx-Vendor
PWR	3716	$105,000,000	115.0	1.98	0.65	2.28	1.790	3.671	0.13	2.58	0.22	12.28

NRC Minimum: **$474,287,737**

Licensee:	% Owned:	Amount of NRC Minimum/Site Specific:	Amount in Trust Fund:
Entergy	100.00%	$474,287,737	$253,967,667

Step 1:
Earnings Credit:

Trust Fund Balance:	Real Rate of Return per year	Years Left in License	Total Real Rate of	Total Earnings:	
$253,967,667	2.00%	12.96	1.292665351	**$328,295,203**	**Total Earnings = Trust Fund balance x (1+RRR)^Years left in license**

Step 2:
Accumulation:

Value of Annuity per year	Real Rate of Return per year	Years of Annuity:	Total Annuity:
See Annuity Sheet	2.00%	14	$0

Total Step 2	
$104,449,541	**Comes from Annuity Sheet**

Total Step 1 + Step 2
$432,744,744

Step 3:
Decom Period:

Total Earnings:	Real Rate of Return per year	Decom Period:	Total Real Rate of	Total Earnings for Decom:	
$432,744,744	2.00%	7	0.148685668	$32,171,471	**Total Earnings for Decom = (1/2) x Total Step 4+5 x [(1+RRR)^Decom period - 1]**

Accumulation during Decon	Total of Steps 1- 3:	
$53,517,000	**$518,433,215**	**Total = Total Earnings + Accumulation + Total Earnings for Decom**

Excess (Shortfall)	**$44,145,478**

Attachment 5
Minimum Funding Assurance Calculation Worksheets

Plant name: Waterford Generating Station, Unit 3

Termination of Operations: 2025

Year	LPSC	CNO	Annuity:	Real Rate of	Total Accumulation
2009	$0	$0	$0	2.00%	$0
2010	$0	$0	$0	2.00%	$0
2011	$0	$0	$0	2.00%	$0
2012	$5,831,000	$189,000	$6,020,000	2.00%	$7,787,512
2013	$5,831,000	$189,000	$6,020,000	2.00%	$7,634,816
2014	$5,831,000	$189,000	$6,020,000	2.00%	$7,485,113
2015	$6,688,000	$189,000	$6,877,000	2.00%	$8,383,025
2016	$6,688,000	$189,000	$6,877,000	2.00%	$8,218,652
2017	$6,688,000	$189,000	$6,877,000	2.00%	$8,057,502
2018	$6,688,000	$189,000	$6,877,000	2.00%	$7,899,511
2019	$6,688,000	$189,000	$6,877,000	2.00%	$7,744,619
2020	$7,580,000	$189,000	$7,769,000	2.00%	$8,577,604
2021	$7,580,000	$189,000	$7,769,000	2.00%	$8,409,415
2022	$7,580,000	$189,000	$7,769,000	2.00%	$8,244,525
2023	$7,580,000	$189,000	$7,769,000	2.00%	$8,082,868
2024	$7,580,000	$189,000	$7,769,000	2.00%	$7,924,380
				Total:	**$104,449,541**

Total Accumulation = Annuity x (1+RRR)^Years left from Accum

Accumulation During Decomm Period

2025	$8,694,000	$0	$8,694,000
2026	$8,694,000	$0	$8,694,000
2027	$8,694,000	$0	$8,694,000
2028	$8,694,000	$0	$8,694,000
2029	$8,694,000	$0	$8,694,000
2030	$10,047,000	$0	$10,047,000
2031	0	$0	$0
		Total:	**$53,517,000**