Entergy

Entergy Operations, Inc.
1340 Echelon Parkway
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Michael A. Krupa
Director
Nuclear Safety & Licensing

March 30, 2001

U. S. Nuclear Regulatory Commission
Attn.: Document Control Desk
Mail Stop OP1-17
Washington, DC 20555-0001

Subject: Entergy Operations, Inc.
Status of Decommissioning Funding Report

Grand Gulf Nuclear Station
Docket No. 50-416
License No. NPF-29

River Bend Station
Docket No. 50-458
License No. NPF-47

Waterford 3 Steam Electric Station
Docket No. 50-382
License No. NPF-38

Reference: 10 CFR50 .75 (f)(1) Reporting and recordkeeping for decommissioning planning

CNRO-2001/00015

Gentlemen:

On behalf of the various reactor licensees, Entergy Operations, Inc. ("EOI"), as operator of the nuclear power reactors listed above, submits documentation in accordance with the biennial reporting requirements contained in 10 CFR Section 50.75(f)(1). EOI will provide reports on the status of its decommissioning funding in the future in accordance with the requirements of 10 CFR Section 50.75(f)(1).

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Please address any comments or questions regarding this matter to Mr. Les England at (601) 368-5766.

Sincerely,

M. A Krupa

MAK/LJS/baa
attachments: 2. GGNS Report
3. RBS Report
4. WF3 Report
(attachment 1 - ANO Report under separate cover)
cc: (see next page)

(All Below w/o Attachments - See File Copy For Attachments)

Mr. J. L. Blount (M-ECH-62)
Mr. W. A. Eaton(G-ESC-VPNO)
Mr. R. K. Edington (R-GSB-40)
Mr. J. T. Herron (W-GSB-300)
Mr. J. R. McGaha (M-ECH-65)
Mr. E.W. Merschoff, RIV
Mr. N. S. Reynolds (Winston & Strawn)
Mr. L. Jager Smith (Wise Carter)
Mr. G. J. Taylor (M-ECH-65)
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Report on Status of Decommissioning Funding
Required by 10 CFR 50.75(f)(1)
March 31, 2001

Grand Gulf Nuclear Station

Minimum Reporting Requirements as per 10 CFR 50.75(f)(1):

1. Decommissioning funds estimated pursuant to 10 CFR 50.75(b) and (c) (2000$):	
System Energy Resources, Inc. ("System Energy") 90% ownership/leasehold interest:	$ 585,739,350 [1]
South Mississippi Electric Power Association ("SMEPA") 10% ownership interest:	$ 65,082,150 [1]
Total	$ 650,821,500
2. Market value of funds accumulated as of December 31, 2000:	
System Energy 90% ownership/leasehold interest:	$ 159,192,944 [2]
SMEPA 10% ownership interest:	$ 10,407,000 [2]
Total	$ 169,599,944
3. Current schedule of annual amounts remaining to be collected:	
System Energy 90% ownership/leasehold interest:	See Attachment 2-C
SMEPA 10% ownership interest:	See Attachment 2-D
4. Assumed rate of decommissioning cost escalation used in funding projections (Attachment 2-C):	
System Energy 90% ownership/leasehold interest:	5.50%
SMEPA 10% ownership interest:	4.00%
5. Assumed average after-tax rates of earnings used in funding projections:	
System Energy 90% ownership/leasehold interest:	See Attachment 2-C
SMEPA 10% ownership interest:	See Attachment 2-D
6. Assumed rates of other factors used in funding projections:	
System Energy 90% ownership/leasehold interest:	See Attachment 2-C
SMEPA 10% ownership interest:	See Attachment 2-D
7. Contracts assuring collection of decommissioning funds:	See Attachment 2-F&G
8. Modifications to method of providing financial assurance since March 31, 1999 filing (external sinking fund):	None
9. Material changes to trust agreements since March 31, 1999 filing:	
System Energy 90% ownership/leasehold interest:	None
SMEPA 10% ownership interest:	See Attachment 2-E

Supplemental Information:

1. Site-Specific cost estimate escalated to 2000 (1993 Base Year Dollars):	
System Energy 90% ownership/leasehold interest:	
NRC License Termination Cost:	$ 473,992,956 [3]
Non-NRC License Termination Cost:	$ 58,208,951 [3]
Total	$ 532,201,907
SMEPA 10% ownership interest:	
NRC License Termination Cost:	$ 47,642,609 [3]
Non-NRC License Termination Cost:	$ 5,850,775 [3]
Total	$ 53,493,384

Report on Status of Decommissioning Funding
Required by 10 CFR 50.75(f)(1)
March 31, 2001

Grand Gulf Nuclear Station

2. Decommissioning method assumed for planning purposes in site-specific estimate:	DECON
3. Year site-specific estimate complete:	1994 [4]
4. Frequency of updates (approximately):	once every 5 years [4]
5. Funding based on NRC minimum or site-specific estimate?:	Site-specific
6. Decommissioning rate regulation:	
System Energy 90% ownership/leasehold interest (Federal Energy Regulatory Commission):	100%
SMEPA 10% ownership interest (Rural Utilities Service):	100%

[1] See Attachment 2-A for calculation.

[2] Source: December 31, 2000 Grand Gulf Trust Fund Reports.

[3] See Attachment 2-B for calculations. Also see footnotes 4 and 5 to Attachment 2-A for information on the generic baseline cost estimate using the waste vendor disposal factor (Barnwell, South Carolina).

[4] On July 31, 2000, the FERC issued an order approving a lower decommissioning costs than requested. SERI filed a motion for rehearing which has been granted. SERI continues to collect at the requested level of $365.9 million, subject to refund. The 1999 cost update ($600.9 million) of $540.8 million for SERI's 90% has not yet been filed with the FERC.

Report on Status of Decommissioning Funding
Required by 10 CFR 50.75(f)(1)
March 31, 2001

Grand Gulf Nuclear Station

2. Decommissioning method assumed for planning purposes in site-specific estimate:	DECON
3. Year site-specific estimate complete:	1994 [4]
4. Frequency of updates (approximately):	once every 5 years [4]
5. Funding based on NRC minimum or site-specific estimate?:	Site-specific
6. Decommissioning rate regulation:	
System Energy 90% ownership/leasehold interest (Federal Energy Regulatory Commission):	100%
SMEPA 10% ownership interest (Rural Utilities Service):	100%

[1] See Attachment 2-A for calculation.

[2] Source: December 31, 2000 Grand Gulf Trust Fund Reports.

[3] See Attachment 2-B for calculations. Also see footnotes 4 and 5 to Attachment 2-A for information on the generic baseline cost estimate using the waste vendor disposal factor (Barnwell, South Carolina).

[4] On July 31, 2000, the FERC issued an order approving a lower decommissioning costs than requested. SERI filed a motion for rehearing which has been granted. SERI continues to collect at the requested level of $365.9 million, subject to refund. The 1999 cost update ($600.9 million) of $540.8 million for SERI's 90% has not yet been filed with the FERC.

GRAND GULF NUCLEAR STATION
CALCULATION OF MINIMUM AMOUNT AS PER 10CFR 50.75 (b) AND (c)

Determination of Minimum Amount

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.
1986 BWR Base Year $: $135,000,000
Labor Region: South
Waste Burial Facility: Barnwell, South Carolina

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

	Factor
L=Labor (South)	1.677 [1]
E=Energy (BWR)	1.209 [2]
B=Waste Burial (BWR)	16.244 [3]

BWR Escalation Factor:

0.65(L) + 0.13(E) + 0.22(B) =	4.8209

1986 BWR Base Year $ Escalated:

$135,000,000 * Escalation Factor =	$ 650,821,500

System Energy interest (90%):	$ 585,739,350 [4]
SMEPA interest (10%)	$ 65,082,150 [5]
Total	$ 650,821,500

[1] Source: Bureau of Labor Statistics: series report id ecu13202i (January 2001).
[2] Source: Bureau of Labor Statistics: series report id wpu0543 and wpu0573 (January 2001).
[3] Source: Nuclear Regulatory Commission:Table 2.1 of "Report on Waste Burial Charges", NUREG-1307 revision 9 (August 2000).
[4] Application of the 8.189 waste vendor disposal factor (South Carolina) from Table 2.1 of "Report on Waste Burial Charges", NUREG 1307 Revision 9 (August 2000) yields a generic baseline cost = $ 370,429,200
[5] Application of the 8.189 waste vendor disposal factor (South Carolina) from Table 2.1 of "Report on Waste Burial Charges", NUREG 1307 Revision 9 (August 2000) yields a generic baseline cost = $ 41,158,800

GRAND GULF NUCLEAR STATION
CALCULATION OF SITE-SPECIFIC COST ESTIMATE
ESCALATED TO 2000 DOLLARS

Site-Specific Cost Estimate (1993$)

	System Energy (90% Interest) [1]	SMEPA (10% Interest) [2]	Total Estimate
Site-Specific Cost Estimate (1993$):			
NRC License Termination Cost:	$ 325,840,205	$ 36,204,467	$ 362,044,672
Non-NRC License Termination Cost:	$ 40,014,976	$ 4,446,108	$ 44,461,084
Total Site-Specific Cost Estimate:	$ 365,855,180	$ 40,650,576	$ 406,505,756
Annual Escalation Factor:	5.50% [1]	4.00% [2]	-
Years of Escalation (1993 Base Year to 1998):	7	7	-
Cumulative Factor (1 + Factor)^7:	1.45	1.32	-
Site-Specific Cost Estimate (2000$):			
NRC License Termination Cost * Cumulative Factor:	$ 473,992,956	$ 47,642,609	$ 521,635,565
Non-NRC License Termination Cost: * Cumulative Factor	$ 58,208,951	$ 5,850,775	$ 64,059,726
Total Site-Specific Cost Estimate:	$ 532,201,907	$ 53,493,384	$ 585,695,291

[1] Funding amounts (Attachment 2-C) based on site-specific cost estimate in 1993$ and 5.50% annual escalation rate and are subject to refund pending final FERC Order in Docket No. ER95-1042-000 (case filed May 1995). On July 31,2000, the FERC issued an order approving a lower decommissioning cost than requested. SERI filed a motion for rehearing which has been granted. SERI continues to collect, subject to refund, at the requested level of $365.9 million to cover its 90% interest.

[2] Funding amounts (Attachment 2-D) based on site-specific cost estimate in 1993$ and 4.0% annual escalation rate.

- Levelized Revenue Requirements
- Diversified Investments

SERI Exhibit___(RKG-

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

Attachment 2-C
GGNS Report

Line No	Year	Revenue Requirements: Owned Portion [1]	Revenue Requirements: Leased Portion [1]	Revenue Requirements: Total	Decommissioning Fund Balances: Owned Portion: Non-Tax Qualified [2]	Decommissioning Fund Balances: Owned Portion: Tax Qualified [3]	Decommissioning Fund Balances: Leased Portion: Non-Tax Qualified [4]	Decommissioning Fund Balances: Leased Portion: Tax Qualified [5]	Decommissioning Fund Balances: Total
1	1995	8,517	1,421	9,939	638	36,352	106	6,327	43,423
2	1996	16,308	2,636	18,944	915	55,468	151	9,436	65,970
3	1997	16,308	2,636	18,944	1,210	75,837	199	12,744	89,990
4	1998	16,308	2,636	18,944	1,525	97,681	250	16,291	115,747
5	1999	16,308	2,636	18,944	1,867	121,243	305	20,117	143,532
6	2000	16,308	2,636	18,944	2,233	146,656	364	24,241	173,494
7	2001	16,308	2,636	18,944	2,622	173,943	427	28,669	205,661
8	2002	16,308	2,636	18,944	3,035	203,064	494	33,394	239,987
9	2003	16,308	2,636	18,944	3,478	234,388	565	38,477	276,908
10	2004	16,308	2,636	18,944	3,948	267,879	641	43,911	316,379
11	2005	16,308	2,636	18,944	4,449	303,752	722	49,731	358,654
12	2006	16,308	2,636	18,944	4,982	342,140	808	55,960	403,890
13	2007	16,308	2,636	18,944	5,553	383,497	900	62,670	452,620
14	2008	16,308	2,636	18,944	6,161	427,844	998	69,866	504,869
15	2009	16,308	2,636	18,944	6,809	475,488	1,103	77,598	560,998
16	2010	16,308	2,636	18,944	7,498	526,486	1,214	85,871	621,069
17	2011	16,308	2,636	18,944	8,225	580,784	1,332	94,681	685,022
18	2012	16,308	2,636	18,944	8,995	638,725	1,456	104,081	753,257
19	2013	16,308	2,636	18,944	9,804	700,254	1,587	114,064	825,709
20	2014	16,308	2,636	18,944	10,696	767,942	1,731	125,047	905,416
21	2015	16,308	1,537	17,846	11,406	840,809	1,848	135,732	989,793
22	2016	16,308	0	16,308	12,163	918,988	1,968	145,604	1,078,723
23	2017	16,308	0	16,308	12,970	1,002,869	2,098	156,198	1,174,133
24	2018	16,308	0	16,308	13,831	1,092,867	2,237	167,561	1,276,496
25	2019	16,308	0	16,308	14,735	1,187,945	2,383	179,528	1,384,591
26	2020	16,308	0	16,308	15,652	1,285,747	2,531	191,740	1,495,670
27	2021	16,308	0	16,308	16,578	1,385,674	2,681	204,110	1,609,043
28	2022	9,513	0	9,513	0	1,460,043	0	213,886	1,673,929
29	2023	0	0	0	0	1,459,109	0	213,735	1,672,844
30	2024	0	0	0	0	1,288,397	0	188,728	1,477,125
31	2025	0	0	0	0	1,094,924	0	160,389	1,255,313
32	2026	0	0	0	0	873,324	0	127,931	1,001,255
33	2027	0	0	0	0	623,693	0	91,369	715,062
34	2028	0	0	0	0	346,427	0	50,759	397,186
35	2029	0	0	0	0	162,041	0	23,748	185,787
36	2030	0	0	0	0	11,383	0	1,671	13,054
37	2031	0	0	0	0	0	0	0	0

Notes:

1) The annual Revenue Requirements are chosen so that their respective decommissioning fund balances are zero in the last year of decommissioning. The 1995 amounts are 8 months actual and 4 months estimated; final year (2022 and 2015) amounts are through July.
2) See Page 2.
3) See Page 3.
4) See Page 4.
5) See Page 5.

