CASE NUMBER:

99-149

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING INCOME STATEMENTS YEAR TO DATE DECEMBER, 2000	CSWCON ACTUAL DEC 00	CPL ACTUAL DEC 00	PSO ACTUAL DEC 00	SWEPCO ACTUAL DEC 00
Depreciation	410,619,501	115,647,605	71,335,752	102,406,365
Amortization	106,221,290	63,138,158	5,082,666	2,273,116
Acquisition Amortization	36,481,419	0	0	0
DEPRECIATION AND AMORTIZATION	553,322,210	178,785,763	76,418,418	104,679,481
FEDTAX - Current Federal Income Tax (Operating)	27,267,728	85,871,152	10,001,120	13,619,314
FEDTAX - Deferred Federal Income Tax (Operating)	47,540,200	16,262,886	22,501,211	14,652,952
FEDTAX - Deferred Investment Tax Credit	(12,750,023)	(5,206,908)	(1,790,808)	(4,481,495)
FEDERAL INCOME TAX	62,057,905	96,927,130	30,711,523	23,790,771
State Income Taxes (Operating)	9,747,615	3,532,176	4,547,171	2,453,470
UK Corp Income Tax - Current	1,381,546	0	-	0
UK Corp Income Tax - Deferred (GAAP Adj)	17,979,214	0	0	0
TOTAL INCOME TAXES	91,166,280	100,459,306	35,258,694	26,244,241
Taxes Other Than Income	191,277,412	76,476,578	28,688,001	53,829,770
TOTAL OPERATING EXPENSE	5,478,060,743	1,464,078,904	865,940,291	995,932,884
OPERATING INCOME	682,984,558	307,098,573	96,668,639	128,277,898
AFUDC-Equity	792,818	-	235,451	445,514
Other Income (Gross)	(6,384,833)	(2,538,550)	7,351,070	834,758
State Income Taxes (Non-Oper)	(168,745)	-	(125,125)	(85,076)
Current Federal Income Tax (Non-Oper)	(5,692,844)	(994,905)	(351,290)	(991,838)
Deferred Federal Income Tax (Non-Oper)	1,268,421	-	-	-
Tax Benefit of Parent Co. Loss	(490,247)	6,068,441	1,782,154	2,553,466
Interest Income - Affiliated West	-	-	-	22,323
Interest Income - Affiliated East	8,758	3,367	1,256	3,719
Interest Income - Nonaffiliated	55,076,422	3,170,316	80,698	1,068,018
Nuclear Decommissioning Trust Income	1,525,895	1,525,895	-	-
Minority Interest	(1,267,020)	0	0	0
Equity in Earnings of Subsidiaries	-	-	-	-
TOTAL OTHER INCOME/DEDUCTIONS	44,668,625	7,234,564	8,974,214	3,850,884
Interest Expense Long Term Debt	300,471,612	96,212,292	26,473,152	43,546,817
Interest Expense ST Debt - Affil West	-	8,206,738	3,530,229	2,668,666
Interest Expense ST Debt - Affil East	47,683,970	7,872,681	3,747,580	1,108,688
Interest Expense ST Debt - Nonaffiliated	119,017,699	1,028,349	-	-
Credit Line Fees Expense - Affil West	-	195,108	45,219	127,073
Credit Line Fees Expense - Affil East	2,992,321	576,824	155,781	264,089
AFUDC - Debt	(14,842,101)	(6,216,050)	(4,395,512)	(2,926,527)
Distributions on Trust Pref Securities	26,602,500	11,940,000	6,000,000	8,662,500
Nuclear Decommissioning Trust Expense	1,525,895	1,525,895	-	-
Preferred Dividend Requirements of Subs	786,755	0	0	0
(Gain)/Loss on Reacq. Preferred Stock	(1,434)	0	0	0
Other Interest	22,138,241	3,424,489	3,423,141	6,005,455
TOTAL INTEREST EXPENSE	506,375,458	124,766,326	38,979,590	59,456,761
INCOME FROM CONTINUING OPERATIONS	221,277,725	189,566,811	66,663,263	72,672,021
INCOME BEFORE EXTRAORDINARY ITEM AND CHANGE IN ACCT PRINCIPLE	221,277,725	189,566,811	66,663,263	72,672,021
NET INCOME	221,277,725	189,566,811	66,663,263	72,672,021
Preferred Stock Dividends	-	241,335	212,561	228,730
Gain/(Loss) on Reacq. Preferred Stock	-	-	1,034	360
BALANCE FOR COMMON	221,277,725	189,325,476	66,451,736	72,443,651

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING INCOME STATEMENTS YEAR TO DATE DECEMBER, 2000	WTU ACTUAL DEC 00	SEEBOARD ACTUAL DEC 00	CORP ACTUAL DEC 00	CSWS ACTUAL DEC 00
Residential	164,141,322	-	-	-
Commercial	97,582,645	-	-	-
Industrial	65,517,453	-	-	-
Other Ultimate	46,059,553	-	-	-
Base/Fuel Revenue by Customer Class	373,300,973	-	-	-
Unbilled Revenue	832,000	-	-	-
Transmission Access Rev - Affil West	7,082,871	-	-	-
Transmission Access Rev - Nonaffiliated	31,080,617	0	-	-
Loss Compensation Rev - Affil West	263,872	0	-	-
Other Non KWH	9,247,684	-	-	-
ULTIMATE REVENUE	421,808,017	-	-	-
Sales for Resale-Nonaffiliated Firm	120,502,791	-	-	-
Sales for Resale-Nonaffiliated Off-Sys	23,760,230	-	-	-
Sales for Resale - Affiliated West	7,839,329	-	-	-
Sales for Resale - Affiliated East	(1,116,281)	0	-	-
SALES FOR RESALE	150,986,069	-	-	-
TOTAL ELECTRIC REVENUE	572,794,086	-	-	-
UK Distribution Revenue	0	350,003,296	0	0
UK Supply Revenue	0	1,170,579,580	0	0
UK Powerlink Revenue	0	64,887,734	0	0
UK Non-Core Revenue	0	267,088,643	0	0
UK Intercompany Revenue	0	(256,780,555)	0	0
UK REVENUE	0	1,595,778,698	0	0
Other Non-Utility Rev-Nonaffiliate	-	-	-	-
Other Non-Utility Rev - Affiliated West	-	-	-	-
OTHER DIVERSIFIED REVENUE	-	-	-	-
TOTAL REVENUE	572,794,086	1,595,778,698	-	-
Fuel Expense	183,153,818	-	-	3,581,598
Purchased Power-Nonaffiliated Firm	-	-	-	-
Purchased Power-Nonaffiliated Off-Sys	69,810,480	-	-	-
Purchased Power - Affiliated West	57,701,972	-	-	-
Purchased Power - Affiliated East	70,790	0	-	-
FUEL AND PURCHASED POWER	310,737,060	-	-	3,581,598
UK Distribution Cost of Sales	0	34,810,755	0	0
UK Supply Cost of Sales	0	1,015,866,856	0	0
UK Powerlink Cost of Sales	0	49,443,277	0	0
UK Non-Core Cost of Sales	0	183,509,125	0	0
UK Intercompany Cost of Sales	0	(227,500,096)	0	0
UK COST OF SALES	0	1,056,129,917	0	0
Other Diversified Cost of Sales	0	0	0	0
Other Production	14,896,872	-	-	20,996,183
Transmission	8,332,766	-	-	4,960,986
Transmission Access Exp - Affil West	(1,820,851)	-	-	-
Transmission Access Exp - Nonaffiliated	13,740,496	0	-	-
Distribution	9,388,981	115,641,738	-	8,276,328
UK Supply	0	100,550,048	0	0
UK Powerlink	0	10,125,787	0	0
UK Non-Core	0	57,855,008	0	0
UK Intercompany	0	(28,766,856)	0	0
Customer Accounting & Collecting	11,394,149	-	-	42,637,881
Customer Service	4,504,305	-	-	8,576,548
Sales Expense	2,691	-	-	138,109
Nuclear Decommissioning	-	-	-	-
Other Non-Utility Expense	-	-	-	-
Total Administrative & General	32,638,700	9,153,054	163,514,809	209,629,759
TOTAL OTHER OPERATING EXPENSE	93,078,109	264,558,779	163,514,809	295,215,794
Maintenance	21,241,277	-	-	6,590,539
TOTAL O & M	114,319,386	264,558,779	163,514,809	301,806,333

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING INCOME STATEMENTS YEAR TO DATE DECEMBER, 2000	WTU ACTUAL DEC 00	SEEBOARD ACTUAL DEC 00	CORP ACTUAL DEC 00	CSWS ACTUAL DEC 00
Depreciation	37,290,248	63,288,309	-	11,697,558
Amortization	17,881,294	11,615,264	378,905	2,140,533
Acquisition Amortization	0	36,481,419	0	0
DEPRECIATION AND AMORTIZATION	55,171,542	111,384,992	378,905	13,838,091
FEDTAX - Current Federal Income Tax (Operating)	6,774,121	(27,099,788)	(34,886,219)	336,535
FEDTAX - Deferred Federal Income Tax (Operating)	9,400,872	-	(418,338)	(427,188)
FEDTAX - Deferred Investment Tax Credit	(1,270,812)	-	-	-
FEDERAL INCOME TAX	14,904,181	(27,099,788)	(35,304,557)	(90,653)
State Income Taxes (Operating)	-	-	-	-
UK Corp Income Tax - Current	0	1,613,046	0	0
UK Corp Income Tax - Deferred (GAAP Adj)	0	17,980,898	0	0
TOTAL INCOME TAXES	14,904,181	(7,505,844)	(35,304,557)	(90,653)
Taxes Other Than Income	25,321,121	-	2,305,736	10,863,046
TOTAL OPERATING EXPENSE	520,453,290	1,424,567,844	130,894,893	329,998,415
OPERATING INCOME	52,340,796	171,210,854	(130,894,893)	(329,998,415)
AFUDC-Equity	111,853	-	-	-
Other Income (Gross)	(6,371,232)	21,520,348	36,815	332,725,236
State Income Taxes (Non-Oper)	-	-	-	-
Current Federal Income Tax (Non-Oper)	(229,101)	(76,762)	-	-
Deferred Federal Income Tax (Non-Oper)	1,237,429	-	-	-
Tax Benefit of Parent Co. Loss	451,157	653,550	(12,615,600)	-
Interest Income - Affiliated West	-	-	29,601,472	-
Interest Income - Affiliated East	416	0	-	-
Interest Income - Nonaffiliated	3,124,380	7,964,476	-	3,638,022
Nuclear Decommissioning Trust Income	-	0	-	-
Minority Interest	0	(1,267,020)	0	0
Equity in Earnings of Subsidiaries	-	-	375,128,646	-
TOTAL OTHER INCOME/DEDUCTIONS	(1,675,098)	28,794,592	392,151,333	336,363,258
Interest Expense Long Term Debt	18,017,350	101,522,465	-	177,340
Interest Expense ST Debt - Affil West	813,283	(431,884)	209,293	2,526,328
Interest Expense ST Debt - Affil East	1,820,553	0	16,813,168	3,460,032
Interest Expense ST Debt - Nonaffiliated	-	-	41,569,726	-
Credit Line Fees Expense - Affil West	19,955	13,413	-	19,526
Credit Line Fees Expense - Affil East	58,248	0	1,536,553	177,989
AFUDC - Debt	(1,304,012)	-	-	-
Distributions on Trust Pref Securities	-	0	-	-
Nuclear Decommissioning Trust Expense	-	0	-	-
Preferred Dividend Requirements of Subs	0	0	0	0
(Gain)/Loss on Reacq. Preferred Stock	0	0	0	0
Other Interest	3,790,637	-	1	3,628
TOTAL INTEREST EXPENSE	23,216,014	101,103,994	60,128,741	6,364,843
INCOME FROM CONTINUING OPERATIONS	27,449,684	98,901,452	201,127,699	-
INCOME BEFORE EXTRAORDINARY ITEM AND CHANGE IN ACCT PRINCIPLE	27,449,684	98,901,452	201,127,699	-
NET INCOME	27,449,684	98,901,452	201,127,699	-
Preferred Stock Dividends	104,129	-	-	-
Gain/(Loss) on Reacq. Preferred Stock	40	0	-	-
BALANCE FOR COMMON	27,345,595	98,901,452	201,127,699	-

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING INCOME STATEMENTS YEAR TO DATE DECEMBER, 2000	COMM ACTUAL DEC 00	LEASING ACTUAL DEC 00	CREDIT ACTUAL DEC 00	CSWE ACTUAL DEC 00
Residential	-	-	-	-
Commercial	-	-	-	-
Industrial	-	-	-	-
Other Ultimate	-	-	-	-
Base/Fuel Revenue by Customer Class	-	-	-	-
Unbilled Revenue	-	-	-	-
Transmission Access Rev - Affil West	-	-	-	-
Transmission Access Rev - Nonaffiliated	0	-	-	0
Loss Compensation Rev - Affil West	-	-	-	0
Other Non KWH	-	-	-	-
ULTIMATE REVENUE	-	-	-	-
Sales for Resale-Nonaffiliated Firm	-	-	-	-
Sales for Resale-Nonaffiliated Off-Sys	-	-	-	-
Sales for Resale - Affiliated West	-	-	-	-
Sales for Resale - Affiliated East	0	-	-	0
SALES FOR RESALE	-	-	-	-
TOTAL ELECTRIC REVENUE	-	-	-	-
UK Distribution Revenue	0	0	0	0
UK Supply Revenue	0	0	0	0
UK Powerlink Revenue	0	0	0	0
UK Non-Core Revenue	0	0	0	0
UK Intercompany Revenue	0	0	0	0
UK REVENUE	0	0	0	0
Other Non-Utility Rev-Nonaffiliate	9,970,652	1,734,381	63,771,510	191,553,931
Other Non-Utility Rev - Affiliated West	49,867	-	64,993,890	-
OTHER DIVERSIFIED REVENUE	10,020,519	1,734,381	128,765,400	191,553,931
TOTAL REVENUE	10,020,519	1,734,381	128,765,400	191,553,931
Fuel Expense	-	-	-	-
Purchased Power-Nonaffiliated Firm	-	-	-	-
Purchased Power-Nonaffiliated Off-Sys	-	-	-	-
Purchased Power - Affiliated West	-	-	-	-
Purchased Power - Affiliated East	0	-	-	0
FUEL AND PURCHASED POWER	-	-	-	-
UK Distribution Cost of Sales	0	0	0	0
UK Supply Cost of Sales	0	0	0	0
UK Powerlink Cost of Sales	0	0	0	0
UK Non-Core Cost of Sales	0	0	0	0
UK Intercompany Cost of Sales	0	0	0	0
UK COST OF SALES	0	0	0	0
Other Diversified Cost of Sales	3,862,182	0	0	-
Other Production	-	-	(1)	-
Transmission	-	-	-	-
Transmission Access Exp - Affil West	-	-	-	-
Transmission Access Exp - Nonaffiliated	0	-	-	0
Distribution	-	-	-	-
UK Supply	0	0	0	0
UK Powerlink	0	0	0	0
UK Non-Core	0	0	0	0
UK Intercompany	0	0	0	0
Customer Accounting & Collecting	-	-	36,995,454	-
Customer Service	-	-	-	-
Sales Expense	-	-	-	-
Nuclear Decommissioning	-	-	-	-
Other Non-Utility Expense	21,547,701	-	-	166,526,871
Total Administrative & General	-	111,565	4,225,829	17,540,888
TOTAL OTHER OPERATING EXPENSE	21,547,701	111,565	41,221,282	184,067,759
Maintenance	-	-	-	-
TOTAL O & M	21,547,701	111,565	41,221,282	184,067,759

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING INCOME STATEMENTS YEAR TO DATE DECEMBER, 2000	COMM ACTUAL DEC 00	LEASING ACTUAL DEC 00	CREDIT ACTUAL DEC 00	CSWE ACTUAL DEC 00
Depreciation	5,864,535	-	-	2,898,941
Amortization	-	-	-	3,083,299
Acquisition Amortization	0	0	0	0
DEPRECIATION AND AMORTIZATION	5,864,535	-	-	5,982,240
FEDTAX - Current Federal Income Tax (Operating)	(11,991,107)	263,769	11,161,674	(7,774,390)
FEDTAX - Deferred Federal Income Tax (Operating)	1,511,443	(414,573)	(3,905,936)	4,833,173
FEDTAX - Deferred Investment Tax Credit	-	-	-	-
FEDERAL INCOME TAX	(10,479,664)	(150,804)	7,255,738	(2,941,217)
State Income Taxes (Operating)	-	-	-	(785,202)
UK Corp Income Tax - Current	0	0	0	0
UK Corp Income Tax - Deferred (GAAP Adj)	0	0	0	0
TOTAL INCOME TAXES	(10,479,664)	(150,804)	7,255,738	(3,726,419)
Taxes Other Than Income	977,908	-	678,670	2,902,003
TOTAL OPERATING EXPENSE	21,772,662	(39,239)	49,155,690	189,225,583
OPERATING INCOME	(11,752,143)	1,773,620	79,609,710	2,328,348
AFUDC-Equity	-	-	-	-
Other Income (Gross)	(2,332,229)	-	(4,230)	33,034
State Income Taxes (Non-Oper)	42,993	-	-	(1,537)
Current Federal Income Tax (Non-Oper)	786,587	-	-	(195,708)
Deferred Federal Income Tax (Non-Oper)	-	-	-	30,992
Tax Benefit of Parent Co. Loss	-	-	616,585	-
Interest Income - Affiliated West	-	-	-	11,827,382
Interest Income - Affiliated East	0	-	-	0
Interest Income - Nonaffiliated	41,844	33,822	84,450	26,412,748
Nuclear Decommissioning Trust Income	0	-	-	0
Minority Interest	0	0	0	0
Equity in Earnings of Subsidiaries	-	-	-	-
TOTAL OTHER INCOME/DEDUCTIONS	(1,460,805)	33,822	696,805	38,106,911
Interest Expense Long Term Debt	-	-	-	14,522,196
Interest Expense ST Debt - Affil West	3,040,946	-	-	9,665,821
Interest Expense ST Debt - Affil East	4,630,747	-	-	7,461,814
Interest Expense ST Debt - Nonaffiliated	12,071	-	66,214,971	10,192,582
Credit Line Fees Expense - Affil West	-	-	-	17,660
Credit Line Fees Expense - Affil East	28,249	-	-	155,281
AFUDC - Debt	-	-	-	-
Distributions on Trust Pref Securities	-	-	-	0
Nuclear Decommissioning Trust Expense	0	-	-	0
Preferred Dividend Requirements of Subs	0	0	0	0
(Gain)/Loss on Reacq. Preferred Stock	0	0	0	0
Other Interest	-	-	-	-
TOTAL INTEREST EXPENSE	7,712,013	-	66,214,971	42,015,354
INCOME FROM CONTINUING OPERATIONS	(20,924,961)	1,807,442	14,091,544	(1,580,095)
INCOME BEFORE EXTRAORDINARY ITEM AND CHANGE IN ACCT PRINCIPLE	(20,924,961)	1,807,442	14,091,544	(1,580,095)
NET INCOME	(20,924,961)	1,807,442	14,091,544	(1,580,095)
Preferred Stock Dividends	-	-	-	-
Gain/(Loss) on Reacq. Preferred Stock	-	-	-	0
BALANCE FOR COMMON	(20,924,961)	1,807,442	14,091,544	(1,580,095)

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING INCOME STATEMENTS YEAR TO DATE DECEMBER, 2000	INTL ACTUAL DEC 00	ENERSHOP ACTUAL DEC 00	ESI ACTUAL DEC 00	TOT_ELIM ACTUAL DEC 00
Residential	-	-	-	0
Commercial	-	-	-	0
Industrial	-	-	-	0
Other Ultimate	-	-	-	0
Base/Fuel Revenue by Customer Class	-	-	-	0
Unbilled Revenue	-	-	-	-
Transmission Access Rev - Affil West	-	-	-	(4,385,913)
Transmission Access Rev - Nonaffiliated	0	0	0	-
Loss Compensation Rev - Affil West	0	0	0	(606,099)
Other Non KWH	-	-	-	167,469
ULTIMATE REVENUE	-	-	-	(4,824,543)
Sales for Resale-Nonaffiliated Firm	-	-	-	0
Sales for Resale-Nonaffiliated Off-Sys	-	-	-	0
Sales for Resale - Affiliated West	-	-	-	(140,817,807)
Sales for Resale - Affiliated East	0	0	0	0
SALES FOR RESALE	-	-	-	(140,817,807)
TOTAL ELECTRIC REVENUE	-	-	-	(145,642,350)
UK Distribution Revenue	0	0	0	-
UK Supply Revenue	0	0	-	-
UK Powerlink Revenue	0	0	0	0
UK Non-Core Revenue	0	0	0	-
UK Intercompany Revenue	0	0	0	0
UK REVENUE	0	0	-	-
Other Non-Utility Rev-Nonaffiliate	4,451,875	4,528,961	4,106,368	-
Other Non-Utility Rev - Affiliated West	-	-	-	(65,043,757)
OTHER DIVERSIFIED REVENUE	4,451,875	4,528,961	4,106,368	(65,043,757)
TOTAL REVENUE	4,451,875	4,528,961	4,106,368	(210,686,107)
Fuel Expense	-	-	-	(3,581,598)
Purchased Power-Nonaffiliated Firm	-	-	-	-
Purchased Power-Nonaffiliated Off-Sys	-	-	-	0
Purchased Power - Affiliated West	-	-	-	(141,256,437)
Purchased Power - Affiliated East	0	0	0	0
FUEL AND PURCHASED POWER	-	-	-	(144,838,035)
UK Distribution Cost of Sales	0	0	0	-
UK Supply Cost of Sales	0	0	0	0
UK Powerlink Cost of Sales	0	0	0	0
UK Non-Core Cost of Sales	0	0	0	0
UK Intercompany Cost of Sales	0	0	0	0
UK COST OF SALES	0	0	0	-
Other Diversified Cost of Sales	0	0	3,643,174	0
Other Production	-	-	-	(20,996,183)
Transmission	-	-	-	(4,960,986)
Transmission Access Exp - Affil West	-	-	-	(4,385,913)
Transmission Access Exp - Nonaffiliated	0	0	0	0
Distribution	-	-	-	(8,276,328)
UK Supply	0	0	0	0
UK Powerlink	0	0	0	0
UK Non-Core	0	0	0	0
UK Intercompany	0	0	0	0
Customer Accounting & Collecting	-	-	-	(107,631,771)
Customer Service	-	-	595,587	(8,576,548)
Sales Expense	-	4,201,661	-	(138,109)
Nuclear Decommissioning	-	-	-	0
Other Non-Utility Expense	47,115,067	-	-	0
Total Administrative & General	4,052,802	2,532,761	2,131,889	(226,153,886)
TOTAL OTHER OPERATING EXPENSE	51,167,869	6,734,422	2,727,476	(381,119,724)
Maintenance	-	-	-	(6,590,539)
TOTAL O & M	51,167,869	6,734,422	2,727,476	(387,710,263)

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING INCOME STATEMENTS YEAR TO DATE DECEMBER, 2000	INTL ACTUAL DEC 00	ENERSHOP ACTUAL DEC 00	ESI ACTUAL DEC 00	TOT_ELIM ACTUAL DEC 00
Depreciation	19,446	169,036	1,706	0
Amortization	397,065	80,990	150,000	0
Acquisition Amortization	0	0	0	0
DEPRECIATION AND AMORTIZATION	416,511	250,026	151,706	0
FEDTAX - Current Federal Income Tax (Operating)	(7,239,174)	(1,274,739)	(10,494,540)	0
FEDTAX - Deferred Federal Income Tax (Operating)	(16,456,302)	-	-	0
FEDTAX - Deferred Investment Tax Credit	-	-	-	0
FEDERAL INCOME TAX	(23,695,476)	(1,274,739)	(10,494,540)	0
State Income Taxes (Operating)	-	-	-	0
UK Corp Income Tax - Current	(231,500)	0	0	0
UK Corp Income Tax - Deferred (GAAP Adj)	(1,684)	0	0	0
TOTAL INCOME TAXES	(23,928,660)	(1,274,739)	(10,494,540)	0
Taxes Other Than Income	24,141	91,295	(17,811)	(10,863,046)
TOTAL OPERATING EXPENSE	27,679,861	5,801,004	(3,989,995)	(543,411,344)
OPERATING INCOME	(23,227,986)	(1,272,043)	8,096,363	332,725,237
AFUDC-Equity	-	-	-	0
Other Income (Gross)	144,422	-	(24,697,551)	(333,086,724)
State Income Taxes (Non-Oper)	-	-	-	0
Current Federal Income Tax (Non-Oper)	(3,639,827)	-	-	0
Deferred Federal Income Tax (Non-Oper)	-	-	-	0
Tax Benefit of Parent Co. Loss	-	-	-	0
Interest Income - Affiliated West	-	-	-	(41,451,177)
Interest Income - Affiliated East	0	0	0	0
Interest Income - Nonaffiliated	9,457,648	-	-	0
Nuclear Decommissioning Trust Income	0	0	0	0
Minority Interest	0	0	0	0
Equity in Earnings of Subsidiaries	-	-	-	(375,128,646)
TOTAL OTHER INCOME/DEDUCTIONS	5,962,243	-	(24,697,551)	(749,666,547)
Interest Expense Long Term Debt	-	-	-	-
Interest Expense ST Debt - Affil West	12,604,065	1,136,328	2,419,030	(46,388,843)
Interest Expense ST Debt - Affil East	768,707	0	0	0
Interest Expense ST Debt - Nonaffiliated	-	-	-	0
Credit Line Fees Expense - Affil West	(37,373)	59,130	93,513	(553,224)
Credit Line Fees Expense - Affil East	39,307	0	0	0
AFUDC - Debt	-	-	-	0
Distributions on Trust Pref Securities	0	0	0	0
Nuclear Decommissioning Trust Expense	0	0	0	0
Preferred Dividend Requirements of Subs	0	0	0	786,755
(Gain)/Loss on Reacq. Preferred Stock	0	0	0	(1,434)
Other Interest	-	-	-	5,490,890
TOTAL INTEREST EXPENSE	13,374,706	1,195,458	2,512,543	(40,665,856)
INCOME FROM CONTINUING OPERATIONS	(30,640,449)	(2,467,501)	(19,113,731)	(376,275,454)
INCOME BEFORE EXTRAORDINARY ITEM AND CHANGE IN ACCT PRINCIPLE	(30,640,449)	(2,467,501)	(19,113,731)	(376,275,454)
NET INCOME	(30,640,449)	(2,467,501)	(19,113,731)	(376,275,454)
Preferred Stock Dividends	-	-	-	(786,755)
Gain/(Loss) on Reacq. Preferred Stock	0	0	0	(1,434)
BALANCE FOR COMMON	(30,640,449)	(2,467,501)	(19,113,731)	(375,490,133)

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	AEP CONSOLIDATED	AEP ELIMINATIONS	AEP	APCO CONSOLIDATED
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	16,327,617,310.17	31,888.92	0.00	2,058,952,169.60
TRANSMISSION	5,609,450,280.81	0.00	0.00	1,177,079,157.65
DISTRIBUTION	10,842,467,319.04	0.00	0.00	1,816,925,297.54
GENERAL	3,725,303,014.90	0.00	0.00	254,370,343.96
CONSTRUCTION WORK IN PROGRESS	1,231,033,560.49	0.00	0.00	110,950,562.22
TOTAL ELECTRIC UTILITY PLANT	37,735,871,485.41	31,888.92	0.00	5,418,277,530.97
LESS ACCUM PRV-DEPR,DEPL,AMORT	(15,559,250,022.20)	0.00	0.00	(2,188,795,658.16)
NET ELECTRIC UTILITY PLANT	22,176,621,463.21	31,888.92	0.00	3,229,481,872.81
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	215,912,133.38	0.00	0.00	22,216,402.42
INVEST IN SUBSIDIARY & ASSOC	818,387,276.62	(8,027,008,382.38)	8,066,942,705.38	603,868.00
TOTAL OTHER INVESTMENTS	3,762,174,771.42	(20,879,535.36)	312,196.63	356,834,341.90
TOTAL OTHER SPECIAL FUNDS	872,478,446.26	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	5,668,952,627.68	(8,047,887,917.74)	8,067,254,902.01	379,654,612.32
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	437,289,749.17	0.00	50,082,161.06	5,846,709.81
ADVANCES TO AFFILIATES	0.00	(3,375,245,284.41)	3,059,698,907.53	8,387,327.03
ACCOUNTS RECEIVABLE-CUSTOMERS	827,146,568.43	216,877,998.30	0.00	243,297,886.42
ACCOUNTS RECEIVABLE - MISC	2,849,404,907.66	0.00	608,998.60	16,179,121.90
A/P FOR UNCOLLECTIBLE ACCOUNTS	(7,701,891.35)	0.00	0.00	(2,588,491.29)
ACCOUNTS RECEIVABLE- ASSOC COS	31,397,446.41	(1,146,009,716.76)	17,202,777.06	63,919,504.93
FUEL	298,695,040.34	0.00	0.00	39,076,198.77
MATERIALS & SUPPLIES	448,991,950.28	(553,811.69)	33,575.21	57,514,845.27
ACCRUED UTILITY REVENUES	325,428,273.36	135,317,066.97	0.00	66,498,505.00
PREPAYMENTS	157,932,204.28	(1,345,872.96)	27,932,511.62	4,168,978.16
ENERGY TRADING CONTRACTS	16,624,601,010.73	22,094,600.00	0.00	2,035,447,785.74
OTHER CURRENT ASSETS	38,959,011.25	0.00	0.00	2,691,610.33
TOTAL CURRENT ASSETS	22,032,144,270.56	(4,148,865,020.55)	3,155,558,931.08	2,540,439,982.07
REGULATORY ASSETS				
REGULATORY ASSETS	3,966,805,261.33	0.00	0.00	552,292,270.29
FAS109 DFIT RECLASS (A/C 254)	(268,929,360.61)	5,522,738.00	(962,631.00)	(41,624,837.00)
NET REGULATORY ASSETS	3,697,875,900.72	5,522,738.00	(962,631.00)	510,667,433.29
DEFERRED CHARGES				
CLEARING ACCOUNTS	3,264,633.99	0.00	55,209.75	437,971.64
UNAMORTIZED DEBT EXPENSE	14,103,009.40	0.00	0.00	3,843,998.16
OTHER DEFERRED DEBITS	955,174,400.23	116,536,861.65	19,157,240.47	44,544,361.22
TOTAL DEFERRED CHARGES	9725942,043.62	116,536,861.65	19,212,450.22	48,826,331.02
TOTAL ASSETS	54,548,136,305.79	(12,074,661,449.72)	11,241,063,652.31	6,709,070,231.51

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	AEP CONSOLIDATED	AEP ELIMINATIONS	AEP	APCO CONSOLIDATED
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	2,151,624,449.00	(741,041,650.43)	2,151,624,449.00	260,457,768.00
PREMIUM ON CAPITAL STOCK	1,955,766,245.27	(263,739,833.73)	1,955,766,245.27	762,826.38
PAID-IN CAPITAL	856,753,178.18	(4,510,121,289.23)	851,452,948.18	714,454,844.23
RETAINED EARNINGS	3,090,051,660.17	(2,495,929,679.95)	3,090,051,634.74	120,583,783.72
COMMON SHAREHOLDERS' EQUITY	8,054,195,532.62	(8,010,832,453.34)	8,048,895,277.19	1,096,259,222.33
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	99,655,000.00	0.00	0.00	10,860,000.00
PS NOT SUBJ MANDATORY REDEMP	61,610,403.00	0.00	0.00	17,790,500.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	333,500,000.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 Y	9,601,987,790.53	(1,100,000.00)	0.00	1,430,812,163.38
TOTAL CAPITALIZATION	18,150,948,726.15	(8,011,932,453.34)	8,048,895,277.19	2,555,721,885.71
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	297,142,229.52	(20,875,789.99)	0.00	50,349,822.41
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	1,408,373,095.23	0.00	0.00	55,533,412.80
TOTAL OTH NONCURRENT LIAB'S	1,705,515,324.75	(20,875,789.99)	0.00	105,883,235.21
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	1,152,304,813.72	0.00	0.00	175,005,581.48
SHORT-TERM DEBT	4,332,462,634.52	0.00	2,857,520,000.00	191,495,000.00
A/P - GENERAL	2,610,021,145.75	5,300,000.00	109,333.40	153,422,482.45
A/P- ASSOC. COS	9,367,164.90	(1,285,923,518.00)	9,610,028.83	107,556,059.02
ADVANCES FROM AFFILIATES	0.00	(2,755,821,028.16)	321,878,625.36	0.00
CUSTOMER DEPOSITS	203,260,447.88	0.00	0.00	12,611,632.66
TAXES ACCRUED	777,961,456.68	(765,550.00)	(12,275,936.16)	63,258,275.40
INTEREST ACCRUED	173,746,112.21	(5,063,325.87)	713,020.65	21,555,163.81
DIVIDENDS DECLARED	2,298,612.28	0.00	0.00	360,635.63
OBLIG UNDER CAP LEASES- CURR	186,920,349.34	0.00	0.00	12,810,652.33
ENERGY TRADING CONTRACTS	16,800,995,618.54	22,094,600.00	0.00	2,091,803,789.07
OTHR CURR & ACCRUED LIAB	816,560,196.24	(525,448.00)	12,592,555.84	72,206,841.80
TOTAL CURRENT LIABILITIES	27,065,898,552.06	(4,020,704,270.03)	3,190,147,627.92	2,902,086,113.65
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	6,123,403,879.41	0.00	2,893,528.00	860,959,744.00
DFIT & DSIT RECLASS (A/C 190)	(1,248,309,896.71)	5,522,738.00	(962,631.00)	(178,486,314.00)
NET DEFERRED INCOME TAXES	4,875,093,982.70	5,522,738.00	1,930,897.00	682,473,430.00
DEF INVESTMENT TAX CREDITS	527,685,041.00	(10,256,370.00)	0.00	43,093,010.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	1,525,705.07	0.00	0.00	1,525,705.07
SFAS 106 - OPEB	4,427,691.38	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	201,703,207.89	0.00	0.00	139,363,347.00
UNAMORT GAIN REACQUIRED DEBT	242,957.87	0.00	0.00	242,957.87
TOTAL REGULATORY LIABILITIES	207,899,562.21	0.00	0.00	141,132,009.94
DEFERRED CREDITS	2,015,095,116.92	(16,415,304.36)	89,850.20	278,680,547.00
TOTAL DEF CREDITS & REG LIAB'S	7,625,773,702.83	(21,148,936.36)	2,020,747.20	1,145,378,996.94
TOTAL CAPITAL & LIABILITIES	54,548,136,305.79	(12,074,661,449.72)	11,241,063,652.31	6,709,070,231.51

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2000

	CSPCO CONSOLIDATED	I&M CONSOLIDATED	KEPCO	KGPCO
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	1,564,254,117.76	2,708,436,064.33	271,106,791.73	0.00
TRANSMISSION	360,301,359.81	945,708,918.18	360,563,524.73	14,609,784.07
DISTRIBUTION	1,096,364,979.35	863,735,761.21	387,498,940.43	75,019,806.88
GENERAL	156,534,340.93	257,152,081.69	67,475,604.28	4,882,930.41
CONSTRUCTION WORK IN PROGRESS	89,338,972.36	96,439,787.21	16,418,798.52	1,207,158.43
TOTAL ELECTRIC UTILITY PLANT	3,266,793,770.21	4,871,472,612.62	1,103,063,659.69	95,719,679.79
LESS ACCUM PRV-DEPR,DEPL,AMORT	(1,299,696,484.09)	(2,280,520,437.58)	(360,647,400.96)	(33,068,666.86)
NET ELECTRIC UTILITY PLANT	1,967,097,286.12	2,590,952,175.04	742,416,258.73	62,651,012.93
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	29,663,747.25	82,745,647.76	5,448,020.84	133,816.54
INVEST IN SUBSIDIARY & ASSOC	430,000.00	0.00	0.00	0.00
TOTAL OTHER INVESTMENTS	181,893,034.18	243,531,708.54	77,768,251.48	238,574.44
TOTAL OTHER SPECIAL FUNDS	27,738.00	778,806,530.26	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	212,014,519.43	1,105,083,886.56	83,216,272.32	372,390.98
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	11,600,205.76	14,835,222.31	2,270,122.74	429,467.87
ADVANCES TO AFFILIATES	2,227,126.33	10,008,409.72	0.00	0.00
ACCOUNTS RECEIVABLE-CUSTOMERS	73,710,578.32	106,832,422.54	34,555,022.04	5,863,079.30
ACCOUNTS RECEIVABLE - MISC	18,806,675.28	27,491,236.70	6,418,575.47	365,192.32
A/P FOR UNCOLLECTIBLE ACCOUNTS	(659,326.19)	(759,246.57)	(282,325.17)	(82,437.78)
ACCOUNTS RECEIVABLE- ASSOC COS	49,590,746.02	48,706,324.31	22,119,462.10	1,983,812.03
FUEL	13,126,241.68	16,532,494.50	4,760,093.69	0.00
MATERIALS & SUPPLIES	38,096,905.67	84,470,696.48	15,408,416.82	202,714.09
ACCRUED UTILITY REVENUES	9,638,317.05	0.00	6,500,053.91	4,265,878.00
PREPAYMENTS	31,419,059.52	5,945,475.51	587,548.22	827,916.23
ENERGY TRADING CONTRACTS	1,085,989,402.61	1,229,682,493.20	483,536,603.99	0.00
OTHER CURRENT ASSETS	15,316,070.19	478,017.45	178,668.32	356,641.60
TOTAL CURRENT ASSETS	1,348,862,002.24	1,544,223,546.15	576,052,242.13	14,212,263.66
REGULATORY ASSETS				
REGULATORY ASSETS	310,427,813.60	649,599,941.71	109,882,669.15	5,659,411.00
FAS109 DFIT RECLASS (A/C 254)	(18,875,289.00)	(97,460,028.00)	(11,367,554.00)	(650,925.00)
NET REGULATORY ASSETS	291,552,524.60	552,139,913.71	98,515,115.15	5,008,486.00
DEFERRED CHARGES				
CLEARING ACCOUNTS	676,080.24	939,100.57	483,549.71	(11,781.64)
UNAMORTIZED DEBT EXPENSE	1,977,534.29	3,418,490.72	492,599.87	0.00
OTHER DEFERRED DEBITS	74,980,550.30	31,798,405.36	10,839,913.72	18,237.82
TOTAL DEFERRED CHARGES	77,634,164.83	36,155,996.65	11,816,063.30	6,456.18
TOTAL ASSETS	3,897,160,497.22	5,828,555,518.11	1,512,015,951.63	82,250,609.75