System Energy Resources, Inc.
Grand Gulf Decommissioning Model
Non-Tax Qualified Trust — Owned Portion
($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]	Qualifying Percent
1	Beginning Balance								486	
2	1995	8,517	5.65%	122	31	1	152	0	638	98.57%
3	1996	16,308	5.90%	233	45	1	277	0	915	98.57%
4	1997	16,308	5.97%	233	62	1	294	0	1,210	98.57%
5	1998	16,308	6.23%	233	84	2	315	0	1,525	98.57%
6	1999	16,308	6.62%	233	110	2	342	0	1,867	98.57%
7	2000	16,308	6.71%	233	135	2	366	0	2,233	98.57%
8	2001	16,308	6.64%	233	158	3	389	0	2,622	98.57%
9	2002	16,308	6.59%	233	183	3	413	0	3,035	98.57%
10	2003	16,308	6.64%	233	213	3	442	0	3,478	98.57%
11	2004	16,308	6.60%	233	241	4	470	0	3,948	98.57%
12	2005	16,308	6.60%	233	273	4	501	0	4,449	98.57%
13	2006	16,308	6.57%	233	305	5	533	0	4,982	98.57%
14	2007	16,308	6.61%	233	342	5	570	0	5,553	98.57%
15	2008	16,308	6.61%	233	381	6	608	0	6,161	98.57%
16	2009	16,308	6.61%	233	422	7	648	0	6,809	98.57%
17	2010	16,308	6.58%	233	463	7	689	0	7,498	98.57%
18	2011	16,308	6.49%	233	502	8	727	0	8,225	98.57%
19	2012	16,308	6.43%	233	545	9	769	0	8,995	98.57%
20	2013	16,308	6.33%	233	586	9	810	0	9,804	98.57%
21	2014	16,308	6.63%	233	669	10	891	0	10,696	98.57%
22	2015	16,308	6.63%	0	721	11	710	0	11,406	100.00%
23	2016	16,308	6.63%	0	769	12	757	0	12,163	100.00%
24	2017	16,308	6.63%	0	820	12	807	0	12,970	100.00%
25	2018	16,308	6.63%	0	874	13	861	0	13,831	100.00%
26	2019	16,308	6.53%	0	918	14	904	0	14,735	100.00%
27	2020	16,308	6.23%	0	932	15	917	0	15,652	100.00%
28	2021	16,308	5.93%	0	942	16	926	0	16,578	100.00%
29	2022	9,513	5.63%	0	946	17	930	17,507	0	100.00%
30	2023	0	0.00%	0	0	0	0	0	0	0.00%
31	2024	0	0.00%	0	0	0	0	0	0	0.00%
32	2025	0	0.00%	0	0	0	0	0	0	0.00%
33	2026	0	0.00%	0	0	0	0	0	0	0.00%
34	2027	0	0.00%	0	0	0	0	0	0	0.00%
35	2028	0	0.00%	0	0	0	0	0	0	0.00%
36	2029	0	0.00%	0	0	0	0	0	0	0.00%
37	2030	0	0.00%	0	0	0	0	0	0	0.00%
38	2031	0	0.00%	0	0	0	0	0	0	0.00%

Notes:
1) See Page 1.
2) Projected after-tax earning rate.
3) Revenue Requirement * (1 - Qualifying Percentage).
4) Prior Year Balance Compounded Semiannually At Current Year Earning Rate + ½ Current Year Transfer * Current Year Earning Rate.
5) Calculated in accordance with fee schedules for investment manager and trustee fees and applicable tax rates.
6) Transfer + Earnings - Management Fee.
7) Assumes that decommissioning expenditures are made at year end and that the Non-Tax Qualified Balance will be drawn down first.
8) Prior Year Balance + Net Additions - Decommissioning Expenditures. Note that the Non-Tax Qualified Balance is utilized to pay decommissioning costs before the Tax Qualified Balance, which results in the fund's liquidation in the first year of decommissioning (2022).

• Levelized Revenue Requirements
• Diversified Investments

System Energy Resources, Inc.
Grand Gulf Decommissioning Model
Tax Qualified Trust — Owned Portion
($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								25,920	
2	1995	8,517	6.87%	8,396	2,100	63	10,432	0	36,352	98.57%
3	1996	16,308	6.94%	16,075	3,124	84	19,116	0	55,468	98.57%
4	1997	16,308	6.83%	16,075	4,402	108	20,369	0	75,837	98.57%
5	1998	16,308	6.93%	16,075	5,904	135	21,844	0	97,681	98.57%
6	1999	16,308	7.12%	16,075	7,651	164	23,562	0	121,243	98.57%
7	2000	16,308	7.25%	16,075	9,532	195	25,413	0	146,656	98.57%
8	2001	16,308	7.27%	16,075	11,440	228	27,287	0	173,943	98.57%
9	2002	16,308	7.19%	16,075	13,309	263	29,121	0	203,064	98.57%
10	2003	16,308	7.24%	16,075	15,550	301	31,324	0	234,388	98.57%
11	2004	16,308	7.20%	16,075	17,758	342	33,491	0	267,879	98.57%
12	2005	16,308	7.19%	16,075	20,185	386	35,874	0	303,752	98.57%
13	2006	16,308	7.17%	16,075	22,746	433	38,388	0	342,140	98.57%
14	2007	16,308	7.23%	16,075	25,765	483	41,357	0	383,497	98.57%
15	2008	16,308	7.23%	16,075	28,809	537	44,347	0	427,844	98.57%
16	2009	16,308	7.25%	16,075	32,164	595	47,644	0	475,488	98.57%
17	2010	16,308	7.23%	16,075	35,580	657	50,998	0	526,486	98.57%
18	2011	16,308	7.16%	16,075	38,947	724	54,298	0	580,784	98.57%
19	2012	16,308	7.12%	16,075	42,660	794	57,941	0	638,725	98.57%
20	2013	16,308	7.04%	16,075	46,323	870	61,529	0	700,254	98.57%
21	2014	16,308	7.29%	16,075	52,565	951	67,689	0	767,942	98.57%
22	2015	16,308	7.29%	16,308	57,598	1,040	72,866	0	840,809	100.00%
23	2016	16,308	7.29%	16,308	63,006	1,135	78,180	0	918,988	100.00%
24	2017	16,308	7.29%	16,308	68,810	1,237	83,881	0	1,002,869	100.00%
25	2018	16,308	7.29%	16,308	75,036	1,347	89,997	0	1,092,867	100.00%
26	2019	16,308	7.16%	16,308	80,234	1,464	95,079	0	1,187,945	100.00%
27	2020	16,308	6.83%	16,308	83,079	1,585	97,802	0	1,285,747	100.00%
28	2021	16,308	6.49%	16,308	85,328	1,710	99,927	0	1,385,674	100.00%
29	2022	9,513	6.16%	9,513	86,965	1,832	94,646	20,277	1,460,043	100.00%
30	2023	0	5.83%	0	86,361	1,920	84,441	85,375	1,459,109	100.00%
31	2024	0	5.67%	0	83,904	1,917	81,987	252,699	1,288,397	100.00%
32	2025	0	5.67%	0	74,088	1,696	72,392	265,864	1,094,924	100.00%
33	2026	0	5.67%	0	62,962	1,445	61,517	283,117	873,324	100.00%
34	2027	0	5.67%	0	50,219	1,158	49,061	298,693	623,693	100.00%
35	2028	0	5.67%	0	35,865	834	35,030	312,296	346,427	100.00%
36	2029	0	5.67%	0	19,921	475	19,446	203,831	162,041	100.00%
37	2030	0	5.67%	0	9,318	236	9,082	159,740	11,383	100.00%
38	2031	0	5.67%	0	655	35	620	12,003	0	100.00%

Notes:
1) See Page 1.
2) Projected after-tax earning rate.
3) Revenue Requirement * Qualifying Percentage .
4) Prior Year Balance Compounded Semiannually At Current Year Earning Rate + ½ Current Year Transfer * Current Year Earning Rate.
5) Calculated in accordance with fee schedules for investment manager and trustee fees and applicable tax rates.
6) Transfer + Earnings - Management Fee.
7) Assumes that decommissioning expenditures are made at year end and that the Non-Tax Qualified Balance will be drawn down first.
8) Prior Year Balance + Net Additions - Decommissioning Expenditures.

• Levelized Revenue Requirements
• Diversified Investments

System Energy Resources, Inc.
Grand Gulf Decommissioning Model
Non-Tax Qualified Trust — Leased Portion
($000)

Total N/A

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
			Non-Tax Qualified Trust							
1	Beginning Balance								81	
2	1995	1,421	5.65%	20	5	0	25	0	106	98.57%
3	1996	2,636	5.90%	38	7	0	45	0	151	98.57%
4	1997	2,636	5.97%	38	10	0	48	0	199	98.57%
5	1998	2,636	6.23%	38	14	0	51	0	250	98.57%
6	1999	2,636	6.62%	38	18	1	55	0	305	98.57%
7	2000	2,636	6.71%	38	22	1	59	0	364	98.57%
8	2001	2,636	6.64%	38	26	1	63	0	427	98.57%
9	2002	2,636	6.59%	38	30	1	67	0	494	98.57%
10	2003	2,636	6.64%	38	35	1	71	0	565	98.57%
11	2004	2,636	6.60%	38	39	1	76	0	641	98.57%
12	2005	2,636	6.60%	38	44	1	81	0	722	98.57%
13	2006	2,636	6.57%	38	49	1	86	0	808	98.57%
14	2007	2,636	6.61%	38	56	1	92	0	900	98.57%
15	2008	2,636	6.61%	38	62	1	98	0	998	98.57%
16	2009	2,636	6.61%	38	68	1	105	0	1,103	99.57%
17	2010	2,636	6.58%	38	75	1	111	0	1,214	98.57%
18	2011	2,636	6.49%	38	81	2	117	0	1,332	98.57%
19	2012	2,636	6.43%	38	88	2	124	0	1,456	98.57%
20	2013	2,636	6.33%	38	95	2	131	0	1,587	98.57%
21	2014	2,636	6.63%	38	108	2	144	0	1,731	98.57%
22	2015	1,537	6.63%	0	117	2	115	0	1,846	100.00%
23	2016	0	6.63%	0	124	2	122	0	1,968	100.00%
24	2017	0	6.63%	0	133	2	130	0	2,098	100.00%
25	2018	0	6.83%	0	141	2	139	0	2,237	100.00%
26	2019	0	6.53%	0	148	3	146	0	2,383	100.00%
27	2020	0	6.23%	0	151	3	148	0	2,531	100.00%
28	2021	0	5.93%	0	152	3	150	0	2,681	100.00%
29	2022	0	5.63%	0	153	3	150	2,831	0	100.00%
30	2023	0	0.00%	0	0	0	0	0	0	0.00%
31	2024	0	0.00%	0	0	0	0	0	0	0.00%
32	2025	0	0.00%	0	0	0	0	0	0	0.00%
33	2026	0	0.00%	0	0	0	0	0	0	0.00%
34	2027	0	0.00%	0	0	0	0	0	0	0.00%
35	2028	0	0.00%	0	0	0	0	0	0	0.00%
36	2029	0	0.00%	0	0	0	0	0	0	0.00%
37	2030	0	0.00%	0	0	0	0	0	0	0.00%
38	2031	0	0.00%	0	0	0	0	0	0	0.00%

Notes:
1) See Page 1.
2) Projected after-tax earning rate.
3) Revenue Requirement * (1 - Qualifying Percentage) .
4) Prior Year Balance Compounded Semiannually At Current Year Earning Rate + ½ Current Year Transfer * Current Year Earning Rate.
5) Calculated in accordance with fee schedules for investment manager and trustee fees and applicable tax rates.
6) Transfer + Earnings - Management Fee.
7) Assumes that decommissioning expenditures are made at year end and that the Non-Tax Qualified Balance will be drawn down first.
8) Prior Year Balance + Net Additions - Decommissioning Expenditures. Note that the Non-Tax Qualified Balance is utilized to pay decommissioning costs before the Tax Qualified Balance, which results in the fund's liquidation in the first year of decommissioning (2022).

• Levelized Revenue Requirements
• Diversified Investments

System Energy Resources, Inc.
Grand Gulf Decommissioning Model
Tax Qualified Trust — Leased Portion
($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								4,578	
2	1995	1,421	6.87%	1,401	368	20	1,749	0	6,327	98.57%
3	1996	2,636	6.94%	2,598	537	26	3,108	0	9,436	98.57%
4	1997	2,636	6.83%	2,598	744	34	3,309	0	12,744	98.57%
5	1998	2,636	6.93%	2,598	989	39	3,547	0	16,291	98.57%
6	1999	2,636	7.12%	2,598	1,273	46	3,825	0	20,117	98.57%
7	2000	2,636	7.25%	2,598	1,579	52	4,125	0	24,241	98.57%
8	2001	2,636	7.27%	2,598	1,889	59	4,428	0	28,669	98.57%
9	2002	2,636	7.19%	2,598	2,192	65	4,725	0	33,394	98.57%
10	2003	2,636	7.24%	2,598	2,556	71	5,083	0	38,477	98.57%
11	2004	2,636	7.20%	2,598	2,914	78	5,434	0	43,911	98.57%
12	2005	2,636	7.19%	2,598	3,307	85	5,821	0	49,731	98.57%
13	2006	2,636	7.17%	2,598	3,723	92	6,228	0	55,960	98.57%
14	2007	2,636	7.23%	2,598	4,213	100	6,710	0	62,670	98.57%
15	2008	2,636	7.23%	2,598	4,707	109	7,196	0	69,866	98.57%
16	2009	2,636	7.25%	2,598	5,251	119	7,731	0	77,596	98.57%
17	2010	2,636	7.23%	2,598	5,806	129	8,275	0	85,871	98.57%
18	2011	2,636	7.16%	2,598	6,351	140	8,810	0	94,681	98.57%
19	2012	2,636	7.12%	2,598	6,954	151	9,401	0	104,081	98.57%
20	2013	2,636	7.04%	2,598	7,548	163	9,982	0	114,064	98.57%
21	2014	2,636	7.29%	2,598	8,561	176	10,983	0	125,047	98.57%
22	2015	1,537	7.29%	1,537	9,338	190	10,685	0	135,732	100.00%
23	2016	0	7.29%	0	10,075	203	9,872	0	145,604	100.00%
24	2017	0	7.29%	0	10,808	216	10,592	0	156,196	100.00%
25	2018	0	7.29%	0	11,594	230	11,364	0	167,561	100.00%
26	2019	0	7.16%	0	12,212	245	11,968	0	179,528	100.00%
27	2020	0	6.83%	0	12,471	260	12,211	0	191,740	100.00%
28	2021	0	6.49%	0	12,646	275	12,371	0	204,110	100.00%
29	2022	0	6.16%	0	12,767	291	12,476	2,700	213,886	100.00%
30	2023	0	5.83%	0	12,651	304	12,348	12,499	213,735	100.00%
31	2024	0	5.67%	0	12,291	303	11,987	36,994	188,728	100.00%
32	2025	0	5.67%	0	10,853	271	10,582	38,921	160,389	100.00%
33	2026	0	5.67%	0	9,223	234	8,989	41,447	127,931	100.00%
34	2027	0	5.67%	0	7,357	192	7,165	43,727	91,369	100.00%
35	2028	0	5.67%	0	5,254	144	5,110	45,719	50,759	100.00%
36	2029	0	5.67%	-	2,919	92	2,827	29,840	23,746	100.00%
37	2030	0	5.67%	0	1,366	56	1,309	23,385	1,671	100.00%
38	2031	0	5.67%	0	96	10	86	1,757	0	100.00%

Notes:
1) See Page 1.
2) Projected after-tax earning rate.
3) Revenue Requirement * Qualifying Percentage .
4) Prior Year Balance Compounded Semiannually At Current Year Earning Rate + ½ Current Year Transfer * Current Year Earning Rate.
5) Calculated in accordance with fee schedules for investment manager and trustee fees and applicable tax rates.
6) Transfer + Earnings - Management Fee.
7) Assumes that decommissioning expenditures are made at year end and that the Non-Tax Qualified Balance will be drawn down first.
8) Prior Year Balance + Net Additions - Decommissioning Expenditures.

• Levelized Revenue Requirements
• Diversified Investments

System Energy Resources, Inc.
Grand Gulf Decommissioning Model
Decommissioning Expenditures
($000)

Line No	Year	Cumulative Nuclear Cost Escalator [1]	Decommissioning Expenditures Estimate [2]	SERI Portion [3]	Escalated [4]	Owned [5]	Leased [6]
1	1993	1.000	0	0	0	0	0
2	1994	1.055	0	0	0	0	0
3	1995	1.113	0	0	0	0	0
4	1996	1.174	0	0	0	0	0
5	1997	1.239	0	0	0	0	0
6	1998	1.307	0	0	0	0	0
7	1999	1.379	0	0	0	0	0
8	2000	1.455	0	0	0	0	0
9	2001	1.535	0	0	0	0	0
10	2002	1.619	0	0	0	0	0
11	2003	1.708	0	0	0	0	0
12	2004	1.802	0	0	0	0	0
13	2005	1.901	0	0	0	0	0
14	2006	2.006	0	0	0	0	0
15	2007	2.116	0	0	0	0	0
16	2008	2.232	0	0	0	0	0
17	2009	2.355	0	0	0	0	0
18	2010	2.485	0	0	0	0	0
19	2011	2.622	0	0	0	0	0
20	2012	2.766	0	0	0	0	0
21	2013	2.918	0	0	0	0	0
22	2014	3.078	0	0	0	0	0
23	2015	3.247	0	0	0	0	0
24	2016	3.426	0	0	0	0	0
25	2017	3.614	0	0	0	0	0
26	2018	3.813	0	0	0	0	0
27	2019	4.023	0	0	0	0	0
28	2020	4.244	0	0	0	0	0
29	2021	4.477	0	0	0	0	0
30	2022	4.723	10,190	9,171	43,315	37,784	5,531
31	2023	4.983	21,824	19,642	97,874	85,375	12,499
32	2024	5.257	61,229	55,106	289,693	252,699	36,994
33	2025	5.546	61,062	54,956	304,785	265,864	38,921
34	2026	5.851	61,635	55,472	324,564	283,117	41,447
35	2027	6.173	61,634	55,471	342,420	298,693	43,727
36	2028	6.513	61,077	54,969	358,015	312,296	45,719
37	2029	6.871	37,787	34,008	233,671	203,831	29,840
38	2030	7.249	28,069	25,262	183,125	159,740	23,385
39	2031	7.648	[illegible],999	1,799	13,760	12,003	1,757
			406,506	365,855	2,147,907	1,873,618	274,289

Notes:
1) Cumulative Nuclear Cost Escalator at 5.5% per year.
2) Decommissioning Cost Estimate (1993 dollars).
3) Decommissioning Cost Estimate * SERI Share (90%).
4) SERI Portion * Cumulative Nuclear Cost Escalator.
5) Escalated Cost * Owned Percentage (87.23%).
6) Escalated Cost * Leased Percentage (12.77%).

GGDecom99study
2-1-2000

SMEPA'S EXTERNAL TRUST FOR GRAND GULF DECOMMISSIONING

$ in 000s

	Proforma Plan 10% ROI			Value	1999 Study
Year	Cumulative Value	Current Year Contrib'n	Current Year Earnings	Current Year Change	SMEPA's 10%Liability Escalated at 4 %
1999	10,220	0	NA	NA	60,093
2000	11,842	571	1,051	1,622	62,497
2001	13,625	571	1,213	1,784	64,997
2002	15,587	571	1,391	1,962	67,596
2003	17,746	571	1,587	2,158	70,300
2004	20,120	571	1,803	2,374	73,112
2005	22,731	571	2,041	2,612	76,037
2006	25,604	571	2,302	2,873	79,078
2007	28,764	571	2,589	3,160	82,241
2008	32,240	571	2,905	3,476	85,531
2009	36,063	571	3,253	3,824	88,952
2010	40,269	571	3,635	4,206	92,510
2011	44,896	571	4,055	4,626	96,211
2012	49,985	571	4,518	5,089	100,059
2013	55,583	571	5,027	5,598	104,062
2014	61,741	571	5,587	6,158	108,224
2015	68,514	571	6,203	6,774	112,553
2016	75,965	571	6,880	7,451	117,055
2017	84,161	571	7,625	8,196	121,737
2018	93,177	571	8,445	9,016	126,607
2019	103,094	571	9,346	9,917	131,671
2020	114,003	571	10,338	10,909	136,938
2021	126,003	571	11,429	12,000	142,416
2022	139,203	571	12,629	13,200	148,112
2023	153,723	571	13,949	14,520	154,037
2024	169,695	571	15,401	15,972	160,198
		14,275	145,200	159,475	

The 1999 value is actual. Others are forecast.
The shut down date was extended by 2 years to 2024 in the ~~1998~~ 9 study.

AMENDMENT NO. 2 TO NUCLEAR DECOMMISSIONING TRUST FUND AGREEMENT BETWEEN SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION AND TRUSTMARK NATIONAL BANK

This Amendment No. 2 to the Nuclear Decommissioning Trust Fund Agreement (the "Trust Agreement") effective *nunc pro tunc* as of February 17, 2000, is between South Mississippi Electric Power Association ("SMEPA"), a Mississippi corporation, and Trustmark National Bank ("Trustee"), a national banking association authorized to exercise corporate trust powers under the laws of the State of Mississippi.

The Trust Agreement, dated the 20th day of June, 1990, is currently in full force and effect between SMEPA and Trustee. The Trust Agreement established a Nuclear Decommissioning Trust Fund and provided for its management by the Trustee under the terms of said Trust Agreement.

THEREFORE, the parties, intending to be legally bound, mutually agree that the Trust Agreement is modified as follows:

1. Article IV, A. (4) is modified to read in its entirety: Equity Investments selected from non-speculative stocks which comprise the Standard and Poors' 500 Index. The equity component of the portfolio shall not exceed 80% of the current market value of the total portfolio, with no minimum percentage required. Sufficient diversification shall be maintained so as to avoid undue concentration in any single industry or company.

2. An additional subsection A. (6) under Article IV is added to read as follows: Nothing in this Article IV shall be construed to prohibit the use of proprietary mutual funds which include the securities described in this article which the Trustee may manage.

All provisions of the Trust Agreement not expressly modified herein will continue in full force and effect.

TRUSTMARK NATIONAL BANK

By: ______ PAUL LAUGHLIN VICE PRESIDENT & TRUST OFFICER
Trust Officer

Date: Feb. 28, 2000

SOUTH MISSISSIPPI ELECTRIC
POWER ASSOCIATION

By: ______
General Manager

Date: February 29, 2000

STATE OF MISSISSIPPI

COUNTY OF FORREST

Personally came and appeared before me, the undersigned authority, in and for said County and State, Paul Laughlin, who acknowledged to me that he is Vice-President and Trust Officer of Trustmark National Bank, and that he signed and delivered the foregoing instrument on the day and year therein mentioned as the act and deed of said corporation, having first been duly authorized so to do.

Given under my hand and official seal of office on this the 28th day of February, 2000.

Judy Blackwell Hurst
Notary Public

My Commission Expires:

MY COMMISSION EXPIRES MAY 25, 2002

STATE OF MISSISSIPPI

COUNTY OF Forrest

Personally came and appeared before me, the undersigned authority, in and for said County and State, Henry Thomas, who acknowledged to me that he is General Manager of South Mississippi Electric Power Association, and that he signed and delivered the foregoing instrument on the day and year therein mentioned as the act and deed of said corporation, having first been duly authorized so to do.

Given under my hand and official seal of office on this the 29th day of February, 2000.

Jean M. Galjour
Notary Public

My Commission Expires:

Jean M. Galjour, Notary Public
Lamar County, Mississippi
My Commission Expires 5/2/2002

JEAN M. GALJOUR NOTARY PUBLIC LAMAR COUNTY, MS

SYSTEM ENERGY RESOURCES, INC.
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 Arkansas Power & Light Company; Louisiana Power & Light Company; Mississippi Power & Light Company; and New Orleans Public Service Inc. (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

A. Monthly Capacity Charge Formula

The Monthly Capacity Charge Formula, as set out in Attachment A, and as applied in accordance with the procedures set out below, shall determine the Monthly Capacity Charge which SERI shall bill to each of the Purchasers.

B. ANNUAL REDETERMINATION

On or about May 1 of each year, beginning in 1996, SERI shall submit an informational filing to the Federal Energy Regulatory Commission ("FERC" or "Commission") containing a redetermination of the Monthly Capacity Charges prepared in accordance with the provisions set out in this Section 2.B. Each annual redetermination of the Monthly Capacity Charges shall reflect application of the Monthly Capacity Charge Formula set out in Attachment A to data for the twelve month period ending December 31 of the prior calendar year ("Test Year"). All data utilized in each such redetermination shall be based on actual results for the Test Year as recorded on the books of SERI in accordance with the Uniform System of Accounts, or such other documentation as may be appropriate or applicable. Each such informational filing shall include workpapers supporting the data and calculations reflected in the redetermined Monthly Capacity Charges. A copy of each such annual informational filing shall also be provided to each of the Purchasers and each of the Purchasers' retail regulators.

The FERC and the Purchasers shall then have until June 15 of the filing year to review the informational filing to ensure that it complies with the requirements of this Section 2.B. If the FERC or the Purchasers should detect an error(s) in the application of the procedure set out in this Section 2.B, such error(s) shall be formally communicated in writing to SERI on or before June 15 of the filing year. Similarly, if SERI should detect an error(s) subsequent to the submission of any annual filing, SERI shall formally notify the FERC and the Purchasers in writing of such error(s). All such indicated errors shall include documentation of the proposed correction(s). SERI shall then have until June 25 of the filing year to file corrected Monthly Capacity Charges. SERI shall provide the FERC with workpapers supporting any corrections made to the Monthly Capacity Charges initially filed on May 1 of that year. A copy of any such correcting filing shall also be provided to each of the Purchasers' retail regulators.

The Monthly Capacity Charges initially filed, or such corrected Monthly Capacity Charges as may be determined pursuant to the terms of this Section 2.B, shall, after acceptance by the FERC, become effective for bills rendered in July for service in June of the filing year. Those Monthly Capacity Charges shall then remain in effect until changed pursuant to the provisions of this PCF.

The Monthly Capacity Charges to be initially effective under this PCF shall be based on the most recently available calendar year data as of the date this PCF becomes effective. Such calendar year data shall be adjusted to reflect on an annualized basis 1) the cost and accounting changes proposed by SERI in its May 12, 1995 filing with the FERC requesting approval of this PCF and 2) the effects of the Stipulation and Agreement approved by the FERC on November 30, 1994, in FERC Docket No. FA89-28 ("1994 FERC Settlement").

C. Interim Redetermination

In the event that either the statutory state (Mississippi) or federal corporate income tax rates decrease after the annual redetermination is submitted in any year, then the Monthly Capacity Charges shall be redetermined on an interim basis to reflect such tax rate decrease. Should such state or federal income tax rates increase, then SERI may, at its sole discretion, redetermine the then effective Monthly Capacity Charges on an interim basis to reflect such tax rate increase. Should such an interim redetermination be made, all other parameters utilized in the determination of the then effective Monthly Capacity Charges shall remain unchanged. The redetermined Monthly Capacity Charges shall become effective commencing with the billing month in which the tax rate(s) change. Any such redetermination shall be submitted to the FERC in an informational filing consisting of the following:

(a) transmittal letter setting out basis for the change

(b) copy of documentation supporting the change in statutory tax rate(s)

(c) redetermination of the Monthly Capacity Charges reflecting the revised tax rate(s)

Any such interim redetermination filing shall be reviewed in the same general manner as an annual redetermination filed pursuant to Section 2.B above.