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2000

	CSPCO CONSOLIDATED	I&M CONSOLIDATED	KEPCO	KGPCO
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	41,026,065.00	56,583,866.43	50,450,000.00	4,100,000.00
PREMIUM ON CAPITAL STOCK	257,892,417.78	4,325,759.12	0.00	0.00
PAID-IN CAPITAL	315,461,176.71	728,746,373.74	158,750,000.00	13,800,000.00
RETAINED EARNINGS	99,068,911.36	3,443,259.42	57,513,179.25	5,219,330.67
COMMON SHAREHOLDERS' EQUITY	713,448,570.85	793,099,258.71	266,713,179.25	23,119,330.67
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	15,000,000.00	64,945,000.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	0.00	8,735,700.00	0.00	0.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	0.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 Y	899,615,328.37	1,298,939,187.39	270,879,970.95	0.00
TOTAL CAPITALIZATION	1,628,063,899.22	2,165,719,146.10	537,593,150.20	23,119,330.67
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	35,198,716.21	62,324,669.43	11,090,982.25	1,072,853.84
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	12,385,571.01	606,903,428.53	7,257,209.37	845,914.52
TOTAL OTH NONCURRENT LIAB'S	47,584,287.22	669,228,097.96	18,348,191.62	1,918,768.36
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	0.00	90,000,000.00	60,000,000.00	10,000,000.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00
A/P - GENERAL	89,845,952.40	119,471,890.76	32,043,340.66	170,340.13
A/P- ASSOC. COS	72,493,116.51	75,486,345.35	37,506,177.30	8,410,024.28
ADVANCES FROM AFFILIATES	90,958,898.25	263,590,336.02	47,635,407.91	24,043,700.77
CUSTOMER DEPOSITS	4,851,435.67	8,973,397.20	4,388,324.84	763,715.98
TAXES ACCRUED	162,903,635.45	68,415,918.37	11,885,108.17	1,626,235.77
INTEREST ACCRUED	13,369,447.51	21,638,715.84	5,610,306.37	577,129.87
DIVIDENDS DECLARED	262,500.00	1,121,706.65	0.00	0.00
OBLIG UNDER CAP LEASES- CURR	7,732,808.42	103,586,766.11	3,092,983.46	299,446.09
ENERGY TRADING CONTRACTS	1,115,967,298.87	1,275,096,619.43	496,884,257.21	0.00
OTHR CURR & ACCRUED LIAB	47,853,057.12	84,237,114.82	11,423,873.71	974,540.13
TOTAL CURRENT LIABILITIES	1,606,238,150.20	2,111,618,810.55	710,469,779.63	46,865,133.02
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	510,956,372.00	830,845,042.00	198,741,326.00	11,974,261.00
DFIT & DSIT RECLASS (A/C 190)	(88,197,720.00)	(342,900,195.00)	(32,806,742.00)	(2,606,317.00)
NET DEFERRED INCOME TAXES	422,758,652.00	487,944,847.00	165,934,584.00	9,367,944.00
DEF INVESTMENT TAX CREDITS	41,234,503.00	113,773,249.00	11,656,628.00	797,780.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	4,427,691.38	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	7,080,975.26	9,929,570.53	3,172,078.10	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	11,508,666.64	9,929,570.53	3,172,078.10	0.00
DEFERRED CREDITS	139,772,338.94	270,341,796.97	64,841,540.08	181,653.70
TOTAL DEF CREDITS & REG LIAB'S	615,274,160.58	881,989,463.50	245,604,830.18	10,347,377.70
TOTAL CAPITAL & LIABILITIES	3,897,160,497.22	5,828,555,518.11	1,512,015,951.63	82,250,609.75

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	OPCO CONSOLIDATED	WPCO	AEGCO	AEPSC
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	2,764,154,663.62	0.00	635,214,874.29	0.00
TRANSMISSION	870,032,743.22	23,712,979.60	0.00	0.00
DISTRIBUTION	1,040,940,218.22	71,076,263.62	0.00	3,871.00
GENERAL	707,417,583.05	8,021,893.04	2,795,210.07	276,241,510.91
CONSTRUCTION WORK IN PROGRESS	195,086,163.12	1,042,680.25	4,291,833.57	26,380,856.91
TOTAL ELECTRIC UTILITY PLANT	5,577,631,371.23	103,853,816.51	642,301,917.93	302,626,238.82
LESS ACCUM PRV-DEPR,DEPL,AMORT	(2,764,130,158.02)	(43,359,204.43)	(315,565,445.50)	(122,495,397.59)
NET ELECTRIC UTILITY PLANT	2,813,501,213.21	60,494,612.08	326,736,472.43	180,130,841.23
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	60,820,164.16	2,271,324.41	0.00	0.00
INVEST IN SUBSIDIARY & ASSOC	858,480.00	0.00	0.00	100,000.00
TOTAL OTHER INVESTMENTS	303,861,696.29	55,000.69	0.00	87,711,019.32
TOTAL OTHER SPECIAL FUNDS	38,292.00	8,236.00	6,020.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	365,578,632.45	2,334,561.10	6,020.00	87,811,019.32
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	31,392,956.66	822,940.21	2,756,742.76	647,833.35
ADVANCES TO AFFILIATES	259,675,848.61	0.00	0.00	6,510,039.12
ACCOUNTS RECEIVABLE-CUSTOMERS	139,732,166.45	6,251,549.54	0.00	24,501.80
ACCOUNTS RECEIVABLE - MISC	39,045,956.40	542,721.38	2,341,227.15	1,263,666.55
A/P FOR UNCOLLECTIBLE ACCOUNTS	(1,054,418.25)	(91,916.61)	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	126,202,646.82	1,427,156.85	21,374,318.15	258,189,401.92
FUEL	82,290,521.67	0.00	11,005,997.70	0.00
MATERIALS & SUPPLIES	96,053,435.03	96,121.59	3,978,153.20	5,291.16
ACCRUED UTILITY REVENUES	263,690.07	2,331,224.00	0.00	0.00
PREPAYMENTS	30,172,757.54	167,258.32	144,699.15	1,262,819.57
ENERGY TRADING CONTRACTS	1,617,660,286.99	0.00	0.00	0.00
OTHER CURRENT ASSETS	2,709,783.46	867,336.78	0.00	9,397,070.58
TOTAL CURRENT ASSETS	2,424,145,631.45	12,414,392.06	41,601,138.11	277,300,624.05
REGULATORY ASSETS				
REGULATORY ASSETS	759,638,474.61	23,209,642.66	32,132,779.00	7,954,726.31
FAS109 DFIT RECLASS (A/C 254)	(44,927,924.61)	(377,385.00)	(50,624,256.00)	(7,491,269.00)
NET REGULATORY ASSETS	714,710,550.00	22,832,257.66	(18,491,477.00)	463,457.31
DEFERRED CHARGES				
CLEARING ACCOUNTS	855,690.43	(10,103.95)	269.91	(22,943.24)
UNAMORTIZED DEBT EXPENSE	3,963,160.15	0.00	103,541.00	41,708.81
OTHER DEFERRED DEBITS	96,870,906.09	1,604,971.11	650,236.87	752,051.86
TOTAL DEFERRED CHARGES	101,689,756.67	1,594,867.16	754,047.78	770,817.43
TOTAL ASSETS	6,419,625,783.78	99,670,690.06	350,606,201.32	546,476,759.34

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	OPCO CONSOLIDATED	WPCO	AEGCO	AEPSC
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	321,201,454.00	2,428,460.00	1,000,000.00	1,350,000.00
PREMIUM ON CAPITAL STOCK	729,130.45	0.00	0.00	0.00
PAID-IN CAPITAL	461,753,529.41	15,595,573.00	23,434,000.00	99,500.00
RETAINED EARNINGS	398,086,502.58	8,721,597.74	9,722,442.59	0.00
COMMON SHAREHOLDERS' EQUITY	1,181,770,616.44	26,745,630.74	34,156,442.59	1,449,500.00
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	8,850,000.00	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	16,647,700.00	0.00	0.00	0.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	0.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 Y	1,077,987,042.65	0.00	(192,341.00)	57,100,000.00
TOTAL CAPITALIZATION	2,285,255,359.09	26,745,630.74	33,964,101.59	58,549,500.00
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	83,865,779.37	3,245,169.42	358,305.36	48,645,455.30
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	458,151,714.04	2,729,089.04	0.00	141,561,014.23
TOTAL OTH NONCURRENT LIAB'S	542,017,493.41	5,974,258.46	358,305.36	190,206,469.53
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	117,506,411.00	21,000,000.00	45,000,000.00	2,000,000.00
SHORT-TERM DEBT	0.00	5,025,000.00	0.00	0.00
A/P - GENERAL	179,690,760.21	274,868.34	6,108,634.87	21,952,415.64
A/P- ASSOC. COS	121,360,192.57	11,818,494.63	7,723,674.51	106,280,277.02
ADVANCES FROM AFFILIATES	167,189,567.41	0.00	28,067,621.06	0.00
CUSTOMER DEPOSITS	39,735,635.16	278,259.37	0.00	0.00
TAXES ACCRUED	223,101,261.61	1,574,616.45	4,992,937.21	45,016,926.65
INTEREST ACCRUED	20,458,502.73	515,048.18	158,100.69	3,106,441.66
DIVIDENDS DECLARED	0.00	0.00	0.00	0.00
OBLIG UNDER CAP LEASES- CURR	32,715,608.93	615,982.80	232,318.91	24,797,738.49
ENERGY TRADING CONTRACTS	1,662,314,547.10	0.00	0.00	0.00
OTHR CURR & ACCRUED LIAB	151,934,370.90	2,849,860.11	9,016,272.12	134,859,183.28
TOTAL CURRENT LIABILITIES	2,716,006,857.62	43,952,129.88	101,299,559.37	338,012,982.74
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	952,818,811.00	22,416,854.00	114,408,060.00	28,099,217.00
DFIT & DSIT RECLASS (A/C 190)	(330,877,812.00)	(5,320,597.00)	(81,479,693.00)	(70,840,114.00)
NET DEFERRED INCOME TAXES	621,940,999.00	17,096,257.00	32,928,367.00	(42,740,897.00)
DEF INVESTMENT TAX CREDITS	25,213,548.00	451,605.00	59,717,590.00	901,894.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	10,993,992.00	5,399,379.00	0.00	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	10,993,992.00	5,399,379.00	0.00	0.00
DEFERRED CREDITS	218,197,534.66	51,429.98	122,338,278.00	1,546,810.07
TOTAL DEF CREDITS & REG LIAB'S	876,346,073.66	22,998,670.98	214,984,235.00	(40,292,192.93)
TOTAL CAPITAL & LIABILITIES	6,419,625,783.78	99,670,690.06	350,606,201.32	546,476,759.34

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	CCCO	FRECO	IFRI	AEPPM
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	0.00	0.00	0.00	0.00
TRANSMISSION	0.00	0.00	0.00	0.00
DISTRIBUTION	0.00	0.00	0.00	0.00
GENERAL	0.00	0.00	0.00	0.00
CONSTRUCTION WORK IN PROGRESS	0.00	0.00	0.00	0.00
TOTAL ELECTRIC UTILITY PLANT	0.00	0.00	0.00	0.00
LESS ACCUM PRV-DEPR,DEPL,AMORT	0.00	0.00	0.00	0.00
NET ELECTRIC UTILITY PLANT	0.00	0.00	0.00	0.00
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	700,846.00	0.00	0.00	0.00
INVEST IN SUBSIDIARY & ASSOC	0.00	1,000.00	0.00	0.00
TOTAL OTHER INVESTMENTS	0.00	14.00	14.00	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	700,846.00	1,014.00	14.00	0.00
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	6,502.63	70,700.68	31,685.77	0.00
ADVANCES TO AFFILIATES	311,714.53	0.00	0.00	0.00
ACCOUNTS RECEIVABLE-CUSTOMERS	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - MISC	5,565.34	0.00	0.00	0.00
A/P FOR UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	60,461.72	249,336.80	59,989.60	100.00
FUEL	0.00	0.00	0.00	0.00
MATERIALS & SUPPLIES	0.00	0.00	0.00	0.00
ACCRUED UTILITY REVENUES	0.00	0.00	0.00	0.00
PREPAYMENTS	0.00	0.00	0.00	0.00
ENERGY TRADING CONTRACTS	0.00	0.00	0.00	0.00
OTHER CURRENT ASSETS	3,244.00	0.00	0.00	0.00
TOTAL CURRENT ASSETS	387,488.22	320,037.48	91,675.37	100.00
REGULATORY ASSETS				
REGULATORY ASSETS	0.00	0.00	0.00	0.00
FAS109 DFIT RECLASS (A/C 254)	(90,000.00)	0.00	0.00	0.00
NET REGULATORY ASSETS	(90,000.00)	0.00	0.00	0.00
DEFERRED CHARGES				
CLEARING ACCOUNTS	0.00	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	0.00	0.00	0.00	0.00
OTHER DEFERRED DEBITS	0.00	5,845.35	590.56	0.00
TOTAL DEFERRED CHARGES	0.00	5,845.35	590.56	0.00
TOTAL ASSETS	998,334.22	326,896.83	92,279.93	100.00

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	CCCO	FRECO	IFRI	AEPPM
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	3,000.00	10,000.00	1,000.00	100.00
PREMIUM ON CAPITAL STOCK	0.00	0.00	0.00	0.00
PAID-IN CAPITAL	1,204,736.00	0.00	0.00	0.00
RETAINED EARNINGS	(0.00)	19,968.85	0.00	(152.00)
COMMON SHAREHOLDERS' EQUITY	1,207,736.00	29,968.85	1,000.00	(52.00)
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	0.00	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	0.00	0.00	0.00	0.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	0.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 Y	0.00	0.00	0.00	0.00
TOTAL CAPITALIZATION	1,207,736.00	29,968.85	1,000.00	(52.00)
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	0.00	0.00	0.00	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	243,566.00	0.00	0.00	0.00
TOTAL OTH NONCURRENT LIAB'S	243,566.00	0.00	0.00	0.00
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	0.00	0.00	0.00	0.00
SHORT-TERM DEBT	0.00	0.00	0.00	0.00
A/P - GENERAL	0.00	0.00	2,602.86	0.00
A/P- ASSOC. COS	28,170.60	6,475.80	1,882.13	235.00
ADVANCES FROM AFFILIATES	0.00	251,520.50	75,589.18	0.00
CUSTOMER DEPOSITS	0.00	0.00	0.00	0.00
TAXES ACCRUED	(1,000.85)	(1,042.27)	0.00	0.00
INTEREST ACCRUED	0.00	0.00	0.00	0.00
DIVIDENDS DECLARED	0.00	0.00	0.00	0.00
OBLIG UNDER CAP LEASES- CURR	0.00	0.00	0.00	0.00
ENERGY TRADING CONTRACTS	0.00	0.00	0.00	0.00
OTHR CURR & ACCRUED LIAB	62,613.47	38,688.73	11,191.76	0.00
TOTAL CURRENT LIABILITIES	89,783.22	295,642.76	91,265.93	235.00
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	32,637.00	0.00	0.00	0.00
DFIT & DSIT RECLASS (A/C 190)	(584,091.00)	0.00	0.00	(83.00)
NET DEFERRED INCOME TAXES	(551,454.00)	0.00	0.00	(83.00)
DEF INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	8,703.00	0.00	0.00	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	8,703.00	0.00	0.00	0.00
DEFERRED CREDITS	0.00	1,285.22	14.00	0.00
TOTAL DEF CREDITS & REG LIAB'S	(542,751.00)	1,285.22	14.00	(83.00)
TOTAL CAPITAL & LIABILITIES	998,334.22	326,896.83	92,279.93	100.00

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	AEPES	AEPINV CONSOLIDATED	AEPR CONSOLIDATED	AEPPRO
ASSETS:				
ELECTRIC UTILITY PLANT				
PRODUCTION	0.00	0.00	186,503,733.92	0.00
TRANSMISSION	0.00	0.00	124,195,866.55	0.00
DISTRIBUTION	0.00	0.00	358,547,855.79	0.00
GENERAL	2,372,916.80	0.00	243,900,156.69	157,280.93
CONSTRUCTION WORK IN PROGRESS	2,357,441.62	0.00	27,174,029.70	0.00
TOTAL ELECTRIC UTILITY PLANT	4,730,358.42	0.00	940,321,642.65	157,280.93
LESS ACCUM PRV-DEPR,DEPL,AMORT	(750,593.49)	0.00	(62,910,301.77)	(41,888.04)
NET ELECTRIC UTILITY PLANT	3,979,764.93	0.00	877,411,340.88	115,392.89
OTHER PROPERTY AND INVESTMENT				
NET NONUTILITY PROPERTY	0.00	0.00	0.00	0.00
INVEST IN SUBSIDIARY & ASSOC	3,166,666.67	1,313,922.20	408,851,359.99	0.00
TOTAL OTHER INVESTMENTS	370,488,783.59	12,587,112.71	727,953,208.01	5,000,000.00
TOTAL OTHER SPECIAL FUNDS	0.00	0.00	0.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	373,655,450.26	13,901,034.91	1,136,804,568.00	5,000,000.00
CURRENT AND ACCRUED ASSETS				
CASH AND CASH EQUIVALENTS	100,093,331.72	0.00	44,009,531.55	33,684,687.63
ADVANCES TO AFFILIATES	0.00	0.00	27,133,773.33	0.00
ACCOUNTS RECEIVABLE-CUSTOMERS	1,363.72	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - MISC	1,142,853,791.73	0.00	78,725,861.49	7,037,337.67
A/P FOR UNCOLLECTIBLE ACCOUNTS	(419,428.12)	0.00	(1,514,287.87)	(250,013.50)
ACCOUNTS RECEIVABLE- ASSOC COS	147,461,957.99	(390.85)	44,748,304.67	898,225.24
FUEL	23,809,839.62	0.00	4,941,172.71	0.00
MATERIALS & SUPPLIES	9,825.52	1,337.79	8,123,152.04	1,819.82
ACCRUED UTILITY REVENUES	0.00	0.00	100,613,538.36	0.00
PREPAYMENTS	5,656,358.98	0.00	4,438,255.17	26,295.96
ENERGY TRADING CONTRACTS	8,630,640,512.00	0.00	45,852,937.20	0.00
OTHER CURRENT ASSETS	0.00	0.00	6,960,568.54	0.00
TOTAL CURRENT ASSETS	10,050,107,553.16	946.94	364,032,807.19	41,398,352.82
REGULATORY ASSETS				
REGULATORY ASSETS	0.00	0.00	0.00	0.00
FAS109 DFIT RECLASS (A/C 254)	0.00	0.00	0.00	0.00
NET REGULATORY ASSETS	0.00	0.00	0.00	0.00
DEFERRED CHARGES				
CLEARING ACCOUNTS	1,185.20	0.00	0.00	0.00
UNAMORTIZED DEBT EXPENSE	0.00	0.00	261,976.40	0.00
OTHER DEFERRED DEBITS	1,981,367.92	0.00	63,661,424.43	30,066,163.74
TOTAL DEFERRED CHARGES	1,982,553.12	0.00	63,923,400.83	30,066,163.74
TOTAL ASSETS	10,429,725,321.47	13,901,981.85	2,442,172,116.90	76,579,909.45

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	AEPES	AEPINV CONSOLIDATED	AEPR CONSOLIDATED	AEPPRO
CAPITALIZATION AND LIABILITIES:				
CAPITALIZATION				
COMMON STOCK				
COMMON STOCK	200.00	100.00	100.00	110,000.00
PREMIUM ON CAPITAL STOCK	0.00	9,900.00	9,900.00	0.00
PAID-IN CAPITAL	36,695,000.00	28,667,873.32	242,734,432.82	3,890,000.00
RETAINED EARNINGS	(40,438,374.55)	(10,179,671.03)	(32,737,617.48)	(5,092,242.82)
COMMON SHAREHOLDERS' EQUITY	(3,743,174.55)	18,498,202.29	210,006,815.34	(1,092,242.82)
CUMULATIVE PREFERRED STOCK				
PS SUBJECT TO MANDATORY REDEMP	0.00	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	0.00	0.00	0.00	0.00
TRUST PREFERRED SECURITIES				
TRUST PREFERRED SECURITIES	0.00	0.00	0.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)				
LONG-TERM DEBT LESS AMT DUE 1 Y	0.00	0.00	1,116,179,851.79	0.00
TOTAL CAPITALIZATION	(3,743,174.55)	18,498,202.29	1,326,186,667.13	(1,092,242.82)
OTHER NONCURRENT LIABILITIES				
OBLIGATIONS UNDER CAP LEASE	498,290.83	0.00	370,262.41	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	8,012,516.43	0.00	302,241.70	63,475.81
TOTAL OTH NONCURRENT LIAB'S	8,510,807.26	0.00	672,504.11	63,475.81
CURRENT LIABILITIES				
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	0.00	0.00	7,403,981.24	0.00
SHORT-TERM DEBT	0.00	0.00	39,890,734.52	0.00
A/P - GENERAL	1,092,308,240.86	0.00	98,230,655.98	4,822,605.60
A/P- ASSOC. COS	135,066,637.93	152,355.48	62,465,157.47	3,583,067.47
ADVANCES FROM AFFILIATES	122,849,665.97	13,828.28	680,464,846.79	0.00
CUSTOMER DEPOSITS	14,450,000.00	0.00	0.00	0.00
TAXES ACCRUED	74,050,286.67	127,115.00	13,220,270.05	(918,654.84)
INTEREST ACCRUED	0.01	0.00	5,908,542.76	0.00
DIVIDENDS DECLARED	0.00	0.00	0.00	0.00
OBLIG UNDER CAP LEASES- CURR	764,438.76	0.00	110,294.32	0.00
ENERGY TRADING CONTRACTS	8,623,324,763.00	0.00	13,225,658.86	0.00
OTHR CURR & ACCRUED LIAB	18,966,380.66	38,727.80	49,161,850.71	3,855,850.33
TOTAL CURRENT LIABILITIES	10,081,780,413.86	332,026.56	970,081,992.70	11,342,868.56
DEF CREDITS & REGULATORY LIAB				
DEFERRED INCOME TAXES	32,698,465.00	7,136.00	88,765,709.41	8,478.00
DFIT & DSIT RECLASS (A/C 190)	(88,010,847.00)	(4,935,383.00)	(23,915,460.71)	(270,802.00)
NET DEFERRED INCOME TAXES	(55,312,382.00)	(4,928,247.00)	64,850,248.70	(262,324.00)
DEF INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00
REGULATORY LIABILITIES				
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	0.00	0.00	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	0.00	0.00	0.00
DEFERRED CREDITS	398,489,656.90	0.00	80,380,704.26	66,528,131.90
TOTAL DEF CREDITS & REG LIAB'S	343,177,274.90	(4,928,247.00)	145,230,952.96	66,265,807.90
TOTAL CAPITAL & LIABILITIES	10,429,725,321.47	13,901,981.85	2,442,172,116.90	76,579,909.45

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	AEPC CONSOLIDATED	CSW CONSOLIDATED	AEPRELLC
ASSETS:			
ELECTRIC UTILITY PLANT			
PRODUCTION	0.00	6,138,963,006.00	0.00
TRANSMISSION	0.00	1,733,245,947.00	0.00
DISTRIBUTION	0.00	5,132,354,325.00	0.00
GENERAL	46,099,662.14	1,697,881,500.00	0.00
CONSTRUCTION WORK IN PROGRESS	38,254,245.58	622,091,031.00	0.00
TOTAL ELECTRIC UTILITY PLANT	84,353,907.72	15,324,535,809.00	0.00
LESS ACCUM PRV-DEPR,DEPL,AMORT	(5,272,325.71)	(6,081,996,060.00)	0.00
NET ELECTRIC UTILITY PLANT	79,081,582.01	9,242,539,749.00	0.00
OTHER PROPERTY AND INVESTMENT			
NET NONUTILITY PROPERTY	0.00	11,912,164.00	0.00
INVEST IN SUBSIDIARY & ASSOC	34,721,759.76	328,405,897.00	0.00
TOTAL OTHER INVESTMENTS	0.00	1,414,819,351.00	0.00
TOTAL OTHER SPECIAL FUNDS	0.00	93,591,630.00	0.00
TOTAL OTHER PROP AND INVSTMNTS	34,721,759.76	1,848,729,042.00	0.00
CURRENT AND ACCRUED ASSETS			
CASH AND CASH EQUIVALENTS	5,096.66	138,703,850.00	0.00
ADVANCES TO AFFILIATES	1,292,138.21	0.00	0.00
ACCOUNTS RECEIVABLE-CUSTOMERS	0.00	0.00	0.00
ACCOUNTS RECEIVABLE - MISC	7,839,856.68	1,499,879,123.00	0.00
A/P FOR UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00
ACCOUNTS RECEIVABLE- ASSOC COS	11,765,169.92	361,446,318.00	1,539.89
FUEL	0.00	103,152,480.00	0.00
MATERIALS & SUPPLIES	(12.72)	145,549,485.00	0.00
ACCRUED UTILITY REVENUES	0.00	0.00	0.00
PREPAYMENTS	2,757.29	46,525,386.00	0.00
ENERGY TRADING CONTRACTS	0.00	1,473,696,389.00	0.00
OTHER CURRENT ASSETS	0.00	0.00	0.00
TOTAL CURRENT ASSETS	20,905,006.04	3,768,953,031.00	1,539.89
REGULATORY ASSETS			
REGULATORY ASSETS	0.00	1,516,007,533.00	0.00
FAS109 DFIT RECLASS (A/C 254)	0.00	0.00	0.00
NET REGULATORY ASSETS	0.00	1,516,007,533.00	0.00
DEFERRED CHARGES			
CLEARING ACCOUNTS	(139,594.63)	0.00	0.00
UNAMORTIZED DEBT EXPENSE	0.00	0.00	0.00
OTHER DEFERRED DEBITS	5,912,906.76	455,792,365.00	0.00
TOTAL DEFERRED CHARGES	5,773,312.13	455,792,365.00	0.00
TOTAL ASSETS	140,481,659.94	16,832,021,720.00	1,539.89

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING BALANCE SHEETS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	AEPC CONSOLIDATED	CSW CONSOLIDATED	AEPRELLC
CAPITALIZATION AND LIABILITIES:			
CAPITALIZATION			
COMMON STOCK			
COMMON STOCK	100.00	2,319,437.00	0.00
PREMIUM ON CAPITAL STOCK	9,900.00	0.00	0.00
PAID-IN CAPITAL	28,290,000.00	1,741,844,480.00	0.00
RETAINED EARNINGS	(40,389,863.31)	1,922,501,377.00	(112,726.61)
COMMON SHAREHOLDERS' EQUITY	(12,089,863.31)	3,666,665,294.00	(112,726.61)
CUMULATIVE PREFERRED STOCK			
PS SUBJECT TO MANDATORY REDEMP	0.00	0.00	0.00
PS NOT SUBJ MANDATORY REDEMP	0.00	18,436,503.00	0.00
TRUST PREFERRED SECURITIES			
TRUST PREFERRED SECURITIES	0.00	333,500,000.00	0.00
LT DEBT (LESS AMT DUE IN 1 YR)			
LONG-TERM DEBT LESS AMT DUE 1 Y	0.00	3,451,766,587.00	0.00
TOTAL CAPITALIZATION	(12,089,863.31)	7,470,368,384.00	(112,726.61)
OTHER NONCURRENT LIABILITIES			
OBLIGATIONS UNDER CAP LEASE	20,997,712.68	0.00	0.00
ACCUM PROVISIONS-RATE REFUND	0.00	0.00	0.00
ACCUMULATED PROVISIONS - MISC	6,807.75	114,377,134.00	0.00
TOTAL OTH NONCURRENT LIAB'S	21,004,520.43	114,377,134.00	0.00
CURRENT LIABILITIES			
PREFERRED STOCK DUE W/IN 1 YR	0.00	0.00	0.00
LONG-TERM DEBT DUE WITHIN 1 YR	0.00	624,388,840.00	0.00
SHORT-TERM DEBT	0.00	1,238,531,900.00	0.00
A/P - GENERAL	1,349,294.59	804,917,727.00	0.00
A/P- ASSOC. COS	6,252,189.21	529,467,947.00	22,174.79
ADVANCES FROM AFFILIATES	122,041,713.89	886,609,117.00	150,589.77
CUSTOMER DEPOSITS	0.00	117,208,047.00	0.00
TAXES ACCRUED	(5,410,386.00)	127,161,440.00	0.00
INTEREST ACCRUED	0.00	85,199,018.00	0.00
DIVIDENDS DECLARED	0.00	553,770.00	0.00
OBLIG UNDER CAP LEASES- CURR	161,310.72	0.00	0.00
ENERGY TRADING CONTRACTS	0.00	1,500,284,085.00	0.00
OTHR CURR & ACCRUED LIAB	2,899,208.01	214,101,264.00	2,198.94
TOTAL CURRENT LIABILITIES	127,293,330.42	6,128,423,155.00	174,963.50
DEF CREDITS & REGULATORY LIAB			
DEFERRED INCOME TAXES	473,097.00	2,467,305,142.00	0.00
DFIT & DSIT RECLASS (A/C 190)	(1,577,136.00)	0.00	(60,697.00)
NET DEFERRED INCOME TAXES	(1,104,039.00)	2,467,305,142.00	(60,697.00)
DEF INVESTMENT TAX CREDITS	0.00	241,101,604.00	0.00
REGULATORY LIABILITIES			
OVER-RECOVERY OF FUEL COST	0.00	0.00	0.00
SFAS 106 - OPEB	0.00	0.00	0.00
DEMAND SIDE MANAGEMENT-CREDIT	0.00	0.00	0.00
OTHER REGULATORY LIABILTIES	0.00	25,755,163.00	0.00
UNAMORT GAIN REACQUIRED DEBT	0.00	0.00	0.00
TOTAL REGULATORY LIABILITIES	0.00	25,755,163.00	0.00
DEFERRED CREDITS	5,377,711.40	384,691,138.00	0.00
TOTAL DEF CREDITS & REG LIAB'S	4,273,672.40	3,118,853,047.00	(60,697.00)
TOTAL CAPITAL & LIABILITIES	140,481,659.94	16,832,021,720.00	1,539.89

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING BALANCE SHEETS YTD THROUGH DECEMBER, 2000	CSW CONSOL ACTUAL DEC 00	RECLASS	COMBINED ACTUAL DEC 00	CPL ACTUAL DEC 00
ASSETS:				
Production	6,138,963,006	202,681,191	5,936,281,815	3,175,867,024
Transmission	1,733,245,947		1,733,245,947	581,931,201
Distribution	3,577,626,318		3,577,626,318	1,221,749,447
General	566,205,923	(408,914,266)	975,120,189	237,764,034
Construction Work in Progress	622,091,031	241,903,438	380,187,593	138,273,198
Nuclear Fuel	236,858,911		236,858,911	236,858,911
ELECTRIC UTILITY PLANT	12,874,991,136	35,670,363	12,839,320,773	5,592,443,815
UK Network	1,554,728,007		1,554,728,007	0
UK Non-Network Land & Building	92,428,644		92,428,644	0
UK Fixtures & Equipment	198,648,129		198,648,129	0
UK Vehicles & Mobile Plant	23,829,773		23,829,773	0
Acquisition Step Up	33,512,689		33,512,689	0
UK PLANT	1,903,147,242	-	1,903,147,242	0
Diversified Plant	546,397,431		546,397,431	-
TOTAL PLANT	15,324,535,809	35,670,363	15,288,865,446	5,592,443,815
ACCUMULATED DEPRECIATION	6,081,996,060	(93,591,630)	6,175,587,690	2,313,889,051
NET PLANT	9,242,539,749	129,261,993	9,113,277,756	3,278,554,764
NET NONUTILITY PROPERTY	11,912,164	11,912,164		
Investment in Subsidiaries	18,988,877	18,988,877	-	-
TOTAL OTHER INVESTMENTS	202,831,612	202,831,612		
TOTAL OTHER SPECIAL INVESMNTS	-			
Cash	127,635,847	15,564,016	112,071,831	4,172,197
Temporary Cash Investments	11,068,003	-	11,068,003	6,594,000
Money Pool Receivable - West	-	-	-	-
CASH AND TEMPORARY INVESTMENTS	138,703,850	15,564,016	123,139,834	10,766,197
Marketable Securities	10,730,413		10,730,413	0
Accounts Receivable - Affiliated West	-		-	29,715,666
Accounts Receivable - Affiliated East	361,446,318		361,446,318	1,556,081
Accounts Receivable - Factored West	-		-	(80,061,490)
Accounts Receivable-Nonaffiliated	1,440,015,128	(81,254,000)	1,521,269,128	146,173,847
Dividends Receivable	-		-	-
Underrecovered Fuel	274,138,614		274,138,614	127,294,948
Materials and Supplies	145,549,485		145,549,485	53,107,619
Fuel Inventory-Utility	103,152,480		103,152,480	22,841,694
Notes Receivable-Current	59,863,995		59,863,995	0
ENERGY TRADING CONTRACTS	1,473,696,389	1,473,696,389		
Prepayments and Other	35,794,973	(1,489,260,405)	1,525,055,378	487,707,223
CURRENT ASSETS	4,043,091,645	(81,254,000)	4,124,345,645	799,101,785
Mirror CWIP	2,830,581		2,830,581	2,830,581
Deferred Plant Costs	4,625,281		4,625,281	-
Equity and Other Investments	328,405,897	(269,403,016)	597,808,913	68,589,168
Notes Receivable-LT	26,045,877		26,045,877	-
Deferred Income Taxes-Asset	-		-	-
Prepaid Benefit Costs	210,758,997		210,758,997	41,867,371
Tax Benefits Provided	-		-	-
Income Tax Related Regulatory Assets	179,741,425		179,741,425	312,874,443
Other Regulatory Assets	994,467,676		994,467,676	949,854,272
Unamort Cost of Reacquired Debt	60,203,956		60,203,956	12,773,311
Goodwill	1,192,998,862		1,192,998,862	0
Nuclear Decommissioning Trust	93,591,630		93,591,630	93,591,630
Deferred Charges & Other Assets	218,987,491	81,254,000	137,733,491	18,402,013
TOTAL DEFERRED CHARGES & OTHER ASSETS	3,312,657,673	(188,149,016)	3,500,806,689	1,500,782,789
TOTAL ASSETS	16,832,021,720	93,591,630	16,738,430,090	5,578,439,338

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING BALANCE SHEETS YTD THROUGH DECEMBER, 2000	CSW CONSOL ACTUAL DEC 00	RECLASS	COMBINED ACTUAL DEC 00	CPL ACTUAL DEC 00
CAPITALIZATION AND LIABILITIES:				
Common Stock	2,319,437		2,319,437	168,888,375
Paid in Capital	1,806,179,572		1,806,179,572	405,000,000
Foreign Currency Translation	(60,129,904)		(60,129,904)	0
Minimum Pension Liability	(4,205,188)		(4,205,188)	-
Retained Earnings	1,922,501,377		1,922,501,377	792,218,830
COMMON STOCK EQUITY	3,666,665,294		3,666,665,294	1,366,107,205
Pref Stock Not Subj Mand Redempt	18,436,503		18,436,503	5,966,569
Pref Stock Subj Mand Redempt	-		-	-
PREFERRED STOCK	18,436,503		18,436,503	5,966,569
TRUST PREFERRED SECURITIES	333,500,000		333,500,000	148,500,000
Long Term Debt	3,455,132,469		3,455,132,469	1,254,820,000
UK Debt Facility	-		-	0
Unamort Discount/Premium on LTD	(3,365,882)		(3,365,882)	(261,383)
TOTAL LONG TERM DEBT	3,451,766,587		3,451,766,587	1,254,558,617
CAPITALIZATION	7,470,368,384		7,470,368,384	2,775,132,391
	-			
MINORITY INTEREST	6,240,122		6,240,122	0
ACCUMULATED PROVISIONS - MISC.	114,377,134	114,377,134		
LTD and PS Due Within Twelve Months	624,388,840		624,388,840	200,000,000
Money Pool Payable - West	-		-	-
Money Pool Payable - East	886,609,117		886,609,117	269,711,657
Loan Notes Payable	17,583,900		17,583,900	-
Commercial Paper	1,220,948,000		1,220,948,000	-
Accounts Payable - Affiliated West	-		-	3,697,555
Accounts Payable - Affiliated East	529,467,947		529,467,947	14,310,840
Accounts Payable-Nonaffiliated	804,917,727		804,917,727	128,956,618
Accrued Taxes	127,162,440		127,162,440	55,526,131
Interest Payable - Affiliated West	-		-	-
Interest Payable - Affiliated East	5,192,710		5,192,710	1,493,885
Accrued Interest	80,006,308		80,006,308	24,723,313
Overrecovered Fuel	-		-	-
Customer Deposits	117,208,047		117,208,047	17,617,387
Deferred Income Taxes - Current	43,423,283		43,423,283	819,275
Dividends Payable	553,770		553,770	40,259
ENERGY TRADING CONTRACTS	1,500,284,085	1,500,284,085		
Other Current Liabilities	214,101,264	(1,503,548,010)	1,717,649,274	512,860,654
Balancing Account	0		0	-
TOTAL CURRENT LIABILITIES	6,171,847,438	(3,263,925)	6,175,111,363	1,229,757,574
	-			
Unbilled Revenue	-		-	(49,760,000)
Unbilled Customer Accounts Sold	-		-	72,713,467
Deferred Income Taxes-Liability	2,423,880,859		2,423,880,859	1,241,977,697
UK Provisions Long-Term	(37,185,842)		(37,185,842)	0
Investment Tax Credits	241,101,604		241,101,604	128,099,498
Tax Benefits Used	-		-	(1)
Income Tax Related Regulatory Liab	-		-	105,943,833
Other Regulatory Liabilities	25,755,163		25,755,163	15,100,000
Other Deferred Credits	412,049,062	(17,521,579)	429,570,641	59,474,879
Other Long-Term Liabilities	3,587,796		3,587,796	0
	-			
TOTAL DEFERRED CREDITS	3,086,710,221		3,086,710,221	1,573,549,373
	-			
TOTAL CAPITAL & LIABILITIES	16,832,021,720	93,591,630	16,738,430,090	5,578,439,338