3. MONTHLY FUEL CHARGE

A. Monthly Fuel Charge Formula

The Monthly Fuel Charge Formula, as set out in Attachment B, applied in accordance with the procedures set out in Section 3.B below shall determine the Monthly Fuel Charge which SERI shall bill to each of the Purchasers.

B. Determination of Monthly Fuel Charge

Each month SERI shall determine the Monthly Fuel Charge applicable to each of the Purchasers, which amount shall be included in SERI's monthly billings to the Purchasers in accordance with the provisions of Section 4 below. The Monthly Fuel Charge to be billed to each of the Purchasers in any month shall be determined by applying the Monthly Fuel Charge Formula set out in Attachment B to fuel cost data for the immediately preceding month.

4. BILLING

SERI shall render a billing to each of the Purchasers each month for service provided during the immediately preceding month. Each such monthly billing shall reflect the Monthly Capacity Charge in effect for that Purchaser during the preceding month together with that Purchaser's Monthly Fuel Charge for the preceding month. In addition, any applicable and appropriate adjustments shall be reflected in each of the monthly billings. The monthly billings shall be submitted to the Purchasers on or before the fifth workday of each month for service provided in the preceding month and 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 at the rate required for refunds rendered pursuant to FERC Regulations under the Federal Power Act. 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 September 1, 1995, or such later date as the FERC may specify, and shall continue in effect until modified or terminated in accordance with the provisions of this PCF or applicable regulations or laws.

6. FORCE MAJEURE

In addition to the rights of SERI under this PCF, or as provided by law, to make a filing for a change in rates outside the terms of this PCF, if any event or events beyond the reasonable control of SERI, including natural disaster, damage or loss of generating capacity, and orders or acts of civil or military authority, cause increased costs to SERI and result in a deficiency in revenues which is not readily capable of being redressed in a timely manner under this PCF, SERI may unilaterally file for rate or other relief outside the provisions of this PCF. Such request shall be considered by the Commission in accordance with its regulations and applicable law governing such filings.

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

LINE NO	DESCRIPTION	TEST YEAR AMOUNT	REFERENCE
1	CAPACITY REVENUE REQUIREMENT		Page 3, Line 1
2	MONTHLY CAPACITY CHARGE FOR AP&L		36% * Line 1 / 12
3	MONTHLY CAPACITY CHARGE FOR LP&L		14% * Line 1 / 12
4	MONTHLY CAPACITY CHARGE FOR MP&L		33% * Line 1 / 12
5	MONTHLY CAPACITY CHARGE FOR NOPSI		17% * Line 1 / 12

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

LINE NO	DESCRIPTION	TEST YEAR AMOUNT	REFERENCE
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 174
9	ACCUMULATED DEFERRED INCOME TAXES		FERC Accounts 190, 281, 282, 283
10	RATE BASE		Sum of Lines 3 - 9

NOTES:

(1) TO BE DETERMINED AS A 13 MONTH AVERAGE BALANCE ENDING WITH DECEMBER OF THE TEST YEAR.

(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.

SYSTEM ENERGY RESOURCES, INC.
MONTHLY CAPACITY CHARGE FORMULA
DEVELOPMENT OF CAPACITY REVENUE REQUIREMENT

LINE NO	DESCRIPTION	TEST YEAR AMOUNT	REFERENCE
1	CAPACITY REVENUE REQUIREMENT		Determined as described in Note 2 below.
2	OPERATION & MAINTENANCE EXPENSE (1)		FERC Accounts 517, 519-525, 528-532, 556,567, 560-573, 901-905, 920-931, 935
3	DEPRECIATION EXPENSE		FERC Account 403-Excluding Decommissioning Expense
4	DECOMMISSIONING EXPENSE (3)		FERC Account 403
5	AMORTIZATION EXPENSE		FERC Accounts 404-407
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 (4)
10	PROVISION FOR DEFERRED INCOME TAX-FEDERAL		Federal Portion of FERC Accounts 410.1, 411.1 (4)
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		Line 14 / Line 16 (Must equal Line 18)
18	COST OF CAPITAL		Page 5, Line 18, Column D

NOTE:

1) EXCLUSIVE OF FUEL EXPENSE IN FERC ACCOUNT 518.

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

3) SHOULD THE FERC APPROVE A CHANGE IN SYSTEM ENERGY'S SCHEDULE OF ANNUAL DECOMMISSIONING EXPENSES DURING THE TEST YEAR, THE ANNUALIZED LEVEL IN EFFECT ON DECEMBER 31 OF THE TEST YEAR SHALL BE UTILIZED. OTHERWISE, THE AMOUNT CHARGED TO FERC ACCOUNT 403 IN THE TEST YEAR SHALL BE UTILIZED.

4) 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

LINE NO	DESCRIPTION	TEST YEAR AMOUNT	REFERENCE
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) * Total Debt Rate (Page 5, Line 16)
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

NOTE:
1) ITEMS FROM TEST YEAR TAX DETERMINATION THAT ARE APPROPRIATE FOR RATEMAKING PURPOSES.

2) RATE IN EFFECT AT TIME OF ANNUAL REDETERMINATION FILING.

SYSTEM ENERGY RESOURCES, INC.
MONTHLY CAPACITY CHARGE FORMULA
DEVELOPMENT OF COST OF CAPITAL

LINE NO	CAPITALIZATION	(A) CAPITAL AMOUNT (1) (2)	(B) CAPITALIZATION RATIO (3)	(C) COST RATE	(D) WEIGHTED COST RATE (7)
1	**BEGINNING OF TEST YEAR**				
2	DEBT				
3	LONG TERM			(4)	
4	SHORT TERM			(5)	
5	TOTAL DEBT			(6)	
6	COMMON EQUITY			13.00%	
7	TOTAL		100.00%	NA	
8	**END OF TEST YEAR**				
9	DEBT				
10	LONG TERM			(4)	
11	SHORT TERM			(5)	
12	TOTAL DEBT			(6)	
13	COMMON EQUITY			13.00%	
14	TOTAL			NA	
15	**AVERAGE RATE FOR TEST YEAR**				
16	TOTAL DEBT	NA	NA	NA	(8)
17	COMMON EQUITY	NA	NA	NA	(8)
18	COST OF CAPITAL	NA	NA	NA	

NOTES:

(1) LONG TERM DEBT SHALL INCLUDE ALL ISSUES AND REFLECT THE PRINCIPAL AMOUNT, NET OF: 1) UNAMORTIZED DEBT DISCOUNT, 2) DEBT PREMIUM, 3) DEBT EXPENSE AND 4) ANY LOSS ON REACQUIRED DEBT.

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

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

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

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

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

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

(8) WEIGHTED AVERAGE RATE BASED ON AMOUNTS AT BEGINNING AND ENDING OF THE TEST YEAR.

ATTACHMENT B

SYSTEM ENERGY RESOURCES, INC.
MONTHLY FUEL CHARGE FORMULA

LINE NO	DESCRIPTION	SERVICE MONTH AMOUNT	REFERENCE
1	FUEL EXPENSE FOR APPLICABLE SERVICE MONTH		FERC Account 518
2	MONTHLY FUEL CHARGE FOR AP&L		36% * Line 1
3	MONTHLY FUEL CHARGE FOR LP&L		14% * Line 1
4	MONTHLY FUEL CHARGE FOR MP&L		33% * Line 1
5	MONTHLY FUEL CHARGE FOR NOPSI		17% * Line 1

Offer of Settlement, Docket Nos. ER89-678-000, EL90-16-000, and EL90-45-000

APPENDIX F

Second Revised Sheet

FILING PUBLIC UTILITY

System Energy Resources, Inc.

Rate Schedule FERC No. 2

PUBLIC UTILITIES RECEIVING SERVICE UNDER RATE SCHEDULE

Arkansas Power & Light Company
Louisiana Power & Light Company
Mississippi Power & Light Company
New Orleans Public Service Inc.

SERVICE TO BE PROVIDED UNDER RATE SCHEDULE

Wholesale Sale of Electric Power

Second Revised Sheet

Unit Power Sales Agreement

THIS AGREEMENT, made, entered into, and effective as of this 10th day of June, 1982, by and among Arkansas Power & Light Company ("AP&L"), Louisiana Power & Light Company ("LP&L"), Mississippi Power & Light Company ("MP&L"), New Orleans Public Service Inc., ("NOPSI") and Middle South Energy, Inc. ("MSE")*,

WITNESSETH THAT:

WHEREAS, MSE* was incorporated on February 11, 1974 under the laws of the State of Arkansas to own certain future generating capacity for the Middle South System, of which AP&L, LP&L, MP&L and NOPSI ("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 two-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, Mississippi and Missouri and generate, transmit and sell electric energy both at retail and wholesale in such states; and

WHEREAS, System Energy has agreed to sell to AP&L, LP&L, MP&L and NOPSI ("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:

* Middle South Energy, Inc.'s name was changed to System Energy Resources, Inc. ("System Energy") on July 22, 1986.

Second Revised Sheet

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 and Unit 2 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	Unit No. 2
AP&L	36%	
LP&L	14%	
MP&L	33%	
NOPSI	17%	
	100%	

1.3 Commencing with the earlier of (a) the date of commercial operation of each Unit or (b) December 31, 1984 (with respect to Unit 1) or December 31, 1988 (with respect to Unit 2) and, respectively 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 each Unit, each Purchaser will pay System Energy an amount equal to such Purchaser's Entitlement Percentage multiplied by System Energy's Total Cost of Service for such Unit for such month.

The "Total Cost of Service" for each Unit for any month shall be the sum of (a) System Energy's Operating Expenses for such month for such Unit, plus (b) an amount equal to one-twelfth of the Composite Percentage multiplied by the Net Unit Investment for such Unit.

"FERC" shall mean the Federal Energy Regulatory Commission (or any successor governmental authority).

"Uniform System" shall mean the Uniform System of Accounts prescribed by the FERC for Major Public Utilities and Licensees, as from time to time in effect.

APPENDIX C

- 3 -

Third Revised Sheet

System Energy's "Operating Expenses" shall include, with respect to each Unit, all amounts properly chargeable to System Energy's operating expense accounts, less any applicable credit thereto, in accordance with the Uniform System; it being understood that for purposes of this Agreement "Operating Expenses" shall include (but not be limited to) (a) depreciation accrued at a rate at least sufficient to fully amortize the non-salvageable plant investment, including the cost of removal of interim retirements, over the estimated then remaining useful life of the unit; (b) obligations incurred in connection with the leasing of fuel inventory and/or amortization of fuel burned; (c) accruals to any reserve established by System Energy to provide for decommissioning the unit over the estimated then remaining useful life of the unit; and (d) accruals for disposal of spent nuclear fuel.

"Net Unit Investment" for any month shall be computed as of the last day of the previous month and shall consist with respect to each Unit, of (a) the aggregate amount properly chargeable at the time in accordance with the Uniform System to System Energy's utility plant accounts (including, but not limited to, (i) construction work in progress, to the extent allowed by the FERC, related to each Unit after its respective Commercial Operation date, and (ii) nuclear fuel accounts other than nuclear fuel in process of fabrication), less the balance, at the time of any accumulated provision for depreciation and amortization of utility plant (exclusive of any decommissioning reserve), including amortization of the cost of nuclear fuel (exclusive of any reserve for disposal of nuclear fuel), as determined in accordance with the Uniform System; plus (b) the aggregate amount properly chargeable at the time in accordance with the Uniform System to accounts representing materials and supplies; plus (c) such reasonable allowances for prepaid items and cash working capital as may from time to time be determined by System Energy; plus (d) recoverable income taxes to the extent previously credited to utility plant accounts and not yet realized excluding amounts related to construction work in progress that are not included in net unit investment but that are included in the allowance for funds used during construction computation; and less (e) accumulated provision for deferred income taxes and less (f) other deferred credits.

"Composite Percentage" for any month shall be that computed as of the last day of the previous month ("computation date") Composite Percentage as of a computation date shall be the sum of (a) thirteen percent (13%) multiplied by the ratio which the Equity Investment, as of such date, is to the Total Capital as of such date; plus (b) the "effective interest rate" per annum of each principal amount of debt (other than loans or advances made by the common stockholder of System Energy) outstanding on such date for money borrowed, multiplied by the ratio which such principal amount is to Total Capital as of such date; plus (c) the "effective dividend rate" per annum of each series of preferred stock outstanding as of such date multiplied by the

First Revised Sheet

ratio which the amount at which such preferred stock would be reflected on a balance sheet of System Energy is to Total Capital as of such date. The "effective interest rate" of each principal amount of debt referred to in clause (b) will reflect the annual interest requirements and to the extent applicable, amortization of issue expenses, discounts and premiums, sinking fund call premiums, expenses and discounts, refunding and retirement expenses, discounts and premiums, and all other expenses applicable to the issue of such indebtedness. The "effective dividend rate" of each series of preferred stock referred to in clause (c) will reflect the annual dividend requirements applicable to each such series of preferred stock.

"Equity Investment" as of any date shall consist of the sum of (a) all amounts theretofore paid to System Energy for all common capital stock theretofore issued, plus all capital contributions, advances or pro rata loans pursuant to any capital contribution agreement, less the sum of any amounts paid by System Energy to its common stockholder in the form of stock retirements, repurchases or redemptions, return of capital or repayments of such advances or loans; plus (b) any credit balance (i) in the paid in capital account not included under (a) and (ii) in the retained earnings account on the books of System Energy as of such date.

"Total Capital" as of any date shall be the Equity Investment, plus the total of the amount which would be reflected on a balance sheet of System Energy for all other securities, debt and preferred stock then outstanding.

Prior to the earlier of (a) the date of commercial operation of each Unit or (b) December 31, 1984 (with respect to Unit 1) or December 31, 1988 (with respect to Unit 2), the Purchasers shall pay System Energy monthly in accordance with their respective Entitlement Percentages for any Power delivered to them from each such Unit hereunder at a rate equal to the incremental cost of energy displaced by such Power on the Middle South System.

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.

First Revised Sheet

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 readings and other metering information as may reasonably be requested.

5. Monthly bills calculated in accordance with the provisions of Section 1.3 shall be issued by System Energy on the fifth working day of each month and shall be payable in immediately available funds on or before the 15th day of such month. After the 15th day, interest shall accrue on any balance due at the rate required for refunds ordered pursuant to FERC Regulations under the Federal Power Act.

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.

Second Revised Sheet

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 not 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.

First Revised Sheet

MIDDLE SOUTH ENERGY, INC. *

By______________________

ARKANSAS POWER & LIGHT COMPANY

By______________________

LOUISIANA POWER & LIGHT COMPANY

By______________________

MISSISSIPPI POWER & LIGHT COMPANY

By______________________

NEW ORLEANS PUBLIC SERVICE INC.

By James M. Cain

* Middle South Energy, Inc.'s name was changed to System Energy Resources, Inc. ("System Energy") on July 22, 1986.

First Revised Sheet

System Energy Resources, Inc.

Billing Format

SERVICES, INC. FAX NO. 504 576 4455 P. 12

Fourth Revised Sheet

SYSTEM ENERGY RESOURCES, INC.

BILLING FORMAT

COST OF SERVICE

MONTH, 199X

GRAND GULF UNIT 1

OPERATING EXPENSES

OPERATION EXPENSES:		
FUEL EXPENSE (ACCOUNT 518)		$
OTHER OPERATION EXPENSES (ACCOUNTS 517, 519-525, 556, 557, 560-567, 901-905, 920-931)		
MAINTENANCE EXPENSES (ACCOUNTS 528-532, 568-573, 935)		
DEPRECIATION EXPENSE (ACCOUNT 403) - SCHEDULE A		
DECOMMISSIONING EXPENSE (ACCOUNT 403) 1/		
AMORTIZATION EXPENSES (ACCOUNTS 404-407)		
TAXES OTHER THAN INCOME TAXES (ACCOUNT 408.1)		
TAXES - INCOME (ACCOUNTS 409.1, 409.3, 410.1, 411.1, 411.4)		
GAINS/LOSSES FROM DISPOSITION OF UTILITY PLANT (ACCOUNTS 411.6-411.7)		
TOTAL OPERATING EXPENSES		$
ADJUSTMENT OF PRIOR BILLINGS - SCHEDULE -		
OPERATING EXPENSES AS BILLED	$	
OPERATING EXPENSES ACTUAL		
RETURN ON NET UNIT INVESTMENT - SCHEDULE B		
TOTAL COST OF SERVICE		$

1/ THE MONTHLY DECOMMISSIONING EXPENSE FOR GRAND GULF UNIT 1 IS IN ACCORDANCE WITH FERC SETTLEMENT AGREEMENT. THE AMOUNT VARIES EACH YEAR BASED ON THE APPROVED DECOMMISSIONING SCHEDULE.

Sixth Revised Sheet

SYSTEM ENERGY RESOURCES, INC. **SCHEDULE A**

DEPRECIATION EXPENSE

MONTH, 199X

PLANT FUNCTION	DEPRECIABLE PLANT BALANCES	EFFECTIVE ACCRUAL RATES 1/	DEPRECIATION EXPENSE
NUCLEAR PLANT (ACCOUNT 101)	$	2.85%	$
TRANSMISSION PLANT (ACCOUNT 101)	$	2.85%	$
GENERAL PLANT OFFICE EQUIPMENT (ACCOUNT 101)	$	2.85%	$
TRANSPORTATION EQUIPMENT (ACCOUNT 101)	$	2.85%	$
TOTAL	$		$

1/ EFFECTIVE JANUARY 1, 1987

Third Revised Sheet

SCHEDULE B
Page 1 of 2

SYSTEM ENERGY RESOURCES, INC.

RETURN ON NET UNIT INVESTMENT AND COMPOSITE PERCENTAGE

MONTH, 199X

PLANT IN SERVICE		
UTILITY PLANT IN SERVICE (ACCOUNTS 101, 106, 120.2–120.4)	$	1/
LESS: ACCUMULATED PROVISION FOR DEPRECIATION/ AMORTIZATION (ACCOUNTS 108, 111, 120.5)	________	1/
(EXCLUSIVE OF ANY DECOMMISSIONING RESERVE AND ANY RESERVE FOR DISPOSAL OF NUCLEAR FUEL)		
NET UTILITY PLANT IN SERVICE	$	1/
WORKING CAPITAL		
MATERIALS & SUPPLIES (ACCOUNTS 154, 163)	$	1/
PREPAYMENTS (ACCOUNT 165 - EXCLUDING PREPAID INTEREST)		1/
WORKING CAPITAL ALLOWANCE	________	2/
TOTAL WORKING CAPITAL	$ ________	
RECOVERABLE INCOME TAXES (ACCOUNT 186)	$ ________	3/
OTHER DEFERRED CREDITS (ACCOUNT 253 - SALE AND LEASEBACK OF A PORTION OF GRAND GULF UNIT 1)	$ ________	4/
ACCUMULATED PROVISION FOR DEFERRED INCOME TAX (ACCOUNTS 190, 282, 283)	$ ________	1/
NET UNIT INVESTMENT	$ ________	1/
RETURN & COMPOSITE PERCENTAGE (SCH. B2) x NET UNIT INVESTMENT DIVIDED BY 12	$ ________	1/

1/ CALCULATED ON PREVIOUS MONTH BALANCES.

2/ EFFECTIVE APRIL, 1990 WORKING CAPITAL ALLOWANCE IS ZERO IN ACCORDANCE WITH THE FERC SETTLEMENT AGREEMENT.

3/ BALANCES ARE EXCLUDED FROM NET UNIT INVESTMENT IN ACCORDANCE WITH SEPTEMBER, 1989 SETTLEMENT AGREEMENT.

4/ REMAINING UNAMORTIZED DEFERRED GAIN WAS AMORTIZED AS A CREDIT TO THE UPSA BILLING RATABLY OVER THE PERIOD JUNE TO DECEMBER 1991.

Fourth Revised Sheet

SYSTEM ENERGY RESOURCES, INC.

SCHEDULE E
Page 2 of 2

RETURN ON NET UNIT INVESTMENT AND COMPOSITE PERCENTAGE
(Continued)
MONTH, 199X

CAPITALIZATION	AMOUNT	CAP. RATIO	RATE	COMPONENT
DEBT (ACCOUNTS 181, 189, 221, 224, 226, 231)	A1	A1/A4	D%	(A1/A4)D%
PREFERRED STOCK (ACCOUNTS 204, 205, 206)	A2	A2/A4	P%	(A2/A4)P%
COMMON EQUITY (ACCOUNTS 201, 202, 203, 207-216.1)	A3	A3/A4	C%	(A3/A4)C%
TOTAL CAPITALIZATION	A4	100%		Composite%

WHERE: D IS WEIGHTED AVERAGE DEBT RATE INCLUDING SHORT TERM DEBT TO THE EXTENT NOT UTILIZED IN AFUDC CALCULATION.

WHERE: P IS WEIGHTED AVERAGE PREFERRED STOCK DIVIDEND RATE.

WHERE: C IS 13% RETURN ON COMMON EQUITY. 1/

1/ EFFECTIVE APRIL 2, 1990

Second Revised Sheet

SYSTEM ENERGY RESOURCES, INC.

SCHEDULE C
PAGE 1 OF 2

INCOME TAX EXPENSE

MONTH, 199X

CURRENT INCOME TAX EXPENSE

FORMULA DESCRIPTION	
+ OPERATING EXPENSES (EXCLUDING INCOME TAXES)	$
+ INCOME TAX DEDUCTIONS	
+ DEFERRED TAX PROVISIONS	
+ RETURN ON NET UNIT INVESTMENT (DEBT COMPONENT)	
+ TOTAL RETURN ON NET UNIT INVESTMENT	
+ ITC AMORTIZATION (ACCOUNT 411.4)	
= TAXABLE INCOME	$
x TAX RATE / (1 - TAX RATE)	
= INCOME TAXES BEFORE ITC PROVISION	$
+ ITC PROVISION	
= CURRENT FEDERAL AND STATE INCOME TAXES	$

DEFERRED INCOME TAX EXPENSE

DESCRIPTION	(1) OPERATING EXPENSES	(2) 1/ ADJUSTMENT FOR PERMANENT DIFFERENCES	(3) OPERATING EXPENSES AS ADJUSTED	(4) 1/ TIMING DIFFERENCES	(5) INCOME TAX DEDUCTION
FUEL EXPENSE (ACCOUNT 518)	$	$	$	$	$
OTHER OPERATIONS EXPENSE (ACCOUNTS 517, 519-525, 556, 557, 560-567, 901-905, 920-931)					
MAINTENANCE EXPENSE (ACCOUNTS 528-532, 568-573, 935)					
DEPRECIATION EXPENSE (ACCOUNTS 403-407)					
DECOMMISSIONING EXPENSE (ACCOUNT 403)					
TAXES OTHER THAN INCOME TAX (ACCOUNT 408.1)					
TAXES CAPITALIZED PER BOOKS					
	$	$	$	$	$
DEFERRED STATE INCOME TAX PROVISION					
NET TIMING DIFFERENCES				$	
DEFERRED FEDERAL INCOME TAX PROVISION				$	

SUMMARY:	
CURRENT FEDERAL TAX EXPENSE (ACCOUNT 409.1)	$
CURRENT STATE TAX EXPENSE (ACCOUNT 409.1)	
DEFERRED FEDERAL TAX EXPENSE (ACCOUNTS 410.1, 411.1)	
DEFERRED STATE TAX EXPENSE (ACCOUNTS 410.1, 411.1)	
ITC PROVISION	
ITC AMORTIZATION (ACCOUNT 411.4)	
TOTAL INCOME TAXES	$

1/ Supporting [illegible] follow on page 2 of 2. These [illegible] necessary to comply with the FERC's [illegible] order no. 144 and 144-A, and with normalization rules under the Internal Revenue Code.

Second Revised Sheet

SYSTEM ENERGY RESOURCES, INC.

SCHEDULE C
Page 2 of 2

INCOME TAX EXPENSE
(Continued)
MONTH, 199X

DEFERRED INCOME TAX EXPENSE SUPPORTING CALCULATIONS

PERMANENT DIFFERENCES:

DEPRECIATION OF AFUDC - $	
TAX BASIS OF UNIT #1	$
TAXES CAPITALIZED PER BOOKS NET OF TEST ENERGY (ACCOUNTS 101.33, 101.34)	
BASIS FOR DEFERRED TAX CALCULATION	$
BOOK BASIS	$
RATIO OF BASIS FOR DEFERRED TAX CALCULATIONS TO BOOK BASIS:	%
BOOK DEPRECIATION OF BASIS FOR DEFERRED TAX CALCULATION	$
BOOK DEPRECIATION (ACCOUNT 403)	( )
DEPRECIATION OF AFUDC	$
MEAL AND ENTERTAINMENT EXPENSE (ACCOUNTS 517, 519-525, 528-532, 556, 557, 560-573, 901-905, 920-931, 935)	$
PENSION EXPENSE (ACCOUNT 926)	$

TIMING DIFFERENCES:

FUEL EXPENSE - $	$
TAX DEPRECIATION OF NUCLEAR FUEL	$
INTEREST AND OTHER DEDUCTIBLE EXPENSES (ACCOUNT 518)	
NUCLEAR FUEL EXPENSE PER BOOKS (ACCOUNT 518)	( )
EXCESS	$
DEPRECIATION EXPENSE - $	
TAX DEPRECIATION OF UNIT 1 (ACCOUNT 403)	$
DEPRECIATION OF BASIS FOR DEFERRED TAX CALCULATION	( )
EXCESS	$
DECOMMISSIONING EXPENSE - $	
TAX DEDUCTION FOR ACCRUED DECOMMISSIONING EXPENSES	$
BOOK ACCRUAL FOR DECOMMISSIONING EXPENSES (ACCOUNT 403)	( )
EXCESS	$
PENSION EXPENSE - $	
TAX DEDUCTION FOR ACCRUED PENSION EXPENSES	$
BOOK ACCRUAL FOR PENSION EXPENSES (ACCOUNT 926)	( )
EXCESS	$

Report on Status of Decommissioning Funding
10 CFR 50.75(f)(1)
March 31, 2001

Attachment 3
RBS Report

River Bend Station

Minimum Reporting Requirements as per 10 CFR 50.75(f)(1):

1. Decommissioning funds estimated pursuant to 10 CFR 50.75(b) and (c) (2000$):	
Regulated 70% Funding Interest	$ 438,857,133
Non-Regulated 30% Interest	$ 188,081,628
Total	$ 626,938,761 [1]
2. Market value of funds accumulated as of December 31, 2000:	
Regulated 70% Funding Interest	$ 90,309,319 [2]
Non-Regulated 30% Interest	$ 156,703,763 [2]
Total	$ 247,013,082
3. Current schedule of annual amounts remaining to be collected:	
Louisiana Jurisdiction	See Attachment 3-E
Texas Jurisdiction	See Attachment 3-F
FERC Jurisdiction	See Attachment 3-G
4. Assumed rate of decommissioning cost escalation used in funding projections:	
Louisiana Jurisdiction - Attachment 3-E	CPI
Texas Jurisdiction - Attachment 3-F	4.81%
FERC Jurisdiction - Attachment 3-G	4.00%
5. Assumed average after-tax rates of earnings used in funding projections :	
Louisiana Jurisdiction	See Attachment 3-E
Texas Jurisdiction	See Attachment 3-F
FERC Jurisdiction	See Attachment 3-G
6. Assumed rates of other factors used in funding projections :	
Louisiana Jurisdiction	See Attachment 3-E
Texas Jurisdiction	See Attachment 3-F
FERC Jurisdiction	See Attachment 3-G
7. Contracts assuring collection of decommissioning funds:	None
8. Modifications to method of providing financial assurance since March 31, 1999 filing (external sinking fund):	None
9. Material changes to trust agreements since March 31, 1999 filing:	None

Supplemental Information:

1. Site-Specific cost estimate escalated to 2000 (Jurisdictional basis):	
Regulated 70% Funding Interest - Louisiana Jurisdiction (1996 Base Year Dollars)	
NRC License Termination Cost:	$ 283,408,307 [3]
Non-NRC License Termination Cost:	$ 38,335,579 [3]
Total	$ 321,743,886
Regulated 70% Funding Interest - Texas Jurisdiction (1996 Base Year Dollars)	
NRC License Termination Cost:	$ 286,616,405 [3]
Non-NRC License Termination Cost:	$ 38,769,526 [3]
Total	$ 325,385,931

Report on Status of Decommissioning Funding
10 CFR 50.75(f)(1)
March 31, 2001

Attachment 3
RBS Report

River Bend Station

Regulated 70% Funding Interest - FERC Jurisdiction (1985 Base Year Dollars)	
NRC License Termination Cost:	$ 169,159,832 [3]
Non-NRC License Termination Cost:	$ 84,744,747 [3]
Total	$ 253,904,579
Non-Regulated Interest (30%)	N/A [4]
2. Decommissioning method assumed for planning purposes in site-specific estimate:	DECON
3. Year site-specific estimate complete:	1996 [5]
4. Frequency of updates (approximately):	once every 5 years
5. Funding based on NRC minimum or site-specific estimate?:	Site-specific
6. Decommissioning rate regulation (approximately):	
Louisiana Public Service Commission (based on 70% funding interest)	20.03%
Public Utility Commission of Texas (based on 70% funding interest)	30.10%
Federal Energy Regulatory Commission (based on 70% funding interest)	2.10%
Unregulated (based on 70% funding interest)	17.77% [6]
Unregulated Interest (prefunded)	30.00% [4]
	100.00%

[1] See Attachment 3-A for calculations.