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING BALANCE SHEETS YTD THROUGH DECEMBER, 2000	PSO ACTUAL DEC 00	SWEPCO ACTUAL DEC 00	WTU ACTUAL DEC 00	SEEBOARD ACTUAL DEC 00
ASSETS:				
Production	914,095,663	1,414,526,586	431,792,542	-
Transmission	396,695,025	519,316,624	235,303,097	-
Distribution	938,052,664	1,001,236,739	416,587,468	-
General	206,731,298	325,948,061	110,832,136	-
Construction Work in Progress	149,095,593	57,994,889	34,823,913	-
Nuclear Fuel	-	-	-	-
ELECTRIC UTILITY PLANT	2,604,670,243	3,319,022,899	1,229,339,156	-
UK Network	0	0	0	1,554,728,007
UK Non-Network Land & Building	0	0	0	92,428,644
UK Fixtures & Equipment	0	0	0	198,648,129
UK Vehicles & Mobile Plant	0	0	0	23,829,773
Acquisition Step Up	0	0	0	33,512,689
UK PLANT	0	0	0	1,903,147,242
Diversified Plant	-	-	-	-
TOTAL PLANT	2,604,670,243	3,319,022,899	1,229,339,156	1,903,147,242
ACCUMULATED DEPRECIATION	1,150,253,476	1,457,004,717	515,041,391	684,282,211
NET PLANT	1,454,416,767	1,862,018,182	714,297,765	1,218,865,031
NET NONUTILITY PROPERTY				
Investment in Subsidiaries	-	-	-	-
TOTAL OTHER INVESTMENTS				
TOTAL OTHER SPECIAL INVESMNTS				
Cash	7,247,116	879,749	2,797,917	73,942,617
Temporary Cash Investments	-	-	-	-
Money Pool Receivable - West	-	-	-	-
CASH AND TEMPORARY INVESTMENTS	7,247,116	879,749	2,797,917	73,942,617
Marketable Securities	0	0	0	10,730,413
Accounts Receivable - Affiliated West	2,791,770	9,335,774	8,226,482	74,461,420
Accounts Receivable - Affiliated East	660,898	2,083,192	7,868,922	0
Accounts Receivable - Factored West	(72,058,472)	(55,327,571)	(26,867,192)	-
Accounts Receivable-Nonaffiliated	132,015,537	96,726,927	62,795,921	214,180,192
Dividends Receivable	-	-	-	0
Underrecovered Fuel	43,267,421	35,468,894	68,107,351	-
Materials and Supplies	29,642,492	25,137,276	10,510,169	13,146,515
Fuel Inventory-Utility	28,113,348	40,023,843	12,173,595	-
Notes Receivable-Current	0	0	0	0
ENERGY TRADING CONTRACTS				
Prepayments and Other	387,992,395	475,742,922	157,168,295	-
CURRENT ASSETS	559,672,505	630,071,006	302,781,460	386,461,157
Mirror CWIP	-	-	-	-
Deferred Plant Costs	-	-	4,625,281	-
Equity and Other Investments	61,082,478	68,751,450	21,811,928	43,501,914
Notes Receivable-LT	-	-	-	-
Deferred Income Taxes-Asset	-	-	-	0
Prepaid Benefit Costs	29,757,559	33,903,626	22,286,281	53,748,000
Tax Benefits Provided	-	-	-	-
Income Tax Related Regulatory Assets	21,811,943	74,941,255	13,968,706	-
Other Regulatory Assets	15,737,150	19,897,585	8,978,669	-
Unamort Cost of Reacquired Debt	13,600,417	22,626,331	11,203,897	-
Goodwill	0	0	0	1,192,998,862
Nuclear Decommissioning Trust	-	-	-	0
Deferred Charges & Other Assets	7,889,248	10,707,407	2,946,621	28,101,575
TOTAL DEFERRED CHARGES & OTHER ASSETS	149,878,795	230,827,654	85,821,383	1,318,350,351
TOTAL ASSETS	2,163,968,067	2,722,916,842	1,102,900,608	2,923,676,539

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING BALANCE SHEETS YTD THROUGH DECEMBER, 2000	PSO ACTUAL DEC 00	SWEPCO ACTUAL DEC 00	WTU ACTUAL DEC 00	SEEBOARD ACTUAL DEC 00
CAPITALIZATION AND LIABILITIES:				
Common Stock	157,230,000	135,659,520	137,214,000	1,000
Paid in Capital	180,000,000	245,000,000	2,236,000	828,999,000
Foreign Currency Translation	0	0	0	(60,203,850)
Minimum Pension Liability	-	-	-	0
Retained Earnings	137,688,384	293,989,298	122,587,708	266,870,322
COMMON STOCK EQUITY	474,918,384	674,648,818	262,037,708	1,035,666,472
Pref Stock Not Subj Mand Redempt	5,283,382	4,704,421	2,482,131	-
Pref Stock Subj Mand Redempt	-	-	-	-
PREFERRED STOCK	5,283,382	4,704,421	2,482,131	-
TRUST PREFERRED SECURITIES	75,000,000	110,000,000	-	0
Long Term Debt	453,360,000	644,335,000	256,310,000	846,057,469
UK Debt Facility	0	0	0	-
Unamort Discount/Premium on LTD	(2,538,946)	1,032,860	(466,622)	(1,100,890)
TOTAL LONG TERM DEBT	450,821,054	645,367,860	255,843,378	844,956,579
CAPITALIZATION	1,006,022,820	1,434,721,099	520,363,217	1,880,623,051
MINORITY INTEREST	0	0	0	2,770,226
ACCUMULATED PROVISIONS - MISC.				
LTD and PS Due Within Twelve Months	20,000,000	595,000	-	203,793,840
Money Pool Payable - West	-	-	-	-
Money Pool Payable - East	81,120,372	16,822,552	58,578,160	0
Loan Notes Payable	-	-	-	17,583,900
Commercial Paper	-	-	-	-
Accounts Payable - Affiliated West	15,542,656	3,264,333	20,231,874	2,723,006
Accounts Payable - Affiliated East	22,872,725	9,825,334	5,910,792	(4,314,556)
Accounts Payable-Nonaffiliated	104,378,502	107,747,289	45,562,192	206,306,205
Accrued Taxes	1,658,886	11,223,508	18,901,452	82,577,764
Interest Payable - Affiliated West	-	-	-	0
Interest Payable - Affiliated East	398,208	24,012	359,677	0
Accrued Interest	7,937,490	13,173,765	3,356,873	22,379,845
Overrecovered Fuel	-	-	-	-
Customer Deposits	19,293,990	16,432,745	2,659,077	61,150,150
Deferred Income Taxes - Current	14,499,716	11,595,080	16,509,212	-
Dividends Payable	53,159	57,264	26,039	0
ENERGY TRADING CONTRACTS				
Other Current Liabilities	401,362,911	492,494,688	162,798,406	86,575,653
Balancing Account	-	-	-	-
TOTAL CURRENT LIABILITIES	689,118,615	683,255,570	334,893,754	678,775,807
Unbilled Revenue	(10,200,000)	(12,283,000)	(9,011,000)	-
Unbilled Customer Accounts Sold	36,340,728	35,215,321	25,080,153	-
Deferred Income Taxes-Liability	297,559,993	387,609,202	140,528,704	288,510,048
UK Provisions Long-Term	0	0	0	(37,185,842)
Investment Tax Credits	35,783,032	53,167,336	24,051,738	-
Tax Benefits Used	-	-	-	-
Income Tax Related Regulatory Liab	50,464,213	60,382,610	27,462,299	-
Other Regulatory Liabilities	2,015,209	8,639,954	-	-
Other Deferred Credits	56,863,457	72,208,750	39,531,743	106,595,453
Other Long-Term Liabilities	0	-	-	3,587,796
TOTAL DEFERRED CREDITS	468,826,632	604,940,173	247,643,637	361,507,455
TOTAL CAPITAL & LIABILITIES	2,163,968,067	2,722,916,842	1,102,900,608	2,923,676,539

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING BALANCE SHEETS YTD THROUGH DECEMBER, 2000	CORP ACTUAL DEC 00	CSWS ACTUAL DEC 00	COMM ACTUAL DEC 00	LEASING ACTUAL DEC 00	CREDIT ACTUAL DEC 00
ASSETS:					
Production	-	-	-	-	-
Transmission	-	-	-	-	-
Distribution	-	-	-	-	-
General	-	93,844,660	-	-	-
Construction Work in Progress	-	-	-	-	-
Nuclear Fuel	-	-	-	-	-
ELECTRIC UTILITY PLANT	-	93,844,660	-	-	-
UK Network	0	0	0	0	0
UK Non-Network Land & Building	0	0	0	0	0
UK Fixtures & Equipment	0	0	0	0	0
UK Vehicles & Mobile Plant	0	0	0	0	0
Acquisition Step Up	0	0	0	0	0
UK PLANT	0	0	0	0	0
Diversified Plant	-	-	114,448,060	-	-
TOTAL PLANT	-	93,844,660	114,448,060	-	-
ACCUMULATED DEPRECIATION	-	38,024,460	10,021,448	-	-
NET PLANT	-	55,820,200	104,426,612	-	-
NET NONUTILITY PROPERTY					
Investment in Subsidiaries	4,110,301,950	-	-	-	-
TOTAL OTHER INVESTMENTS					
TOTAL OTHER SPECIAL INVESMNTS					
Cash	1,200	2,126,882	2,000	12,470	(423,612)
Temporary Cash Investments	-	-	-	992,296	-
Money Pool Receivable - West	-	-	-	-	-
CASH AND TEMPORARY INVESTMENTS	1,200	2,126,882	2,000	1,004,766	(423,612)
Marketable Securities	0	0	0	0	0
Accounts Receivable - Affiliated West	(364,433)	29,141,067	131,345	1	743,551
Accounts Receivable - Affiliated East	-	-	0	-	349,277,225
Accounts Receivable - Factored West	-	-	-	-	392,066,267
Accounts Receivable-Nonaffiliated	2,078,768	412,956	3,935,608	-	597,536,989
Dividends Receivable	1,375,337	-	-	-	-
Underrecovered Fuel	-	-	-	-	-
Materials and Supplies	-	-	2,417,333	-	-
Fuel Inventory-Utility	-	-	-	-	-
Notes Receivable-Current	0	0	0	0	0
ENERGY TRADING CONTRACTS					
Prepayments and Other	197,965	399,588	230,601	-	4,771,618
CURRENT ASSETS	3,288,837	32,080,493	6,716,887	1,004,767	1,343,972,038
Mirror CWIP	-	-	-	-	-
Deferred Plant Costs	-	-	-	-	-
Equity and Other Investments	-	1,316,106	3,741,186	52,026,553	-
Notes Receivable-LT	-	-	-	-	-
Deferred Income Taxes-Asset	-	-	0	-	9,082,387
Prepaid Benefit Costs	-	28,564,619	360,372	-	-
Tax Benefits Provided	-	-	-	(1,037,181)	-
Income Tax Related Regulatory Assets	-	-	398,033	-	-
Other Regulatory Assets	-	-	-	-	-
Unamort Cost of Reacquired Debt	-	-	-	-	-
Goodwill	0	0	0	0	0
Nuclear Decommissioning Trust	-	-	0	-	-
Deferred Charges & Other Assets	30,195,356	355,524	(139,307)	-	-
TOTAL DEFERRED CHARGES & OTHER ASSETS	30,195,356	30,236,249	4,360,284	50,989,372	9,082,387
TOTAL ASSETS	4,143,786,143	118,136,942	115,503,783	51,994,139	1,353,054,425

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING BALANCE SHEETS YTD THROUGH DECEMBER, 2000	CORP ACTUAL DEC 00	CSWS ACTUAL DEC 00	COMM ACTUAL DEC 00	LEASING ACTUAL DEC 00	CREDIT ACTUAL DEC 00
CAPITALIZATION AND LIABILITIES:					
Common Stock	2,319,437	100,000	1,000	1,000	1,000
Paid in Capital	1,806,179,572	-	-	25,125,901	94,400,056
Foreign Currency Translation	0	0	0	0	0
Minimum Pension Liability	(4,205,188)	-	0	-	-
Retained Earnings	1,902,351,377	-	(52,904,934)	2,341,434	-
COMMON STOCK EQUITY	3,706,645,198	100,000	(52,903,934)	27,468,335	94,401,056
Pref Stock Not Subj Mand Redempt	-	-	-	-	-
Pref Stock Subj Mand Redempt	-	-	-	-	-
PREFERRED STOCK	-	-	-	-	-
TRUST PREFERRED SECURITIES	-	-	-	-	-
Long Term Debt	-	-	-	-	-
UK Debt Facility	0	0	0	0	0
Unamort Discount/Premium on LTD	-	(1)	-	-	-
TOTAL LONG TERM DEBT	-	(1)	-	-	-
CAPITALIZATION	3,706,645,198	99,999	(52,903,934)	27,468,335	94,401,056
MINORITY INTEREST	0	0	3,469,896	0	0
ACCUMULATED PROVISIONS - MISC.					
LTD and PS Due Within Twelve Months	-	-	-	-	-
Money Pool Payable - West	-	-	-	-	-
Money Pool Payable - East	392,468,092	67,908,284	-	-	-
Loan Notes Payable	-	-	-	-	-
Commercial Paper	-	-	-	-	1,220,948,000
Accounts Payable - Affiliated West	12,354,461	3,726,582	154,235,894	280,226	226,914
Accounts Payable - Affiliated East	-	-	-	-	-
Accounts Payable-Nonaffiliated	4,532,614	6,123,191	5,960,831	23,782	-
Accrued Taxes	(21,272,997)	3,678,235	(4,180,623)	-	2,680,153
Interest Payable - Affiliated West	-	-	908,370	-	-
Interest Payable - Affiliated East	-	613,537	-	-	-
Accrued Interest	4,012,066	-	-	-	-
Overrecovered Fuel	-	-	-	-	-
Customer Deposits	-	-	54,698	-	-
Deferred Income Taxes - Current	-	-	-	-	-
Dividends Payable	-	-	-	-	1,752,386
ENERGY TRADING CONTRACTS					
Other Current Liabilities	(149,312)	16,346,453	602,818	-	33,045,916
Balancing Account	-	-	-	-	-
TOTAL CURRENT LIABILITIES	391,944,924	98,396,282	157,581,988	304,008	1,258,653,369
Unbilled Revenue	-	-	-	-	-
Unbilled Customer Accounts Sold	-	-	-	-	-
Deferred Income Taxes-Liability	80,425	12,385,719	6,282,828	24,235,930	-
UK Provisions Long-Term	0	0	0	0	0
Investment Tax Credits	-	-	-	-	-
Tax Benefits Used	(683,339)	-	-	(14,134)	-
Income Tax Related Regulatory Liab	-	-	-	-	-
Other Regulatory Liabilities	-	-	-	-	-
Other Deferred Credits	45,798,935	7,254,942	1,073,005	-	-
Other Long-Term Liabilities	-	0	0	-	0
TOTAL DEFERRED CREDITS	45,196,021	19,640,661	7,355,833	24,221,796	-
TOTAL CAPITAL & LIABILITIES	4,143,786,143	118,136,942	115,503,783	51,994,139	1,353,054,425

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING BALANCE SHEETS YTD THROUGH DECEMBER, 2000	CSWE ACTUAL DEC 00	INTL ACTUAL DEC 00	ENERSHOP ACTUAL DEC 00	ESI ACTUAL DEC 00	TOT_ELIM ACTUAL DEC 00
ASSETS:					
Production	-	-	-	-	-
Transmission	-	-	-	-	0
Distribution	-	-	-	-	0
General	-	-	-	-	0
Construction Work in Progress	-	-	-	-	0
Nuclear Fuel	-	-	-	-	0
ELECTRIC UTILITY PLANT	-	-	-	-	-
UK Network	0	0	0	0	0
UK Non-Network Land & Building	0	0	0	0	0
UK Fixtures & Equipment	0	0	0	0	0
UK Vehicles & Mobile Plant	0	0	0	0	0
Acquisition Step Up	0	0	0	0	0
UK PLANT	0	0	0	0	0
Diversified Plant	417,673,376	6,389,990	912,554	6,973,451	0
TOTAL PLANT	417,673,376	6,389,990	912,554	6,973,451	-
ACCUMULATED DEPRECIATION	4,981,876	1,443,604	455,186	190,270	0
NET PLANT	412,691,500	4,946,386	457,368	6,783,181	-
NET NONUTILITY PROPERTY					
Investment in Subsidiaries	-	730,403,520	-	-	(4,840,705,470)
TOTAL OTHER INVESTMENTS					
TOTAL OTHER SPECIAL INVESMNTS					
Cash	20,387,603	925,692	-	-	0
Temporary Cash Investments	-	3,481,707	-	-	0
Money Pool Receivable - West	-	-	-	-	-
CASH AND TEMPORARY INVESTMENTS	20,387,603	4,407,399	-	-	-
Marketable Securities	0	0	0	0	-
Accounts Receivable - Affiliated West	159,319,649	(1,379,900)	1,410	23,983,539	(336,107,341)
Accounts Receivable - Affiliated East	0	0	0	0	0
Accounts Receivable - Factored West	-	-	-	0	(157,751,542)
Accounts Receivable-Nonaffiliated	78,252,024	67,878,450	1,119,768	36,908,141	81,254,000
Dividends Receivable	-	-	-	-	(1,375,337)
Underrecovered Fuel	-	-	-	-	0
Materials and Supplies	-	-	-	11,588,081	0
Fuel Inventory-Utility	-	-	-	-	0
Notes Receivable-Current	-	59,863,995	0	0	0
ENERGY TRADING CONTRACTS					
Prepayments and Other	8,962,231	29,927	395,507	1,457,106	0
CURRENT ASSETS	266,921,507	130,799,871	1,516,685	73,936,867	(413,980,220)
Mirror CWIP	-	-	-	-	0
Deferred Plant Costs	-	-	-	-	0
Equity and Other Investments	137,039,531	155,190,047	-	(15,241,448)	0
Notes Receivable-LT	15,183	26,030,694	-	-	0
Deferred Income Taxes-Asset	-	19,408,844	0	0	(28,491,231)
Prepaid Benefit Costs	-	-	271,169	-	0
Tax Benefits Provided	339,707	-	-	-	697,474
Income Tax Related Regulatory Assets	-	-	-	-	(244,252,955)
Other Regulatory Assets	-	-	-	-	0
Unamort Cost of Reacquired Debt	-	-	-	-	-
Goodwill	0	0	0	0	0
Nuclear Decommissioning Trust	0	0	0	0	0
Deferred Charges & Other Assets	16,256,072	-	356,347	22,662,635	0
TOTAL DEFERRED CHARGES & OTHER ASSETS	153,650,493	200,629,585	627,516	7,421,187	(272,046,712)
TOTAL ASSETS	833,263,500	1,066,779,362	2,601,569	88,141,235	(5,526,732,402)

<PAGE>

CENTRAL AND SOUTH WEST AND SUBSIDIARY COMPANIES CONSOLIDATING BALANCE SHEETS YTD THROUGH DECEMBER, 2000	CSWE ACTUAL DEC 00	INTL ACTUAL DEC 00	ENERSHOP ACTUAL DEC 00	ESI ACTUAL DEC 00	TOT_ELIM ACTUAL DEC 00
CAPITALIZATION AND LIABILITIES:					
Common Stock	1,000	1,000	100	1,000	(599,098,995)
Paid in Capital	108,139,293	829,000,000	900	-	(2,717,901,150)
Foreign Currency Translation	-	73,946	-	0	0
Minimum Pension Liability	0	0	0	0	0
Retained Earnings	50,791,204	(26,523,231)	(15,982,836)	(21,915,368)	(1,529,010,811)
COMMON STOCK EQUITY	158,931,497	802,551,715	(15,981,836)	(21,914,368)	(4,846,010,956)
Pref Stock Not Subj Mand Redempt	-	-	-	-	0
Pref Stock Subj Mand Redempt	-	-	-	-	0
PREFERRED STOCK	-	-	-	-	0
TRUST PREFERRED SECURITIES	0	0	0	0	0
Long Term Debt	-	-	-	250,000	0
UK Debt Facility	0	0	0	0	0
Unamort Discount/Premium on LTD	(30,900)	-	-	-	0
TOTAL LONG TERM DEBT	(30,900)	-	-	250,000	-
CAPITALIZATION	158,900,597	802,551,715	(15,981,836)	(21,664,368)	(4,846,010,956)
MINORITY INTEREST	0	0	0	0	0
ACCUMULATED PROVISIONS - MISC.					
LTD and PS Due Within Twelve Months	200,000,000	-	-	-	0
Money Pool Payable - West	-	-	-	-	-
Money Pool Payable - East	0	0	0	0	0
Loan Notes Payable	-	-	-	-	0
Commercial Paper	-	-	-	-	0
Accounts Payable - Affiliated West	-	232,308,181	67,191	644,806	(449,303,679)
Accounts Payable - Affiliated East	363,318,939	30,603,064	17,461,854	69,478,955	0
Accounts Payable-Nonaffiliated	27,646,006	398,546	405,740	42,081,746	124,794,465
Accrued Taxes	(8,004,219)	(8,745,091)	(460,701)	(6,420,058)	-
Interest Payable - Affiliated West	-	(32,055)	109,141	-	(985,456)
Interest Payable - Affiliated East	2,137,130	166,261	-	-	0
Accrued Interest	3,437,500	-	-	-	985,456
Overrecovered Fuel	-	-	-	-	0
Customer Deposits	-	-	-	-	-
Deferred Income Taxes - Current	-	-	-	-	-
Dividends Payable	-	-	-	-	(1,375,337)
ENERGY TRADING CONTRACTS					
Other Current Liabilities	2,917,641	(17,373)	30,661	3,474,672	5,305,486
Balancing Account	-	-	0	-	-
TOTAL CURRENT LIABILITIES	591,452,997	254,681,533	17,613,886	109,260,121	(320,579,065)
Unbilled Revenue	-	-	-	-	81,254,000
Unbilled Customer Accounts Sold	-	-	-	-	(169,349,669)
Deferred Income Taxes-Liability	51,703,880	-	952,182	545,482	(28,491,231)
UK Provisions Long-Term	0	0	0	0	0
Investment Tax Credits	-	-	-	-	0
Tax Benefits Used	-	-	-	-	697,474
Income Tax Related Regulatory Liab	-	-	-	-	(244,252,955)
Other Regulatory Liabilities	-	-	-	-	0
Other Deferred Credits	31,206,026	9,546,114	17,337	-	0
Other Long-Term Liabilities	0	0	-	-	0
TOTAL DEFERRED CREDITS	82,909,906	9,546,114	969,519	545,482	(360,142,381)
TOTAL CAPITAL & LIABILITIES	833,263,500	1,066,779,362	2,601,569	88,141,235	(5,526,732,402)

<PAGE>
American Electric Power Co. and Subsidiaries
Consolidated Statement of Cash Flows
YTD December 31, 2000

	AEP CONS.	ELIM & ADJ	COMBINED	AEP Inc.
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	267,067,592	(359,189,321)	626,256,913	267,067,698
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	1,299,400,018		1,299,400,018	3,662,826
Prov for Def Income Taxes (net)	(170,220,072)	(12,009,613)	(158,210,459)	(2,574,739)
Def Invest Tax Credits (net)	(36,198,382)	1,004,898	(37,203,280)	
AFUDC - Equity	(5,805,028)		(5,805,028)	
Equity/Undist. Subs. Earnings	(29,463,485)	(31,109,475)	1,645,990	31,109,475
Decrease (Increase) in:				
Accounts Receivable (net)	(1,631,810,136)	572,867,032	(2,204,677,168)	(14,142,428)
Fuel, Materials & Supplies	147,381,879	553,812	146,828,067	(33,575)
Accrued Utility Revenues	(78,540,191)	(129,734,067)	51,193,876	
Incr (Decr) in Accounts Payable	1,322,064,076	(860,831,318)	2,182,895,394	511,904
Other Oper. Items (net) (Sch 1)	419,353,374	64,228,254	355,125,120	339,234,953
NET CASH PROVIDED (USED) OPERATING	1,503,229,645	(754,219,798)	2,257,449,443	624,836,114
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant	(1,742,417,983)	7,704,805	(1,750,122,788)	
Other Gross Additions	(36,750,023)		(36,750,023)	
Total Gross Additions	(1,779,168,006)	7,704,805	(1,786,872,811)	0
AFUDC - Equity	5,805,028		5,805,028	
Cash Used Plant & Prop. Adds	(1,773,362,978)	7,704,805	(1,781,067,783)	0
Invest in Subs - Equity & Debt	72,842,890	21,521,432	51,321,458	(21,421,432)
Proceeds - Sales of Property	46,062,593	(2,743,840)	48,806,433	
Proceeds - Sale & Leaseback Trans	2,351,385		2,351,385	
Other Investing Activities	(102,117,510)		(102,117,510)	
NET CASH PROVIDED (USED) INVESTING	(1,754,223,620)	26,482,397	(1,780,706,017)	(21,421,432)
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent	0	(18,252,578)	18,252,578	
Common Stock	14,231,343		14,231,343	890,346
Preferred Stock	0		0	
Minority Interest	3,176,534		3,176,534	
Long-term Debt	1,120,512,423		1,120,512,423	
Change in Money Pool	0	1,011,892,348	(1,011,892,348)	(2,737,820,282)
Short-term Debt (net)	1,308,142,001	(392,000,000)	1,700,142,001	2,800,245,000
Total Issuances	2,446,062,301	601,639,770	1,844,422,531	63,315,064
Cash Paid To Retire:				
Preferred Stock	(20,422,113)		(20,422,113)	
Long-term Debt	(1,564,691,662)		(1,614,691,662)	
Total Retirements	(1,585,113,775)	0	(1,635,113,775)	0
Dividends Paid on Common Stock	(804,835,822)	703,221,607	(1,508,057,429)	(619,340,590)
Dividends Paid on Preferred Stock	(11,080)	8,143,671	(8,154,751)	
NET CASH PROVIDED (USED) FINANCING	56,101,624	1,313,005,048	(1,306,903,424)	(556,025,526)
EFFECT OF EXCHANGE RATE CHANGES	23,633,715		23,633,715	
NET INCREASE (DECREASE) IN CASH	(171,258,636)	585,267,647	(806,526,283)	47,389,156
CASH AT BEGINNING OF PERIOD	608,548,825	50,060,172	608,488,653	2,693,005
CASH AT END OF PERIOD	437,290,189	635,327,819	(198,037,630)	50,082,161
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	842,485,352	(111,793,020)	954,278,372	112,491,869
Income Taxes (State & Federal)	449,386,124		449,386,124	(10,670,721)
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	100,548,924	(5,941,153)	106,490,077	0
NonUtility Assets - Capital Leases	17,092,735		17,092,735	0
Total Capital Leases	117,641,659	(5,941,153)	123,582,812	0

<PAGE>
American Electric Power Co. and Subsidiaries
Consolidated Statement of Cash Flows
YTD December 31, 2000

	AEPSC	APCo CONSOL.	OPCo CONSOL.	I&M CONSOL.
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income		73,844,300	83,737,348	(132,031,676)
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	4,084,568	163,201,630	200,350,113	163,390,579
Prov for Def Income Taxes (net)	(18,052,509)	8,601,465	(56,149,256)	(125,178,640)
Def Invest Tax Credits (net)	(50,808)	(4,914,869)	(3,398,498)	(7,853,383)
AFUDC - Equity		(110,160)	(1,418,896)	(1,680,479)
Equity/Undist. Subs. Earnings		0	0	
Decrease (Increase) in:				
Accounts Receivable (net)	(195,913,635)	(166,911,392)	51,923,649	(49,354,361)
Fuel, Materials & Supplies		18,486,803	63,940,240	10,742,647
Accrued Utility Revenues		(13,080,471)	45,311,593	44,427,559
Incr (Decr) in Accounts Payable	101,648,659	159,369,639	56,069,903	85,056,087
Other Oper. Items (net) (Sch 1)	176,980,960	41,882,428	198,126,908	119,321,686
NET CASH PROVIDED (USED) OPERATING	68,697,235	280,369,373	638,493,104	106,840,019
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant	0	(199,395,385)	(255,434,540)	(172,751,404)
Other Gross Additions	(27,386,260)		0	0
Total Gross Additions	(27,386,260)	(199,395,385)	(255,434,540)	(172,751,404)
AFUDC - Equity		110,160	1,418,896	1,680,479
Cash Used Plant & Prop. Adds	(27,386,260)	(199,285,225)	(254,015,644)	(171,070,925)
Invest in Subs - Equity & Debt	(100,000)			
Proceeds - Sales of Property		117,171	4,612,858	586,706
Proceeds - Sale & Leaseback Trans		41,940	1,741,155	0
Other Investing Activities				
NET CASH PROVIDED (USED) INVESTING	(27,486,260)	(199,126,114)	(247,661,631)	(170,484,219)
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent		0		
Common Stock				
Preferred Stock		0		
Minority Interest				
Long-term Debt		74,787,500	74,747,500	199,220,000
Change in Money Pool	(6,510,039)	(8,387,327)	(92,486,283)	253,581,926
Short-term Debt (net)	(39,900,000)	68,015,000	(194,918,000)	(224,262,000)
Total Issuances	(46,410,039)	134,415,173	(212,656,783)	228,539,926
Cash Paid To Retire:				
Preferred Stock		(9,923,538)	(181,761)	(314,439)
Long-term Debt	(2,000,000)	(136,166,125)	(30,662,486)	(148,000,000)
Total Retirements	(2,000,000)	(146,089,663)	(30,844,247)	(148,314,439)
Dividends Paid on Common Stock		(126,611,811)	(271,812,643)	(26,289,998)
Dividends Paid on Preferred Stock		(1,938,471)	(1,262,465)	(3,367,735)
NET CASH PROVIDED (USED) FINANCING	(48,410,039)	(140,224,772)	(516,576,138)	50,567,754
EFFECT OF EXCHANGE RATE CHANGES				
NET INCREASE (DECREASE) IN CASH	(7,199,064)	(58,981,513)	(125,744,665)	(13,076,446)
CASH AT BEGINNING OF PERIOD	7,846,897	64,828,221	157,137,623	27,911,668
CASH AT END OF PERIOD	647,833	5,846,708	31,392,958	14,835,222
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	7,639,771	124,578,700	87,120,127	82,510,624
Income Taxes (State & Federal)	5,071,686	63,681,652	142,709,558	73,253,996
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	31,090,622	13,795,260	16,474,352	6,282,935
NonUtility Assets - Capital Leases	0	320,736	530,876	15,934,985
Total Capital Leases	31,090,622	14,115,996	17,005,228	22,217,920

<PAGE>
American Electric Power Co. and Subsidiaries
Consolidated Statement of Cash Flows
YTD December 31, 2000

	CSPCo CONSOL.	KEPCo	KGPCo	WPCo
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	94,966,012	20,763,113	785,908	3,790,909
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	100,181,927	31,034,538	3,104,782	3,205,233
Prov for Def Income Taxes (net)	(4,062,668)	3,765,685	102,861	2,647,536
Def Invest Tax Credits (net)	(3,481,527)	(1,252,055)	(71,524)	(36,308)
AFUDC - Equity	(1,803,785)	57	665	391
Equity/Undist. Subs. Earnings				
Decrease (Increase) in:				
Accounts Receivable (net)	(29,735,957)	(20,930,045)	(3,117,043)	(734,126)
Fuel, Materials & Supplies	11,957,036	8,385,845	184,531	18,079
Accrued Utility Revenues	38,479,123	7,236,935	(308,429)	(489,406)
Incr (Decr) in Accounts Payable	81,284,213	39,882,867	1,836,331	2,916,998
Other Oper. Items (net) (Sch 1)	79,353,056	6,356,860	(9,371,990)	(6,117,584)
NET CASH PROVIDED (USED) OPERATING	367,137,430	95,243,800	(6,853,908)	5,201,722
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant	(129,790,287)	(36,208,575)	(5,093,440)	(4,156,148)
Other Gross Additions	0	0		
Total Gross Additions	(129,790,287)	(36,208,575)	(5,093,440)	(4,156,148)
AFUDC - Equity	1,803,785	(57)	(665)	(391)
Cash Used Plant & Prop. Adds	(127,986,502)	(36,208,632)	(5,094,105)	(4,156,539)
Invest in Subs - Equity & Debt				
Proceeds - Sales of Property	991,696	265,519		0
Proceeds - Sale & Leaseback Trans	568,290			0
Other Investing Activities				
NET CASH PROVIDED (USED) INVESTING	(126,426,516)	(35,943,113)	(5,094,105)	(4,156,539)
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent				
Common Stock				
Preferred Stock				
Minority Interest				
Long-term Debt		69,685,000		
Change in Money Pool	88,731,773	47,635,408	24,043,701	
Short-term Debt (net)	(45,500,000)	(39,665,000)	(4,050,000)	2,025,000
Total Issuances	43,231,773	77,655,408	19,993,701	2,025,000
Cash Paid To Retire:				
Preferred Stock	(10,000,000)			
Long-term Debt	(25,274,435)	(105,000,000)	(5,000,000)	
Total Retirements	(35,274,435)	(105,000,000)	(5,000,000)	0
Dividends Paid on Common Stock	(240,600,148)	(30,360,003)	(2,752,002)	(2,860,002)
Dividends Paid on Preferred Stock	(1,575,000)			
NET CASH PROVIDED (USED) FINANCING	(234,217,810)	(57,704,595)	12,241,699	(835,002)
EFFECT OF EXCHANGE RATE CHANGES				
NET INCREASE (DECREASE) IN CASH	6,493,104	1,596,092	293,686	210,181
CASH AT BEGINNING OF PERIOD	5,107,103	674,031	135,782	612,760
CASH AT END OF PERIOD	11,600,207	2,270,123	429,468	822,941
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	68,506,474	29,260,541	1,913,179	1,657,125
Income Taxes (State & Federal)	81,108,520	7,922,921	1,720,643	932,758
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	10,606,135	2,817,370	263,896	262,288
NonUtility Assets - Capital Leases	170,487	0	7,265	128,386
Total Capital Leases	10,776,622	2,817,370	271,161	390,674

<PAGE>
American Electric Power Co. and Subsidiaries
Consolidated Statement of Cash Flows
YTD December 31, 2000

	AEP PRO SERV	AEGCo	CCCo	COpCo
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	(2,352,360)	7,984,600		0
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	12,620	22,161,904		
Prov for Def Income Taxes (net)	(1,869)	(5,841,950)	(5,535)	0
Def Invest Tax Credits (net)	2,687	(3,396,972)		
AFUDC - Equity		0		
Equity/Undist. Subs. Earnings				
Decrease (Increase) in:				
Accounts Receivable (net)	4,148,517	1,391,510	209,018	0
Fuel, Materials & Supplies	(28)	6,486,411		
Accrued Utility Revenues				
Incr (Decr) in Accounts Payable	2,359,330	(3,324,291)	(1,606)	0
Other Oper. Items (net) (Sch 1)	48,721,521	(3,630,266)	62,380	0
NET CASH PROVIDED (USED) OPERATING	52,890,418	21,830,946	264,257	0
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant		(5,189,799)		
Other Gross Additions				
Total Gross Additions	0	(5,189,799)	0	0
AFUDC - Equity		0		
Cash Used Plant & Prop. Adds	0	(5,189,799)	0	0
Invest in Subs - Equity & Debt				
Proceeds - Sales of Property				
Proceeds - Sale & Leaseback Trans				
Other Investing Activities	(4,664,000)			
NET CASH PROVIDED (USED) INVESTING	(4,664,000)	(5,189,799)	0	0
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent	0	(5,801,000)		
Common Stock				
Preferred Stock				
Minority Interest				
Long-term Debt				
Change in Money Pool		28,067,621	(311,715)	
Short-term Debt (net)	(14,550,000)	(24,700,000)		
Total Issuances	(14,550,000)	(2,433,379)	(311,715)	0
Cash Paid To Retire:				
Preferred Stock				
Long-term Debt				
Total Retirements	0	0	0	0
Dividends Paid on Common Stock		(1,935,000)		
Dividends Paid on Preferred Stock				
NET CASH PROVIDED (USED) FINANCING	(14,550,000)	(4,368,379)	(311,715)	0
EFFECT OF EXCHANGE RATE CHANGES				
NET INCREASE (DECREASE) IN CASH	33,676,418	12,272,768	(47,458)	0
CASH AT BEGINNING OF PERIOD	8,269	(9,516,026)	53,961	0
CASH AT END OF PERIOD	33,684,687	2,756,742	6,503	0
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	46,677	3,530,540	433	0
Income Taxes (State & Federal)	(70,848)	6,819,720	2,787	0
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	0	8,435	0	0
NonUtility Assets - Capital Leases	0	0	0	0
Total Capital Leases	0	8,435	0	0

<PAGE>
American Electric Power Co. and Subsidiaries
Consolidated Statement of Cash Flows
YTD December 31, 2000

	AEPINV	FRECo	IFRI	AEPR CONSOL.	AEPC CONSOL.
CASH FLOWS - OPERATING ACTIVITIES:					
Consolidated Net Income	(422,682)	0		1,901,965	(25,528,926)
Adj. to Recon. N/I to Cash Flow:					
Depreciation & Amortization				56,523,423	4,789,689
Prov for Def Income Taxes (net)	(91,259)			27,524,655	(1,764,965)
Def Invest Tax Credits (net)					
AFUDC - Equity					
Equity/Undist. Subs. Earnings	172,274			(44,240,461)	18,071,353
Decrease (Increase) in:					
Accounts Receivable (net)	21,587	(178,780)	2,133	18,961,632	(14,181,872)
Fuel, Materials & Supplies	(1,338)			(5,728,540)	2,516,459
Accrued Utility Revenues				(70,383,028)	
Incr (Decr) in Accounts Payable	(58,911)	(34,049)	(130,823)	14,025,151	(747,406)
Other Oper. Items (net) (Sch 1)	203,149	27,760	11,037	(507,991)	(6,983,861)
NET CASH PROVIDED (USED) OPERATING	(177,180)	(185,069)	(117,653)	(1,923,194)	(23,829,529)
CASH FLOWS - INVESTING ACTIVITIES:					
Plant & Property Additions:					
Gross Additions to Utility Plant				(49,267,347)	(14,066,391)
Other Gross Additions				(1,408,341)	
Total Gross Additions	0	0	0	(50,675,688)	(14,066,391)
AFUDC - Equity					
Cash Used Plant & Prop. Adds	0	0	0	(50,675,688)	(14,066,391)
Invest in Subs - Equity & Debt				0	
Proceeds - Sales of Property				2,710,334	
Proceeds - Sale & Leaseback Trans					
Other Investing Activities	(5,640,325)	0		(43,863,267)	(46,579,084)
NET CASH PROVIDED (USED) INVESTING	(5,640,325)	0	0	(91,828,621)	(60,645,475)
CASH FLOWS - FINANCING ACTIVITIES:					
Proceeds from Issuances of:					
Capital Contributions from Parent	5,743,578	0			840,000
Common Stock					
Preferred Stock					
Minority Interest				3,176,534	(3,469,896)
Long-term Debt				267,839,999	30,000,000
Change in Money Pool	13,828	251,520	75,589	653,331,075	120,749,576
Short-term Debt (net)				37,254,339	(5,500,000)
Total Issuances	5,757,406	251,520	75,589	961,601,947	142,619,680
Cash Paid To Retire:					
Preferred Stock					
Long-term Debt				(872,136,754)	(60,000,000)
Total Retirements	0	0	0	(872,136,754)	(60,000,000)
Dividends Paid on Common Stock					
Dividends Paid on Preferred Stock					
NET CASH PROVIDED (USED) FINANCING	5,757,406	251,520	75,589	89,465,193	82,619,680
EFFECT OF EXCHANGE RATE CHANGES				(1,382,874)	
NET INCREASE (DECREASE) IN CASH	(60,099)	66,451	(42,064)	(5,669,496)	(1,855,324)
CASH AT BEGINNING OF PERIOD	60,099	4,249	73,750	49,679,027	1,860,422
CASH AT END OF PERIOD	0	70,700	31,686	44,009,531	5,098
CASH PAID DURING THE PERIOD FOR:					
Interest (net of ABFUDC)	7,646	0	0	118,507,863	6,436,437
Income Taxes (State & Federal)	(301,195)	0	0	(33,979,298)	(5,492,143)
NONCASH INVESTING ACTIVITIES:					
Utility Assets - Capital Leases	0	0	0	354,657	22,902,591
NonUtility Assets - Capital Leases	0	0	0	0	0
Total Capital Leases	0	0	0	354,657	22,902,591