[2] Source: December 31, 2000 River Bend Station Trust Fund Report.

[3] See Attachments 3-B, 3-C, and 3-D for calculations. Also see footnote 4 to Attachment 3-A for information on the generic baseline cost estimate using the waste vendor disposal factor (Barnwell, South Carolina).

[4] Cajun contributed $132 million to prefund its decommissioning obligation with respect to its former 30% ownership share.

[5] A 1999 cost update was prepared and filed with the LPSC and the PUCT. Funding continues to be based on the 1996 estimate.

[6] This amount is below the 20% threshold provided in footnote No. 8 to NUREG 1577, Rev 1, "Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance" dated March 1999.

RIVER BEND STATION
CALCULATION OF MINIMUM AMOUNT AS PER 10CFR 50.75 (b) AND (c)
Determination of Minimum Amount

Entergy Gulf States, Inc.: 90% ownership interest
Plant Location: St. Francisville, Louisiana
Reactor Type: Boiling Water Reactor ("BWR")
Power Level: <3400 MWt (Approx. 2894 MWt.)
1986 BWR Base Year $: $130,046,000
Waste Burial Facility: Barnwell, South Carolina

10 CFR 50.75(c)(2) Escalation Factor Formula:
0.65(L) + 0.13(E) + 0.22(B)

	Factor
L= Labor (South)	1.677 [1]
E= Energy (BWR)	1.209 [2]
B= Waste Burial (BWR)	16.244 [3]

BWR Escalation Factor:

0.65(L) + 0.13(E) + 0.22(B) =	4.8209

1986 BWR Base Year $ Escalated:

$ 130,046,000 * Escalation Factor =	$	626,938,761 [4]
Regulated 70% Funding Interest	**$**	**438,857,133** [4]
Non-regulated 30% Interest	**$**	**188,081,628** [4,5]
Total	**$**	**626,938,761**

[1] Source: Bureau of Labor Statistics: series report id ecu13202i (January 2001).
[2] Source: Bureau of Labor Statistics: series report id wpu0543 and wpu0573 (January 2001).
[3] Source: Nuclear Regulatory Commission:Table 2.1 of "Report on Waste Burial Charges", NUREG-1307 revision 9 (August 2000).
[4] Application of the 8.189 waste vendor disposal factor (South Carolina) from Table 2.1 of "Report on Waste Burial Charges", NUREG 1307 Revision 9 (August 2000) yields a generic baseline cost of:

Regulated 70% Funding Interest =	$	277,538,971
Non-regulated 30% Interest =	$	118,945,273
Total generic baseline cost =	$	396,484,245

[5] Cajun contributed $132 million to prefund its decommissioning obligation with respect ot its former 30% ownership share.

RIVER BEND STATION
CALCULATION OF SITE-SPECIFIC COST ESTIMATE
ESCALATED TO 2000 DOLLARS
RIVER BEND 70% FUNDING INTEREST
LOUISIANA JURISDICTION

Site-Specific Cost Estimate (1996$)

Site-Specific Cost Estimate (1996$ - 70%):	
NRC License Termination Cost:	$ 258,324,954 [2]
Non-NRC License Termination Cost:	$ 34,942,648 [3]
Total Site-Specific Cost Estimate:	$ 293,267,602 [1]
Annual Escalation Factor:	CPI [1]
Years of Escalation (1996 Base Year to 2000):	4
Cumulative Factor :	1.097
Site-Specific Cost Estimate (2000$):	
NRC License Termination Cost * Cumulative Factor:	$ 283,408,307
Non-NRC License Termination Cost: * Cumulative Factor:	$ 38,335,579
Total Site-Specific Cost Estimate:	$\boxed{\$ \ 321,743,886}$

[1] The Louisiana Public Service Commission authorized funding amounts (Attachment 3-E) based on 70% of the site-specific cost estimate of $418,953,716 in 1996$ and escalated annually at rates tied to projections of the Consumer Price Index-Urban ("CPI"). The projection for the CPI from the period 1996 through 2000 was 9.71%.

[2] From 1996 Decommissioning Cost Estimate for River Bend, Table C, times 70%.

[3] From 1996 Decommissioning Cost Estimate for River Bend, Table C, times 70%.

RIVER BEND STATION
CALCULATION OF SITE-SPECIFIC COST ESTIMATE
ESCALATED TO 2008 DOLLARS
RIVER BEND 70% FUNDING INTEREST
TEXAS JURISDICTION

Site-Specific Cost Estimate (1996$)

Site-Specific Cost Estimate (1996$ - 70%):

NRC License Termination Cost:	$ 237,514,518 [2]
Non-NRC License Termination Cost:	$ 32,127,698 [3]
Total Site-Specific Cost Estimate:	$ 269,642,216 [1]

Annual Escalation Factor:	4.81% [1]
Years of Escalation (1996 Base Year to 2000):	4
Cumulative Factor (1+Factor)^4:	1.207

Site-Specific Cost Estimate (2000$):

NRC License Termination Cost * Cumulative Factor:	$ 286,616,405
Non-NRC License Termination Cost: * Cumulative Factor.	$ 38,769,526
Total Site-Specific Cost Estimate:	$ 325,385,931

[1] The Public Utility Commission of Texas authorized funding amounts (Attachment 3-F) based on 70% of site-specific cost estimate of $418,953,716 in 1996$ adjusted to reflect statutory contingency limit of 10% for ratemaking purposes. Cost estimate escalated annually at 4.81%.

[2] From 1996 Decommissioning Cost Estimate for River Bend, Table C, times 70%.

[3] From 1996 Decommissioning Cost Estimate for River Bend, Table C, times 70%.

RIVER BEND STATION
CALCULATION OF SITE-SPECIFIC COST ESTIMATE
ESCALATED TO 2000 DOLLARS
RIVER BEND 30% FUNDING INTEREST
NON-REGULATED

Site-Specific Cost Estimate (1985$)

Site-Specific Cost Estimate (1985$ - 70%):		
NRC License Termination Cost:	$	93,928,450
Non-NRC License Termination Cost:	$	47,055,750
Total Site-Specific Cost Estimate:	$	140,984,200 [1]
Annual Escalation Factor:		4.00% [1]
Years of Escalation (1985 Base Year to 2000):		15
Cumulative Factor $(1+\text{Factor})^{\wedge 15}$:		1.801
Site-Specific Cost Estimate (2000$):		
NRC License Termination Cost * Cumulative Factor:	$	169,159,832
Non-NRC License Termination Cost: * Cumulative Factor	$	84,744,747
Total Site-Specific Cost Estimate:	$	253,904,579

[1] FERC authorized funding amounts (Attachment 3-G) based on 70% of site-specific cost estimate in 1985$ escalated annually at 4.0%.

ENTERGY GULF STATES UTILITIES
RIVER BEND UNIT 1 DECOMMISSIONING MODEL
Revenue Requirements Summary

($000)
Page 1

ASSUMPTIONS:
2.7% Decommissioning cost escalation
EGSI rate of return on trust funds
Levelized Real

Line	Year	Revenue Requirement (1)	Decommissioning Fund Balances: Non-Tax Qualified (2)	Decommissioning Fund Balances: Tax Qualified (3)	Decommissioning Fund Balances: Total	Decomm. Expenditures (4)
1	1997	2,217	572	15,722	16,294	0
2	1998	2,277	603	19,055	19,658	0
3	1999	2,340	638	22,718	23,356	0
4	2000	2,404	675	26,723	27,398	0
5	2001	2,469	714	31,065	31,779	0
6	2002	2,537	755	35,768	36,523	0
7	2003	2,606	769	40,890	41,659	0
8	2004	2,677	845	46,368	47,213	0
9	2005	2,750	894	52,324	53,218	0
10	2006	2,825	946	58,758	59,704	0
11	2007	2,902	1,001	65,706	66,707	0
12	2008	2,982	1,059	73,205	74,264	0
13	2009	3,063	1,121	81,293	82,414	0
14	2010	3,147	1,186	90,013	91,199	0
15	2011	3,233	1,255	99,409	100,664	0
16	2012	3,321	1,328	109,531	110,859	0
17	2013	3,412	1,406	120,428	121,834	0
18	2014	3,505	1,488	132,157	133,645	0
19	2015	3,601	1,575	144,775	146,350	0
20	2016	3,699	1,667	158,345	160,012	0
21	2017	3,800	1,765	172,935	174,700	0
22	2018	3,904	1,868	188,616	190,484	0
23	2019	4,011	1,979	205,463	207,442	0
24	2020	4,120	2,096	223,860	225,956	0
25	2021	4,233	2,216	242,620	244,836	0
26	2022	4,348	2,346	262,119	264,465	0
27	2023	4,467	2,464	281,806	284,280	0
28	2024	4,589	2,569	301,527	304,096	0
29	2025	2,750	0	316,742	316,742	4,843
30	2026	0	0	316,504	316,504	14,541
31	2027	0	0	274,585	274,585	55,290
32	2028	0	0	221,119	221,119	64,654
33	2029	0	0	163,577	163,577	66,241
34	2030	0	0	101,271	101,271	66,296
35	2031	0	0	40,134	40,134	64,338
36	2032	0	0	0	0	41,042

(1) The annual Revenue Requirement is chosen so that their respective decommissioning fund balances are zero in the last year of decommissioning.
(2) See Page 2
(3) See Page 3
(4) See Page 4

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ENTERGY GULF STATES UTILITIES
RIVER BEND UNIT 1 DECOMMISSIONING MODEL
($000)
Page 2

				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)
1	Beginning Balance								545
2	1997	2,217	5.32%	0	29	2	27	0	572
3	1998	2,277	5.69%	0	33	2	31	0	603
4	1999	2,340	5.98%	0	37	2	35	0	638
5	2000	2,404	5.98%	0	39	2	37	0	675
6	2001	2,469	5.98%	0	41	2	39	0	714
7	2002	2,537	5.98%	0	43	2	41	0	755
8	2003	2,606	5.98%	0	46	2	44	0	799
9	2004	2,677	5.98%	0	48	2	46	0	845
10	2005	2,750	5.98%	0	51	2	49	0	894
11	2006	2,825	5.98%	0	54	2	52	0	946
12	2007	2,902	5.98%	0	57	2	55	0	1,001
13	2008	2,982	5.98%	0	61	2	58	0	1,059
14	2009	3,063	5.98%	0	64	3	62	0	1,121
15	2010	3,147	5.98%	0	68	3	65	0	1,186
16	2011	3,233	5.98%	0	72	3	69	0	1,255
17	2012	3,321	5.98%	0	76	3	73	0	1,328
18	2013	3,412	5.98%	0	81	3	78	0	1,406
19	2014	3,505	5.98%	0	85	3	82	0	1,488
20	2015	3,601	5.98%	0	90	3	87	0	1,575
21	2016	3,699	5.98%	0	96	3	92	0	1,667
22	2017	3,800	5.98%	0	101	3	98	0	1,765
23	2018	3,904	5.98%	0	107	3	104	0	1,869
24	2019	4,011	5.98%	0	113	3	110	0	1,979
25	2020	4,120	5.98%	0	120	4	117	0	2,096
26	2021	4,233	5.83%	0	124	4	120	0	2,216
27	2022	4,348	5.50%	0	124	4	120	0	2,336
28	2023	4,467	5.15%	0	122	4	118	0	2,454
29	2024	4,589	4.80%	0	119	4	115	0	2,569
30	2025	2,750	4.44%	0	57	3	54	2623	0
31	2026	0	4.27%	0	0	0	0	0	0
32	2027	0	4.27%	0	0	0	0	0	0
33	2028	0	4.27%	0	0	0	0	0	0
34	2029	0	4.27%	0	0	0	0	0	0
35	2030	0	4.27%	0	0	0	0	0	0
36	2031	0	4.27%	0	0	0	0	0	0
37	2032	0	4.27%	0	0	0	0	0	0
	Levelized	2,217	0						