<PAGE>
American Electric Power Co. and Subsidiaries
Consolidated Statement of Cash Flows
YTD December 31, 2000

	AEPPM	AEPES	CSW CONSOL.	AEPRELLC (AEP Retail)
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income		9,798,951	222,064,480	(112,727)
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization		1,989,241	541,706,945	
Prov for Def Income Taxes (net)	0	(57,205,115)	70,136,541	(60,697)
Def Invest Tax Credits (net)			(12,750,023)	
AFUDC - Equity			(792,821)	
Equity/Undist. Subs. Earnings			(3,466,651)	
Decrease (Increase) in:				
Accounts Receivable (net)	0	(999,357,733)	(786,776,302)	(1,540)
Fuel, Materials & Supplies		1,892,498	27,980,999	
Accrued Utility Revenues				
Incr (Decr) in Accounts Payable	0	935,386,886	706,822,337	22,175
Other Oper. Items (net) (Sch 1)	0	155,510,391	(148,731,096)	2,199
NET CASH PROVIDED (USED) OPERATING	0	48,015,119	616,194,409	(150,590)
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant		(324,217)	(878,445,255)	
Other Gross Additions			(7,955,422)	
Total Gross Additions	0	(324,217)	(886,400,677)	0
AFUDC - Equity			792,821	
Cash Used Plant & Prop. Adds	0	(324,217)	(885,607,856)	0
Invest in Subs - Equity & Debt			72,842,890	
Proceeds - Sales of Property			39,522,149	
Proceeds - Sale & Leaseback Trans				
Other Investing Activities		(3,166,667)	1,795,833	0
NET CASH PROVIDED (USED) INVESTING	0	(3,490,884)	(771,446,984)	0
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent		17,470,000		0
Common Stock			13,340,997	
Preferred Stock				
Minority Interest			3,469,896	
Long-term Debt			404,232,424	
Change in Money Pool		122,849,666	494,141,025	150,590
Short-term Debt (net)		(108,175,000)	(506,177,338)	
Total Issuances	0	32,144,666	409,007,004	150,590
Cash Paid To Retire:				
Preferred Stock			(2,375)	
Long-term Debt			(230,451,862)	
Total Retirements	0	0	(230,454,237)	0
Dividends Paid on Common Stock			(185,495,232)	
Dividends Paid on Preferred Stock			(11,080)	
NET CASH PROVIDED (USED) FINANCING	0	32,144,666	(6,953,545)	150,590
EFFECT OF EXCHANGE RATE CHANGES			25,016,589	
NET INCREASE (DECREASE) IN CASH	0	76,668,901	(137,189,531)	0
CASH AT BEGINNING OF PERIOD	0	23,424,431	275,893,381	0
CASH AT END OF PERIOD	0	100,093,332	138,703,850	0
CASH PAID DURING THE PERIOD FOR:				
Interest (net of ABFUDC)	0	7,461,093	302,607,796	1,477
Income Taxes (State & Federal)	0	(11,121,338)	127,797,426	0
NONCASH INVESTING ACTIVITIES:				
Utility Assets - Capital Leases	0	1,631,536	0	0
NonUtility Assets - Capital Leases	0	0	0	0
Total Capital Leases	0	1,631,536	0	0

<PAGE>
Central & Southwest Corporation and Subsidiaries
Consolidated Statement of Cash Flows
YTD December 31, 2000

	CSW CONS.	ELIM & ADJ	COMBINED	CSW CORP.
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	222,064,480	(375,488,677)	597,553,157	201,127,699
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	541,706,945		541,706,945	378,905
Prov for Def Income Taxes (net)	70,136,541	0	70,136,541	(418,338)
Def Invest Tax Credits (net)	(12,750,023)	0	(12,750,023)	0
AFUDC - Equity	(792,821)		(792,821)	0
Equity/Undist. Subs. Earnings	(3,466,651)	54,850,884	(58,317,535)	(38,388,030)
Decrease (Increase) in:	0	0	0	
Accounts Rec. Affiliated West	0	(186,879,838)	186,879,838	321,087,299
Accounts Rec. Affiliated East	(361,446,318)	0	(361,446,318)	0
Accounts Rec. - Factored West	0	9,401,303	(9,401,303)	
Accounts Rec. - Factored East	0	0	0	
Accounts Rec. - Nonaffiliated	(425,329,984)		(425,329,984)	501,607
Dividends Receivable	0		0	
Fuel, Materials & Supplies	27,980,999	0	27,980,999	0
Accrued Utility Revenues	0	0	0	0
Accounts Payable - Affiliated West	0	147,086,411	(147,086,411)	(20,316,265)
Accounts Payable - Affilaited East	128,100,309		128,100,309	0
Accounts Payable - Nonaffiliated	578,722,028		578,722,028	26,886
Interest Payable - Affiliated West	0	(3,367,250)	3,367,250	0
Interest Payable - Affiliated East	5,192,710		5,192,710	0
Other Oper. Items (net) (Sch 1)	(153,923,806)	33,937,144	(188,647,705)	10,050,172
NET CASH PROVIDED (USED) OPERATING	616,194,409	(320,460,023)	935,867,677	474,049,935
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant	(878,445,255)	0	(878,445,255)	
Other Gross Additions	(7,955,422)		(7,955,422)	
Total Gross Additions	(886,400,677)	0	(886,400,677)	0
AFUDC - Equity	792,821		792,821	
Cash Used Plant & Prop. Adds	(885,607,856)	0	(885,607,856)	0
Invest in Subs - Equity & Debt	72,842,890	44,002,128	28,840,762	(44,002,128)
Proceeds - Sales of Property	39,522,149	0	39,522,149	
Proceeds - Sale & Leaseback Trans	0		0	
Other Investing Activities	1,795,833	(17,372,599)	19,168,432	
NET CASH PROVIDED (USED) INVESTING	(771,446,984)	26,629,529	(798,076,513)	(44,002,128)
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent	0	(44,606,597)	44,606,597	
Common Stock	13,340,997		13,340,997	13,340,997
Preferred Stock	0		0	0
Minority Interest	3,469,896		3,469,896	0
Long-term Debt	404,232,424		404,232,424	0
Money Pool Payable - East	494,141,025		494,141,025	0
Money Pool Payable - West	0	0	0	653,805,303
Short-term Debt (net)	(506,177,338)		(506,177,338)	(953,623,908)
Total Issuances	409,007,004	(44,606,597)	453,613,601	(286,477,608)
Cash Paid To Retire:				
Preferred Stock	(2,375)		(2,375)	0
Long-term Debt	(230,451,862)		(230,451,862)	0
Total Retirements	(230,454,237)	0	(230,454,237)	0
Dividends Paid on Common Stock	(185,495,232)	337,650,336	(523,145,568)	(185,495,232)
Dividends Paid on Preferred Stock	(11,080)	786,755	(797,835)	0
NET CASH PROVIDED (USED) FINANCING	(6,953,545)	293,830,494	(300,784,039)	(471,972,840)
EFFECT OF EXCHANGE RATE CHANGES	25,016,589		25,016,589	
NET INCREASE (DECREASE) IN CASH	(137,189,531)	0	(137,976,286)	(41,925,033)
CASH AT BEGINNING OF PERIOD	275,893,381	0	275,893,381	41,926,233
CASH AT END OF PERIOD	138,703,850	0	137,917,095	1,200

<PAGE>
Central & Southwest Corporation and Subsidiaries
Consolidated Statement of Cash Flows
YTD December 31, 2000

	CSWSC	CPLCo CONSOL.	PSOCo CONSOL.	SWEPCo CONSOL.
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	0	189,566,811	66,663,263	72,672,021
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	13,838,091	178,785,763	76,418,418	104,679,480
Prov for Def Income Taxes (net)	(427,188)	16,262,886	22,501,211	14,652,952
Def Invest Tax Credits (net)	0	(5,206,908)	(1,790,808)	(4,481,495)
AFUDC - Equity	0		(235,451)	(445,517)
Equity/Undist. Subs. Earnings	0	0	0	0
Decrease (Increase) in:				
Accounts Rec. Affiliated West	8,122,226	(14,461,996)	(509,166)	(3,282,940)
Accounts Rec. Affiliated East	0	(1,556,081)	(660,898)	(2,083,192)
Accounts Rec. - Factored West		33,214,776	39,889,833	20,583,194
Accounts Rec. - Factored East			0	
Accounts Rec. - Nonaffiliated	964,314	(50,099,295)	(67,545,362)	(16,471,521)
Dividends Receivable				
Fuel, Materials & Supplies	0	8,681,476	675,695	22,103,007
Accrued Utility Revenues	0	0	0	0
Accounts Payable - Affiliated West	2,225,270	(14,996,589)	1,645,335	(8,913,313)
Accounts Payable - Affilaited East	0	14,310,840	8,975,404	9,825,334
Accounts Payable - Nonaffiliated	(17,517,973)	46,557,596	78,708,775	43,051,804
Interest Payable - Affiliated West	442,167	1,414,664	232,942	588,648
Interest Payable - Affiliated East	613,537	1,493,885	398,208	24,012
Other Oper. Items (net) (Sch 1)	4,981,304	(26,047,637)	(63,804,248)	(51,897,531)
NET CASH PROVIDED (USED) OPERATING	13,241,748	377,920,191	161,563,151	200,604,943
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant	(2,299,499)	(199,484,282)	(177,086,740)	(120,670,785)
Other Gross Additions	0		0	0
Total Gross Additions	(2,299,499)	(199,484,282)	(177,086,740)	(120,670,785)
AFUDC - Equity	0		235,451	445,517
Cash Used Plant & Prop. Adds	(2,299,499)	(199,484,282)	(176,851,289)	(120,225,268)
Invest in Subs - Equity & Debt	0			0
Proceeds - Sales of Property	13,115,816	0	0	0
Proceeds - Sale & Leaseback Trans	0		0	0
Other Investing Activities	0			0
NET CASH PROVIDED (USED) INVESTING	10,816,317	(199,484,282)	(176,851,289)	(120,225,268)
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent	0	0		0
Common Stock	0			0
Preferred Stock	0	0		0
Minority Interest	0			0
Long-term Debt	0	149,247,902	105,624,759	149,359,763
Money Pool Payable - East	67,908,284	269,711,657	81,120,372	16,822,552
Money Pool Payable - West	(90,173,315)	(322,157,843)	(79,169,026)	(140,897,523)
Short-term Debt (net)	0	0	0	0
Total Issuances	(22,265,031)	96,801,716	107,576,105	25,284,792
Cash Paid To Retire:				
Preferred Stock	0	0	(1,475)	(840)
Long-term Debt	0	(101,440,000)	(20,000,000)	(45,595,000)
Total Retirements	0	(101,440,000)	(20,001,475)	(45,595,840)
Dividends Paid on Common Stock		(155,999,948)	(67,999,920)	(62,000,009)
Dividends Paid on Preferred Stock		(248,883)	(212,911)	(231,736)
NET CASH PROVIDED (USED) FINANCING	(22,265,031)	(160,887,115)	19,361,799	(82,542,793)
EFFECT OF EXCHANGE RATE CHANGES	0			
NET INCREASE (DECREASE) IN CASH	1,793,034	17,548,794	4,073,661	(2,163,118)
CASH AT BEGINNING OF PERIOD	333,848	7,994,664	3,173,455	3,042,867
CASH AT END OF PERIOD	2,126,882	25,543,458	7,247,116	879,749

<PAGE>
Central & Southwest Corporation and Subsidiaries
Consolidated Statement of Cash Flows
YTD December 31, 2000

	WTUCo	SEEBOARD	CSW COMM	LEASING	CREDIT
CASH FLOWS - OPERATING ACTIVITIES:					
Consolidated Net Income	27,449,684	98,901,451	(20,924,961)	1,807,422	14,091,544
Adj. to Recon. N/I to Cash Flow:					
Depreciation & Amortization	55,171,543	99,769,727	5,864,535		0
Prov for Def Income Taxes (net)	10,638,301	17,421,984	1,511,443	(414,573)	0
Def Invest Tax Credits (net)	(1,270,812)	0	0	0	0
AFUDC - Equity	(111,853)	0	0	0	0
Equity/Undist. Subs. Earnings	0	(13,527,487)	0	0	0
Decrease (Increase) in:					
Accounts Rec. Affiliated West	(3,389,847)	(83,819,920)	(130,185)		(242,856)
Accounts Rec. Affiliated East	(7,868,922)				(349,277,225)
Accounts Rec. - Factored West	22,679,088				(125,768,194)
Accounts Rec. - Factored East					
Accounts Rec. - Nonaffiliated	(12,865,484)	540,290	(2,717,001)	0	(148,339,588)
Dividends Receivable					
Fuel, Materials & Supplies	8,478,146	(1,535,903)	(2,048,469)	0	0
Accrued Utility Revenues	0	0	0	0	0
Accounts Payable - Affiliated West	15,353,347	33,184,459	66,344,272	55,007	(3,793,616)
Accounts Payable - Affilaited East	5,910,792	0			
Accounts Payable - Nonaffiliated	7,129,141	0	466,772	(7,884)	0
Interest Payable - Affiliated West	112,635	0	420,113	0	0
Interest Payable - Affiliated East	359,677	0	0	0	0
Other Oper. Items (net) (Sch 1)	(37,639,600)	(28,259,416)	(4,852,873)	(4,264,322)	12,865,600
NET CASH PROVIDED (USED) OPERATING	90,135,836	122,675,185	43,933,646	(2,824,350) 2,806,350	(600,464,335)
CASH FLOWS - INVESTING ACTIVITIES:					
Plant & Property Additions:					
Gross Additions to Utility Plant	(64,589,262)	(130,811,479)	(38,950,120)	0	0
Other Gross Additions	0	0	(7,955,422)	0	0
Total Gross Additions	(64,589,262)	(130,811,479)	(46,905,542)	0	0
AFUDC - Equity	111,853	0	0	0	0
Cash Used Plant & Prop. Adds	(64,477,409)	(130,811,479)	(46,905,542)	0	0
Invest in Subs - Equity & Debt		4,330,839	0	0	0
Proceeds - Sales of Property	0	25,860,779	0	0	0
Proceeds - Sale & Leaseback Trans	0	0	0	0	0
Other Investing Activities		5,013,871	(500,000)	0	0
NET CASH PROVIDED (USED) INVESTING	(64,477,409)	(95,605,990)	(47,405,542)	0	0
CASH FLOWS - FINANCING ACTIVITIES:					
Proceeds from Issuances of:					
Capital Contributions from Parent	0	0	0	5,620,069	38,986,528
Common Stock	0	0	0	0	0
Preferred Stock	0	0	0	0	0
Minority Interest		0	3,469,896	0	0
Long-term Debt	0	0	0	0	0
Money Pool Payable - East	58,578,160	0	0	0	0
Money Pool Payable - West	(21,407,596)	0	0	0	0
Short-term Debt (net)	0	(19,214,430)	0	0	466,661,000
Total Issuances	37,170,564	(19,214,430)	3,469,896	5,620,069	505,647,528
Cash Paid To Retire:					
Preferred Stock	(60)	0	0	0	0
Long-term Debt	(48,000,000)	0	0	0	0
Total Retirements	(48,000,060)	0	0	0	0
Dividends Paid on Common Stock	(18,000,031)	(17,372,599)	0	(3,000,000)	(13,277,829)
Dividends Paid on Preferred Stock	(104,305)	0	0	0	0
NET CASH PROVIDED (USED) FINANCING	(28,933,832)	(36,587,029)	3,469,896	2,620,069	492,369,699
EFFECT OF EXCHANGE RATE CHANGES		(5,795,041)	0	0	0
NET INCREASE (DECREASE) IN CASH	(3,275,405)	(15,312,875)	(2,000)	(204,281)	(108,094,636)
CASH AT BEGINNING OF PERIOD	6,073,322	89,255,492	4,000	1,209,047	107,671,025
CASH AT END OF PERIOD	2,797,917	73,942,617	2,000	1,004,766	(423,611)

<PAGE>
Central & Southwest Corporation and Subsidiaries
Consolidated Statement of Cash Flows
YTD December 31, 2000

	CSW ENERGY	ESI	CSW INT'L.	CSW ENERSHOP
CASH FLOWS - OPERATING ACTIVITIES:				
Consolidated Net Income	(1,580,095)	(19,113,731)	(30,640,450)	(2,467,501)
Adj. to Recon. N/I to Cash Flow:				
Depreciation & Amortization	5,982,240	151,706	416,511	250,026
Prov for Def Income Taxes (net)	4,864,165	0	(16,456,302)	0
Def Invest Tax Credits (net)	0	0	0	0
AFUDC - Equity	0	0	0	0
Equity/Undist. Subs. Earnings	(5,561,498)	0	(840,520)	0
Decrease (Increase) in:				
Accounts Rec. Affiliated West	2,478,014	(23,820,958)	(15,202,563)	52,730
Accounts Rec. Affiliated East				
Accounts Rec. - Factored West	0			
Accounts Rec. - Factored East				
Accounts Rec. - Nonaffiliated	(66,099,208)	1,036,519	(64,738,346)	503,091
Dividends Receivable				
Fuel, Materials & Supplies	0	(8,372,953)	0	0
Accrued Utility Revenues	0	0	0	0
Accounts Payable - Affiliated West	(149,362,048)	(28,069,663)	(22,221,051)	(18,221,556)
Accounts Payable - Affilaited East	2,137,130	69,478,955	0	17,461,854
Accounts Payable - Nonaffiliated	373,466,056	16,461,953	30,786,254	(407,352)
Interest Payable - Affiliated West	711,583	(358,565)	(203,185)	6,248
Interest Payable - Affiliated East	2,137,130	0	166,261	0
Other Oper. Items (net) (Sch 1)	(10,275,612)	7,797,943	195,953	2,502,562
NET CASH PROVIDED (USED) OPERATING	158,897,857	15,191,206	(118,737,438)	(319,898)
CASH FLOWS - INVESTING ACTIVITIES:				
Plant & Property Additions:				
Gross Additions to Utility Plant	(144,542,873)	0	(10,215)	0
Other Gross Additions	0	0	0	0
Total Gross Additions	(144,542,873)	0	(10,215)	0
AFUDC - Equity	0	0	0	0
Cash Used Plant & Prop. Adds	(144,542,873)	0	(10,215)	0
Invest in Subs - Equity & Debt		0	68,512,051	0
Proceeds - Sales of Property		225,656	0	319,898
Proceeds - Sale & Leaseback Trans		0	0	0
Other Investing Activities	(1,024,833)	0	15,679,394	0
NET CASH PROVIDED (USED) INVESTING	(145,567,706)	225,656	84,181,230	319,898
CASH FLOWS - FINANCING ACTIVITIES:				
Proceeds from Issuances of:				
Capital Contributions from Parent	0	0	0	0
Common Stock	0	0	0	0
Preferred Stock	0	0	0	0
Minority Interest	0	0	0	0
Long-term Debt	0	0	0	0
Money Pool Payable - East	0	0	0	0
Money Pool Payable - West	0	0	0	0
Short-term Debt (net)	0	0	0	0
Total Issuances	0	0	0	0
Cash Paid To Retire:				
Preferred Stock	0	0	0	0
Long-term Debt	0	(15,416,862)	0	0
Total Retirements	0	(15,416,862)	0	0
Dividends Paid on Common Stock	0	0	0	0
Dividends Paid on Preferred Stock	0	0	0	0
NET CASH PROVIDED (USED) FINANCING	0	(15,416,862)	0	0
EFFECT OF EXCHANGE RATE CHANGES	0	0	30,811,630	
NET INCREASE (DECREASE) IN CASH	13,330,151	0	(3,744,578)	0
CASH AT BEGINNING OF PERIOD	7,057,451	0	8,151,977	0
CASH AT END OF PERIOD	20,387,602	0	4,407,399	0

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	AEP CONSOLIDATED	AEP ELIMINATIONS	AEP	APCO CONSOLIDATED
BALANCE AT BEGINNING OF YEAR	3,629,908,332.31	(1,396,378,887.94)	1,740,366,607.31	175,854,480.59
Preferred Stock Dividend Req of Subsidiaries	(10,963,432.71)	0.00		
Net Income (Loss)	278,031,324.51	(453,368,825.01)	267,067,866.37	73,844,300.42
NET INCOME (LOSS)	267,067,891.80	(453,368,825.01)	267,067,866.37	73,844,300.42
TOTAL	3,896,976,224.11	(3,739,289,437.95)	2,007,434,473.68	249,698,781.01
DEDUCTIONS:				
Div Declrd - Common Stk - Asso	(0.00)	943,821,753.93	0.00	(126,611,810.52)
Div Declrd - Common - NonAssoc	(804,835,821.60)	0.00	(619,340,589.60)	0.00
DIVIDEND DECLARED ON COMMON	(804,835,821.60)	1,129,316,985.93	(619,340,589.60)	(126,611,810.52)
Dividends Decl-Preferred Stock	0.00	10,323,033.97	0.00	(1,771,127.26)
DIVIDEND DECLARED ON PREFERRED	0.00	10,323,033.97	0.00	(1,771,127.26)
ADJUSTMENT RETAINED EARNINGS	(2,088,742.34)	(1,887,713,760.69)	1,701,957,750.66	(732,059.51)
TOTAL DEDUCTIONS	(806,924,563.94)	1,144,290,825.21	1,082,617,161.06	(129,114,997.29)
BALANCE AT END OF PERIOD	3,090,051,660.17	(2,594,998,612.74)	3,090,051,634.74	120,583,783.72

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	CSPCO CONSOLIDATED	I&M CONSOLIDATED	KEPCO	KGPCO
BALANCE AT BEGINNING OF YEAR	246,583,844.18	166,388,687.17	67,110,068.92	7,185,424.40
Preferred Stock Dividend Req of Subsidiaries				
Net Income (Loss)	94,966,011.81	(132,031,676.11)	20,763,113.13	785,908.27
NET INCOME (LOSS)	94,966,011.81	(132,031,676.11)	20,763,113.13	785,908.27
TOTAL	341,549,855.99	34,357,011.06	87,873,182.05	7,971,332.67
DEDUCTIONS:				
Div Declrd - Common Stk - Asso	(240,600,147.95)	(26,289,998.00)	(30,360,002.80)	(2,752,002.00)
Div Declrd - Common - NonAssoc	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	(240,600,147.95)	(26,289,998.00)	(30,360,002.80)	(2,752,002.00)
Dividends Decl-Preferred Stock	(1,400,000.00)	(4,489,442.20)	0.00	0.00
DIVIDEND DECLARED ON PREFERRED	(1,400,000.00)	(4,489,442.20)	0.00	0.00
ADJUSTMENT RETAINED EARNINGS	(480,796.68)	(134,311.44)	0.00	0.00
TOTAL DEDUCTIONS	(242,480,944.63)	(30,913,751.64)	(30,360,002.80)	(2,752,002.00)
BALANCE AT END OF PERIOD	99,068,911.36	3,443,259.42	57,513,179.25	5,219,330.67

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	OPCO CONSOLIDATED	WPCO	AEGCO	AEPSC
BALANCE AT BEGINNING OF YEAR	587,424,262.56	7,790,690.63	3,672,842.69	0.00
Preferred Stock Dividend Req of Subsidiaries				
Net Income (Loss)	83,737,347.24	3,790,909.11	7,984,599.90	0.00
NET INCOME (LOSS)	83,737,347.24	3,790,909.11	7,984,599.90	0.00
TOTAL	671,161,609.80	11,581,599.74	11,657,442.59	0.00
DEDUCTIONS:				
Div Declrd - Common Stk - Asso	(271,812,642.71)	(2,860,002.00)	(1,935,000.00)	0.00
Div Declrd - Common - NonAssoc	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	(271,812,642.71)	(2,860,002.00)	(1,935,000.00)	0.00
Dividends Decl-Preferred Stock	(1,262,464.51)	0.00	0.00	0.00
DIVIDEND DECLARED ON PREFERRED	(1,262,464.51)	0.00	0.00	0.00
ADJUSTMENT RETAINED EARNINGS	0.00	0.00	0.00	0.00
TOTAL DEDUCTIONS	(273,075,107.22)	(2,860,002.00)	(1,935,000.00)	0.00
BALANCE AT END OF PERIOD	398,086,502.58	8,721,597.74	9,722,442.59	0.00

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	CCCO	FRECO	IFRI	AEPPM
BALANCE AT BEGINNING OF YEAR	0.00	19,968.85	0.00	(152.00)
Preferred Stock Dividend Req of Subsidiaries				
Net Income (Loss)	0.00	0.00	0.00	0.00
NET INCOME (LOSS)	0.00	0.00	0.00	0.00
TOTAL	0.00	19,968.85	0.00	(152.00)
DEDUCTIONS:				
Div Declrd - Common Stk - Asso	0.00	0.00	0.00	0.00
Div Declrd - Common - NonAssoc	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	0.00	0.00	0.00	0.00
Dividends Decl-Preferred Stock	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON PREFERRED	0.00	0.00	0.00	0.00
ADJUSTMENT RETAINED EARNINGS	0.00	0.00	0.00	0.00
TOTAL DEDUCTIONS	0.00	0.00	0.00	0.00
BALANCE AT END OF PERIOD	0.00	19,968.85	0.00	(152.00)

<PAGE>
AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	AEPES	AEPINV CONSOLIDATED	AEPR CONSOLIDATED	AEPPRO
BALANCE AT BEGINNING OF YEAR	(50,237,325.79)	(9,756,988.87)	(34,639,938.20)	(2,739,882.86)
Preferred Stock Dividend Req of Subsidiaries				
Net Income (Loss)	9,798,951.24	(422,682.16)	1,902,316.72	(2,352,359.96)
NET INCOME (LOSS)	9,798,951.24	(422,682.16)	1,902,316.72	(2,352,359.96)
TOTAL	(40,438,374.55)	(10,179,671.03)	(32,737,621.48)	(5,092,242.82)
DEDUCTIONS:				
Div Declrd - Common Stk - Asso	0.00	0.00	0.00	0.00
Div Declrd - Common - NonAssoc	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON COMMON	0.00	0.00	0.00	0.00
Dividends Decl-Preferred Stock	0.00	0.00	0.00	0.00
DIVIDEND DECLARED ON PREFERRED	0.00	0.00	0.00	0.00
ADJUSTMENT RETAINED EARNINGS	0.00	0.00	0.00	0.00
TOTAL DEDUCTIONS	0.00	0.00	0.00	0.00
BALANCE AT END OF PERIOD	(40,438,374.55)	(10,179,671.03)	(32,737,621.48)	(5,092,242.82)

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES
CONSOLIDATING RETAINED EARNINGS
YEAR TO DATE THROUGH DECEMBER 31, 2000

DESCRIPTION	AEPC CONSOLIDATED	CSW CONSOLIDATED	AEPRELLC
BALANCE AT BEGINNING OF YEAR	(14,860,938.51)	1,889,541,725.00	0.00
Preferred Stock Dividend Req of Subsidiaries			
Net Income (Loss)	(25,528,924.80)	221,277,725.00	(112,726.61)
NET INCOME (LOSS)	(25,528,924.80)	221,277,725.00	(112,726.61)
TOTAL	(40,389,863.31)	2,110,819,450.00	(112,726.61)
DEDUCTIONS:			
Div Declrd - Common Stk - Asso	0.00		
Div Declrd - Common - NonAssoc	0.00	(185,495,232.00)	
DIVIDEND DECLARED ON COMMON	0.00	(185,495,232.00)	0.00
Dividends Decl-Preferred Stock	0.00		
DIVIDEND DECLARED ON PREFERRED	0.00	0.00	0.00
ADJUSTMENT RETAINED EARNINGS	0.00	(2,822,841.00)	0.00
TOTAL DEDUCTIONS	0.00	(188,318,073.00)	0.00
BALANCE AT END OF PERIOD	(40,389,863.31)	1,922,501,377.00	(112,726.61)

Notes to Consolidating Financial Statements.

Notes to financial statements are incorporated herein by reference to the 2000 Annual Report on Form 10-K filed by the respective companies reporting to the Securities and Exchange Commission pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

OHIO VALLEY ELECTRIC CORPORATION
STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2000
(in thousands)
(UNAUDITED)

OPERATING REVENUES	$440,796
OPERATING EXPENSES:	
Fuel	85,309
Purchased Power	288,588
Other Operation	24,123
Maintenance	21,650
Depreciation	2,746
Taxes Other Than Federal Income Taxes	5,457
Federal Income Taxes	4,338
TOTAL OPERATING EXPENSES	432,211
OPERATING INCOME	8,585
NONOPERATING INCOME	665
INCOME BEFORE INTEREST CHARGES	9,250
INTEREST CHARGES	6,612
NET INCOME	$ 2,638

OHIO VALLEY ELECTRIC CORPORATION
STATEMENT OF RETAINED EARNINGS
YEAR ENDED DECEMBER 31, 2000
(in thousands)
(UNAUDITED)

RETAINED EARNINGS JANUARY 1	$1,995
NET INCOME	2,638
CASH DIVIDENDS DECLARED	2,700
RETAINED EARNINGS DECEMBER 31	$1,933

OHIO VALLEY ELECTRIC CORPORATION
BALANCE SHEET
DECEMBER 31, 2000
(in thousands)
(UNAUDITED)

ASSETS

ELECTRIC UTILITY PLANT:	
Electric Plant (at cost)	$299,817
Construction Work in Progress	11,999
Total Electric Utility Plant	311,816
Accumulated Depreciation and Amortization	289,989
NET ELECTRIC UTILITY PLANT	21,827
INVESTMENTS AND OTHER	47,170
CURRENT ASSETS:	
Cash and Cash Equivalents	3,747
Accounts Receivable	39,675
Coal in Storage - at average cost	4,206
Materials and Supplies - at average cost	10,292
Prepayments and Other	5,727
TOTAL CURRENT ASSETS	63,647
FUTURE FEDERAL INCOME TAX BENEFITS	23,773
REGULATORY ASSETS	30,337
TOTAL	$186,754

OHIO VALLEY ELECTRIC CORPORATION
BALANCE SHEET
DECEMBER 31, 2000
(in thousands)
(UNAUDITED)

CAPITALIZATION AND LIABILITIES

SHAREHOLDERS' EQUITY:	
Common Stock - Par Value $100:	
Authorized - 300,000 Shares	
Outstanding - 100,000 Shares	$ 10,000
Retained Earnings	1,933
Total Shareowners' Equity	11,933
Long-term Debt - Notes Payable	36,103
TOTAL CAPITALIZATION	48,036
CURRENT LIABILITIES:	
Long-term Debt Due Within One Year	13,946
Short-term Debt	40,000
Accounts Payable	9,288
Taxes Accrued	11,126
Interest Accrued and Other	3,037
TOTAL CURRENT LIABILITIES	77,397
INVESTMENT TAX CREDITS	10,610
POSTRETIREMENT BENEFIT OBLIGATION	21,677
AMOUNTS DUE TO CUSTOMERS FOR FEDERAL INCOME TAXES	19,183
OTHER REGULATORY LIABILITIES AND DEFERRED CREDITS	9,851
TOTAL	$186,754

OHIO VALLEY ELECTRIC CORPORATION
STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2000
(in thousands)
(UNAUDITED)

OPERATING ACTIVITIES:	
Net Income	$ 2,638
Adjustments for Noncash Items:	
Depreciation	2,746
Future Federal Income Tax Benefits	(2,318)
Changes in Certain Current Assets and Liabilities:	
Accounts Receivable	10,898
Coal, Materials and Supplies	2,553
Accounts Payable	1,669
Accrued Taxes	2,288
SO2 Allowances	1,915
Other (net)	(1,168)
Net Cash Flows From Operating Activities	21,221
INVESTING ACTIVITIES:	
Construction Expenditures	(9,782)
Reimbursement for Plant Replacements and Additional Facilities	2,746
Advances Returned from Subsidiary	7,356
Net Cash Flows From Investing Activities	320
FINANCING ACTIVITIES:	
Retirement of Long-term Debt	(7,856)
Change in Short-term Debt	(10,000)
Dividends Paid	(2,700)
Net Cash Flows Used For Financing Activities	(20,556)
Net Increase in Cash and Cash Equivalents	985
Cash and Cash Equivalents January 1	2,762
Cash and Cash Equivalents December 31	$ 3,747
Supplemental Disclosure:	
Interest Paid (net of capitalized amounts)	$6,417
Income Taxes Paid	$4,100

EXHIBIT A

Incorporation By Reference
Form 10K
Annual Report

	Year	File Number
AEP	2000	1-3525
AEGCo	2000	0-18135
APCo	2000	1-3457
CPL	2000	0-346
CSP	2000	1-2680
I&M	2000	1-3570
KPCo	2000	1-6858
OPCo	2000	1-6543
PSO	2000	0-343
SWEPCo	2000	1-3146
WTU	2000	0-340

KPSC Case No. 99-149
Attachment 3B
Item No. 1

2000 Annual Reports

American Electric Power Company, Inc.

AEP Generating Company

Appalachian Power Company

Central Power and Light Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Ohio Power Company

Public Service Company of Oklahoma

Southwestern Electric Power Company

West Texas Utilities Company

Audited Financial Statements and
Management's Discussion and Analysis

AEP AMERICAN ELECTRIC POWER

AEP: America's Energy Partner®

Contents

GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
2004 True-up Proceeding	A filing to be made after January 10, 2004 under the Texas Legislation to finalize the amount of stranded costs and the recovery of such costs.
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned subsidiaries consolidated.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated and unaffiliated domestic electric utility companies.
AEP East electric operating companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPR	AEP Resources, Inc.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP Power Pool	AEP System Power Pool. Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale system sales of the member companies.
AEP West electric operating companies	CPL, PSO, SWEPCo and WTU.
AFUDC	Allowance for funds used during construction, a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant.
Alliance RTO	Alliance Regional Transmission Organization, an ISO formed by AEP and four unaffiliated utilities.
Amos Plant	John E. Amos Plant, a 2,900 MW generation station jointly owned and operated by APCo and OPCo.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Arkansas Commission	Arkansas Public Service Commission.
Buckeye	Buckeye Power, Inc., an unaffiliated corporation.
CLECO	Central Louisiana Electric Company, Inc., an unaffiliated corporation.
COLI	Corporate owned life insurance program.
Cook Plant	The Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
CPL	Central Power and Light Company, an AEP electric utility subsidiary.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP.
CSW Energy	CSW Energy, Inc., an AEP subsidiary which invests in energy projects and builds power plants.
CSW International	CSW International, Inc., an AEP subsidiary which invests in energy projects and entities outside the United States.
D.C. Circuit Court	The United States Court of Appeals for the District of Columbia Circuit.
DHMV	Dolet Hills Mining Venture.
DOE	United States Department of Energy.
ECOM	Excess Cost Over Market.
ENEC	Expanded Net Energy Costs.
EITF	The Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	The Electric Reliability Council of Texas.
EWGs	Exempt Wholesale Generators.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.

FERC	Federal Energy Regulatory Commission.
FMB	First Mortgage Bond.
FUCOs	Foreign Utility Companies.
GAAP	Generally Accepted Accounting Principles.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IPC	Installment Purchase Contract.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
ISO	Independent system operator.
Joint Stipulation	Joint Stipulation and Agreement for Settlement of APCo's WV rate proceeding.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas.
Michigan Legislation	The Customer Choice and Electricity Reliability Act, a Michigan law which provides for customer choice of electricity supplier.
Midwest ISO	An independent operator of transmission assets in the Midwest.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
Money Pool	AEP System's Money Pool.
MPSC	Michigan Public Service Commission.
MTN	Medium Term Notes.
MW	Megawatt.
MWH	Megawatthour.
NEIL	Nuclear Electric Insurance Limited.
Nox	Nitrogen oxide.
Nox Rule	A final rules issued by Federal EPA which requires NOx reductions in 22 eastern states including seven of the states in which AEP companies operates.
NP	Notes Payable.
NRC	Nuclear Regulatory Commission.
Ohio Act	The Ohio Electric Restructuring Act of 1999.
Ohio EPA	Ohio Environmental Protection Agency.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OVEC	Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo own a 44.2% equity interest.
PCBs	Polychlorinated Biphenyls.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PRP	Potentially Responsible Party.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	The Public Utilities Commission of Ohio.
PUCT	The Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act of 1935, as amended.
PURPA	The Public Utility Regulatory Policies Act of 1978.
RCRA	Resource Conservation and Recovery Act of 1976, as amended.
Registrant Subsidiaries	AEP subsidiaries who are SEC registrants; AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
SEC	Securities and Exchange Commission.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.

SFAS 71	Statement of Financial Accounting Standards No. 71, <u>Accounting for the Effects of Certain Types of Regulation</u>.
SFAS 101	Statement of Financial Accounting Standards No. 101, <u>Accounting for the Discontinuance of Application of Statement 71.</u>
SFAS 121	Statement of Financial Accounting Standards No. 121, <u>Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of.</u>
SFAS 133	Statement of Financial Accounting Standards No. 133, <u>Accounting for Derivative Instruments and Hedging Activities.</u>
SNF	Spent Nuclear Fuel.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant, owned 25.2% by Central Power and Light Company, an AEP electric utility subsidiary .
STPNOC	STP Nuclear Operating Company, a non-profit Texas corporation which operates STP on behalf of its joint owners including CPL.
Superfund	The Comprehensive Environmental, Response, Compensation and Liability Act.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Texas Appeals Court	The Third District of Texas Court of Appeals.
Texas Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
Travis District Court	State District Court of Travis County, Texas.
TVA	Tennessee Valley Authority.
U.K.	The United Kingdom.
UN	Unsecured Note.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WV	West Virginia.
WVPSC	Public Service Commission of West Virginia.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
WTU	West Texas Utilities Company, an AEP electric utility subsidiary.
Yorkshire	Yorkshire Electricity Group plc, a U.K. regional electricity company owned jointly by AEP and New Century Energies.
Zimmer Plant	William H. Zimmer Generating Station, a 1,300 MW coal-fired unit owned 25.4% by Columbus Southern Power Company, an AEP subsidiary.