(1) Iterated
(2) Projected after-tax earning rate
(3) Revenue Requirement * (1-Qualifying Percentage)
(4) Prior Year Balance Compounded Semiannually at Current Year Earning Rate+
1/2 (Current Year Transfer- Decomm Expenditures) * Current Year Earning Rate
(5) Calculated in accordance with fee schedules for investment manager and trustee fees and applicable tax rates
(6) Transfer+Earnings-Management Fee
(7) Assumes that decommissioning expenditures are made at year end and that the Non-Tax Qualified Balance will be drawn down first
(8) Prior Year Balance + Net Additions - Decommissioning Expenditures. Note that the Non-Tax Qualified Balance is utilized to pay decommissioning costs before the Tax Qualified Balance, which results in the fund's liquidation in

ENTERGY GULF STATES UTILITIES
RIVER BEND UNIT 1 DECOMMISSIONING MODEL
Tax Qualified Trust - Owned Portion
($000)
Page 3

Line No.	Year	Revenue Reqmt. (1)	Tax Qualified Trust: Earning Rate (2)	Transfer to Trust (3)	Earnings (4)	Mgmt. Fee (5)	Net Additions (6)	Decomm. Expend. (7)	Balance (8)
1	Beginning Balance								12,683
2	1997	2,217	6.02%	2,217	842	19	3,039	0	15,722
3	1998	2,277	6.30%	2,277	1,078	22	3,333	0	19,055
4	1999	2,340	6.57%	2,340	1,349	26	3,663	0	22,718
5	2000	2,404	6.71%	2,404	1,631	30	4,005	0	26,723
6	2001	2,469	6.71%	2,469	1,908	34	4,342	0	31,065
7	2002	2,537	6.71%	2,537	2,205	38	4,703	0	35,768
8	2003	2,608	6.71%	2,608	2,528	42	5,092	0	40,860
9	2004	2,677	6.71%	2,677	2,877	46	5,509	0	46,368
10	2005	2,750	6.71%	2,750	3,258	50	5,955	0	52,324
11	2006	2,825	6.71%	2,825	3,665	55	6,435	0	58,758
12	2007	2,902	6.71%	2,902	4,108	61	6,948	0	65,706
13	2008	2,982	6.71%	2,982	4,583	66	7,498	0	73,205
14	2009	3,063	6.71%	3,063	5,097	72	8,088	0	81,293
15	2010	3,147	6.71%	3,147	5,652	79	8,720	0	90,013
16	2011	3,233	6.71%	3,233	6,250	86	9,397	0	99,409
17	2012	3,321	6.71%	3,321	6,894	93	10,121	0	109,531
18	2013	3,412	6.71%	3,412	7,587	102	10,897	0	120,428
19	2014	3,505	6.71%	3,505	8,334	111	11,728	0	132,157
20	2015	3,601	6.71%	3,601	9,137	120	12,618	0	144,775
21	2016	3,699	6.71%	3,699	10,001	130	13,570	0	158,346
22	2017	3,800	6.71%	3,800	10,931	141	14,590	0	172,935
23	2018	3,904	6.71%	3,904	11,930	153	15,680	0	188,615
24	2019	4,011	6.71%	4,011	13,003	166	16,848	0	205,463
25	2020	4,120	6.71%	4,120	14,156	179	18,097	0	223,560
26	2021	4,233	6.55%	4,233	15,022	194	19,060	0	242,620
27	2022	4,348	6.18%	4,348	15,360	209	19,499	0	262,119
28	2023	4,467	5.76%	4,467	15,444	224	19,687	0	281,806
29	2024	4,589	5.34%	4,589	15,372	240	19,721	0	301,527
30	2025	2,750	4.89%	2,750	14,938	253	17,435	2,220	316,742
31	2026	0	4.65%	0	14,562	259	14,303	14,541	316,504
32	2027	0	4.65%	0	13,603	243	13,360	55,299	274,565
33	2028	0	4.65%	0	11,413	205	11,207	64,654	221,119
34	2029	0	4.65%	0	8,861	162	8,699	66,241	163,577
35	2030	0	4.65%	0	6,107	115	5,992	66,298	101,271
36	2031	0	4.65%	0	3,268	67	3,201	64,336	40,134
37	2032	0	4.65%	0	934	25	909	41,042	0

(1) See page 2
(2) Projected after-tax earning rate
(3) Revenue Requirement * Qualifying Percentage
(4) Prior Year Balance Compounded Semiannually at Current Year Earning Rate+
1/2 (Current Year Transfer- Decomm Expenditures) * Current Year Earning Rate
(5) Calculated in accordance with fee schedules for investment manager and trustee fees and applicable tax rates
(6) Transfer+Earnings-Management Fee
(7) Assumes that the Non-Tax Qualified Balance will be
drawn down first
(8) Prior Year Balance + Net Additions - Decommissioning Expenditures.

($000)
Page 4

Line No.	Year	Cumulative Nuclear Cost Escalator (1)	Decommissioning Expenditures Estimate (2)	EGSI Portion (3)	Escalated (4)	RETAIL (5)	
1	1996	1.000	0	0	0	0	0
2	1997	1.027	0	0	0	0	0
3	1998	1.055	0	0	0	0	0
4	1999	1.084	0	0	0	0	0
5	2000	1.114	0	0	0	0	0
6	2001	1.144	0	0	0	0	0
7	2002	1.175	0	0	0	0	0
8	2003	1.207	0	0	0	0	0
9	2004	1.240	0	0	0	0	0
10	2005	1.274	0	0	0	0	0
11	2006	1.309	0	0	0	0	0
12	2007	1.345	0	0	0	0	0
13	2008	1.382	0	0	0	0	0
14	2009	1.420	0	0	0	0	0
15	2010	1.459	0	0	0	0	0
16	2011	1.499	0	0	0	0	0
17	2012	1.540	0	0	0	0	0
18	2013	1.582	0	0	0	0	0
19	2014	1.625	0	0	0	0	0
20	2015	1.669	0	0	0	0	0
21	2016	1.715	0	0	0	0	0
22	2017	1.762	0	0	0	0	0
23	2018	1.810	0	0	0	0	0
24	2019	1.859	0	0	0	0	0
25	2020	1.910	0	0	0	0	0
26	2021	1.962	0	0	0	0	0
27	2022	2.016	0	0	0	0	0
28	2023	2.071	0	0	0	0	0
29	2024	2.128	0	0	0	0	0
30	2025	2.186	5,988	0	0	0	0
31	2026	2.246	17,497	4,192	9,163	4,843	0
32	2027	2.307	64,780	12,248	27,509	14,541	0
33	2028	2.370	73,726	45,346	104,613	55,299	0
34	2029	2.435	73,519	51,608	122,311	64,654	0
35	2030	2.502	73,773	51,463	125,313	66,241	0
36	2031	2.570	67,656	51,641	129,206	68,298	0
37	2032	2.640	42,015	47,359	121,713	64,338	0
38				29,411	77,644	41,042	0
39							0
Total			418,954	293,268	717,472	379,256	0
							0

Escalator 2.73%
Estimate 418,954

1) Cumulative Nuclear Cost Escalator at 2.73% per year
2) Decommissioning Cost Estimate (1996 dollars)
3) Decommissioning Cost Estimate * EGSI Share
4) EGSI Portion * Cumulative Nuclear Cost Escalator

DCC

PUC DOCKET NO. 16705
SOAH DOCKET NO. 473-96-2285

APPLICATION OF ENTERGY TEXAS FOR APPROVAL OF ITS TRANSITION TO COMPETITION PLAN AND THE TARIFFS IMPLEMENTING THE PLAN, AND FOR THE AUTHORITY TO RECONCILE FUEL COSTS, TO SET REVISED FUEL FACTORS, AND TO RECOVER A SURCHARGE FOR UNDER-RECOVERED FUEL COSTS	§ § § § § § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

SECOND ORDER ON REHEARING

This Second Order on Rehearing (Order) addresses the application filed by Entergy Gulf States, Inc. (EGS or the Company) on November 27, 1996, in accordance with Paragraph 9b of the Stipulation and Agreement approved by the Commission in Docket No. 11292.[1] Through this Order, the Commission adopts in part and modifies in part the Proposal for Decision (PFD) as corrected and the Supplemental Proposal for Decision (SPFD) issued by the State Office of Administrative Hearings (SOAH) Administrative Law Judges (ALJs) in late March 1998.[2]

I. Introduction

The SOAH ALJs conducted separate evidentiary hearings on the four component parts of this docket: fuel, revenue requirement, cost allocation/rate design, and competitive issues. After completion of the hearings and review of the record evidence, the ALJs recommended that the Commission order EGS to reduce its current Texas retail base rates by $137 million, which

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[1] *Application of Entergy Corporation and Gulf States Utilities Company for Sale, Transfer or Merger*, Docket No. 11292, 19 P.U.C. BULL. 2040, 2041 (Ordering Paragraph 5) (Dec. 29, 1993).

[2] The ALJs issued the PFD on March 25, 1998, as revised by clarifications, revised text, and revised schedules filed on June 4, 12, and 16, 1998. The ALJs issued the SPFD, which addresses supplemental fuel-related issues, on March 27, 1998. The Commission considered the matters addressed in this Order at its open meetings convened on June 30, July 8 through 10, July 13, July 16, and July 22, 1998. The Commission issued its "final" order in this docket on July 22, 1998. The Commission considered motions for rehearing at its open meetings convened on August 26, and October 8, 1998. A more detailed procedural history of this case is contained in Attachment A to the PFD and the Findings of Fact (FoF) and Conclusions of Law (CoL), as modified, contained in this Order.

Non-Reconcilable Fuel and Purchased Power Expenses

177. It is reasonable to include non-reconcilable coal, gas, and purchased power expenses in the amount of $4,853,684 in cost of service.

Decommissioning Expense

178. The cost to decommission the River Bend plant, adjusted for a ten percent ceiling value for contingencies, will be $385.2 million. EGS' 70% share of this amount is $269,640,000.

179. Based on the Commission's previous adoption of low level radioactive waste disposal costs at 7.5%, the fact that River Bend specific inflation factor has been very low in the past several years, and the fact that decommissioning does escalate at a rate higher than general inflation, a 4.81% escalation rate is reasonable.

180. An 11.47% trust equity return and overall 6.6% return for the trust fund results from the most reasonable assessment of return projections.

181. Total company annual decommissioning expense of $8,551,000 is EGS' reasonable and necessary share of River Bend decommissioning costs as evaluated in PFD §VII.B.

Depreciation Rates and Expense

182. The total reasonable depreciation expense for EGS is stated on Commission Schedule I.

Production Plant

183. Because EGS has no specific plan to retire any generating unit soon, it is reasonable to assume that the units will be retired in the middle of the year, because they may, in fact, be retired at any time during the year.

184. The retirement dates for planning purposes should be used for depreciation purposes, as well. The River Bend license expiration date of August 29, 2025 should be used as the

SIGNED AT AUSTIN, TEXAS the 13th day of October 1998.

PUBLIC UTILITY COMMISSION OF TEXAS

PAT WOOD, III, CHAIRMAN

JUDY WALSH, COMMISSIONER

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Public Utility Commission of Texas
Docket No. 16705
Entergy Gulf States, Inc.
Summary of Texas Retail Revenue Requirement Allocation
(Thousands of Dollars)

Description	Texas Retail	Resid.	SGS	GS	LGS	LPS	HLFS	LTG
Eligible Fuel & Purch Power	257,233	79,128	3,781	40,234	22,104	54,567	56,086	1,332
Non-Eligible Fuel & Purch Power	6,481	2,419	141	1,122	512	1,142	1,119	27
Operating and Maintenance	125,312	62,481	4,385	21,035	7,939	14,594	13,483	1,396
Decommissioning Expense	3,665	1,458	90	658	280	596	570	14
Depreciation Expense	60,177	27,332	1,900	11,926	4,233	6,982	6,337	1,466
Amortization	(7,778)	(3,095)	(190)	(1,396)	(594)	(1,265)	(1,210)	(29)
Interest on Customer Deposits	501	230	16	102	36	59	53	7
Taxes Other Than State Income Tax	39,737	17,006	1,109	7,341	2,914	5,599	5,317	450
State Income Taxes	0	0	0	0	0	0	0	0
Federal Income Taxes	27,586	12,459	842	5,469	1,934	3,247	3,005	630
Return on Invested Capital (Return on Rate Base)	108,476	49,683	3,401	21,961	7,761	12,659	11,529	1,483
Gains From Disposition of Allowance	-	-	-	-	-	-	-	-
TOTAL REVENUE REQUIREMENT	621,390	249,101	15,475	108,452	47,119	98,179	96,289	6,775
Quality of Service Adj. Allocated-Rate Base	2,211	1,013	69	448	158	258	235	30
Quality of Service Adj. Reallocated -Distribution Lines	(2,211)	(1,285)	(81)	(615)	(164)	(49)	-	(19)
Adjustment due to IS-Credits to LPS & HLFS	(5,918)					(4,944)	(974)	
Adjustment due to IS-Credits allocated to Firm Classes	5,918	2,463	151	1,113	475	805	887	23
Adjustment due to Senior Citizen Discount Residential	(457)	(457)						
Adjustment due to Senior Citizen Discount Allocated to All	457	183	11	80	35	72	71	5
TOTAL REVENUE REQUIREMENT ADJUSTED	621,390	251,019	15,626	109,477	47,623	94,322	96,508	6,815
Fixed Fuel Factor Revenue	228,784	79,128	3,781	40,234	22,104	30,507	51,697	1,332
Non Fixed Fuel Factor Revenue	28,449					24,060	4,389	
Other Revenues	16,926	7,980	515	3,671	1,290	1,767	1,554	150
BASE RATE REVENUE Before Imputation	347,230	163,911	11,330	65,573	24,229	37,988	38,868	5,332
Imputation due to SSTS	7,222					5,393	1,829	
Imputation due to EEDS	1,261			29	452	585	195	
BASE RATE REVENUE w/ Imputation	338,747	163,911	11,330	65,544	23,777	32,010	36,844	5,332

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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. § 1.468A-3T(g) (1986).

3/ See letter of September 22, 1987 of William J. Dwyer, Chief, Branch 6 Corporation Tax Division, IRS at 1.