FORWARD LOOKING INFORMATION

This discussion includes forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. These forward-looking statements reflect assumptions, and involve a number of risks and uncertainties. Among the factors both foreign and domestic that could cause actual results to differ materially from forward looking statements are: electric load and customer growth; abnormal weather conditions; available sources of and prices for coal and gas; availability of generating capacity; the impact of the merger with CSW including actual merger savings being less than the related rate reductions; risks related to energy trading and construction under contract; the speed and degree to which competition is introduced to our power generation business; the structure and timing of a competitive market for electricity and its impact on prices; the ability to recover net regulatory assets, other stranded costs and implementation costs in connection with deregulation of generation in certain states; new legislation and government regulations; the ability to successfully control costs; the success of new business ventures; international developments affecting our foreign investments; the economic climate and growth in our service and trading territories both domestic and foreign; the ability of the Company to successfully challenge new environmental regulations and to successfully litigate claims that the Company violated the Clean Air Act; successful resolution of litigation regarding municipal franchise fees in Texas; inflationary trends; changes in electricity and gas market prices; interest rates; foreign exchange rates, and other risks and unforeseen events.

AMERICAN ELECTRIC POWER COMPANY, INC.
AND SUBSIDIARY COMPANIES

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Selected Consolidated Financial Data

Year Ended December 31,	2000	1999	1998	1997	1996
INCOME STATEMENTS DATA (in millions):					
Total Revenues	$13,694	$12,407	$11,840	$11,163	$11,017
Operating Income	2,026	2,325	2,280	2,198	2,368
Income From Continuing Operations	302	986	975	949	871
Discontinued Operations	-	-	-	-	132
Extraordinary Loss	(35)	(14)	-	(285)	-
Net Income	267	972	975	664	1,003

December 31,	2000	1999	1998	1997	1996
BALANCE SHEETS DATA (in millions):					
Property, Plant and Equipment	$38,088	$36,938	$35,655	$33,496	$32,443
Accumulated Depreciation and Amortization	15,695	15,073	14,136	13,229	12,494
Net Property, Plant and Equipment	$22,393	$21,865	$21,519	$20,267	$19,949
Total Assets	$54,548	$35,719	$33,418	$30,092	$29,228
Common Shareholders' Equity	8,054	8,673	8,452	8,220	8,334
Cumulative Preferred Stocks of Subsidiaries:					
Not Subject to Mandatory Redemption	61	63	222	223	382
Subject to Mandatory Redemption*	100	119	128	154	543
Trust Preferred Securities	334	335	335	335	-
Long-term Debt*	10,754	11,524	11,113	9,354	9,112
Obligations Under Capital Leases*	614	610	539	549	422

*Including portion due within one year

Year Ended December 31,	2000	1999	1998	1997	1996
COMMON STOCK DATA:					
Earnings per Common Share:					
Continuing Operations	$0.94	$3.07	$3.06	$2.99	$2.79
Discontinued Operations	-	-	-	-	0.42
Extraordinary Loss	(.11)	(.04)	-	(0.90)	-
Net Income	$0.83	$3.03	$3.06	$2.09	$3.21
Average Number of Shares Outstanding (in millions)	322	321	318	316	312
Market Price Range: High	$48-15/16	$48-3/16	$53-5/16	$ 52	$44-3/4
Low	25-15/16	30-9/16	42-1/16	39-1/8	38-5/8
Year-end Market Price	46-1/2	32-1/8	47-1/16	51-5/8	41-1/8
Cash Dividends on Common*	$2.40	$2.40	$2.40	$2.40	$2.40
Dividend Payout Ratio*	289.2%	79.2%	78.4%	114.8%	74.5%
Book Value per Share	$25.01	$26.96	$26.46	$25.91	$26.45

The consolidated financial statements give retroactive effect to AEP's merger with CSW, which was accounted for as a pooling of interests, as if AEP and CSW had always been combined.
*Based on AEP historical dividend rate.

American Electric Power Company, Inc. (AEP) is one of the largest investor owned electric public utility holding companies in the U.S. serving over 4.8 million retail customers in eleven states (Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia) and selling bulk power at wholesale both within and beyond its domestic retail service area. AEP has 38,000 megawatts of generation and over 38,000 miles of transmission lines and 186,000 miles of distribution lines in the U.S. Subsidiaries own 1,250 megawatts as independent power producers in Colorado, Florida and Texas. In recent years AEP has expanded its domestic operations to include gas marketing, processing, storage and transportation operations, electric, gas and coal trading operations and telecommunication services and invested in and acquired foreign distribution operations in the U.K., Australia and Brazil and electricity generating facilities in China and Mexico. Subsidiaries also provide power engineering, generation and transmission plant maintenance and construction, and energy management services worldwide. AEP is one of the largest traders of electricity and gas in the U.S. In 2000 we established an energy trading operation in Europe.

Presently AEP is in the process of restructuring its assets and operations to separate the regulated operations from the non-regulated operations and to functionally and, where permitted by law, structurally unbundle its domestic vertically integrated electric utility business into separate generation, transmission and distribution businesses. The purpose of this restructuring is to focus our management and technical expertise to maximize the potential for growth of both non-regulated and regulated operations, to evaluate the performance of these separate and different businesses and to meet the separation requirements of federal and state restructuring legislation and codes of conduct. Five of AEP's 11 states (Arkansas, Ohio, Texas, Virginia, and West Virginia) are in various stages of transitioning to deregulation of generation and to customer choice and market-based pricing from monopoly and regulator set rates for the retail sale of electricity. When the transition is implemented in those states, transmission will be regulated by the Federal Energy Regulatory Commission and distribution services will continue to be cost-based rate regulated by the states. Although we are actively supporting the transition to competition, there is little progress in the remaining six states. Therefore, in the near term, our retail electric business in Indiana, Kentucky, Louisiana, Michigan, Oklahoma and Tennessee will continue to be operated as an integrated public utility subject to state regulation. The foreign energy delivery investments and operations are not cost-based rate regulated but they are generally subject to different forms of price controls, such as capped prices. As such these foreign investments and operations will be included in our unbundled regulated business.

On November 1, 2000, AEP filed a restructuring plan under PUHCA with the SEC seeking approval to form two wholly owned holding company subsidiaries of AEP to separately own AEP's regulated and non-regulated subsidiaries and to structurally separate into separate legal entities along functional lines (i.e. generation, transmission and distribution) six of the electric utility operating companies (APCo, CPL, CSPCo, OPCo, SWEPCo and WTU). These six operating companies do business in the states that are implementing restructuring (Arkansas, Ohio, Texas, Virginia and West Virginia). The remaining domestic electric operating companies will be functionally unbundled for internal management and internal reporting purposes and for financial segment reporting but will not be structurally unbundled into separate companies since state law and/or regulation prohibits such action. One holding company will hold the unbundled non-regulated electric generation subsidiaries and the non-regulated domestic and foreign subsidiaries including the European trading company and the foreign generating companies, while the other holding company will hold the bundled domestic regulated electric utility companies and the foreign distribution companies. The restructuring will facilitate management's strategy to grow the deregulated wholesale electricity supply and electric and gas trading business and to evaluate the other business operations to explore ways to improve their results of operations and to continuously evaluate and where necessary reshape our business to grow earnings and improve shareholder value. The legal transfer of assets and structural separation plans will also require FERC, certain state and other regulatory approvals.

2000 was a year of accomplishment that positions AEP for earnings growth. In 2000 we completed the merger of AEP and CSW, greatly increasing the scope and size of AEP; achieved the targeted merger savings; returned the two unit 2,110 MW Cook Plant to service after an extended outage; reached a settlement on a restructuring plan in Ohio that will allow our electric generating and supply business in Ohio to transition over five years to market pricing and recover its stranded cost, including generation-related regulatory assets; continued to grow our domestic electricity and gas trading businesses to become one of the largest electricity and gas traders; established and grew an energy trading operation in Europe; added to our gas assets and operations with the announcement in the first quarter of 2001 of the planned acquisition of Houston Pipe Line Company; restructured our incentive compensation plans to more closely align them with the creation of shareholder value; reduced our power plant operation and maintenance costs while increasing plant availability; established AEP Pro Serv, Inc. to market AEP's expertise in power engineering, environmental engineering and generating plant maintenance services worldwide; closed contracts to design, build, operate and market the output of new power plants for Dow Chemical, Buckeye Power and Columbia Energy; and initiated a re-design of our existing PeopleSoft financial software as part of an enterprise-wide application to fully integrate our financial, work management and supply chain software and to provide data on a business unit basis consistent with our corporate separation initiative.

Although 2000 was a year marked by significant accomplishments that position AEP for future earnings growth, it resulted in a reduction in earnings and earnings per share due mainly to non-recurring items, such as: a loss incurred from a court decision disallowing tax deductions for interest related to AEP's COLI program; the write-off of non-recoverable merger costs; the expensing of Cook nuclear restart costs in contrast to 1999 when a significant portion of the restart costs were deferred with regulatory approval; the write-off of certain extraordinary costs that were stranded and liabilities incurred in connection with the restructuring of the regulation of the electric utility business in Ohio, Virginia, and West Virginia to transition that portion of AEP's domestic electricity supply business from cost-based rate regulation to customer choice and market pricing; the recognition of losses associated with a CSW investment in Chile which was sold in the fourth quarter; an impairment writedown of AEP's investment in Yorkshire to reflect a pending sale of the investment in 2001; and write-offs of unrecoverable contract costs and goodwill on certain of CSW's non-regulated businesses acquired in the merger.

Earnings in 2001 are expected to improve significantly with the return of Cook Plant's 2,110 MW of generating capacity due to the completion of restart efforts and the cessation of significant restart costs at Cook and the growth of our wholesale marketing and trading business.

Our focus for 2001 will be on completing our corporate separation plan to separate our regulated and non-regulated businesses. We believe that a successful implementation of this plan will support our business objective of unlocking shareholder value by providing managers with a simpler structure through which business unit performance can be more easily anticipated and monitored thereby focusing management attention; permitting more efficient financing; and meeting the regulatory codes of conduct required as part of industry restructuring.

Although management expects that the future outlook for results of operations is excellent there are contingencies, challenges and obstacles to overcome and manage, such as new more stringent Federal EPA environmental requirements and recent complaints and related litigation, further delays in transition to competition supported in part by concerns that California's energy crisis could happen in our service territory, the recovery of generation-related regulatory assets and other stranded costs in Texas and any additional state jurisdictions that we can successfully promote the adoption of customer choice and a transition to market pricing from regulated rate setting, franchise fee litigation in Texas, litigation concerning AEP's financial disclosures regarding the extended Cook Plant safety outage and timing of the successful completion of restart efforts, the amortization of transition regulatory assets from the introduction of competition to our previously regulated domestic generation business and the amortization of deferred costs from the successful effort to restart Cook Plant and to merge AEP and CSW and the outcome of litigation to recover $90 million of duplicate tax expense from May 2001 to April 2002 resulting from restructuring in Ohio. These challenges, contingencies and obstacles, which are discussed in detail in the Notes to Consolidated Financial Statements and in Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters, are receiving management's full attention and we intend to work diligently to resolve these matters by finding workable solutions that balance the interests of our customers, our employees and our shareholders.

Results of Operations

Net Income

Although revenues increased by $1.3 billion net income declined to $267 million or $0.83 per share in 2000 from $972 million or $3.03 per share in 1999. The decrease was primarily due to Cook Nuclear Plant restart costs, a disallowance of tax deductions for corporate owned life insurance (COLI), expensing of costs related to AEP's recently completed merger with CSW, write offs related to non-regulated subsidiaries and an extraordinary loss from the discontinuance of regulatory accounting for generation in certain states. In 1999 net income was virtually unchanged as increased expenses to prepare the Cook Nuclear Plant for restart, net of related deferrals, were offset by a gain from a sale of a 50% interest in a cogeneration project.

Revenues Increase

AEP's revenues include a significant number of transactions from the trading of electricity and gas. Revenues from trading of electricity are recorded net of purchases as domestic electric utility wholesale sales for transactions in AEP's traditional marketing area (up to two transmission systems from the AEP service territory) and as revenues from worldwide electric and gas operations for transactions beyond two transmission systems from AEP. Revenues from gas trading are recorded net of purchases and reported in revenues from worldwide electric and gas operations. Trading transactions involve the purchase and sale of substantial amounts of electricity and gas.

The level of electricity trading transactions tends to fluctuate due to the highly competitive nature of the short-term (spot) energy market and other factors, such as affiliated and unaffiliated generating plant availability, weather conditions and the economy. The FERC rules, which introduced a greater degree of competition into the wholesale energy market, have had a major effect on the volume of electricity trading as most electricity is traded in the short-term market.

AEP's total revenues increased 10% in 2000 and 5% in 1999. The table below shows the changes in the components of revenues from domestic electric utility operations and worldwide electric and gas operations. While worldwide electric and gas operations revenues increased 12% in 2000, most of the increase in total revenues was caused by the increased revenues from domestic electric utility operations.

(Dollars in Millions)	Increase (Decrease) From Previous Year 2000 Amount	%	1999 Amount	%
Domestic Electric Utility Operations:				
Retail:				
Residential	$ 230		$ 18	
Commercial	163		56	
Industrial	(71)		11	
Other	25		7	
	347	4.2	92	1.1
Wholesale	672	59.9	(145)	(11.5)
Other	(30)	(6.8)	57	15.3
Total Domestic Electric Utility Operations	989	10.1	4	-
Worldwide Electric and Gas Operations	298	11.6	563	28.1
Total	$1,287	10.4	$ 567	4.8

The increase in total revenues from domestic electric utility operations in 2000 was primarily due to a 38% increase in wholesale sales volume and increased retail fuel revenues as a result of higher gas prices used to generate electricity. The reduction in industrial revenues in 2000 is attributable to the expiration of a long-term contract on December 31, 1999. The significant increase in wholesale sales volume, which accounted for a 60% increase in wholesale revenues, resulted from efforts to grow AEP's energy marketing and trading operations, favorable market conditions, and the availability of additional generation due to the return to service of one of the Cook Plant nuclear units in June 2000 and improved generating unit availability due mainly to improved outage management. The second Cook Plant unit which returned to service in December 2000 did not have a significant impact on revenues.

In 1999 revenues from domestic electric utility operations were unchanged. A 1% gain in retail revenues was more than offset by a 12% decline in wholesale revenues. The 12% decline in wholesale revenues in 1999 was predominantly due to a decrease in wholesale energy sales and a reduction in net revenues from power trading due to a decline in margins. The decrease in wholesale sales reflects the expiration in July 1998 of a power contract which supplied power to several municipal customers and the decision by another wholesale customer who buys energy under a unit power agreement not to take energy from AEP during an outage of that unit. The decline in wholesale margins in 1999 reflects the moderation of weather and the effected capacity shortages experienced in the summer of 1998.

Revenues from worldwide electric and gas operations increased 12% in 2000 due to increased natural gas and gas liquid product prices. Volumes of natural gas remained consistent with the prior year, however, prices increased significantly.

In 1999 revenues derived from worldwide electric and gas operations increased 28%. This increase is primarily due to the acquisitions in December 1998, of CitiPower in Australia and of LIG, and the commercial operation of a two-unit 250 MW coal-fired generating plant in China.

Operating Expenses Increase

Changes in the components of operating expenses were as follows:

(Dollars in Millions)	Increase (Decrease) From Previous Year 2000 Amount	%	1999 Amount	%
Fuel and Purchased Power	$ 679	19.7	$ (6)	(0.2)
Maintenance and Other Operation	342	12.8	79	3.0
Merger Costs	203	-	-	-
Depreciation and Amortization	51	5.0	22	2.2
Taxes Other Than Income Taxes	7	1.1	5	0.8
Worldwide Electric and Gas Operations	304	13.3	422	22.7
Total	$1,586	15.7	$522	5.5

Fuel and purchased power expense increased 20% in 2000 due to a significant increase in the cost of natural gas used for generation. Natural gas usage for generation declined 5% while the cost of natural gas consumed rose 60%. Net income was not impacted by this significant cost increase due to the operation of fuel recovery mechanisms. These fuel recovery mechanisms generally provide for the deferral of fuel costs above the amounts included in rates or the accrual of revenues for fuel costs not yet recovered. Upon regulatory commission review and approval of the unrecovered fuel costs, the accrued or deferred amounts are billed to customers.

The increase in maintenance and other operation expense in 2000 was mainly due to increased expenditures to prepare the Cook Plant nuclear units for restart following an extended NRC monitored outage and increased usage of and prices for emissions allowances. The increase in Cook Plant restart costs resulted from the effect of deferring restart costs in 1999 and an increase in the restart expenditure level. The Cook Plant began an extended outage in September 1997 when both nuclear generating units were shut down because of questions regarding the operability of certain safety systems. In 1999 a portion of incremental restart expenses were deferred in accordance with IURC and MPSC settlement agreements which resolved all jurisdictional rate-related issues related to the Cook Plant's extended outage. Unit 2 returned to service in June and achieved full power operation on July 5, 2000 and Unit 1 returned to service in December and achieved full power operation on January 3, 2001. The increase in emission allowance usage and prices resulted from the stricter air quality standards of Phase II of the 1990 Clean Air Act Amendments, which became effective on January 1, 2000. The increase in maintenance and other operation expense in 1999 was primarily due to a NRC required 10-year inspection of STP Units 1 and 2 and increased expenditures to prepare the Cook Plant nuclear units for restart. Although a portion of Cook Plant restart costs were deferred in 1999 pursuant to regulatory orders, net expenditures charged to expense increased over 1998.

With the consummation of the merger with CSW, certain deferred merger costs were expensed. The merger costs charged to expense included transaction and transition costs not allocable to and recoverable from ratepayers under regulatory commission approved settlement agreements to share net merger savings.

Worldwide electric and gas operations expense in 2000 increased 13% to $2.6 billion from $2.3 billion. The increase was due to the increase in natural gas prices, the write down to market value of a CSW available-for-sale investment in a Chilean-based electric company sold in December 2000 and the effect of a gain in 1999 on the planned sale of a 50% interest in a cogeneration project. Federal law limits ownership in qualifying cogeneration facilities to 50%. CSW Energy constructed the project and completed the sale of a 50% interest in the project to an unaffiliated entity in 1999. Expenses of the worldwide electric and gas operations increased in 1999 due to the addition of expenses of businesses acquired in December 1998 and the start of commercial operation of the two-unit 250 MW coal-fired generating plant in China.

Interest and Preferred Dividends

In 2000 interest and preferred stock dividends increased by 16% to $1,160 million from $996 million in 1999 due to additional interest expense from the ruling on the litigation with the government disallowing COLI tax deductions and AEP's intention to maintain flexibility for corporate separation by issuing short-term debt at flexible rates. The use of fixed interest rate swaps has been employed to mitigate the risk from floating interest rates.

The 11% increase in interest and preferred stock dividends in 1999 was due primarily to increased interest expense on long-term debt. Long-term debt outstanding increased $564 million in 1999.

Other Income

Other income decreased from $139 million in 1999 to $33 million in 2000 primarily due to a write-down of AEP's Yorkshire investment to reflect a proposed sale in 2001, losses of non-regulated subsidiaries accounted for on an equity basis, and a charge for the discontinuance of an electric storage water heater demand side management program.

Other income increased 46% in 1999 primarily due to gains from the sale of investments at SEEBOARD and from interest income related to a cogeneration power plant.

Income Taxes

Income taxes increased in 2000 primarily due to an unfavorable ruling in AEP's suit against the government over interest deductions claimed relating to AEP's COLI program and nondeductible merger related costs.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Consolidated Statements of Income
(in millions - except per share amounts)

	Year Ended December 31, 2000	1999	1998
REVENUES:			
Domestic Electric Utility Operations	$10,827	$ 9,838	$ 9,834
Worldwide Electric and Gas Operations	2,867	2,569	2,006
TOTAL REVENUES	13,694	12,407	11,840
EXPENSES:			
Fuel and Purchased Power	4,128	3,449	3,455
Maintenance and Other Operation	3,017	2,675	2,596
Non-recoverable Merger Costs	203	-	-
Depreciation and Amortization	1,062	1,011	989
Taxes Other Than Income Taxes	671	664	659
Worldwide Electric and Gas Operations	2,587	2,283	1,861
TOTAL EXPENSES	11,668	10,082	9,560
OPERATING INCOME	2,026	2,325	2,280
OTHER INCOME (net)	33	139	95
INCOME BEFORE INTEREST, PREFERRED DIVIDENDS AND INCOME TAXES	2,059	2,464	2,375
INTEREST AND PREFERRED DIVIDENDS	1,160	996	898
INCOME BEFORE INCOME TAXES	899	1,468	1,477
INCOME TAXES	597	482	502
INCOME BEFORE EXTRAORDINARY ITEM	302	986	975
EXTRAORDINARY LOSSES:			
DISCONTINUANCE OF REGULATORY ACCOUNTING FOR GENERATION	(35)	(8)	-
LOSS ON REACQUIRED DEBT	-	(6)	-
NET INCOME	$ 267	$ 972	$ 975
AVERAGE NUMBER OF SHARES OUTSTANDING	322	321	318
EARNINGS PER SHARE:			
Income Before Extraordinary Item	$ 0.94	$3.07	$3.06
Extraordinary Losses	(0.11)	(.04)	-
Net Income	$ 0.83	$3.03	$3.06
CASH DIVIDENDS PAID PER SHARE	$ 2.40	$2.40	$2.40

See Notes to Consolidated Financial Statements beginning on page L-1.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

Consolidated Balance Sheets

(in millions - except share data)

	December 31, 2000	December 31, 1999
ASSETS		
CURRENT ASSETS:		
Cash and Cash Equivalents	$ 437	$ 609
Special Deposits	-	50
Accounts Receivable:		
Customers	827	553
Miscellaneous	2,883	1,486
Allowance for Uncollectible Accounts	(11)	(12)
Energy Trading Contracts	16,627	1,001
Other	1,268	1,311
TOTAL CURRENT ASSETS	22,031	4,998
PROPERTY PLANT AND EQUIPMENT:		
Electric:		
Production	16,328	15,869
Transmission	5,609	5,495
Distribution	10,843	10,432
Other (including gas and coal mining assets and nuclear fuel)	4,077	4,081
Construction Work in Progress	1,231	1,061
Total Property, Plant and Equipment	38,088	36,938
Accumulated Depreciation and Amortization	15,695	15,073
NET PROPERTY, PLANT AND EQUIPMENT	22,393	21,865
REGULATORY ASSETS	3,698	3,464
INVESTMENTS IN POWER AND COMMUNICATIONS PROJECTS	782	862
GOODWILL (NET OF AMORTIZATION)	1,382	1,531
LONG-TERM ENERGY TRADING CONTRACTS	1,620	136
OTHER ASSETS	2,642	2,863
TOTAL	$54,548	$35,719

See Notes to Consolidated Financial Statements beginning on page L-1.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Consolidated Balance Sheets

	December 31, 2000	December 31, 1999
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts Payable	$ 2,627	$ 1,280
Short-term Debt	4,333	3,012
Long-term Debt Due Within One Year*	1,152	1,367
Energy Trading Contracts	16,801	964
Other	2,154	1,443
TOTAL CURRENT LIABILITIES	27,067	8,066
LONG-TERM DEBT*	9,602	10,157
CERTAIN SUBSIDIARY OBLIGATED, MANDATORILY REDEEMABLE, PREFERRED SECURITIES OF SUBSIDIARY TRUSTS HOLDING SOLELY JUNIOR SUBORDINATED DEBENTURES OF SUCH SUBSIDIARIES	334	335
DEFERRED INCOME TAXES	4,875	5,150
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	203	213
DEFERRED INVESTMENT TAX CREDITS	528	580
LONG-TERM ENERGY TRADING CONTRACTS	1,381	108
DEFERRED CREDITS AND REGULATORY LIABILITIES	637	607
OTHER NONCURRENT LIABILITIES	1,706	1,648
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES*	161	182
COMMITMENTS AND CONTINGENCIES (Note 8)		
COMMON SHAREHOLDERS' EQUITY:		
Common Stock-Par Value $6.50:		
(2000 / 1999)		
Shares Authorized. .600,000,000 / 600,000,000		
Shares Issued. . . .331,019,146 / 330,692,317		
(8,999,992 shares were held in treasury at December 31, 2000 and 1999)	2,152	2,149
Paid-in Capital	2,915	2,898
Accumulated Other Comprehensive Income (Loss)	(103)	(4)
Retained Earnings	3,090	3,630
TOTAL COMMON SHAREHOLDERS' EQUITY	8,054	8,673
TOTAL	$54,548	$35,719

*See Accompanying Schedules.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

Consolidated Statements of Cash Flows

(in millions)

	Year Ended December 31, 2000	1999	1998
OPERATING ACTIVITIES:			
Net Income	$ 267	$ 972	$ 975
Adjustments for Noncash Items:			
Depreciation and Amortization	1,299	1,294	1,171
Deferred Federal Income Taxes	(170)	180	(2)
Deferred Investment Tax Credits	(36)	(38)	(37)
Amortization (Deferral) of Operating Expenses and Carrying Charges (net)	48	(151)	15
Equity in Earnings of Yorkshire Electricity Group plc	(44)	(45)	(38)
Extraordinary Item	35	14	-
Deferred Costs Under Fuel Clause Mechanisms	(449)	(191)	36
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(1,632)	(80)	(329)
Fuel, Materials and Supplies	147	(162)	(23)
Accrued Utility Revenues	(79)	(35)	5
Accounts Payable	1,322	74	270
Taxes Accrued	172	29	20
Payment of Disputed Tax and Interest Related to COLI	319	(16)	(303)
Other (net)	304	(231)	195
Net Cash Flows From Operating Activities	1,503	1,614	1,955
INVESTING ACTIVITIES:			
Construction Expenditures	(1,773)	(1,680)	(1,396)
Investment in CitiPower	-	-	(1,054)
Investment in Gas Assets	-	-	(340)
Other	19	7	(54)
Net Cash Flows Used For Investing Activities	(1,754)	(1,673)	(2,844)
FINANCING ACTIVITIES:			
Issuance of Common Stock	14	93	96
Issuance of Long-term Debt	1,124	1,391	2,645
Retirement of Cumulative Preferred Stock	(20)	(170)	(28)
Retirement of Long-term Debt	(1,565)	(915)	(1,101)
Change in Short-term Debt (net)	1,308	812	264
Dividends Paid on Common Stock	(805)	(833)	(827)
Other Financing Activities	-	(43)	-
Net Cash Flows From Financing Activities	56	335	1,049
Effect of Exchange Rate Change on Cash	23	(2)	-
Net Increase (Decrease) in Cash and Cash Equivalents	(172)	274	160
Cash and Cash Equivalents January 1	609	335	175
Cash and Cash Equivalents December 31	$ 437	$ 609	$ 335

See Notes to Consolidated Financial Statements beginning on page L-1.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Consolidated Statements of Common Shareholders' Equity
(in millions)

	Common Shares	Stock Amount	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
JANUARY 1, 1998	326	$2,036	$2,818	$3,356	$ 23	$8,233
Conforming Change in Accounting Policy	-	-	-	(13)	-	(13)
Reclassification Adjustment	-	85	(85)	-	-	-
Adjusted Balance at Beginning of Period	326	2,121	2,733	3,343	23	8,220
Issuances	2	13	83	-	-	96
Retirements and Other	-	-	2	3	-	5
Cash Dividends Declared	-	-	-	(827)	-	(827)
						7,494
Comprehensive Income:						
Other Comprehensive Income, Net of Taxes						
Foreign Currency Translation Adjustment	-	-	-	-	6	6
Unrealized Loss on Securities	-	-	-	-	(14)	(14)
Adjustments for Gain Included in Net Income	-	-	-	-	(7)	(7)
Minimum Pension Liability	-	-	-	-	(1)	(1)
Net Income	-	-	-	975	-	975
Total Comprehensive Income						959
DECEMBER 31, 1998	328	2,134	2,818	3,494	7	8,453
Conforming Change in Accounting Policy	-	-	-	(1)	-	(1)
Adjusted Balance at Beginning of Period	328	2,134	2,818	3,493	7	8,452
Issuances	3	15	77	-	-	92
Retirements and Other	-	-	3	-	-	3
Cash Dividends Declared	-	-	-	(833)	-	(833)
						7,714
Comprehensive Income:						
Other Comprehensive Income, Net of Taxes						
Foreign Currency Translation Adjustment	-	-	-	-	(13)	(13)
Minimum Pension Liability	-	-	-	-	2	2
Net Income	-	-	-	972	-	972
Total Comprehensive Income						961
DECEMBER 31, 1999	331	2,149	2,898	3,632	(4)	8,675
Conforming Change in Accounting Policy	-	-	-	(2)	-	(2)
Adjusted Balance at Beginning of Period	331	2,149	2,898	3,630	(4)	8,673
Issuances	-	3	11	-	-	14
Cash Dividends Declared	-	-	-	(805)	-	(805)
Other	-	-	6	(2)	-	4
						7,886
Comprehensive Income:						
Other Comprehensive Income, Net of Taxes						
Foreign Currency Translation Adjustment	-	-	-	-	(119)	(119)
Reclassification Adjustment For Loss Included in Net Income	-	-	-	-	20	20
Net Income	-	-	-	267	-	267
Total Comprehensive Income						168
DECEMBER 31, 2000	331	$2,152	$2,915	$3,090	$(103)	$8,054

See Notes to Consolidated Financial Statements beginning on page L-1.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries

	December 31, 2000			
	Call Price per Share (a)	Shares Authorized(b)	Shares Outstanding(g)	Amount (In Millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	614,608	$ 61
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	(d)	1,950,000	333,100	$ 33
6.02% - 6-7/8% (c)	(e)	1,650,000	513,450	52
7% (f)	(f)	250,000	150,000	15
Total Subject to Mandatory Redemption (c)				$100

	December 31, 1999			
	Call Price per Share (a)	Shares Authorized(b)	Shares Outstanding(g)	Amount (In Millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	629,671	$ 63
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	(d)	1,950,000	343,100	$ 34
6.02% - 6-7/8% (c)	(e)	1,950,000	597,950	60
7% (f)	(f)	250,000	250,000	25
Total Subject to Mandatory Redemption (c)				$119

NOTES TO SCHEDULE OF CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES

(a) At the option of the subsidiary the shares may be redeemed at the call price plus accrued dividends. The involuntary liquidation preference is $100 per share for all outstanding shares.

(b) As of December 31, 2000 the subsidiaries had 13,592,750, 22,200,000 and 7,713,495 shares of $100, $25 and no par value preferred stock, respectively, that were authorized but unissued.

(c) Shares outstanding and related amounts are stated net of applicable retirements through sinking funds(generally at par) and reacquisitions of shares in anticipation of future requirements. The subsidiaries reacquired enough shares in 1997 to meet all sinking fund requirements on certain series until 2008 and on certain series until 2009 when all remaining outstanding shares must be redeemed. The sinking fund provisions of the series subject to mandatory redemption aggregate (after deducting sinking fund requirements) of $5 million in 2002, $12 million in 2003, $12 million in 2004 and $2 million in 2005.

(d) Not callable prior to 2003; after that the call price is $100 per share.

(e) Not callable prior to 2000; after that the call price is $100 per share.

(f) With sinking fund.

(g) The number of shares of preferred stock redeemed is 209,563 shares in 2000, 1,698,276 shares in 1999 and 281,250 shares in 1998.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Schedule of Consolidated Long-term Debt of Subsidiaries

Maturity	Weighted Average Interest Rate December 31, 2000	Interest Rates at December 31, 2000	Interest Rates at December 31, 1999	December 31, 2000 (in millions)	December 31, 1999 (in millions)
FIRST MORTGAGE BONDS					
2000-2003	6.96%	5.91%-8.95%	5.25%-8.95%	$ 1,247	$ 1,621
2004-2008	6.97%	6-1/8%-8%	6-1/8%-8%	1,140	1,148
2020-2025	7.74%	6-7/8%-8.80%	6-7/8%-8.80%	1,104	1,172
INSTALLMENT PURCHASE CONTRACTS (a)					
2000-2009	5.53%	4.90%-7.70%	4.80%-7.70%	234	235
2011-2030	6.02%	4.875%-8.20%	3.332%-8.20%	1,447	1,477
NOTES PAYABLE (b)					
2000-2021	7.14%	6.20%-9.60%	5.8675%-9.60%	1,181	2,030
SENIOR UNSECURED NOTES					
2000-2004	6.99%	6.50%-7.45%	6.07%-7.45%	2,049	1,403
2005-2009	6.59%	6.24%-6.91%	6.24%-6.91%	475	488
2038	7.30%	7.20%-7-3/8%	7.20%-7-3/8%	340	340
JUNIOR DEBENTURES					
2025-2038	8.05%	7.60%-8.72%	7.60%-8.72%	620	620
YANKEE BONDS AND EURO BONDS					
2001-2006	8.51%	7.98%-8.875%	7.98%-8.875%	684	742
OTHER LONG-TERM DEBT (c)				280	300
Unamortized Discount (net)				(47)	(52)
Total Long-term Debt Outstanding (d)				10,754	11,524
Less Portion Due Within One Year				1,152	1,367
Long-term Portion				$ 9,602	$10,157

NOTES TO SCHEDULE OF CONSOLIDATED LONG-TERM DEBT OF SUBSIDIARIES

(a) For certain series of installment purchase contracts interest rates are subject to periodic adjustment. Certain series will be purchased on demand at periodic interest-adjustment dates. Letters of credit from banks and standby bond purchase agreements support certain series.

(b) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving credit agreements with a number of banks and other financial institutions. At expiration all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(c) Other long-term debt consists of a liability along with accrued interest for disposal of spent nuclear fuel (see Note 8 of the Notes to Consolidated Financial Statements) and financing obligation under sale lease back agreements.

(d) Long-term debt outstanding at December 31, 2000 is payable as follows:

Principal Amount (in millions)	
2001	$ 1,152
2002	1,167
2003	1,628
2004	884
2005	616
Later Years	5,354
Total Principal Amount	10,801
Unamortized Discount	(47)
Total	$10,754

AMERICAN ELECTRIC POWER COMPANY INC. AND SUBSIDIARY COMPANIES
Index to Notes to Consolidated Financial Statements

The notes listed below are combined with the notes to financial statements for AEP and its other subsidiary registrants. The combined footnotes begin on page L-1.

MANAGEMENT'S RESPONSIBILITY

The management of American Electric Power Company, Inc. is responsible for the integrity and objectivity of the information and representations in this annual report, including the consolidated financial statements. These statements have been prepared in conformity with generally accepted accounting principles, using informed estimates where appropriate, to reflect the Company's financial condition and results of operations. The information in other sections of the annual report is consistent with these statements.

The Company's Board of Directors has oversight responsibilities for determining that management has fulfilled its obligation in the preparation of the financial statements and in the ongoing examination of the Company's established internal control structure over financial reporting. The Audit Committee, which consists solely of outside directors and which reports directly to the Board of Directors, meets regularly with management, Deloitte & Touche LLP - independent auditors and the Company's internal audit staff to discuss accounting, auditing and reporting matters. To ensure auditor independence, both Deloitte & Touche LLP and the internal audit staff have unrestricted access to the Audit Committee.

The financial statements have been audited by Deloitte & Touche LLP, whose report appears on the next page. The auditors provide an objective, independent review as to management's discharge of its responsibilities insofar as they relate to the fairness of the Company's reported financial condition and results of operations. Their audit includes procedures believed by them to provide reasonable assurance that the financial statements are free of material misstatement and includes an evaluation of the Company's internal control structure over financial reporting.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors
of American Electric Power Company, Inc.:

We have audited the consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits. The consolidated financial statements give retroactive effect to the merger of American Electric Power Company, Inc. and its subsidiaries and Central and South West Corporation and its subsidiaries, which has been accounted for as a pooling of interests as described in Note 3 to the consolidated financial statements. We did not audit the consolidated balance sheet of Central and South West Corporation and its subsidiaries as of December 31, 1999, or the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for the years ended December 31, 1999 and 1998, which statements reflect total assets of $14,162,000,000 as of December 31, 1999, and total revenues of $5,537,000,000 and $5,482,000,000 for the years ended December 31, 1999 and 1998, respectively. Those consolidated statements, before the restatement described in Note 3, were audited by other auditors whose report, dated February 25, 2000, has been furnished to us, and our opinion, insofar as it relates to those amounts included for Central and South West Corporation and its subsidiaries for 1999 and 1998, is based solely on the report of such other auditors.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and its subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America.

We also audited the adjustments described in Note 3 that were applied to restate the 1999 and 1998 financial statements to give retroactive effect to the change in the method of accounting for vacation pay accruals. In our opinion, such adjustments are appropriate and have been properly applied.

Deloitte & Touche LLP
Columbus, Ohio
February 26, 2001

AEP GENERATING COMPANY

-This page intentionally left blank.-

AEP GENERATING COMPANY
Selected Financial Data

	Year Ended December 31,				
	2000	1999	1998 (in thousands)	1997	1996
INCOME STATEMENTS DATA:					
Operating Revenues	$228,516	$217,189	$224,146	$227,868	$225,892
Operating Expenses	220,092	211,849	215,415	218,828	215,997
Operating Income	8,424	5,340	8,731	9,040	9,895
Nonoperating Income	3,429	3,659	3,364	3,603	3,695
Income Before Interest Charges	11,853	8,999	12,095	12,643	13,590
Interest Charges	3,869	2,804	3,149	3,857	4,159
Net Income	$ 7,984	$ 6,195	$ 8,946	$ 8,786	$ 9,431

	December 31,				
	2000	1999	1998 (in thousands)	1997	1996
BALANCE SHEETS DATA:					
Electric Utility Plant	$642,302	$640,093	$636,460	$633,450	$632,257
Accumulated Depreciation	315,566	295,065	277,855	257,191	238,532
Net Electric Utility Plant	$326,736	$345,028	$358,605	$376,259	$393,725
Total Assets	$374,602	$398,640	$403,892	$419,058	$442,911
Common Stock and Paid-in Capital	$ 24,434	$ 30,235	$ 36,235	$ 40,235	$ 45,235
Retained Earnings	9,722	3,673	2,770	2,528	1,886
Total Common Shareholder's Equity	$ 34,156	$ 33,908	$ 39,005	$ 42,763	$ 47,121
Long-term Debt (a)	$ 44,808	$ 44,800	$ 44,792	$ 69,570	$ 89,554
Total Capitalization and Liabilities	$374,602	$398,640	$403,892	$419,058	$442,911

(a) Including portion due within one year.

AEP Generating Company is engaged in the generation and wholesale sale of electric power to two affiliates under long-term agreements.