FEDERAL ENERGY REGULATORY COMMISSION

IRS Schedule Of Ruling Amounts,
dated May 22, 1989

Internal Revenue Service

Department of the Treasury

P.O. Box 7604
Ben Franklin Station
Washington, DC 20044

Index No.: 0468A.10-03

B.J. Willis, Vice President
and Controller
Gulf States Utilities Co.
350 Pine St., P.O. Box 2951
Beaumont, TX 77704

Person to Contact:
Martin Schaffer
Telephone Number:
(202) 566-6589
Refer Reply to:
CC:P&SI:6 TR-31-824-89
Date: MAY 22 1989

In re: Schedule of Ruling Amounts
Gulf States Utilities Co.
River Bend Nuclear Power Plant

Company:	Gulf States Utilities Co. EIN: 74-0662730
Plant:	River Bend Nuclear Power Plant (a 940MW boiling water reactor)
Location:	Just south of St. Francisville, LA (28 miles north of Baton Rouge, LA)
Utility:	Cajun Electric Power Cooperative
Commission A:	Federal Energy Regulatory Commission
Commission B:	Public Utility Commission of Texas
Commission C:	Louisiana Public Service Commission
State A:	Texas
State B:	Louisiana

Dear Mr. Willis:

This is in response to your request dated February 24, 1989, for a revised schedule of ruling amounts. Information was submitted by the Company in accordance with section 1.468A-3(h)(2) of the Income Tax Regulations. The facts as represented by the Company follow.

The Company, incorporated in State A, is an electric utility operating in States A and B. The Company owns 70 percent of the Plant as a tenant in common. The Utility owns the other 30 percent.

The Plant began commercial operations on June 16, 1986, and its operating license is scheduled to expire on August 29, 2025.

The rates for electric energy generated by the Plant are established by Commissions A, B, and C. The Internal Revenue Service approved a schedule of ruling amounts within the jurisdiction of Commission B on November 15, 1988, and within Commission C's jurisdiction on September 27, 1988.

The original schedule of ruling amounts under Commission A's jurisdiction was approved by the Internal Revenue Service on September 27, 1988. However, the Company failed to make a contribution to the nuclear decommissioning fund for the year 1986 with thirty days of receipt of the approved schedule, as required by section 1.468A-8(b)(2) of the regulations. This failure shortened the funding period, as defined in section 1.468A-3(c)(1), and thus changed the qualifying percentage, as defined in section 1.468-3(d)(4).

By orders dated July 22, 1987, September 25, 1987, January 21, 1988, and May 18, 1988, Commission A (jurisdictional percentage: 5.6358 percent) determined the amount of decommissioning costs to be included in the Company's cost of service for ratemaking purposes. There is no proceeding pending before Commission A that may result in an increase or decrease in the amount of these decommissioning costs.

The estimated cost of decommissioning the Plant is $201,406,000 in 1985 dollars. This estimate, based on the prompt removal/dismantlement method of decommissioning, was calculated by a site-specific engineering study ordered by the Company. The Company's share of the total estimated cost of decommissioning is $140,984,200, and its Commission A jurisdictional share is $7,945,588.

Based on an assumed inflation rate of four percent, the total cost of decommissioning expressed in future dollars is $966,950,206. The Company's share of this amount is $676,865,144. The Commission A jurisdictional amount is $38,146,766.

Using an assumed after-tax rate of return of nine percent, Commission A determined the amount of decommissioning costs to be included in the Company's 1988 cost of service (~~the Company~~'s annual share of the total estimated costs) to be $112,914.

The estimated year in which substantial decommissioning costs will first be incurred is 2026. The estimated year in which decommissioning of Plant will be substantially complete is 2031.

The first taxable year for which a deductible payment was made to the nuclear decommissioning fund is 1988. The taxable year that includes the estimated date on which decommissioning costs will no longer be included in the Company's cost of service is 2025. The taxable year that includes the estimated date on which the Plant will no longer be included in the Company's rate base is 2026 (January 1).

The funding period, the level funding limitation period, and the estimated period over which the nuclear decommissioning fund is to be in effect all are 38 years. The estimated useful life of the Plant is 40 years.

The Company's qualifying percentage is 95 percent.

Section 88 of the Internal Revenue Code provides that a taxpayer who is required to include nuclear decomissioning costs in its cost of service for ratemaking purposes shall include this amount in its gross income.

Section 468A(a) of the Code provides that a taxpayer may elect to deduct the amount of payments made to a qualified nuclear decommissioning fund. However, section 468A(b) limits the amount paid into the fund for any taxable year to the lesser of the amount of nuclear decomissioning costs allocable to the fund which is included in the taxpayer's cost of service for ratemaking purposes for the taxable year or the ruling amount applicable to this year.

Section 468A(d)(1) of the Code provides that no deduction shall be allowed for any payment to the fund unless the taxpayer requests and receives from the Secretary a schedule of ruling amounts. The "ruling amount" for any taxable year is defined under section 468A(d)(2) as the amount which the Secretary determines to be necessary to fund that portion of nuclear decommissioning costs which bears the same ratio to the total nuclear decommissioning costs in regard to the nuclear power plant as the period for which the decommissioning fund is in effect bears to the estimated

Waterford 3 Steam Electric Station
Report on Status of Decommissioning Funding
10 CFR 50.75(f)(1)
March 31, 2001

Minimum Reporting Requirements as per 10 CFR 50.75(f)(1):

1. Decommissioning funds estimated pursuant to 10 CFR 50.75(b) and © (2000$):	$ 549,683,400	[1]
2. Market value of funds accumulated as of December 31, 2000:	$ 111,197,817	[2]
3. Current schedule of annual amounts remaining to be collected:	See Attachment 4-C	
4. Assumed rate of decommissioning cost escalation used in funding projections (Attachment 4-C):	5.50%	
5. Assumed average after-tax rates of earnings used in funding projections :	See Attachment 4-C	
6. Assumed rates of other factors used in funding projections:	See Attachment 4-C	
7. Contracts assuming collection of decommissioning funds:	None	
8. Modifications to method of providing financial assurance since March 31, 1999 filing (external sinking fund):	None	
9. Material changes to trust agreements since March 31, 1999 filing:	None	

Supplemental Information:

1. Site-Specific cost estimate escalated to 2000 (1993 Base Year Dollars):		
NRC License Termination Amount:	$ 421,908,237	[3]
Non-NRC License Termination Cost:	$ 43,772,733	[3]
Total	$ 465,680,970	
2. Decommissioning method assumed for planning purposes in site-specific estimate:	DECON	
3. Year site specific estimate complete:	1994	[4]
4. Frequency of updates (approximately):	once every 5 years	[4]
5. Funding based on NRC minimum or site-specific estimate?:	Site-specific	
6. Decommissioning rate regulation (approximately):		
Louisiana Public Service Commission	97%	
Council of the City of New Orleans	3%	

[1] See Attachment 4-A for caluculations.
[2] Source: December 31, 2000 Waterford 3 Trust Fund Report.
[3] See Attachment 4-B for caluculations. Also see footnote 4 to Attachment 4-A for information on the generic baseline cost estimate using the waste vendor disposal factor (Barnwell, South Carolina).
[4] Entergy Louisiana filed a 1999 decommissioning cost update of $481.5 million for Waterford 3 with the LPSC in the third quarter of 2000.

WATERFORD 3 STEAM ELECTRIC STATION
CALCULATION OF SITE-SPECIFIC COST ESTIMATE
ESCALATED TO 2000 DOLLARS

Site-Specific Cost Estimate (1993$)

Site-Specific Cost Estimate (1993$):			
NRC License Termination Cost:	$	290,035,252	
Non-NRC License Termination Cost:	$	30,090,988	
Total Site-Specific Cost Estimate:	$	320,126,240	1
Annual Escalation Factor:		5.50%	1
Years of Escalation (1993 Base Year to 2000):		7	
Cumulative Factor (1 + Factor)^7		1.455	
Site-Specific Cost Estimate (2000$):			
NRC License Termination Cost * Cumulative Factor:	$	421,908,237	
Non-NRC License Termination Cost * Cumulative Factor:	$	43,772,733	
Total Site-Specific Cost Estimate:	$	465,680,970	

[1]The funding amounts (Attachment 4-C) are based on site-specific cost estimates in 1993$ and an escalation rate of 5.50%.

WATERFORD 3 STEAM ELECTRIC STATION
CALCULATION OF MINIMUM AMOUNT AS PER 10 CFR 50.75(b) AND (c)

Determination of Minimum Amount

Entergy Louisiana, Inc.: 100% ownership/leasehold interest
Plant Location: Taft, Louisiana
Reactor Type: Pressurized Water Reactor ("PWR")
Power Level: >3,400 MWt.
1986 PWR Base Year $: $105,000,000
Labor Region: South
Waste Burial Facility: Barnwell, South Carolina

10 CFR 50.75(c)(2) Escalation Factor Formula:

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

	Factor	
L= Labor (South)	1.677	1
E= Energy (PWR)	1.205	2
B= Waste Burial (PWR)	18.129	3

PWR Escalation Factor:

0.65(L) + 0.13(E) + 0.22(B) = 5.23508

1986 PWR Base Year $ Escalated:

$ 105,000,000 * Escalation Factor = $ 549,683,400 [4]

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[1] Source: Bureau of Labor Statistics: series report id ecu13202i (January 2001).
[2] Source: Bureau of Labor Statistics: series report id wpu0543 and wpu0573 (January 2001).
[3] Source: Nuclear Regulatory Commission:Table 2.1 of "Report on Waste Burial Charges", NUREG-1307 revision 9 (August 2000).
[4] Application of the 8.052 waste vendor disposal factor (South Carolina) from Table 2.1 of "Report on Waste Burial Charges", NUREG 1307 Revision 9 (August 2000) yields a generic baseline cost = $ 316,904,700

Docket No. U-20925
Schedule TSC-6
Page 2 of 2

Attachment 4-C
WF3 Report

LOUISIANA POWER & LIGHT COMPANY

Waterford-3 Decommissioning Model
Trust Fund Summary
($000)

Line No	Year	Revenue Rqmt. [1]	Tax Qualified Trust: Earning Rate [2]	Transfer To Trust [3]	Earnings [4]	Management Fee	Net Additions [5]	Decomm. Expend [6]	Balance [7]
1	Beginning Balance								29,172
2	1995	8,786	0.0675	8,786	2,299	74	11,011	0	40,183
3	1996	8,786	0.0675	8,786	3,055	90	11,750	0	51,933
4	1997	8,786	0.0675	8,786	3,861	105	12,541	0	64,474
5	1998	8,786	0.0675	8,786	4,722	122	13,386	0	77,860
6	1999	8,786	0.0800	8,786	6,705	140	15,351	0	93,211
7	2000	10,422	0.0800	10,422	8,023	161	18,284	0	111,495
8	2001	10,422	0.0800	10,422	9,515	185	19,752	0	131,246
9	2002	10,422	0.0800	10,422	11,127	211	21,338	0	152,584
10	2003	10,422	0.0800	10,422	12,868	239	23,051	0	175,635
11	2004	10,422	0.0800	10,422	14,749	269	24,902	0	200,536
12	2005	12,352	0.0800	12,352	16,858	303	28,907	0	229,443
13	2006	12,352	0.0800	12,352	19,217	341	31,228	0	260,671
14	2007	12,352	0.0800	12,352	21,765	382	33,735	0	294,406
15	2008	12,352	0.0800	12,352	24,518	426	36,443	0	330,849
16	2009	12,352	0.0800	12,352	27,491	474	39,369	0	370,218
17	2010	14,744	0.0800	14,744	30,800	527	45,016	0	415,234
18	2011	14,744	0.0800	14,744	34,473	586	48,630	0	463,865
19	2012	14,744	0.0800	14,744	38,441	650	52,535	0	516,399
20	2013	14,744	0.0800	14,744	42,728	719	56,753	0	573,152
21	2014	14,744	0.0800	14,744	47,359	793	61,309	0	634,461
22	2015	17,597	0.0800	17,597	52,476	876	69,197	0	703,658
23	2016	17,597	0.0800	17,597	58,122	966	74,753	0	778,410
24	2017	17,597	0.0800	17,597	64,222	1,064	80,754	0	859,165
25	2018	17,597	0.0800	17,597	70,812	1,170	87,238	0	946,403
26	2019	17,597	0.0800	17,597	77,930	1,285	94,242	0	1,040,645
27	2020	20,986	0.0800	20,986	85,756	1,411	105,341	0	1,145,986
28	2021	20,986	0.0675	20,986	79,368	1,539	98,824	0	1,244,810
29	2022	20,986	0.0675	20,986	88,151	1,668	105,478	0	1,350,288
30	2023	20,986	0.0675	20,986	93,391	1,806	112,581	0	1,462,869
31	2024	20,986	0.0675	20,986	101,119	1,960	120,164	(3,333)	1,579,699
32	2025	0	0.0675	0	108,429	2,033	106,396	(91,609)	1,594,487
33	2026	0	0.0675	0	109,444	2,049	107,395	(96,647)	1,605,235
34	2027	0	0.0675	0	110,182	2,043	108,139	(128,670)	1,584,703
35	2028	0	0.0675	0	108,773	1,863	106,910	(372,283)	1,319,330
36	2029	0	0.0675	0	90,558	1,501	89,057	(397,480)	1,010,906
37	2030	0	0.0675	0	69,388	1,069	68,298	(413,229)	665,975
38	2031	0	0.0675	0	45,712	628	45,086	(434,804)	276,257
39	2032	0	0.0675	0	18,962	288	18,674	(164,583)	130,347
40	2033	0	0.0675	0	8,947	114	8,833	(139,179)	1
		424,475		424,475	1,820,312	32,140	2,212,647	(2,241,818)	

Notes:

1) The 1995 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement.
4) Prior Year Balance compounded semiannually at Current Year Earning Rate + ½ Current Year Transfer * Current Year Earning Rate.
5) Transfer + Earnings - Management Fee.
6) Decommissioning expenditures.
7) Prior Year Balance + Net Additions - Decommissioning Expenditure.