Operating revenues are derived from the sale of Rockport Plant energy and capacity to two affiliated companies, I&M and KPCo pursuant to FERC approved long-term unit power agreements. Under the terms of its unit power agreement, I&M is required to buy all of AEGCo's Rockport capacity when the unit power agreement with KPCo expires in 2004. The unit power agreements provide for recovery of costs including a FERC approved rate of return on common equity and a return on other capital net of temporary cash investments.

Net income increased $1.8 million or 29% as a result of the recordation of income tax accrual adjustments and an increase in return on other capital. Comparative net income was increased by the income tax accrual adjustments since an unfavorable income tax accrual adjustment was recorded in 1999 and income tax accrual adjustments are not included in billings under the terms of the unit power agreements. Return on other capital increased as a result of higher interest charges without an offset for earnings on temporary cash investments in 2000.

Income statement items which changed significantly were:

(dollars in millions)	Increase (Decrease) From Previous Year Amount	%
Operating Revenues	$11.3	5
Fuel Expense	8.5	9
Maintenance Expense	(0.9)	(8)
Taxes Other Than Federal Income Taxes	0.5	10
Interest Charges	1.1	38

The increase in operating revenues reflects recovery under the unit power agreements of higher fuel expense and an increase in the return on other capital.

Fuel expense increased due to an increase in generation reflecting greater availability of the Rockport Plant generating units in 2000 and an increase in the cost of fuel.

The decrease in maintenance expense can be attributed to cost containment efforts and the shorter duration in 2000 of maintenance outages for boiler inspection and repair than in 1999.

Taxes other than federal income taxes increased due to an increase in state income taxes which resulted from an increase in taxable income in 2000 and adjustments to estimated prior year taxes following the filing of the 1999 and 1998 returns.

The increase in interest charges was primarily due to an increase in interest rates in 2000. AEGCo's long-term debt interest rates are variable on a daily basis which results in interest charges adjusting quickly to market rate changes.

AEP GENERATING COMPANY
Statements of Income

	Year Ended December 31, 2000	1999 (in thousands)	1998
OPERATING REVENUES	$228,516	$217,189	$224,146
OPERATING EXPENSES:			
Fuel	102,978	94,481	96,791
Rent - Rockport Plant Unit 2	68,283	68,283	68,283
Other Operation	10,295	10,451	10,001
Maintenance	9,616	10,492	11,894
Depreciation	22,162	21,845	21,652
Taxes Other Than Federal Income Taxes	5,060	4,585	3,495
Federal Income Taxes	1,698	1,712	3,299
TOTAL OPERATING EXPENSES	220,092	211,849	215,415
OPERATING INCOME	8,424	5,340	8,731
NONOPERATING INCOME	3,429	3,659	3,364
INCOME BEFORE INTEREST CHARGES	11,853	8,999	12,095
INTEREST CHARGES	3,869	2,804	3,149
NET INCOME	$ 7,984	$ 6,195	$ 8,946

Statements of Retained Earnings

	Year Ended December 31, 2000	1999 (in thousands)	1998
RETAINED EARNINGS JANUARY 1	$3,673	$2,770	$2,528
NET INCOME	7,984	6,195	8,946
CASH DIVIDENDS DECLARED	1,935	5,292	8,704
RETAINED EARNINGS DECEMBER 31	$9,722	$3,673	$2,770

See Notes to Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
Balance Sheets

	December 31, 2000	1999
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$635,215	$629,286
General	2,795	2,400
Construction Work in Progress	4,292	8,407
Total Electric Utility Plant	642,302	640,093
Accumulated Depreciation	315,566	295,065
NET ELECTRIC UTILITY PLANT	326,736	345,028
CURRENT ASSETS:		
Cash and Cash Equivalents	2,757	317
Accounts Receivable:		
Affiliated Companies	21,374	22,464
Miscellaneous	2,341	2,643
Fuel - at average cost	11,006	17,505
Materials and Supplies - at average cost	3,979	3,966
Prepayments	145	150
TOTAL CURRENT ASSETS	41,602	47,045
REGULATORY ASSETS	5,504	5,744
DEFERRED CHARGES	760	823
TOTAL	$374,602	$398,640

See Notes to Financial Statements beginning on page L-1.

	December 31, 2000	December 31, 1999
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - Par Value $1,000:		
Authorized and Outstanding - 1,000 Shares	$ 1,000	$ 1,000
Paid-in Capital	23,434	29,235
Retained Earnings	9,722	3,673
TOTAL CAPITALIZATION AND COMMON SHAREHOLDER'S EQUITY	34,156	33,908
OTHER NONCURRENT LIABILITIES	358	592
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	44,808	44,800
Short-term Debt - Notes Payable	-	24,700
Advances from Affiliates	28,068	-
Accounts Payable:		
General	6,109	7,539
Affiliated Companies	7,724	19,451
Taxes Accrued	4,993	4,285
Rent Accrued - Rockport Plant Unit 2	4,963	4,963
Other	4,443	4,763
TOTAL CURRENT LIABILITIES	101,108	110,501
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	122,188	127,759
REGULATORY LIABILITIES:		
Deferred Investment Tax Credits	59,718	63,114
Amounts Due to Customers for Income Taxes	23,996	26,266
TOTAL REGULATORY LIABILITIES	83,714	89,380
DEFERRED INCOME TAXES	32,928	36,500
DEFERRED CREDITS	150	-
CONTINGENCIES (Note 8)		
TOTAL	$374,602	$398,640

See Notes to Financial Statements beginning on page L-1.

AEP GENERATING COMPANY

Statements of Cash Flows

	Year Ended December 31, 2000	1999	1998
		(in thousands)	
OPERATING ACTIVITIES:			
Net Income	$ 7,984	$ 6,195	$ 8,946
Adjustments for Noncash Items:			
Depreciation	22,162	21,845	21,652
Deferred Federal Income Taxes	(5,842)	(5,282)	5,544
Deferred Investment Tax Credits	(3,396)	(3,448)	(3,454)
Amortization of Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	(5,571)	(5,571)	(5,571)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable	1,392	(2,213)	(2,184)
Fuel, Materials and Supplies	6,486	(6,263)	(855)
Accounts Payable	(13,157)	14,394	2,892
Taxes Accrued	708	1,058	(193)
Other (net)	1,232	(1,570)	2,542
Net Cash Flows From Operating Activities	11,998	19,145	29,319
INVESTING ACTIVITIES:			
Construction Expenditures	(5,190)	(8,349)	(6,574)
Proceeds From Sales of Property	-	331	2,254
Net Cash Flows Used For Investing Activities	(5,190)	(8,018)	(4,320)
FINANCING ACTIVITIES:			
Return of Capital to Parent Company	(5,801)	(6,000)	(4,000)
Retirement of Long-term Debt	-	-	(25,000)
Change in Short-term Debt (net)	(24,700)	250	12,700
Change in Advances From Affiliates (net)	28,068	-	-
Dividends Paid	(1,935)	(5,292)	(8,704)
Net Cash Flows Used For Financing Activities	(4,368)	(11,042)	(25,004)
Net Increase (Decrease) in Cash and Cash Equivalents	2,440	85	(5)
Cash and Cash Equivalents January 1	317	232	237
Cash and Cash Equivalents December 31	$ 2,757	$ 317	$ 232

Supplemental Disclosure:
Cash paid (received) for interest net of capitalized amounts was $3,531,000, $2,468,000 and $3,060,000 and for income taxes was $6,820,000, $6,565,000 and $(2,131,000) in 2000, 1999 and 1998, respectively.

See Notes to Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
Statements of Capitalization

	December 31, 2000	December 31, 1999
	(in thousands)	
COMMON STOCK EQUITY (a)	$ 34,156	$ 33,908
LONG-TERM DEBT		
Installment Purchase Contracts - City of Rockport (b)		
Series Due Date		
1995 A, 2025 (c)	22,500	22,500
1995 B, 2025 (c)	22,500	22,500
Unamortized Discount	(192)	(200)
Amount Due Within One Year	(44,808)	(44,800)
	-	-
TOTAL CAPITALIZATION	$ 34,156	$ 33,908

(a) In 2000, 1999 and 1998, AEGCo returned capital to AEP in the amounts of $5.8 million, $6 million and $4 million, respectively. There were no other material transactions affecting common stock and paid-in capital in 2000, 1999 and 1998.

(b) Installment purchase contracts were entered into in connection with the issuance of pollution control revenue bonds by the City of Rockport, Indiana. Under the terms of the installment purchase contracts, AEGCo is required to pay amounts sufficient to enable the payment of interest and principal on the related pollution control revenue bonds issued to refinance the construction costs of pollution control facilities at the Rockport Plant. On the Series 1995 A and B bonds the principal is payable at maturity or on the demand of bondholders. AEGCo has agreements that provide for brokers to remarket bonds tendered. In the event the bonds cannot be remarketed, AEGCo has a standby bond purchase agreement with a bank that provides for the bank to purchase any bonds not remarketed. The purchase agreement expires in 2001. Therefore, the installment purchase contracts have been reclassified as due within one year.

(c) These series have an adjustable interest rate that can be a daily, weekly, commercial paper or term rate as designated by AEGCo. AEGCo selected a daily rate which ranged from 1.65% to 6.1% during 2000 and 1.4% to 5.2% during 1999 and averaged 4.1% in 2000 and 3.2% in 1999. The interest rates were 5% and 4.9% at December 31, 2000 and 4.95% and 4.8% at December 31, 1999 for Series A and Series B, respectively.

See Notes to Financial Statements beginning on page L-1.

AEP GENERATING COMPANY
Index to Notes to Financial Statements

The notes listed below are combined with the notes to financial statements for AEP and its other subsidiary registrants. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholder and Board of Directors
of AEP Generating Company:

We have audited the accompanying balance sheets and statements of capitalization of AEP Generating Company as of December 31, 2000 and 1999, and the related statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of AEP Generating Company as of December 31, 2000 and 1999, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP
Columbus, Ohio
February 26, 2001

-This page intentionally left blank.-

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

-This page intentionally left blank.-

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
Selected Consolidated Financial Data

	Year Ended December 31,				
	2000	1999	1998	1997	1996
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	$1,860,165	$1,650,937	$1,672,244	$1,628,515	$1,624,869
Operating Expenses	1,659,011	1,409,701	1,443,701	1,388,521	1,381,993
Operating Income	201,154	241,236	228,543	239,994	242,876
Nonoperating Income (Loss)	11,752	8,096	(8,301)	(222)	128
Income Before Interest Charges	212,906	249,332	220,242	239,772	243,004
Interest Charges	148,000	128,840	126,912	119,258	109,315
Income Before Extraordinary Item	64,906	120,492	93,330	120,514	133,689
Extraordinary Gain	8,938	-	-	-	-
Net Income	73,844	120,492	93,330	120,514	133,689
Preferred Stock Dividend Requirements	2,504	2,706	2,497	7,006	15,938
Earnings Applicable to Common Stock	$ 71,340	$ 117,786	$ 90,833	$ 113,508	$ 117,751

	Year Ended December 31,				
	2000	1999	1998	1997	1996
			(in thousands)		
BALANCE SHEETS DATA:					
Electric Utility Plant	$5,418,278	$5,262,951	$5,087,359	$4,901,046	$4,717,132
Accumulated Depreciation and Amortization	2,188,796	2,079,490	1,984,856	1,869,057	1,782,017
Net Electric Utility Plant	$3,229,482	$3,183,461	$3,102,503	$3,031,989	$2,935,115
Total Assets	$6,646,153	$4,354,400	$4,047,038	$3,883,430	$3,800,737
Common Stock and Paid-in Capital	$ 975,676	$ 974,717	$ 924,091	$ 873,506	$ 835,838
Retained Earnings	120,584	175,854	179,461	207,544	208,472
Total Common Shareholder's Equity	$1,096,260	$1,150,571	$1,103,552	$1,081,050	$1,044,310
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$ 17,790	$ 18,491	$ 19,359	$ 19,747	$ 29,815
Subject to Mandatory Redemption	10,860	20,310	22,310	22,310	190,000
Total Cumulative Preferred Stock	$ 28,650	$ 38,801	$ 41,669	$ 42,057	$ 219,815
Long-term Debt (a)	$1,605,818	$1,665,307	$1,552,455	$1,494,535	$1,365,842
Obligations Under Capital Leases (a)	$ 63,160	$ 64,645	$ 65,175	$ 60,110	$ 51,969
Total Capitalization and Liabilities	$6,646,153	$4,354,400	$4,047,038	$3,883,430	$3,800,737

(a) *Including portion due within one year*

APCo is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power to 909,000 retail customers in southwestern Virginia and southern West Virginia. APCo as a member of the AEP Power Pool shares in the revenues and costs of the AEP Power Pool's wholesale sales to neighboring utility systems and power marketers. APCo also sells wholesale power to municipalities.

The cost of the AEP System's generating capacity is allocated among the AEP Power Pool members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. AEP Power Pool members are also compensated for their out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received or purchased from the AEP Power Pool.

The AEP Power Pool calculates each company's prior twelve month peak demand relative to the total peak demand of all member companies as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR) which determines each company's percentage share of revenues or costs. APCo as a member of the AEP Power Pool shares in the revenues and costs of the AEP Power Pool's wholesale sales to and net forward trades with other utility systems and power marketers. Revenues from forward electricity trades are recorded net of purchases as operating revenues for transactions in AEP's traditional marketing area (up to two transmission systems from the AEP service territory) and as nonoperating income for transactions beyond two transmission systems from AEP. The AEP Power Pool also enters into power trading transactions for options, futures and swaps. APCo's share of these transactions is recorded in nonoperating income.

In February 2001 the U.S. District Court for the Southern District of Ohio ruled against AEP and certain of its subsidiaries, including APCo, in a suit over deductibility of interest claimed in AEP's consolidated tax return related to a corporate owned life insurance (COLI) program. In 1998 and 1999 APCo paid the disputed taxes and interest attributable to the COLI interest deductions for taxable years 1991-98. The payments were included in Other Property and Investments pending the resolution of this matter. As a result of the Court's decision, net income was reduced by $82 million in 2000.

Results of Operations

Net Income

Income before extraordinary items decreased $55.6 million or 46% in 2000 primarily due to the COLI decision. An extraordinary gain from the discontinuance of SFAS 71 regulatory accounting of $9 million after tax was recorded in June 2000. (See Note 7 of the Notes to Consolidated Financial Statements).

Net income increased $27.2 million or 29% in 1999 primarily due to a nonoperating gain in 1999 on the sale of real estate and mining assets by APCo's inactive mining subsidiaries and a decline in operating expenses.

Operating Revenues

The 13% increase in operating revenues in 2000 resulted from APCo's share of increased wholesale electricity transactions by the AEP Power Pool. Operating revenues decreased 1% in 1999 primarily due to a decrease in wholesale sales and a decline in net revenues reflecting lower margins on wholesale trading transactions. The changes in the components of revenues were as follows:

(dollars in millions)	Increase (Decrease) From Previous Year			
	2000		1999	
	Amount	%	Amount	%
Retail:				
Residential	$ 15.5		$ 19.4	
Commercial	9.2		17.1	
Industrial	(15.1)		(4.4)	
Other	1.7		0.9	
	11.3	1	33.0	3
Wholesale	237.0	88	(80.6)	(23)
Transmission and Other	(39.1)	(44)	26.3	42
Total	$209.2	13	$(21.3)	(1)

Retail revenues increased in 1999 primarily due to a 2% increase in retail sales reflecting higher residential and commercial sales. The increase in retail sales was primarily due to colder winter weather and customer growth.

The increase in wholesale revenues in 2000 is due to a significant increase in AEP Power Pool transactions. As a result of an affiliated company's major industrial customer's decision not to continue its purchased power agreement, additional power was available to the AEP Power Pool for wholesale sales contributing to the increase in APCo's wholesale revenues. The decline in wholesale revenues in 1999 reflects the termination of a contract with several municipal customers in July 1998 and a decline in margins on regulated power trading transactions. The decline in margins reflects the moderation in 1999 of extreme weather in 1998 and capacity shortages experienced in the summer of 1998.

In 2000 transmission and other revenues decreased substantially due to the combined effect of an unfavorable mark-to-market adjustment in 2000 on outstanding forward trading contracts, a favorable adjustment to a provision for revenue refunds recorded in 1999 in connection with the execution of a final rate refund and a favorable adjustment to rental income in 1999 for agreed to retroactive billings to telecommunications companies for pole attachments.

Operating Expenses

Operating expenses increased 18% in 2000 primarily due to an increase in purchased power expense, other operation expense and federal income taxes offset in part by a decrease in fuel expense. The decrease in operating expenses in 1999 was mainly due to a decline in purchased power expense. Changes in the components of operating expenses are as follows:

(dollars in millions)	Increase (Decrease) From Previous Year			
	2000		1999	
	Amount	%	Amount	%
Fuel	$(75.6)	(17)	$ 7.2	2
Purchased Power	223.8	88	(49.0)	(16)
Other Operation	33.0	13	(5.1)	(2)
Maintenance	0.7	1	(11.0)	(8)
Depreciation and Amortization	14.2	10	5.1	4
Taxes Other Than Federal Income Taxes	8.8	8	1.5	1
Federal Income Taxes	44.4	63	17.3	32
Total	$249.3	18	$(34.0)	(2)

Fuel expense decreased in 2000 due to the combined effect of the discontinuance of deferral accounting for over or under recovery of fuel costs in the West Virginia jurisdiction effective January 1, 2000 under the terms of a rate settlement agreement and a decline in generation due to scheduled plant maintenance. The increase in fuel expense in 1999 was primarily due to increases in generation reflecting greater utilization of internally generated power.

The significant increase in purchased power expense in 2000 reflects additional purchases of power from the AEP Power Pool as a result of increased availability of generation. The AEP Power Pool was able to supply more energy to APCo since an affiliate's out of service nuclear unit went on line in June 2000, a major industrial customer discontinued purchasing power from an affiliate in January 2000, and generating unit outage management improved.

The reduction in purchased power expense in 1999 was primarily due to reduced capacity charges from the AEP Power Pool as a result of declines in APCo's MLR and decreased purchases from the AEP Power

Pool. The decline in purchases from the AEP Power Pool can be attributed to increased internal generation and the termination of a contract with several municipal customers.

The increase in other operation expense in 2000 was due to increased marketing and trading costs including increased accruals for incentive compensation and increased use of emission allowances due to stricter air quality standards of Phase II of the 1990 Clean Air Act Amendments which became effective January 1, 2000.

Maintenance expense decreased in 1999 primarily as a result of expenditures during 1998 to restore service and make repairs following two severe snowstorms.

Depreciation and amortization expense increased in 2000 due to the amortization, beginning in July 2000, of a new transition regulatory asset established in June 2000 for the net generation-related regulatory assets related to the Company's Virginia and West Virginia jurisdictions that were transferred to the distribution portion of the business and are being recovered through regulated rates (see Note 7 for further discussion of the effects of restructuring). Additional investments in distribution plant also contributed to the increase in depreciation and amortization expense.

The increase in taxes other than federal income taxes in 2000 is primarily due to an increase in the WV state income taxes due to disallowance of the COLI program interest deductions.

Federal income taxes attributable to operations increased in 2000 due to the disallowance of COLI interest deductions. The increase in 1999 is primarily due to an increase in pre-tax operating income and changes in certain book/tax differences accounted for on a flow-through basis for rate-making purposes.

Nonoperating Income

The increase in nonoperating income in 1999 is primarily due to the effect of non-regulated electricity trading and a gain on the sale of coal lands and mining assets by APCo's inactive coal mining subsidiaries. In 1999 nonoperating income included a gain from APCo's share of the AEP Power Pool's trading transactions outside of the AEP System's traditional marketing area. In November 1999 the subsidiaries sold coal lands and mining assets to an unaffiliated company that had been leasing the assets.

Interest Charges

Interest charges increased in 2000 due to recognizing previously deferred interest payments to the IRS related to the COLI disallowances and interest on resultant state income tax deficiencies.

Extraordinary Gain

The extraordinary gain recorded in June 2000 was the result of the discontinuance of SFAS 71 for the generation portion of APCo's business.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Income

	Year Ended December 31,		
	2000	1999	1998
		(in thousands)	
OPERATING REVENUES	$1,860,165	$1,650,937	$1,672,244
OPERATING EXPENSES:			
Fuel	369,161	444,711	437,500
Purchased Power	477,910	254,100	303,116
Other Operation	282,610	249,616	254,718
Maintenance	124,493	123,834	134,856
Depreciation and Amortization	163,089	148,874	143,809
Taxes Other Than Federal Income Taxes	126,447	117,641	116,070
Federal Income Taxes	115,301	70,925	53,632
Total Operating Expenses	1,659,011	1,409,701	1,443,701
OPERATING INCOME	201,154	241,236	228,543
NONOPERATING INCOME (LOSS)	11,752	8,096	(8,301)
INCOME BEFORE INTEREST CHARGES	212,906	249,332	220,242
INTEREST CHARGES	148,000	128,840	126,912
INCOME BEFORE EXTRAORDINARY ITEM	64,906	120,492	93,330
EXTRAORDINARY GAIN - DISCONTINUANCE OF REGULATORY ACCOUNTING FOR GENERATION (Inclusive of Tax Benefit of $7,872,000)	8,938	-	-
NET INCOME	73,844	120,492	93,330
PREFERRED STOCK DIVIDEND REQUIREMENTS	2,504	2,706	2,497
EARNINGS APPLICABLE TO COMMON STOCK	$ 71,340	$ 117,786	$ 90,833

See Notes to Consolidated Financial Statements Beginning on Page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 2000	December 31, 1999
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,058,952	$2,014,968
Transmission	1,177,079	1,151,377
Distribution	1,816,925	1,741,685
General	254,371	247,798
Construction Work in Progress	110,951	107,123
Total Electric Utility Plant	5,418,278	5,262,951
Accumulated Depreciation and Amortization	2,188,796	2,079,490
NET ELECTRIC UTILITY PLANT	3,229,482	3,183,461
OTHER PROPERTY AND INVESTMENTS	56,967	126,592
LONG-TERM ENERGY TRADING CONTRACTS	322,688	33,954
CURRENT ASSETS:		
Cash and Cash Equivalents	5,847	64,828
Advances to Affiliates	8,387	-
Accounts Receivable:		
Customers	243,298	109,525
Affiliated Companies	63,919	37,827
Miscellaneous	16,179	9,154
Allowance for Uncollectible Accounts	(2,588)	(2,609)
Fuel - at average cost	39,076	58,161
Materials and Supplies - at average cost	57,515	56,917
Accrued Utility Revenues	66,499	53,418
Energy Trading Contracts	2,036,001	143,777
Prepayments	6,307	7,713
TOTAL CURRENT ASSETS	2,540,440	538,711
REGULATORY ASSETS	447,750	436,894
DEFERRED CHARGES	48,826	34,788
TOTAL	$6,646,153	$4,354,400

See Notes to Consolidated Financial Statements Beginning on Page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

	December 31, 2000	December 31, 1999
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - No Par Value:		
Authorized - 30,000,000 Shares		
Outstanding - 13,499,500 Shares	$ 260,458	$ 260,458
Paid-in Capital	715,218	714,259
Retained Earnings	120,584	175,854
Total Common Shareholder's Equity	1,096,260	1,150,571
Cumulative Preferred Stock:		
Not Subject to Mandatory Redemption	17,790	18,491
Subject to Mandatory Redemption	10,860	20,310
Long-term Debt	1,430,812	1,539,302
TOTAL CAPITALIZATION	2,555,722	2,728,674
OTHER NONCURRENT LIABILITIES	105,883	132,130
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	175,006	126,005
Short-term Debt	191,495	123,480
Accounts Payable - General	153,422	59,150
Accounts Payable - Affiliated Companies	107,556	42,459
Taxes Accrued	63,258	49,038
Customer Deposits	12,612	12,898
Interest Accrued	21,555	19,079
Energy Trading Contracts	2,091,804	140,279
Other	85,378	71,044
TOTAL CURRENT LIABILITIES	2,902,086	643,432
DEFERRED INCOME TAXES	682,474	671,917
DEFERRED INVESTMENT TAX CREDITS	43,093	57,259
LONG-TERM ENERGY TRADING CONTRACTS	259,438	26,256
REGULATORY LIABILITIES AND DEFERRED CREDITS	97,457	94,732
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$6,646,153	$4,354,400

See Notes to Consolidated Financial Statements Beginning on Page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	Year Ended December 31, 2000	1999	1998
	(in thousands)		
OPERATING ACTIVITIES:			
Net Income	$ 73,844	$ 120,492	$ 93,330
Adjustments for Noncash Items:			
Depreciation and Amortization	163,202	149,791	144,967
Deferred Federal Income Taxes	8,602	13,033	(2,338)
Deferred Investment Tax Credits	(4,915)	(4,972)	(5,265)
Deferred Power Supply Costs (net)	(84,408)	35,955	30,081
Provision for Rate Refunds	(4,818)	4,818	(31,019)
Extraordinary Gain - Discontinuance of SFAS 71	(8,938)	-	-
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(166,911)	10,989	(1,562)
Fuel, Materials and Supplies	18,487	(4,812)	(5,006)
Accrued Utility Revenues	(13,081)	(7,433)	5,223
Accounts Payable	159,369	(9,273)	14,066
Taxes Accrued	14,220	13,319	(5,830)
Revenue Refunds Accrued	181	(95,267)	91,956
Incentive Plan Accrued	10,662	1,507	(3,429)
Disputed Tax and Interest Related to COLI	72,440	(4,124)	(68,316)
Change in Operating Reserves	(19,770)	7,451	10,052
Net Change in Energy Trading Contracts	3,749	(14,531)	3,529
Rate Stabilization Deferral	75,601	-	-
Other (net)	(9,647)	(24,681)	13,011
Net Cash Flows From Operating Activities	287,869	192,262	283,450
INVESTING ACTIVITIES:			
Construction Expenditures	(199,285)	(211,416)	(204,869)
Proceeds from Sales of Property and Other	159	19,296	2,930
Net Cost of Removal and Other	(7,500)	(24,373)	(9,286)
Net Cash Flows Used For Investing Activities	(206,626)	(216,493)	(211,225)
FINANCING ACTIVITIES:			
Capital Contributions from Parent Company	-	50,000	50,000
Issuance of Long-term Debt	74,788	227,236	211,944
Retirement of Cumulative Preferred Stock	(9,924)	(2,675)	(294)
Retirement of Long-term Debt	(136,166)	(116,688)	(157,973)
Change in Short-term Debt (net)	68,015	47,080	(53,900)
Change in Advances to Affiliates	(8,387)	-	-
Dividends Paid on Common Stock	(126,612)	(121,392)	(118,916)
Dividends Paid on Cumulative Preferred Stock	(1,938)	(2,257)	(2,278)
Net Cash Flows From (Used For) Financing Activities	(140,224)	81,304	(71,417)
Net Increase (Decrease) in Cash and Cash Equivalents	(58,981)	57,073	808
Cash and Cash Equivalents January 1	64,828	7,755	6,947
Cash and Cash Equivalents December 31	$ 5,847	$ 64,828	$ 7,755

Supplemental Disclosure:
Cash paid for interest net of capitalized amounts was $124,579,000, $125,900,000 and $124,027,000 and for income taxes was $63,682,000, $55,157,000 and $65,102,000 in 2000, 1999 and 1998, respectively. Noncash acquisitions under capital leases were $14,116,000, $13,868,000 and $21,146,000 in 2000, 1999 and 1998, respectively.

See Notes to Consolidated Financial Statements Beginning on Page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

Consolidated Statements of Retained Earnings

	2000	1999	1998
	Year Ended December 31, (in thousands)		
Retained Earnings January 1	$175,854	$179,461	$207,544
Net Income	73,844	120,492	93,330
	249,698	299,953	300,874
Deductions:			
Cash Dividends Declared:			
Common Stock	126,612	121,392	118,916
Cumulative Preferred Stock:			
4-1/2% Series	811	850	875
5.90% Series	307	425	455
5.92% Series	364	364	364
6.85% Series	289	579	579
Total Cash Dividends Declared	128,383	123,610	121,189
Capital Stock Expense	731	489	224
Total Deductions	129,114	124,099	121,413
Retained Earnings December 31	$120,584	$175,854	$179,461

See Notes to Consolidated Financial Statements Beginning on Page L-1.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Capitalization

						December 31, 2000	December 31, 1999
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						$1,096,260	$1,150,571
PREFERRED STOCK - authorized shares 8,000,000 no par value							
Series(a)	Call Price December 31, 2000 (b)	Number of Shares Redeemed Year Ended December 31, 2000	1999	1998	Shares Outstanding December 31, 2000		
Not Subject to Mandatory Redemption:							
4-1/2%	$110.00	7,011	8,671	3,878	177,905	17,790	18,491
Subject to Mandatory Redemption:							
5.90% (c)	(e)	10,000	20,000	-	47,100	4,710	5,710
5.92% (c)	(e)	-	-	-	61,500	6,150	6,150
6.85% (d)	(f)	84,500	-	-	-	-	8,450
						10,860	20,310
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						739,015	844,472
Installment Purchase Contracts						234,782	264,217
Senior Unsecured Notes						468,113	392,844
Junior Debentures						161,367	161,228
Other Long-term Debt						2,541	2,546
Less Portion Due Within One Year						(175,006)	(126,005)
Long-term Debt Excluding Portion Due Within One Year						1,430,812	1,539,302
TOTAL CAPITALIZATION						$2,555,722	$2,728,674

(a) The sinking fund provisions of each series subject to mandatory redemption have been met by purchase of shares in advance of the due date.
(b) The cumulative preferred stock is callable at the price indicated plus accrued dividends. The involuntary liquidation preference is $100 per share. The aggregate involuntary liquidation price for all shares of cumulative preferred stock may not exceed $300 million. The unissued shares of the cumulative preferred stock may or may not possess mandatory redemption characteristics upon issuance.
(c) Commencing in 2003 and continuing through 2007 APCo may redeem at $100 per share 25,000 shares of the 5.90% series and 30,000 shares of the 5.92% series outstanding under sinking fund provisions at its option and all outstanding shares must be reacquired in 2008. Shares redeemed in 2000 and 1999 may be applied to meet the sinking fund requirement.
(d) Commencing in 2000 and continuing through date of redemption, a sinking fund for the 6.85% cumulative preferred stock will require the redemption of 60,000 shares each year, in each case at $100 per share. The Company has the non-cumulative option to redeem up to 60,000 additional shares on any sinking fund date at a redemption price of $100 per share.
(e) Not callable until after 2002.
(f) This series of preferred stock was redeemed in 2000.

See Notes to Consolidated Financial Statements Beginning on Page L-1.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
6.35	2000 - March 1	$ -	$ 48,000
6.71	2000 - June 1	-	48,000
6-3/8	2001 - March 1	100,000	100,000
7.38	2002 - August 15	50,000	50,000
7.40	2002 - December 1	30,000	30,000
6.65	2003 - May 1	40,000	40,000
6.85	2003 - June 1	30,000	30,000
6.00	2003 - November 1	30,000	30,000
7.70	2004 - September 1	21,000	21,000
7.85	2004 - November 1	50,000	50,000
8.00	2005 - May 1	50,000	50,000
6.89	2005 - June 22	30,000	30,000
6.80	2006 - March 1	100,000	100,000
8.50	2022 - December 1	70,000	70,000
7.80	2023 - May 1	30,237	30,237
7.15	2023 - November 1	20,000	20,000
7.125	2024 - May 1	45,000	50,000
8.00	2025 - June 1	45,000	50,000
Unamortized Discount		(2,222)	(2,765)
Total		$739,015	$844,472

Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into, in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
Industrial Development Authority of Russell County, Virginia:			
7.70	2007 - November 1	$ 17,500	$ 17,500
5.00	2021 - November 1	19,500	19,500
Putnam County, West Virginia:			
5.45	2019 - June 1	40,000	40,000
6.60	2019 - July 1	30,000	30,000
Mason County, West Virginia:			
7-7/8	2013 - November 1	10,000	10,000
7.40	2014 - January 1	-	30,000
6.85	2022 - June 1	40,000	40,000
6.60	2022 - October 1	50,000	50,000
6.05	2024 - December 1	30,000	30,000
Unamortized Discount		(2,218)	(2,783)
Total		$234,782	$264,217

Under the terms of the installment purchase contracts, APCo is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
(a)	2001 - June 27	$ 75,000	$ -
7.45	2004 - November 1	50,000	50,000
6.60	2009 - May 1	150,000	150,000
7.20	2038 - March 31	100,000	100,000
7.30	2038 - June 30	100,000	100,000
Unamortized Discount		(6,887)	(7,156)
Total		$468,113	$392,844

(a) A floating interest rate is determined monthly. The rate on December 31, 2000 was 6.95%.

Junior debentures outstanding were as follows:

	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
8-1/4% Series A due 2026 - September 30	$ 75,000	$ 75,000
8% Series B due 2027 - March 31	90,000	90,000
Unamortized Discount	(3,633)	(3,772)
Total	$161,367	$161,228

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of the Company.

At December 31, 2000, future annual long-term debt payments are as follows:

	Amount (in thousands)
2001	$ 175,006
2002	80,006
2003	100,007
2004	121,008
2005	80,010
Later Years	1,064,741
Total Principal Amount	1,620,778
Unamortized Discount	(14,960)
Total	$1,605,818

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
Index to Notes to Consolidated Financial Statements

The notes listed below are combined with the notes to financial statements for AEP and its other subsidiary registrants. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Appalachian Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Appalachian Power Company and its subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Appalachian Power Company and its subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 26, 2001

-This page intentionally left blank.-

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES

-This page intentionally left blank.-

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES

Selected Consolidated Financial Data

	Year Ended December 31, 2000	1999	1998 (in thousands)	1997	1996
INCOME STATEMENTS DATA:					
Operating Revenues	$1,771,177	$1,482,475	$1,406,117	$1,376,282	$1,300,688
Operating Expenses	1,464,079	1,188,490	1,123,330	1,124,963	1,019,498
Operating Income	307,098	293,985	282,787	251,319	281,190
Nonoperating Income (Loss)	7,235	8,113	760	8,277	(11,145)
Income Before Interest Charges	314,333	302,098	283,547	259,596	270,045
Interest Charges	124,766	114,380	122,036	131,173	127,451
Income Before Extraordinary Item	189,567	187,718	161,511	128,423	142,594
Extraordinary Loss	-	(5,517)	-	-	-
Net Income	189,567	182,201	161,511	128,423	142,594
Preferred Stock Dividend Requirements	241	6,931	6,901	9,523	13,563
Gain (Loss) on Reacquired Preferred Stock	-	(2,763)	-	2,402	-
Earnings Applicable to Common Stock	$ 189,326	$ 172,507	$ 154,610	$ 121,302	$ 129,031

	December 31, 2000	1999	1998 (in thousands)	1997	1996
BALANCE SHEETS DATA:					
Electric Utility Plant	$5,592,444	$5,511,894	$5,336,191	$5,215,749	$5,116,570
Accumulated Depreciation and Amortization	2,297,189	2,247,225	2,072,686	1,891,406	1,732,252
Net Electric Utility Plant	$3,295,255	$3,264,669	$3,263,505	$3,324,343	$3,384,318
Total Assets	$5,472,496	$4,847,850	$4,735,476	$4,897,380	$4,919,014
Common Stock and Paid-in Capital	$ 573,888	$ 573,888	$ 573,888	$ 573,888	$ 573,888
Retained Earnings	792,219	758,894	734,387	828,777	864,475
Total Common Shareholder's Equity	$1,366,107	$1,332,782	$1,308,275	$1,402,665	$1,438,363
Preferred Stock	$ 5,967	$ 5,967	$ 163,204	$ 163,204	$ 250,351
CPL - Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Dentures of CPL	148,500	150,000	150,000	150,000	-
Long-term Debt (a)	$1,454,559	$1,454,541	$1,350,706	$1,414,335	$1,613,805
Total Capitalization and Liabilities	$5,472,496	$4,847,850	$4,735,476	$4,897,380	$4,919,014

(a) Including portion due within one year.

CPL is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power and provides electric power to approximately 680,000 retail customers in southern Texas. CPL also sells electric power at wholesale to other utilities, municipalities and rural electric cooperatives. CPL participates in power marketing and trading activities conducted on its behalf by the AEP System.

CPL shares in the revenues and costs of the AEP Power Pool's wholesale sales to and net forward trades with other utility systems and power marketers. Revenues from trading of electricity are recorded net of purchases as operating revenues.

Results of Operations

Income before extraordinary item increased $2 million or 1% in 2000 primarily as a result of increased retail energy sales, the post merger implementation of AEP's power marketing and trading operations which increased wholesale sales to neighboring utilities and power marketers and the effect of an unfavorable adjustment in 1999 as a result of FERC's approval of a transmission coordination agreement. These items were offset in part by a rise in interest expense. Income before extraordinary item increased $26 million or 16% in 1999 as a result of lower interest charges and increased retail sales. In 1999 CPL recorded an extraordinary loss as a result of a write-off of unamortized expenses associated with the reacquisition of long-term debt.

Operating Revenues

Operating revenues increased 19% in 2000 and 5% in 1999. The increase in 2000 was primarily due to an increase in fuel-related revenues and a rise in energy sales. Increases in retail and transmission revenues were the primary reasons for the increase in 1999.

The following analyzes the changes in operating revenues:

(dollars in millions)	Increase (Decrease) From Previous Year			
	2000		1999	
	Amount	%	Amount	%
Retail:				
Residential	$109.5		$13.4	
Commercial	66.9		16.1	
Industrial	39.5		21.1	
Other	6.9		3.7	
	222.8	17	54.3	4
Wholesale	64.8	85	9.2	14
Transmission and Other	1.1	1	12.9	15
Total	$288.7	19	$76.4	5

Retail operating revenues increased 17% in 2000 due to an increase in fuel and purchased power related revenues, reflecting rising prices for natural gas and purchased power, and an increase in weather-related demand for electricity. In 1999 an increase in fuel and purchased power related revenues and a modest increase in usage accounted for the increase in retail revenues. The increase in 1999 revenues was partially offset by a reduction in base rates resulting from a PUCT rate order. Since the Texas fuel and purchased power clause recovery mechanism provides for the accrual of revenues to recover fuel and purchased power cost increases until reviewed and approved for billing to customers by the PUCT, increases in fuel and purchased power expenses and related accrued revenues do not adversely affect results of operations.

The significant increase in wholesale revenues in 2000 is attributable to increased sales to other utilities and CPL's initial participation after the merger in the AEP System's power marketing and trading operations. The volume of electricity sales to other utilities, both affiliated and unaffiliated, increased as demand for energy rose in response to warmer summer weather. Since CPL became a subsidiary of AEP as a result of the merger in June 2000, CPL shares in the AEP System's power marketing and trading transactions with other non-affiliated entities. Trading involves the purchase and sale of substantial amounts of electricity with non-affiliated parties. Revenues from trading are recorded net of purchases.

Operating Expenses Increase

Total operating expenses increased 23% in 2000 and 6% in 1999 primarily due to increased costs of fuel and purchased power and a rise in other operation expense. The changes in the components of operating expenses were:

(dollars in millions)	Increase (Decrease) From Previous Year			
	2000		1999	
	Amount	%	Amount	%
Fuel	$146.9	36	$ 18.0	5
Purchased Power	109.2	160	28.1	70
Other Operation	28.4	10	30.1	12
Maintenance	(9.6)	(14)	6.4	10
Depreciation and Amortization	1.1	1	(7.1)	(4)
Taxes Other Than Federal Income Taxes	(4.5)	(5)	13.6	19
Federal Income Taxes	4.1	4	(23.9)	(21)
Total	$275.6	23	$ 65.2	6

Fuel expense increased in 2000 and 1999 primarily due to a rise in the average cost of fuel primarily from a large increases in natural gas prices. CPL uses natural gas as fuel for 71% of its generating capacity. The nature of the natural gas market is such that both long-term and short-term contracts are generally based on the current spot market price. Changes in natural gas prices affect CPL's fuel expense, however, as explained above, they generally do not impact results of operations.

The rise in purchased power expense in 2000 was due to an increase in the cost of purchased electricity as a result of the rise in spot market natural gas prices, an increase in the quantity of energy purchased to meet the rise in demand, and increased cogeneration purchases. Purchased power expense increased 70% in 1999 due primarily to higher economy energy purchases reflecting the rise in natural gas prices.

Other operation expense increased in 2000 due primarily to an increase in transmission expenses that resulted from new prices for the ERCOT transmission grid. Each year ERCOT establishes new rates to allocate the costs of the Texas transmission system to Texas electric utilities. In addition to higher transmission expenses, other operation expense increased due to higher administrative expenses resulting from the Company's share of STP voluntary severance expenses and Texas regulatory expenses.

In 1999 the increase in other operation expense was caused mainly by a rise in outside service expenses associated with the Texas Legislation and securitization of generation-related regulatory assets, as well as higher transmission expenses. The increase in transmission expense was due primarily to the settlement of a complaint with Texas Utilities Electric Company and the absence in 1999 of a transmission service agreement adjustment made in 1998 related to a final order by the PUCT on a joint complaint filed by CPL and WTU asserting that Texas Utilities Electric Company had been effectively double charging for transmission service within ERCOT.

Maintenance expenses decreased in 2000 and increased in 1999 as a result of a 10-year service inspection and refueling of STP Units 1 and 2 performed in 1999. Also contributing to the increase in maintenance expense in 1999 were scheduled power plant repairs at some of CPL's other generating plants.

Taxes other than income taxes increased in 1999 due primarily to higher franchise tax expenses.

Federal income tax expense associated with utility operations decreased in 1999 as a result of reduced taxable income, the reclassification of certain income tax related regulatory assets designated for securitization consistent with the Texas Legislation, and prior year income tax liability adjustments.

Interest Charges

The increase in interest charges in 2000 can be attributed to higher average interest rates associated with short term and long term debt. Interest charges decreased in 1999 due primarily to the maturity and reacquisition of long-term debt during 1998 and 1999.

Preferred Stock Dividends

Preferred stock dividends decreased in 2000 as a result of the redemption of preferred stock in the fourth quarter of 1999, which resulted in a loss on reacquired preferred stock recorded in 1999.

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES
Consolidated Statements of Income

	2000	1999	1998
	Year Ended December 31, (in thousands)		
OPERATING REVENUES	$1,771,177	$1,482,475	$1,406,117
OPERATING EXPENSES:			
Fuel	550,903	403,989	385,944
Purchased Power	177,387	68,155	40,062
Other Operation	319,539	291,131	261,058
Maintenance	60,528	70,165	63,779
Depreciation and Amortization	178,786	177,702	184,805
Taxes Other Than Federal Income Taxes	80,009	84,538	70,927
Federal Income Tax	96,927	92,810	116,755
Total Operating Expenses	1,464,079	1,188,490	1,123,330
OPERATING INCOME	307,098	293,985	282,787
NONOPERATING INCOME	7,235	8,113	760
INCOME BEFORE INTEREST CHARGES	314,333	302,098	283,547
INTEREST CHARGES	124,766	114,380	122,036
INCOME BEFORE EXTRAORDINARY ITEM	189,567	187,718	161,511
EXTRAORDINARY LOSS ON REACQUIRED DEBT (INCLUSIVE OF TAX $2,971,000)	-	(5,517)	-
NET INCOME	189,567	182,201	161,511
PREFERRED STOCK DIVIDEND REQUIREMENTS	241	6,931	6,901
LOSS ON REACQUIRED PREFERRED STOCK	-	(2,763)	-
EARNINGS APPLICABLE TO COMMON STOCK	$ 189,326	$ 172,507	$ 154,610

See Notes to Consolidated Financial Statements beginning on page L-1.

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 2000	December 31, 1999
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$3,175,867	$3,152,319
Transmission	581,931	566,629
Distribution	1,221,750	1,157,091
General	237,764	307,378
Construction Work in Progress	138,273	101,550
Nuclear Fuel	236,859	226,927
Total Electric Utility Plant	5,592,444	5,511,894
Accumulated Depreciation and Amortization	2,297,189	2,247,225
NET ELECTRIC UTILITY PLANT	3,295,255	3,264,669
OTHER PROPERTY AND INVESTMENTS	44,225	41,433
LONG-TERM ENERGY TRADING CONTRACTS	66,231	-
CURRENT ASSETS:		
Cash and Cash Equivalents	14,253	7,995
Special Deposits for Reacquisition of Long-term Debt	-	50,000
Accounts Receivable:		
General	67,787	49,228
Affiliated Companies	31,272	15,254
Allowance for Uncollectible Accounts	(1,675)	-
Fuel Inventory - at LIFO cost	22,842	26,434
Materials and Supplies - at average cost	53,108	58,196
Under-recovered Fuel Costs	127,295	30,423
Energy Trading Contracts	481,206	-
Prepayments	3,014	3,188
TOTAL CURRENT ASSETS	799,102	240,718
REGULATORY ASSETS	202,440	223,359
REGULATORY ASSETS DESIGNATED FOR SECURITIZATION	953,249	953,249
NUCLEAR DECOMMISSIONING TRUST FUND	93,592	86,122
DEFERRED CHARGES	18,402	38,300
TOTAL	$5,472,496	$4,847,850

See Notes to Consolidated Financial Statements beginning on page L-1.

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES

	December 31, 2000	December 31, 1999
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - $25 Par Value:		
Authorized - 12,000,000 Shares		
Outstanding - 6,755,535 Shares	$ 168,888	$ 168,888
Paid-in Capital	405,000	405,000
Retained Earnings	792,219	758,894
Total Common Shareholder's Equity	1,366,107	1,332,782
Preferred Stock	5,967	5,967
CPL - Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of CPL	148,500	150,000
Long-term Debt	1,254,559	1,304,541
TOTAL CAPITALIZATION	2,775,133	2,793,290
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	200,000	150,000
Advances from Affiliates	269,712	322,158
Accounts Payable - General	128,957	88,702
Accounts Payable - Affiliated Companies	40,962	35,344
Taxes Accrued	55,526	41,121
Interest Accrued	26,217	14,723
Energy Trading Contracts	489,888	-
Other	40,630	25,349
TOTAL CURRENT LIABILITIES	1,251,892	677,397
DEFERRED INCOME TAXES	1,242,797	1,234,175
DEFERRED INVESTMENT TAX CREDITS	128,100	133,306
LONG-TERM ENERGY TRADING CONTRACTS	65,740	-
DEFERRED CREDITS	8,834	9,682
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$5,472,496	$4,847,850

See Notes to Consolidated Financial Statements beginning on page L-1.

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2000	1999 (in thousands)	1998
OPERATING ACTIVITIES:			
Net Income	$ 189,567	$ 182,201	$ 161,511
Adjustments for Noncash Items:			
Depreciation and Amortization	178,786	177,702	184,805
Refunds Due Customers	-	-	(63,713)
Changes for Investments and Assets	-	-	18,669
Extraordinary Loss on Reacquired Debt	-	5,517	-
Deferred Federal Income Taxes	16,263	19,938	(8,328)
Deferred Investment Tax Credits	(5,207)	(5,207)	(3,858)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(32,902)	(13,426)	10,255
Fuel, Materials and Supplies	8,680	(4,476)	(48)
Interest Accrued	11,494	(12,313)	(1,343)
Fuel Recovery	(96,872)	(40,046)	52,364
Accounts Payable	45,873	(3,061)	41,179
Taxes Accrued	14,405	(5,734)	33,297
Transmission Coordination Agreement Settlement	15,519	(15,519)	-
Other (net)	21,023	19,420	12,839
Net Cash Flows From Operating Activities	366,629	304,996	437,629
INVESTING ACTIVITIES:			
Construction Expenditures	(199,484)	(210,823)	(123,803)
Proceeds from Sales of Property and Other	-	15,063	(7,181)
Net Cash Flows Used For Investing Activities	(199,484)	(195,760)	(130,984)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	149,248	358,887	-
Redemption of Preferred Stock	-	(160,001)	-
Retirement of Long-term Debt	(151,440)	(261,700)	(64,000)
Change in Advances from Affiliates (net)	(52,446)	161,860	17,517
Special Deposit for Reacquisitions	50,000	(50,000)	-
Dividends Paid on Common Stock	(156,000)	(148,000)	(249,000)
Dividends Paid on Cumulative Preferred Stock	(249)	(7,835)	(7,219)
Net Cash Flows Used For Financing Activities	(160,887)	(106,789)	(302,702)
Net Increase in Cash and Cash Equivalents	6,258	2,447	3,943
Cash and Cash Equivalents January 1	7,995	5,548	1,605
Cash and Cash Equivalents December 31	$ 14,253	$ 7,995	$ 5,548

Supplemental Disclosure:
Cash paid for interest net of capitalized amounts (including distributions on Trust Preferred Securities) was $110,010,000, $125,222,000 and $99,239,000 and for income taxes was $48,141,000, $78,393,000 and $94,245,000 in 2000, 1999 and 1998, respectively.

See Notes to Consolidated Financial Statements beginning on page L-1.

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES
Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2000	1999 (in thousands)	1998
BALANCE AT BEGINNING OF PERIOD AS PREVIOUSLY REPORTED	$764,225	$739,031	$833,282
CONFORMING CHANGE IN ACCOUNTING POLICY	(5,331)	(4,644)	(4,505)
ADJUSTED BALANCE AT BEGINNING OF PERIOD	758,894	734,387	828,777
NET INCOME	189,567	182,201	161,511
DEDUCTIONS:			
Cash Dividends Declared:			
Common Stock	156,000	148,000	249,000
Preferred Stock	241	6,931	6,901
Other	1	-	-
LOSS ON REACQUIRED PREFERRED STOCK	-	(2,763)	-
BALANCE AT END OF PERIOD	$792,219	$758,894	$734,387

See Notes to Consolidated Financial Statements beginning on page L-1.

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES
Consolidated Statements of Capitalization

						December 31, 2000	December 31, 1999
						(in thousands)	
COMMON SHAREHOLDERS' EQUITY						$1,366,107	$1,332,782
PREFERRED STOCK - authorized shares 3,035,000 $100 par value							
Series	Call Price December 31, 2000	Number of Shares Redeemed Year Ended December 31, 2000	1999	1998	Shares Outstanding December 31, 2000		
Not Subject to Mandatory Redemption:							
4.00%	$105.75	-	-	-	42,038	4,204	4,204
4.20%	103.75	-	-	-	17,476	1,748	1,748
Premium						15	15
Total Preferred Stock						5,967	5,967
TRUST PREFERRED SECURITIES:							
CPL-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of CPL, 8.00%, due April 30, 2037						148,500	150,000
LONG-TERM (See Schedule of Long-term Debt):							
First Mortgage Bonds						615,000	764,991
Installment Purchase Contracts						489,559	489,550
Senior Unsecured Notes						350,000	200,000
Less Portion Due Within One year						(200,000)	(150,000)
Long-term Debt Excluding Portion Due Within One Year						1,254,559	1,304,541
TOTAL CAPITALIZATION						$2,775,133	$2,793,290

See Notes to Consolidated Financial Statements beginning on page L-1.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2000	1999
		(in thousands)	
7.50	2020 - March 1	$ -	$ 50,000
7.25	2004 - October 1	100,000	100,000
7.50	2002 - December 1	115,000	115,000
6-7/8	2003 - February 1	50,000	50,000
7-1/8	2008 - February 1	75,000	75,000
6.00	2000 - April 1	-	100,000
7.50	2023 - April 1	75,000	75,000
6-5/8	2005 - July 1	200,000	200,000
Unamortized Discount		-	(9)
Total		$615,000	$764,991

Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	December 31, 2000	1999
		(in thousands)	
Matagorda County Naviagation District, Texas:			
6.00	2028 - July 1	$120,265	$120,265
6.10	2028 - July 1	100,635	100,635
6-1/8	2030 - May 1	60,000	60,000
4.90	2030 - May 1	111,700	111,700
4.95	2030 - May 1	50,000	50,000
Guadalupe-Blanco River Authority District, Texas:			
(a)	2015 - November 1	40,890	40,890
Red River Authority District, Texas:			
6.00	2020 - June 1	6,330	6,330
Unamortized Discount		(261)	(270)
Total		$489,559	$489,550

(a) A floating interest rate is determined monthly. The rate on December 31, 2000 was 4.90%.

Under the terms of the installment purchase contracts, CPL is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2000	1999
		(in thousands)	
(b)	2001 - November 23	$200,000	$200,000
(c)	2002 - February 22	150,000	-
Total		$350,000	$200,000

(b) A floating interest rate is determined monthly. The rate on December 31, 2000 was 7.35063%.
(c) A floating interest rate is determined monthly. The rate on December 31, 2000 was 7.20313%.

At December 31, 2000, future annual long-term debt payments are as follows:

	Amount (in thousands)
2001	$ 200,000
2002	265,000
2003	50,000
2004	100,000
2005	200,000
Later Years	639,820
Total Principal Amount	1,454,820
Unamortized Discount	(261)
Total	$1,454,559

CENTRAL POWER AND LIGHT COMPANY AND SUBSIDIARIES
Index to Notes to Consolidated Financial Statements

The notes listed below are combined with the notes to financial statements for AEP and its other subsidiary registrants. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors
of Central Power and Light Company:

We have audited the accompanying consolidated balance sheet and consolidated statement of capitalization of Central Power and Light Company and subsidiary as of December 31, 2000, and the related consolidated statements of income, retained earnings, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The consolidated financial statements of the Company for the years ended December 31, 1999 and 1998, before the restatement described in Note 3 to the consolidated financial statements, were audited by other auditors whose report, dated February 25, 2000, expressed an unqualified opinion on those statements.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the 2000 consolidated financial statements present fairly, in all material respects, the financial position of Central Power and Light Company and subsidiary as of December 31, 2000, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

We also audited the adjustments described in Note 3 that were applied to restate the 1999 and 1998 consolidated financial statements to give retroactive effect to the conforming change in the method of accounting for vacation pay accruals. In our opinion, such adjustments are appropriate and have been properly applied.

Deloitte & Touche LLP
Columbus, Ohio
February 26, 2001

-This page intentionally left blank.-

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

-This page intentionally left blank.-

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
Selected Consolidated Financial Data

	Year Ended December 31, (in thousands)				
	2000	1999	1998	1997	1996
INCOME STATEMENTS DATA:					
Operating Revenues	$1,356,408	$1,229,994	$1,187,745	$1,094,851	$1,105,683
Operating Expenses	1,160,531	1,007,204	975,534	899,724	920,136
Operating Income	195,877	222,790	212,211	195,127	185,547
Nonoperating Income (Loss)	5,153	2,709	(1,343)	3,137	(970)
Income Before Interest Charges	201,030	225,499	210,868	198,264	184,577
Interest Charges (net)	80,828	75,229	77,824	78,885	77,469
Income Before Extraordinary Item	120,202	150,270	133,044	119,379	107,108
Extraordinary Item	(25,236)	-	-	-	-
Net Income	94,966	150,270	133,044	119,379	107,108
Preferred Stock Dividend Requirements	1,783	2,131	2,131	2,442	6,029
Earnings Applicable to Common Stock	$ 93,183	$ 148,139	$ 130,913	$ 116,937	$ 101,079

	December 31, (in thousands)				
	2000	1999	1998	1997	1996
BALANCE SHEETS DATA:					
Electric Utility Plant	$3,266,794	$3,151,619	$3,053,565	$2,976,110	$2,899,893
Accumulated Depreciation	1,299,697	1,210,994	1,134,348	1,074,588	1,016,909
Net Electric Utility Plant	$1,967,097	$1,940,625	$1,919,217	$1,901,522	$1,882,984
Total Assets	$3,894,934	$2,809,990	$2,681,690	$2,613,860	$2,541,586
Common Stock and Paid-in Capital	$ 614,380	$ 613,899	$ 613,518	$ 613,138	$ 615,735
Retained Earnings	99,069	246,584	186,441	138,172	99,582
Total Common Shareholder's Equity	$ 713,449	$ 860,483	$ 799,959	$ 751,310	$ 715,317
Cumulative Preferred Stock - Subject to Mandatory Redemption (a)	$ 15,000	$ 25,000	$ 25,000	$ 25,000	$ 75,000
Long-term Debt (a)	$ 899,615	$ 924,545	$ 959,786	$ 969,600	$ 897,281
Obligations Under Capital Leases (a)	$ 42,932	$ 40,270	$ 42,362	$ 38,587	$ 36,134
Total Capitalization and Liabilities	$3,894,934	$2,809,990	$2,681,690	$2,613,860	$2,541,586

(a) Including portion due within one year.

Columbus Southern Power Company is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power to 667,000 retail customers in central and southern Ohio. CSPCo as a member of the AEP Power Pool shares in the revenues and costs of the AEP Power Pool's wholesale sales to neighboring utility systems and power marketers. CSPCo also sells wholesale power to municipalities.

The cost of the AEP System's generating capacity is allocated among the AEP Power Pool members based on their relative peak demands and generating reserves through the payment of capacity charges and receipt of capacity credits. AEP Power Pool members are also compensated for their out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool.

The AEP Power Pool calculates each company's prior twelve month peak demand relative to the total peak demand of all member companies as a basis for sharing AEP Power Pool revenues and costs. The result of this calculation is the member load ratio (MLR) which determines each company's percentage share of AEP Power Pool revenues and costs. CSPCo as a member of the AEP Power Pool shares in the revenues and costs of the AEP Power Pool's wholesale sales to and net forward trades with other utility systems and power marketers. Revenues from forward electricity trades are recorded net of purchases as operating revenues for transactions in AEP's traditional marketing area (up to two transmission systems from the AEP service territory) and as nonoperating income for transactions beyond two transmission systems from AEP. The AEP Power Pool also enters into power trading transactions for options, futures and swaps. CSPCo's share of these transactions is recorded in nonoperating income.

In February 2001 the U.S. District Court for the Southern District of Ohio ruled against AEP and certain of its subsidiaries, including CSPCo, in a suit over deductibility of interest claimed in AEP's consolidated tax return related to a corporate owned life insurance (COLI) program. In 1998 and 1999 CSPCo paid the disputed taxes and interest attributable to the COLI interest deductions for taxable years 1991-98. The payments were included in Other Property and Investments pending the resolution of this matter. As a result of the Court's decision, net income was reduced by $41 million in 2000.

Results of Operations
Net Income Decreases

Income before extraordinary item decreased by $30 million or 20% primarily due to increases in federal income tax expense and related interest charges as a result of the U.S. District Court's decision denying COLI deductions. An extraordinary loss related to the discontinuance of SFAS 71 regulatory accounting of $25 million after tax was recorded in September 2000 in connection with the PUCO approval of a plan to transition CSPCo's generation business from cost based rate regulation to customer choice and market pricing.

Operating Revenues Increase

Operating revenues increased $126.4 million in 2000 due to a significant increase in AEP Power Pool wholesale marketing and trading transactions. Changes in the components of operating revenues were as follows:

(dollars in millions)	Increase (Decrease) From Previous Year Amount	%
Retail:		
Residential	$ 0.8	
Commercial	14.1	
Industrial	(6.0)	
Other	0.9	
Wholesale	123.5	102.6
Transmission	(0.1)	(0.2)
Other	(6.8)	(32.1)
Total	$126.4	10.3

The increase in wholesale revenues is due to a significant increase in AEP Power Pool transactions. As a result of a major industrial customer's decision in January 2000 not to continue purchasing power from an affiliate, additional power was available to the AEP Power Pool for sale on the wholesale market accounting in part for the increase in the CSPCo's wholesale Power Pool revenues. The increase in AEP Power Pool wholesale sales also resulted from growing AEP's power marketing and trading operation, favorable wholesale market conditions and increased availability of generation. AEP generating unit availability was increased due to the return to service of one of an affiliate's nuclear generating units and improved generating unit outage management. With the return to service in June 2000 of one of an affiliate's two nuclear generating units that affiliate supplied more power to the AEP Power Pool at a lower cost reducing the need to acquire higher cost power on the open market.

Operating Expenses Rise

Operating expenses increased by 15% in 2000 mostly due to increases in purchased power expense, other operation expense and federal income taxes. Changes in the components of operating expenses were:

(dollars in millions)	Increase (Decrease) From Previous Year Amount	%
Fuel	$ 3.6	2.0
Purchased Power Expense	82.2	31.0
Other Operation Expense	31.2	16.3
Maintenance Expense	4.5	6.8
Depreciation	5.1	5.4
Taxes Other Than Federal Income Taxes	3.1	2.6
Federal Income Taxes	23.6	27.5
Total	$153.3	15.2

The increase in other operation expense was due to increased power generation costs that resulted from higher emission allowance consumption, increased emission allowance cost and increased costs for power trading reflecting the growth of the power marketing and trading operation.

The increase in purchased power expense reflects additional purchases of power from the AEP Power Pool as a result of increased availability of AEP Pool generation. The AEP Power Pool was able to supply more energy to CSPCo since an affiliate's out of service nuclear unit went on line in June 2000, a major industrial customer discontinued purchasing power from an affiliate in January 2000, and generating unit outage managements improved.

Additional generating unit boiler repairs and maintenance of overhead transmission and distribution lines accounted for the increase in maintenance expense.

Depreciation expenses increased due to additional plant investment.

The increase in federal income tax expense was primarily due to the court ruling related to the AEP's COLI program.

Nonoperating Income

The increase in nonoperating income in 2000 was due to an increase in net gains from non-regulated AEP Power Pool trading transactions outside of the AEP System's traditional marketing area. The AEP Power Pool enters into power trading transactions for the purchase and sale of electricity and for options, futures and swaps. The Company's share of the AEP Power Pool's gains and losses from forward electricity trading transactions outside of the AEP System traditional marketing area and for speculative financial transactions (options, futures, swaps) is included in nonoperating income. The increase in nonoperating income is also attributable to the reversal in the first quarter of 2000 of a remaining provision for potential liability for clean-up of possible environmental contamination after the state of Ohio reviewed the matter and determined that no further corrective action would be required.

Interest Charges Increase

Interest charges increased as a result of the recognition of deferred interest payments to the IRS related to the COLI disallowances.

Extraordinary Loss

An extraordinary loss was recorded in the third quarter of 2000 when CSPCo discontinued the application of SFAS 71 regulatory accounting for the generation portion of its business due to the approval by the PUCO in September 2000 of a stipulation agreement providing for a transition from cost based rate regulation for CSPCo's generation business to customer choice and market pricing.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

Consolidated Statements of Income

	Year Ended December 31,		
	2000	1999	1998
		(in thousands)	
OPERATING REVENUES	$1,356,408	$1,229,994	$1,187,745
OPERATING EXPENSES:			
Fuel	189,155	185,511	189,031
Purchased Power	347,693	265,457	237,688
Other Operation	221,775	190,614	202,720
Maintenance	69,676	65,229	62,095
Depreciation	99,640	94,532	91,218
Taxes Other Than Federal Income Taxes	123,291	120,147	116,548
Federal Income Taxes	109,301	85,714	76,234
TOTAL OPERATING EXPENSES	1,160,531	1,007,204	975,534
OPERATING INCOME	195,877	222,790	212,211
NONOPERATING INCOME (LOSS)	5,153	2,709	(1,343)
INCOME BEFORE INTEREST CHARGES	201,030	225,499	210,868
INTEREST CHARGES	80,828	75,229	77,824
INCOME BEFORE EXTRAORDINARY ITEM	120,202	150,270	133,044
EXTRAORDINARY LOSS:			
Discontinuance of Regulatory Accounting for Generation (inclusive of tax benefit of $14,148,000)	(25,236)	-	-
NET INCOME	94,966	150,270	133,044
PREFERRED STOCK DIVIDEND REQUIREMENTS	1,783	2,131	2,131
EARNINGS APPLICABLE TO COMMON STOCK	$ 93,183	$ 148,139	$ 130,913

Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2000	1999	1998
		(in thousands)	
Retained Earnings January 1	$246,584	$186,441	$138,172
Net Income	94,966	150,270	133,044
	341,550	336,711	271,216
Deductions:			
Cash Dividends Declared:			
Common Stock	240,600	87,996	82,644
Cumulative Preferred Stock - 7% Series	1,400	1,750	1,750
Total Cash Dividends Declared	242,000	89,746	84,394
Capital Stock Expense	481	381	381
Total Deductions	242,481	90,127	84,775
Retained Earnings December 31	$ 99,069	$246,584	$186,441

See Notes to Consolidated Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 2000	December 31, 1999
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$1,564,254	$1,544,858
Transmission	360,302	350,826
Distribution	1,096,365	1,032,550
General	156,534	141,137
Construction Work in Progress	89,339	82,248
Total Electric Utility Plant	3,266,794	3,151,619
Accumulated Depreciation	1,299,697	1,210,994
NET ELECTRIC UTILITY PLANT	1,967,097	1,940,625
OTHER PROPERTY AND INVESTMENTS	39,848	80,008
LONG-TERM ENERGY TRADING CONTRACTS	172,167	21,278
CURRENT ASSETS:		
Cash and Cash Equivalents	11,600	5,107
Accounts Receivable:		
Customers	73,711	77,418
Affiliated Companies	49,591	28,453
Miscellaneous	18,807	8,887
Allowance for Uncollectible Accounts	(659)	(3,045)
Fuel - at average cost	13,126	21,484
Materials and Supplies - at average cost	38,097	41,696
Accrued Utility Revenues	9,638	48,117
Energy Trading Contracts	1,085,989	90,103
Prepayments	46,735	37,969
TOTAL CURRENT ASSETS	1,346,635	356,189
REGULATORY ASSETS	291,553	339,103
DEFERRED CHARGES	77,634	72,787
TOTAL	$3,894,934	$2,809,990

See Notes to Consolidated Financial Statements beginning on page L-1.

	December 31, 2000	December 31, 1999
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - No Par Value:		
Authorized - 24,000,000 Shares		
Outstanding - 16,410,426 Shares	$ 41,026	$ 41,026
Paid-in Capital	573,354	572,873
Retained Earnings	99,069	246,584
Total Common Shareholder's Equity	713,449	860,483
Cumulative Preferred Stock - Subject to Mandatory Redemption	15,000	25,000
Long-term Debt	899,615	924,545
TOTAL CAPITALIZATION	1,628,064	1,810,028
OTHER NONCURRENT LIABILITIES	47,584	43,056
CURRENT LIABILITIES:		
Short-term Debt	-	45,500
Advances from Affiliates	88,732	-
Accounts Payable - General	89,846	28,279
Accounts Payable - Affiliated Companies	72,493	52,776
Taxes Accrued	162,904	143,477
Interest Accrued	13,369	13,936
Energy Trading Contracts	1,115,967	87,911
Other	60,701	34,375
TOTAL CURRENT LIABILITIES	1,604,012	406,254
DEFERRED INCOME TAXES	422,759	447,607
DEFERRED INVESTMENT TAX CREDITS	41,234	44,716
DEFERRED CREDITS	12,861	41,875
LONG-TERM ENERGY TRADING CONTRACTS	138,420	16,454
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$3,894,934	$2,809,990

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES

Consolidated Statements of Cash Flows

	2000	1999	1998
	Year Ended December 31, (in thousands)		
OPERATING ACTIVITIES:			
Net Income	$ 94,966	$ 150,270	$133,044
Adjustments for Noncash Items:			
Depreciation	100,182	94,962	91,426
Deferred Federal Income Taxes	(4,063)	10,481	17,101
Deferred Investment Tax Credits	(3,482)	(3,994)	(4,224)
Deferred Fuel Costs (net)	5,352	8,889	(11,311)
Extraordinary Loss - Discontinuance of SFAS 71	25,236	-	-
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(29,737)	5,166	(5,910)
Fuel, Materials and Supplies	11,957	(7,777)	(8,226)
Accrued Utility Revenues	38,479	(7,990)	11,638
Accounts Payable	81,284	9,292	476
Disputed Tax and Interest Related to COLI	39,483	(2,240)	(37,243)
Other (net)	7,480	(13,426)	29,776
Net Cash Flows From Operating Activities	367,137	243,633	216,547
INVESTING ACTIVITIES:			
Construction Expenditures	(127,987)	(115,321)	(114,979)
Proceeds from Sale and Leaseback Transactions and Other	1,560	1,858	2,637
Net Cash Flows Used For Investing Activities	(126,427)	(113,463)	(112,342)
FINANCING ACTIVITIES:			
Change in Advances from Affiliates (net)	88,732	-	-
Issuance of Long-term Debt	-	-	111,075
Retirement of Preferred Stock	(10,000)	-	-
Retirement of Long-term Debt	(25,274)	(35,523)	(122,206)
Change in Short-term Debt (net)	(45,500)	(7,000)	(14,100)
Dividends Paid on Common Stock	(240,600)	(87,996)	(82,644)
Dividends Paid on Cumulative Preferred Stock	(1,575)	(1,750)	(1,750)
Net Cash Flows Used For Financing Activities	(234,217)	(132,269)	(109,625)
Net Increase (Decrease) in Cash and Cash Equivalents	6,493	(2,099)	(5,420)
Cash and Cash Equivalents January 1	5,107	7,206	12,626
Cash and Cash Equivalents December 31	$ 11,600	$ 5,107	$ 7,206

Supplemental Disclosure:
Cash paid for interest net of capitalized amounts was $68,506,000, $72,007,000 and $73,917,000 and for income taxes was $81,109,000, $71,809,000 and $53,410,000 in 2000, 1999 and 1998, respectively. Noncash acquisitions under capital leases were $10,777,000, $6,855,000 and $11,107,000 in 2000, 1999 and 1998, respectively.

See Notes to Consolidated Financial Statements beginning on page L-1.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Capitalization

						December 31, 2000	December 31, 1999
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						$ 713,449	$ 860,483
PREFERRED STOCK - authorized shares 2,500,000 $100 par value authorized shares 7,000,000 $25 par value							
Series	Call Price December 31, 2000	Number of Shares Redeemed Year Ended December 31, 2000	1999	1998	Shares Outstanding December 31, 2000		
Subject to Mandatory Redemption:							
7.00%	(a)	100,000	-	-	150,000	15,000	25,000
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						537,119	562,327
Installment Purchase Contracts						91,166	91,112
Senior Unsecured Notes						159,318	159,212
Junior Debentures						112,012	111,894
Total Long-term Debt						899,615	924,545
TOTAL CAPITALIZATION						$1,628,064	$1,810,028

(a) Commencing in 2000, a sinking fund will require the redemption of 50,000 shares at $100 a share on or before August 1 of each year. The Company has the right, on each sinking fund date, to redeem an additional 50,000 shares which the company did in August 2000. Redemption of this series is prohibited prior to August 1, 2000. The sinking fund provisions of the 7% series aggregate $5,000,000 in 2002, 2003 and 2004.

See Notes to Consolidated Financial Statements beginning on page L-1.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
7.25	2002 - October 1	$ 56,500	$ 75,000
7.15	2002 - November 1	20,000	20,000
6.80	2003 - May 1	45,000	50,000
6.60	2003 - August 1	40,000	40,000
6.10	2003 - November 1	20,000	20,000
6.55	2004 - March 1	50,000	50,000
6.75	2004 - May 1	50,000	50,000
8.70	2022 - July 1	35,000	35,000
8.40	2022 - August 1	15,000	15,000
8.55	2022 - August 1	15,000	15,000
8.40	2022 - August 15	25,500	25,500
8.40	2022 - October 15	13,000	15,000
7.90	2023 - May 1	50,000	50,000
7.75	2023 - August 1	33,000	33,000
7.45	2024 - March 1	30,000	30,000
7.60	2024 - May 1	41,000	41,000
Unamortized Discount		(1,881)	(2,173)
Total		$537,119	$562,327

Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into in connection with the issuance of pollution control revenue bonds by the Ohio Air Quality Development Authority:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
6-3/8	2020 - December 1	$48,550	$48,550
6-1/4	2020 - December 1	43,695	43,695
Unamortized Discount		(1,079)	(1,133)
Total		$91,166	$91,112

Under the terms of the installment purchase contracts, CSPCo is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at the Zimmer Plant.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
6.85	2005 - October 3	$ 48,000	$ 48,000
6.51	2008 - February 1	52,000	52,000
6.55	2008 - June 26	60,000	60,000
Unamortized Discount		(682)	(788)
Total		$159,318	$159,212

Junior debentures outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
8-3/8	2025 - September 30	$ 75,000	$ 75,000
7.92	2027 - March 31	40,000	40,000
Unamortized Discount		(2,988)	(3,106)
Total		$112,012	$111,894

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of the Company.

At December 31, 2000, future annual long-term debt payments are as follows:

	Amount (in thousands)
2001	$ -
2002	76,500
2003	105,000
2004	100,000
2005	48,000
Later Years	576,745
Total Principal Amount	906,245
Unamortized Discount	(6,630)
Total	$899,615

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
Index to Notes to Consolidated Financial Statements

The notes listed below are combined with the notes to financial statements for AEP and its other subsidiary registrants. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors
of Columbus Southern Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Columbus Southern Power Company and its subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Columbus Southern Power Company and its subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP
Columbus, Ohio
February 26, 2001

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

-This page intentionally left blank.-

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
Selected Consolidated Financial Data

	Year Ended December 31,				
	2000	1999	1998 (in thousands)	1997	1996
INCOME STATEMENTS DATA:					
Operating Revenues	$1,548,476	$1,394,119	$1,405,794	$1,339,232	$1,328,493
Operating Expenses	1,583,178	1,285,467	1,239,787	1,131,444	1,108,076
Operating Income (Loss)	(34,702)	108,652	166,007	207,788	220,417
Nonoperating Income (Loss)	9,933	4,530	(839)	4,415	2,729
Income (Loss) Before Interest Charges	(24,769)	113,182	165,168	212,203	223,146
Interest Charges	107,263	80,406	68,540	65,463	65,993
Net Income (Loss)	(132,032)	32,776	96,628	146,740	157,153
Preferred Stock Dividend Requirements	4,624	4,885	4,824	5,736	10,681
Earnings (Loss) Applicable to Common Stock	$ (136,656)	$ 27,891	$ 91,804	$ 141,004	$ 146,472

	December 31,				
	2000	1999	1998 (in thousands)	1997	1996
BALANCE SHEETS DATA:					
Electric Utility Plant	$4,871,473	$4,770,027	$4,631,848	$4,514,497	$4,377,669
Accumulated Depreciation and Amortization	2,280,521	2,194,397	2,081,355	1,973,937	1,861,893
Net Electric Utility Plant	$2,590,952	$2,575,630	$2,550,493	$2,540,560	$2,515,776
Total Assets	$5,818,547	$4,576,696	$4,148,523	$3,967,798	$3,897,484
Common Stock and Paid-in Capital	$ 789,656	$ 789,323	$ 789,189	$ 789,056	$ 787,856
Retained Earnings	3,443	166,389	253,154	278,814	269,071
Total Common Shareholder's Equity	$ 793,099	$ 955,712	$1,042,343	$1,067,870	$1,056,927
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$ 8,736	$ 9,248	$ 9,273	$ 9,435	$ 21,977
Subject to Mandatory Redemption (a)	64,945	64,945	68,445	68,445	135,000
Total Cumulative Preferred Stock	$ 73,681	$ 74,193	$ 77,718	$ 77,880	$ 156,977
Long-term Debt (a)	$1,388,939	$1,324,326	$1,175,789	$1,049,237	$1,042,104
Obligations Under Capital Leases (a)	$ 163,173	$ 187,965	$ 186,427	$ 195,227	$ 130,965
Total Capitalization and Liabilities	$5,818,547	$4,576,696	$4,148,523	$3,967,798	$3,897,484

(a) Including portion due within one year.

I&M is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power to 565,000 retail customers in its service territory in northern and eastern Indiana and a portion of southwestern Michigan. As a member of the AEP Power Pool, I&M shares the revenues and the costs of the AEP Power Pool's wholesale sales to neighboring utilities and power marketers. I&M also sells wholesale power to municipalities and electric cooperatives.

The cost of the AEP System's generating capacity is allocated among the AEP Power Pool members based on their relative peak demands and generating reserves through the payment of capacity charges or the receipt of capacity credits. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool.

The AEP Power Pool calculates each company's prior twelve month peak demand relative to the total peak demand of all member companies as a basis for sharing revenues and costs. The result of this calculation is each company's member load ratio (MLR) which determines each company's percentage share of revenues or costs. I&M as a member of the AEP Power Pool shares in the revenues and costs of the AEP Power Pool's wholesale sales to and net forward trades with other utility systems and power marketers. Revenues from forward electricity trades in AEP's traditional marketing area (up to two transmission systems from the AEP service territory) are recorded net of purchases as operating revenues and as nonoperating income for trades beyond two transmission systems from AEP. The AEP Power Pool also enters into power trading transactions for options, futures and swaps. I&M's share of these transactions is recorded in nonoperating income.

I&M is committed under unit power agreements to purchase all of AEGCo's 50% share of the 2,600 MW Rockport Plant capacity unless it is sold to other utilities. AEGCo is an affiliate that is not a member of the AEP Power Pool. A long-term unit power agreement with an unaffiliated utility expired at the end of 1999 for the sale of 455 MW of AEGCo's Rockport Plant capacity. An agreement between AEGCo and KPCo provides for the sale of 390 MW of AEGCo's Rockport Plant capacity to KPCo through 2004. Therefore, effective January 1, 2000, I&M began purchasing 910 MW of AEGCo's 50% share of Rockport Plant capacity.

Results of Operations

During 2000 both of the Cook Plant nuclear units were successfully restarted after being shutdown in September 1997 due to questions regarding the operability of certain safety systems which arose during a NRC architect engineer design inspection. See discussion in Note 4 of the Notes to Consolidated Financial Statements.

In February 2001 the U.S. District Court for the Southern District of Ohio ruled against AEP and certain of its subsidiaries, including I&M, in a suit over deductibility of interest claimed in AEP's consolidated tax return related to a corporate owned life insurance (COLI) program. In 1998 and 1999 I&M paid the disputed taxes and interest attributable to the COLI interest deductions for the taxable years 1991-98. The payments were included in Other Property and Investments pending the resolution of this matter. As a result of the Court's decision, I&M's net income was reduced by $66 million in 2000.

As a result of the costs incurred in 2000 to restart the Cook Plant nuclear units and the disallowance of COLI interest deductions, net income declined $165 million in 2000. In 1999 net income declined $64 million due primarily to the cost of efforts to restart the Cook Plant units.

Operating Revenues

Operating revenues increased 11% in 2000 and decreased 1% in 1999. The increase in operating revenues in 2000 was primarily due to increased wholesale sales to the AEP Power Pool. The decrease in 1999 was primarily due to a decline in margins on wholesale sales and net power trading transactions within the AEP Power Pool's traditional marketing area. The following analyzes the changes in operating revenues:

(dollars in millions)	Increase (Decrease) From Previous Year 2000 Amount	%	1999 Amount	%
Retail:				
Residential	$(37.3)		$ 3.4	
Commercial	(16.2)		0.7	
Industrial	(30.0)		(5.7)	
Other	(5.0)		(0.2)	
	(88.5)	(9)	(1.8)	-
Wholesale	253.7	84	(18.2)	(6)
Transmission and Other	(10.8)	(21)	8.3	20
Total	$154.4	11	$(11.7)	(1)

The increase in operating revenues in 2000 is primarily due to increased wholesale sales to the AEP Power Pool. With the return to service of the Cook Plant units and purchasing more power from AEGCo due to the expiration of AEGCo's contract to sell power to an unaffiliated entity, I&M had more electricity available to sell to the AEP Power Pool. A decline in retail sales and retail price which led to a decrease in retail operating revenues partly offset the increase in wholesale revenues.

Operating revenues decreased slightly in 1999 primarily due to reduced margins on I&M's MLR share of wholesale sales and net revenues from regulated power trading transactions in the AEP Power Pool's traditional marketing area. The decline in margins reflects the moderation in 1999 of extreme weather in 1998 and capacity shortages experienced in the summer of 1998.

Operating Expenses Increase

Total operating expenses increased 23% in 2000 and 4% in 1999 primarily due to costs related to the extended Cook Plant outage and efforts to restart the Cook Plant units. Also contributing to the increase in operating expenses in 2000 was the unfavorable COLI tax ruling and the additional purchases of power due to the expiration of an AEGCo unit power agreement to sell part of its Rockport Plant generation to an unaffiliated utility. The changes in the components of operating expenses were:

(dollars in millions)	Increase (Decrease) From Previous Year 2000 Amount	%	1999 Amount	%
Fuel	$ 25.5	14	$ 12.8	7
Purchased Power	60.4	22	(21.1)	(7)
Other Operation	137.5	30	114.3	33
Maintenance	84.5	62	(22.3)	(14)
Depreciation and Amortization	4.9	3	4.9	3
Taxes Other Than Federal Income Taxes	11.0	19	(8.8)	(13)
Federal Income Taxes	(26.1)	(149)	(34.1)	(66)
Total	$297.7	23	$ 45.7	4

The increase in fuel expense in 2000 reflects an increase in nuclear generation as the Cook Plant units returned to service following an extended outage. Fuel expense increased in 1999 primarily due to an increase in coal-fired generation replacing power purchases from the AEP Power Pool.

Purchased power expense increased in 2000 due to increased purchases from AEGCo. As a result of the expiration of AEGCo's power sale contract with an unaffiliated utility on December 31, 1999, I&M was obligated to buy more of AEGCo's share of Rockport Plant power. The decrease in purchased power expense in 1999 reflects the purchase of less power in 1999 at lower prices from the AEP Power Pool, AEGCo and unaffiliated entities.

The increases in other operation expense in 2000 and 1999 were primarily due to expenditures to prepare the Cook Plant nuclear units for restart.

Maintenance expense increased in 2000 primarily due to expenditures to prepare the Cook Plant units for restart. The decline in maintenance expense in 1999 was due to cost containment efforts including staff reductions at I&M's fossil-fired power plants, in the engineering and maintenance staff of AEP Service Corporation and in I&M's transmission and distribution operations.

In 1999 the IURC and MPSC approved settlement agreements which allowed the deferral of $200 million of Cook Plant restart costs in 1999 for amortization over five years from 1999 through 2003. As a result, other operation and maintenance expense in 1999 reflected a net deferral of $160 million. See discussion in Note 4 of the Notes to Consolidated Financial Statements.

The increase in taxes other than federal income tax in 2000 is primarily attributable to an increase in Indiana supplemental net income tax reflecting the COLI decision related interest deduction disallowance and a favorable accrual adjustment recorded in December 1999 related to the filing of the 1998 tax return. The decrease in taxes other than federal income taxes in 1999 was primarily due to a decline in estimated taxable income for Indiana supplemental income tax.

Federal income taxes attributable to operations decreased in 2000 and 1999 due to decreases in pre-tax operating income. In 2000 the decrease was partially offset by an increase in tax expense related to the unfavorable ruling in the suit against the IRS over interest deductions claimed for the COLI program.

Nonoperating Income

The increase in nonoperating income in 2000 and 1999 is primarily due to the effect of net gains on non-regulated electricity trading transactions. The AEP Power Pool enters into non-regulated transactions for the purchase and sale of electricity options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area. I&M's share of the AEP Power Pool's non-regulated trading transactions are included in nonoperating income.

Interest Charges

Interest charges increased in 2000 and 1999 due to increased borrowings to support expenditures for the Cook Plant restart effort and in 2000 also due to the recognition of deferred interest payments to the IRS on the disputed taxes.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Income

	Year Ended December 31, 2000	1999 (in thousands)	1998
OPERATING REVENUES	$1,548,476	$1,394,119	$1,405,794
OPERATING EXPENSES:			
Fuel	210,870	185,419	172,592
Purchased Power	337,376	276,962	298,046
Other Operation	599,012	461,494	347,207
Maintenance	219,854	135,331	157,593
Depreciation and Amortization	154,920	149,988	145,112
Taxes Other Than Federal Income Taxes	69,761	58,713	67,592
Federal Income Tax Expense (Credit)	(8,615)	17,560	51,645
Total Operating Expenses	1,583,178	1,285,467	1,239,787
OPERATING INCOME (LOSS)	(34,702)	108,652	166,007
NONOPERATING INCOME (LOSS)	9,933	4,530	(839)
INCOME (LOSS) BEFORE INTEREST CHARGES	(24,769)	113,182	165,168
INTEREST CHARGES	107,263	80,406	68,540
NET INCOME (LOSS)	(132,032)	32,776	96,628
PREFERRED STOCK DIVIDEND REQUIREMENTS	4,624	4,885	4,824
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	$ (136,656)	$ 27,891	$ 91,804

See Notes to Consolidated Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 2000	December 31, 1999
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,708,436	$2,587,288
Transmission	945,709	928,758
Distribution	863,736	818,697
General (including nuclear fuel)	257,152	244,981
Construction Work in Progress	96,440	190,303
Total Electric Utility Plant	4,871,473	4,770,027
Accumulated Depreciation and Amortization	2,280,521	2,194,397
NET ELECTRIC UTILITY PLANT	2,590,952	2,575,630
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	778,720	707,967
LONG-TERM ENERGY TRADING CONTRACTS	194,947	23,131
OTHER PROPERTY AND INVESTMENTS	131,417	190,527
CURRENT ASSETS:		
Cash and Cash Equivalents	14,835	3,863
Accounts Receivable:		
Customers	106,832	91,268
Affiliated Companies	48,706	48,901
Miscellaneous	27,491	18,644
Allowance for Uncollectible Accounts	(759)	(1,848)
Fuel - at average cost	16,532	27,597
Materials and Supplies - at average cost	84,471	84,149
Accrued Utility Revenues	-	44,428
Energy Trading Contracts	1,229,683	97,946
Prepayments	6,424	7,631
TOTAL CURRENT ASSETS	1,534,215	422,579
REGULATORY ASSETS	552,140	624,810
DEFERRED CHARGES	36,156	32,052
TOTAL	$5,818,547	$4,576,696

See Notes to Consolidated Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

	December 31, 2000	December 31, 1999
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - No Par Value:		
Authorized - 2,500,000 Shares		
Outstanding - 1,400,000 Shares	$ 56,584	$ 56,584
Paid-in Capital	733,072	732,739
Retained Earnings	3,443	166,389
Total Common Shareholder's Equity	793,099	955,712
Cumulative Preferred Stock:		
Not Subject to Mandatory Redemption	8,736	9,248
Subject to Mandatory Redemption	64,945	64,945
Long-term Debt	1,298,939	1,126,326
TOTAL CAPITALIZATION	2,165,719	2,156,231
OTHER NONCURRENT LIABILITIES:		
Nuclear Decommissioning	560,628	501,185
Other	108,600	242,522
TOTAL OTHER NONCURRENT LIABILITIES	669,228	743,707
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	90,000	198,000
Short-term Debt	-	224,262
Advances from Affiliates	253,582	-
Accounts Payable - General	119,472	78,784
Accounts Payable - Affiliated Companies	75,486	31,118
Taxes Accrued	68,416	48,970
Interest Accrued	21,639	13,955
Obligations Under Capital Leases	100,848	11,072
Energy Trading Contracts	1,275,097	95,564
Other	97,070	91,684
TOTAL CURRENT LIABILITIES	2,101,610	793,409
DEFERRED INCOME TAXES	487,945	622,157
DEFERRED INVESTMENT TAX CREDITS	113,773	121,627
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	81,299	85,005
LONG-TERM ENERGY TRADING CONTRACTS	156,736	17,887
DEFERRED CREDITS	42,237	36,673
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$5,818,547	$4,576,696

See Notes to Consolidated Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2000	1999	1998
		(in thousands)	
OPERATING ACTIVITIES:			
Net Income (Loss)	$(132,032)	$ 32,776	$ 96,628
Adjustments for Noncash Items:			
Depreciation and Amortization	163,391	153,921	149,209
Amortization of Incremental Nuclear Refueling Outage Expenses (net)	5,737	8,480	14,142
Amortization (Deferral) of Nuclear Outage Costs (net)	40,000	(160,000)	-
Deferred Federal Income Taxes	(125,179)	85,727	17,905
Deferred Investment Tax Credits	(7,854)	(8,152)	(8,266)
Unrecovered Fuel and Purchased Power Costs	37,501	(84,696)	(46,846)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(25,305)	(19,178)	1,462
Fuel, Materials and Supplies	10,743	(12,880)	(2,983)
Accrued Utility Revenues	44,428	(7,151)	(6,756)
Accounts Payable	85,056	19,068	22,440
Taxes Accrued	19,446	13,809	(11,689)
Disputed Tax and Interest Related to COLI	56,856	(3,228)	(53,628)
Other (net)	(41,900)	12,831	(8,176)
Net Cash Flows From Operating Activities	130,888	31,327	163,442
INVESTING ACTIVITIES:			
Construction Expenditures	(171,071)	(165,331)	(147,627)
Proceeds from Sales of Property and Other	587	2,501	4,419
Net Cash Flows Used For Investing Activities	(170,484)	(162,830)	(143,208)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	199,220	247,989	170,675
Retirement of Cumulative Preferred Stock	(314)	(3,597)	(120)
Retirement of Long-term Debt	(148,000)	(109,500)	(55,000)
Changes in Advances from Affiliates (net)	253,582	-	-
Change in Short-term Debt (net)	(224,262)	115,562	(10,900)
Dividends Paid on Common Stock	(26,290)	(114,656)	(117,464)
Dividends Paid on Cumulative Preferred Stock	(3,368)	(5,856)	(4,734)
Net Cash Flows From (Used For) Financing Activities	50,568	129,942	(17,543)
Net Increase (Decrease) in Cash and Cash Equivalents	10,972	(1,561)	2,691
Cash and Cash Equivalents January 1	3,863	5,424	2,733
Cash and Cash Equivalents December 31	$ 14,835	$ 3,863	$ 5,424

Supplemental Disclosure:
Cash paid (received) for interest net of capitalized amounts was $82,511,000, $78,703,000 and $66,313,000 and for income taxes was $73,254,000, $(71,395,000) and $36,413,000 in 2000, 1999 and 1998, respectively. Noncash acquisitions under capital leases were $22,218,000, $10,852,000 and $9,658,000 in 2000, 1999 and 1998, respectively.

See Notes to Consolidated Financial Statements beginning on page L-1.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2000	1999	1998
		(in thousands)	
Retained Earnings January 1	$ 166,389	$253,154	$278,814
Net Income (Loss)	(132,032)	32,776	96,628
	34,357	285,930	375,442
Deductions:			
Cash Dividends Declared:			
Common Stock	26,290	114,656	117,464
Cumulative Preferred Stock:			
4-1/8% Series	230	244	247
4.56% Series	66	66	67
4.12% Series	74	78	79
5.90% Series	897	963	985
6-1/4% Series	1,203	1,250	1,266
6.30% Series	834	834	834
6-7/8% Series	1,186	1,238	1,255
Total Cash Dividends Declared	30,780	119,329	122,197
Capital Stock Expense	134	212	91
Total Deductions	30,914	119,541	122,288
Retained Earnings December 31	$ 3,443	$166,389	$253,154

See Notes to Consolidated Financial Statements beginning on page L-1.

Consolidated Statements of Capitalization

	December 31, 2000	December 31, 1999
	(in thousands)	
COMMON SHAREHOLDER'S EQUITY	$ 793,099	$ 955,712

PREFERRED STOCK:
$100 Par Value - Authorized 2,250,000 shares
$25 Par Value - Authorized 11,200,000 shares

Series	Call Price December 31, 2000	Number of Shares Redeemed Year Ended December 31, 2000	1999	1998	Shares Outstanding December 31, 2000	2000	1999
Not Subject to Mandatory Redemption:							
4-1/8%	106.125	3,750	97	771	55,389	5,539	5,914
4.56%	102	-	150	650	14,412	1,441	1,441
4.12%	102.728	1,375	-	200	17,556	1,756	1,893
						8,736	9,248
Subject to Mandatory Redemption:							
5.90% (a,b)		-	15,000	-	152,000	15,200	15,200
6-1/4% (a,b)		-	10,000	-	192,500	19,250	19,250
6.30% (a,b)		-	-	-	132,450	13,245	13,245
6-7/8% (a,c)		-	10,000	-	172,500	17,250	17,250
						64,945	64,945

	2000	1999
LONG-TERM DEBT (See Schedule of Long-term Debt):		
First Mortgage Bonds	308,976	356,820
Installment Purchase Contracts	309,717	309,568
Senior Unsecured Notes	397,435	297,282
Other Long-term Debt	211,307	199,259
Junior Debentures	161,504	161,397
Less Portion Due Within One Year	(90,000)	(198,000)
Long-term Debt Excluding Portion Due Within One Year	1,298,939	1,126,326
TOTAL CAPITALIZATION	$2,165,719	$2,156,231

(a) Not callable until after 2002. There are no aggregate sinking fund provisions through 2002. Sinking fund provisions require the redemption of 15,000 shares in 2003 and 67,500 shares in each 2004 and 2005.
(b) Commencing in 2004 and continuing through 2008 the Company may redeem, at $100 per share, 20,000 shares of the 5.90% series, 15,000 shares of the 6-1/4% series and 17,500 shares of the 6.30% series outstanding under sinking fund provisions at its option and all remaining outstanding shares must be redeemed not later than 2009. Shares redeemed in 1999 and 1997 may be applied to meet the sinking fund requirement.
(c) Commencing in 2003 and continuing through the year 2007, a sinking fund will require the redemption of 15,000 shares each year and the redemption of the remaining shares outstanding on April 1, 2008, in each case at $100 per share. Shares redeemed in 1999 and 1997 may be applied to meet the sinking fund requirement.

See Notes to Consolidated Financial Statements beginning on page L-1.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
6.40	2000 - March 1	$ -	$ 48,000
7.63	2001 - June 1	40,000	40,000
7.60	2002 - November 1	50,000	50,000
7.70	2002 - December 15	40,000	40,000
6.10	2003 - November 1	30,000	30,000
8.50	2022 - December 15	75,000	75,000
7.35	2023 - October 1	20,000	20,000
7.20	2024 - February 1	30,000	30,000
7.50	2024 - March 1	25,000	25,000
Unamortized Discount		(1,024)	(1,180)
		$308,976	$356,820

Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into, in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
City of Lawrenceburg, Indiana:			
7.00	2015 - April 1	$ 25,000	$ 25,000
5.90	2019 - November 1	52,000	52,000
City of Rockport, Indiana:			
(a)	2014 - August 1	50,000	50,000
7.60	2016 - March 1	40,000	40,000
6.55	2025 - June 1	50,000	50,000
(b)	2025 - June 1	50,000	50,000
City of Sullivan, Indiana:			
5.95	2009 - May 1	45,000	45,000
Unamortized Discount		(2,283)	(2,432)
		$309,717	$309,568

(a) A variable interest rate is determined weekly. The average weighted interest rate was 4.5% for 2000 and 3.2% for 1999.
(b) An adjustable interest rate can be a daily, weekly, commercial paper or term rate as designated by I&M. A weekly rate was selected which ranged from 2.9% to 5.9% in 2000 and from 2.2% to 5.6% in 1999 and averaged 4.2% and 3.2% during 2000 and 1999, respectively.

Under the terms of the installment purchase contracts, I&M is required to pay amounts sufficient to enable the cities to pay interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain generating plants. On the two variable rate series the principal is payable at the stated maturities or on the demand of the bondholders at periodic interest adjustment dates which occur weekly. The variable rate bonds due in 2014 are supported by a bank letter of credit which expires in 2002. I&M has agreements that provide for brokers to remarket the adjustable rate bonds due in 2025 tendered at interest adjustment dates. In the event certain bonds cannot be remarketed, I&M has a standby bond purchase agreement with a bank that provides for the bank to purchase any bonds not remarketed. The purchase agreement expires in 2001. Accordingly, the variable and adjustable rate installment purchase contracts have been classified for repayment purposes based on the expiration dates of the standby purchase agreement and the letter of credit.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
(a)	2000 - November 22	$ -	$100,000
(b)	2002 - September 3	200,000	-
6-7/8	2004 - July 1	150,000	150,000
6.45	2008 - November 10	50,000	50,000
Unamortized Discount		(2,565)	(2,718)
		$397,435	$297,282

(a) A floating interest rate is determined monthly. The rate on December 31, 1999 was 7.1%.
(b) A floating interest rate is determined quarterly. The rate on December 31, 2000 was 7.31%.

Junior debentures outstanding were as follows:

% Rate	Due	December 31, 2000	December 31, 1999
		(in thousands)	
8.00	2026 - March 31	$ 40,000	$ 40,000
7.60	2038 - June 30	125,000	125,000
Unamortized Discount		(3,496)	(3,603)
Total		$161,504	$161,397

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of I&M.

At December 31, 2000, future annual long-term debt payments are as follows:

	Amount (in thousands)
2001	$ 90,000
2002	340,000
2003	30,000
2004	150,000
2005	-
Later Years	788,307
Total Principal Amount	1,398,307
Unamortized Discount	(9,368)
Total	$1,388,939

The notes listed below are combined with the notes to financial statements for AEP and its other subsidiary registrants. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Indiana Michigan Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Indiana Michigan Power Company and its subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Indiana Michigan Power Company and its subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 26, 2001

KENTUCKY POWER COMPANY

KENTUCKY POWER COMPANY
Selected Financial Data

	2000	1999	1998	1997	1996
	Year Ended December 31, (in thousands)				
INCOME STATEMENTS DATA:					
Operating Revenues	$410,403	$373,982	$362,999	$340,635	$323,321
Operating Expenses	360,665	319,307	311,106	293,779	281,978
Operating Income	49,738	54,675	51,893	46,856	41,343
Nonoperating Income (Loss)	2,070	(327)	(1,726)	(464)	(594)
Income Before Interest Charges	51,808	54,348	50,167	46,392	40,749
Interest Charges	31,045	28,918	28,491	25,646	23,776
Net Income	$ 20,763	$ 25,430	$ 21,676	$ 20,746	$ 16,973

	2000	1999	1998	1997	1996
	December 31, (in thousands)				
BALANCE SHEETS DATA:					
Electric Utility Plant	$1,103,064	$1,079,048	$1,043,711	$1,006,955	$951,602
Accumulated Depreciation and Amortization	360,648	340,008	315,546	296,318	286,640
Net Electric Utility Plant	$ 742,416	$ 739,040	$ 728,165	$ 710,637	$664,962
Total Assets	$1,512,016	$ 986,638	$ 921,847	$ 886,671	$833,579
Common Stock and Paid-in Capital	$ 209,200	$ 209,200	$ 199,200	$ 179,200	$159,200
Retained Earnings	57,513	67,110	71,452	78,076	84,090
Total Common Shareholder's Equity	$ 266,713	$ 276,310	$ 270,652	$ 257,276	$243,290
Long-term Debt(a)	$ 330,880	$ 365,782	$ 368,838	$ 341,051	$293,198
Obligations Under Capital leases (a)	$ 14,184	$ 15,141	$ 18,977	$ 18,725	$ 12,850
Total Capitalization and Liabilities	$1,512,016	$ 986,638	$ 921,847	$ 886,671	$833,579

(a) Including portion due within one year.

KPCo is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power serving 172,000 retail customers in eastern Kentucky. KPCo as a member of the AEP System Power Pool (AEP Power Pool) shares in the revenues and costs of the AEP Power Pool's wholesale sales to neighboring utility systems and power marketers. KPCo also sells wholesale power to municipalities.

The cost of the AEP System's generating capacity is allocated among the AEP Power Pool members based on their relative peak demands and generating reserves through the payment of capacity charges or the receipt of credits. AEP Power Pool members are also compensated for their out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool.

The AEP Power Pool calculates each company's prior twelve month peak demand relative to the total peak demand of all member companies as a basis for sharing AEP Power Pool revenues and costs. The result of this calculation is the member load ratio (MLR) which determines each company's percentage share of AEP Power Pool revenues or costs. KPCo as a member of the AEP Power Pool shares in the revenues and costs of the AEP Power Pool's wholesale sales to and net forward trades with other utility systems and power marketers. Revenues from forward electricity trades are recorded net of purchases as operating revenues for transactions in AEP's traditional marketing area (up to two transmission systems from the AEP service territory) and as nonoperating income for transactions beyond two transmission systems from AEP. The AEP Power Pool also enters into power trading transactions for options, futures and swaps. KPCo's share of these transactions is recorded in nonoperating income.

In February 2001 the U.S. District Court for the Southern District of Ohio ruled against AEP and certain of its subsidiaries, including KPCo, in a suit over deductibility of interest claimed in AEP's consolidated tax return related to a corporate owned life insurance (COLI) program. In 1998 and 1999 KPCo paid the disputed taxes and interest attributable to the COLI interest deductions for taxable years 1992-98. The payments were included in Other Property and Investments pending the resolution of this matter. As a result of the Court's decision, net income was reduced by $8 million in 2000.

Net Income Decreases

Net income decreased $4.7 million or 18% in 2000 primarily due to the COLI decision and an increase in maintenance expense.

Operating Revenues Increase

Operating revenues increased $36 million or 10% in 2000 due to a significant increase in AEP Power Pool transactions. Changes in the components of operating revenues were as follows:

(dollars in millions)	Increase (Decrease) From Previous Year Amount	%
Retail:		
Residential	$ 6.1	5.7
Commercial	(0.2)	(0.3)
Industrial	(3.5)	(3.7)
	2.4	0.9
Wholesale	37.2	49.0
Transmission	2.8	62.6
Other	(6.0)	(22.3)
Total	$36.4	9.7

The increase in operating revenues is due to increased KWH sales to residential customers as a result of colder weather and a significant increase in AEP Power Pool wholesale transactions. As a result of an affiliated company's major industrial customer's decision not to continue its purchased power agreement, additional power was available to the AEP Power Pool for wholesale sales contributing to the increase in the company's revenue. Purchased power also increased due to the availability of the Rockport Plant from which the company, under a unit power agreement, purchases 15% of the available power from Rockport. Rockport Plant generated 8% more KWH in the year 2000 than in the year 1999. In 2000 other revenues decreased substantially due to the effect of favorable adjustment to rental income in 1999 reflecting agreed to retroactive revisions to the billings for pole attachments with telecommunications companies.

Operating Expenses Increase

Operating expenses increased $41.4 million primarily due to increased purchased power, maintenance costs and federal income taxes. Changes in the components of operating expenses were as follows:

(dollars in millions)	Increase (Decrease) From Previous Year Amount	%
Fuel	$(9.7)	(11.5)
Purchased Power	41.6	38.6
Other Operation	0.8	1.6
Maintenance	4.4	20.6
Depreciation and Amortization	1.8	6.2
Taxes Other Than Federal Income Taxes	(1.1)	(10.6)
Federal Income Taxes	3.6	27.1
Total	$41.4	13.0

Fuel expense decreased due to a decline in internal generation as a result of planned outages in 2000 at the company's Big Sandy Plant Unit 2. Purchased Power expense increased due to a significant increase in AEP Power Pool wholesale transactions and affiliated power purchases under a unit power agreement.

The planned outages at Big Sandy Plant caused the increase in maintenance expense. Comparing 2000 to 1999, unit 1 of the Big Sandy Plant, experienced 3.6 weeks of various outages compared to 1 week of outages in 1999. Unit 2 experienced 6.8 weeks of outages in 2000 compared to 4.6 weeks in 1999.

An increase in transmission plant investment and improvements to distribution facilities accounted for the increase in depreciation expense.

Taxes other than federal income taxes decreased due to decreased Kentucky state income taxes as a result of lower pre-tax operating income partly offset by the unfavorable ruling in AEP's suit against the government over interest deductions claimed in prior years related to a COLI program.

The increase in federal income tax expense was primarily due to the unfavorable ruling in AEP's suit against the government over interest deductions claimed in prior years related to a COLI program.

Nonoperating Income Increase

Nonoperating income increased due to the favorable effect of non-regulated electric trading outside the AEP Power Pool's traditional marketing area. The AEP Power Pool enters into transactions for the purchase and sale of electricity options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area. The company's share of the AEP Power Pool's non-regulated trading transactions are included in nonoperating income.

Interest Charges Increase

The increase in interest charges resulted from the U.S. District Court's unfavorable decision denying Federal income tax deductions for COLI interest resulting in the incurrance of interest on taxes owed for prior years.

KENTUCKY POWER COMPANY
Statements of Income

	Year Ended December 31, 2000	1999 (in thousands)	1998
OPERATING REVENUES	$410,403	$373,982	$362,999
OPERATING EXPENSES:			
Fuel	74,638	84,369	83,303
Purchased Power	149,345	107,763	100,620
Other Operation	53,325	52,468	47,802
Maintenance	25,866	21,452	30,462
Depreciation and Amortization	31,028	29,221	28,080
Taxes Other Than Federal Income Taxes	9,709	10,854	9,687
Federal Income Taxes	16,754	13,180	11,152
TOTAL OPERATING EXPENSES	360,665	319,307	311,106
OPERATING INCOME	49,738	54,675	51,893
NONOPERATING INCOME (LOSS)	2,070	(327)	(1,726)
INCOME BEFORE INTEREST CHARGES	51,808	54,348	50,167
INTEREST CHARGES	31,045	28,918	28,491
NET INCOME	$ 20,763	$ 25,430	$ 21,676

Statements of Retained Earnings

	Year Ended December 31, 2000	1999 (in thousands)	1998
RETAINED EARNINGS JANUARY 1	$67,110	$71,452	$78,076
NET INCOME	20,763	25,430	21,676
CASH DIVIDENDS DECLARED	30,360	29,772	28,300
RETAINED EARNINGS DECEMBER 31	$57,513	$67,110	$71,452

See Notes to Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
Balance Sheets

	December 31, 2000	December 31, 1999
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$ 271,107	$ 268,618
Transmission	360,563	355,442
Distribution	387,499	372,752
General	67,476	67,608
Construction Work in Progress	16,419	14,628
Total Electric Utility Plant	1,103,064	1,079,048
Accumulated Depreciation and Amortization	360,648	340,008
NET ELECTRIC UTILITY PLANT	742,416	739,040
OTHER PROPERTY AND INVESTMENTS	6,559	12,406
LONG-TERM ENERGY TRADING CONTRACTS	76,657	8,010
CURRENT ASSETS:		
Cash and Cash Equivalents	2,270	674
Accounts Receivable:		
Customers	34,555	18,952
Affiliated Companies	22,119	15,223
Miscellaneous	6,419	8,343
Allowance for Uncollectible Accounts	(282)	(637)
Fuel - at average cost	4,760	10,441
Materials and Supplies - at average cost	15,408	18,113
Accrued Utility Revenues	6,500	13,737
Energy Trading Contracts	483,537	33,919
Prepayments	766	1,450
TOTAL CURRENT ASSETS	576,052	120,215
REGULATORY ASSETS	98,515	96,296
DEFERRED CHARGES	11,817	10,671
TOTAL	$1,512,016	$ 986,638

See Notes to Financial Statements beginning on page L-1.

	December 31, 2000	December 31, 1999
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - Par Value $50:		
Authorized - 2,000,000 Shares		
Outstanding - 1,009,000 Shares	$ 50,450	$ 50,450
Paid-in Capital	158,750	158,750
Retained Earnings	57,513	67,110
Total Common Shareholder's Equity	266,713	276,310
Long-term Debt	270,880	260,782
TOTAL CAPITALIZATION	537,593	537,092
OTHER NONCURRENT LIABILITIES	18,348	23,797
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	60,000	105,000
Short-term Debt	-	39,665
Advances from Affiliates	47,636	-
Accounts Payable - General	32,043	9,923
Accounts Payable - Affiliated Companies	37,506	19,743
Customer Deposits	4,389	4,143
Taxes Accrued	11,885	9,860
Interest Accrued	5,610	4,843
Energy Trading Contracts	496,884	33,094
Other	14,517	12,020
TOTAL CURRENT LIABILITIES	710,470	238,291
DEFERRED INCOME TAXES	165,935	165,007
DEFERRED INVESTMENT TAX CREDITS	11,656	12,908
LONG-TERM ENERGY TRADING CONTRACTS	61,632	6,194
DEFERRED CREDITS	6,382	3,349
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$1,512,016	$986,638

KENTUCKY POWER COMPANY
Statements of Cash Flows

	Year Ended December 31, 2000	1999	1998
	(in thousands)		
OPERATING ACTIVITIES:			
Net Income	$ 20,763	$ 25,430	$ 21,676
Adjustments for Noncash Items:			
Depreciation and Amortization	31,034	29,228	28,092
Deferred Income Taxes	3,765	2,596	3,607
Deferred Investment Tax Credits	(1,252)	(1,292)	(1,415)
Deferred Fuel Costs (net)	2,948	828	(449)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(20,930)	(6,618)	(6,663)
Fuel, Materials and Supplies	8,386	(7,014)	3,199
Accrued Utility Revenues	7,237	(177)	(579)
Accounts Payable	39,883	4,935	157
Taxes Accrued	2,025	2,604	1,126
Disputed Tax and Interest Related to COLI	5,943	(567)	(5,376)
Other (net)	(4,559)	(3,019)	(2,215)
Net Cash Flows From Operating Activities	95,243	46,934	41,160
INVESTING ACTIVITIES:			
Construction Expenditures	(36,209)	(44,339)	(43,769)
Proceeds from Sales of Property	266	168	-
Net Cash Flows Used For Investing Activities	(35,943)	(44,171)	(43,769)
FINANCING ACTIVITIES:			
Capital Contributions from Parent Company	-	10,000	20,000
Issuance of Long-term Debt	69,685	79,740	29,816
Retirement of Long-term Debt	(105,000)	(83,307)	(2,203)
Change in Short-term Debt (net)	(39,665)	19,315	(16,150)
Change in Advances from Affiliates (net)	47,636	-	-
Dividends Paid	(30,360)	(29,772)	(28,300)
Net Cash Flows From (Used For) Financing Activities	(57,704)	(4,024)	3,163
Net Increase (Decrease) in Cash and Cash Equivalents	1,596	(1,261)	554
Cash and Cash Equivalents January 1	674	1,935	1,381
Cash and Cash Equivalents December 31	$ 2,270	$ 674	$ 1,935

Supplemental Disclosure:
Cash paid for interest net of capitalized amounts was $28,619,000, $29,845,000 and $27,857,000 and for income taxes was $7,923,000, $12,050,000 and $8,607,000 in 2000, 1999 and 1998, respectively. Noncash acquisitions under capital leases were $2,817,000, $2,219,000 and $4,890,000 in 2000, 1999 and 1998, respectively.

See Notes to Financial Statements beginning on page L-1.

	December 31, 2000	December 31, 1999
	(in thousands)	
COMMON SHAREHOLDER'S EQUITY	$266,713	$276,310
LONG-TERM DEBT (See Schedule of Long-term Debt):		
First Mortgage Bonds	119,341	119,270
Senior Unsecured Notes	147,490	157,502
Notes Payable	25,000	50,000
Junior Debentures	39,049	39,010
Less Portion Due Within One Year	(60,000)	(105,000)
Long-term Debt Excluding Portion Due Within One Year	270,880	260,782
TOTAL CAPITALIZATION	$537,593	$537,092

See Notes to Financial Statements beginning on page L-1.

KENTUCKY POWER COMPANY
Schedule of Long-term Debt

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
8.95	2001 - May 10	$ 20,000	$ 20,000
8.90	2001 - May 21	40,000	40,000
6.65	2003 - May 1	15,000	15,000
6.70	2003 - June 1	15,000	15,000
6.70	2003 - June 1	15,000	15,000
7.90	2023 - June 1	14,500	14,500
Unamortized Discount		(159)	(230)
		$119,341	$119,270

Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
(a)	2000 - November 2	$ -	$ 80,000
(b)	2002 - November 19	70,000	-
6.91	2007 - October 1	48,000	48,000
6.45	2008 - November 10	30,000	30,000
Unamortized Discount		(510)	(498)
		147,490	157,502
Less Portion Due Within One Year		-	80,000
Total		$147,490	$ 77,502

(a) A floating interest rate is determined monthly. The rate on December 31, 1999 was 7.23%.
(b) A floating interest rate is determined monthly. The rate on December 31, 2000 was 7.4075%.

Notes Payable to Banks outstandings were as follows:

6.57	2000 - April 1	$ -	$25,000
7.45	2002 - September 20	25,000	25,000
Total		$25,000	$50,000

Junior debentures outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
8.72	2025 - June 30	$40,000	$40,000
Unamortized Discount		(951)	(990)
Total		$39,049	$39,010

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of the Company.

At December 31, 2000, future annual long-term debt payments are as follows:

	Amount (in thousands)
2001	$ 60,000
2002	95,000
2003	45,000
2004	-
2005	-
Later Years	132,500
Total Principal Amount	332,500
Unamortized Discount	(1,620)
Total	$330,880

KENTUCKY POWER COMPANY
Index to Notes to Financial Statements

The notes listed below are combined with the notes to financial statements for AEP and its other subsidiary registrants. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholder and Board of
Directors of Kentucky Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Kentucky Power Company as of December 31, 2000 and 1999, and the related statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2000 and 1999, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 26, 2001

OHIO POWER COMPANY AND SUBSIDIARIES

-This page intentionally left blank.-

OHIO POWER COMPANY AND SUBSIDIARIES
Selected Consolidated Financial Data

	Year Ended December 31,				
	2000	1999	1998	1997	1996
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	$2,227,902	$2,039,263	$2,105,547	$1,892,110	$1,911,708
Operating Expenses	2,001,075	1,750,434	1,816,175	1,615,717	1,614,547
Operating Income	226,827	288,829	289,372	276,393	297,161
Nonoperating Income (Loss)	(5,004)	7,000	588	14,822	6,374
Income Before Interest Charges	221,823	295,829	289,960	291,215	303,535
Interest Charges	119,210	83,672	80,035	82,526	85,880
Income Before Extraordinary Item	102,613	212,157	209,925	208,689	217,655
Extraordinary Loss	(18,876)	-	-	-	-
Net Income	83,737	212,157	209,925	208,689	217,655
Preferred Stock Dividend Requirements	1,266	1,417	1,474	2,647	8,778
Earnings Applicable to Common Stock	$ 82,471	$ 210,740	$ 208,451	$ 206,042	$ 208,877

	December 31,				
	2000	1999	1998	1997	1996
			(in thousands)		
BALANCE SHEETS DATA:					
Electric Utility Plant	$5,577,631	$5,400,917	$5,257,841	$5,155,797	$4,996,621
Accumulated Depreciation and Amortization	2,764,130	2,621,711	2,461,376	2,349,995	2,216,534
Net Electric Utility Plant	$2,813,501	$2,779,206	$2,796,465	$2,805,802	$2,780,087
Total Assets	$6,252,436	$4,677,209	$4,344,680	$4,163,202	$4,092,166
Common Stock and Paid-in Capital	$ 783,684	$ 783,577	$ 783,536	$ 783,497	$ 781,863
Retained Earnings	398,086	587,424	587,500	590,151	584,015
Total Common Shareholder's Equity	$1,181,770	$1,371,001	$1,371,036	$1,373,648	$1,365,878
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$ 16,648	$ 16,937	$ 17,370	$ 17,542	$ 38,532
Subject to Mandatory Redemption (a)	8,850	8,850	11,850	11,850	109,900
Total Cumulative Preferred Stock	$ 25,498	$ 25,787	$ 29,220	$ 29,392	$ 148,432
Long-term Debt (a)	$1,195,493	$1,151,511	$1,084,928	$1,095,226	$1,069,729
Obligations Under Capital Leases (a)	$ 116,581	$ 136,543	$ 142,635	$ 157,487	$ 131,285
Total Capitalization and Liabilities	$6,252,436	$4,677,209	$4,344,680	$4,163,202	$4,092,166

(a) Including portion due within one year.

OPCo is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power to 696,000 retail customers in northwestern, east central, eastern and southern sections of Ohio. OPCo supplies electric power to the AEP Power Pool and shares the revenues and costs of the AEP Power Pool's wholesale sales to neighboring utility systems and power marketers. OPCo also sells wholesale power to municipalities and cooperatives.

The cost of the AEP System's generating capacity is allocated among the AEP Power Pool members based on their relative peak demands and generating reserves through the payment of capacity charges or the receipt of capacity credits. AEP Power Pool members are also compensated for their out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool.

The AEP Power Pool calculates each company's prior twelve month peak demand relative to the total peak demand of all member companies as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR) which determines each company's percentage share of AEP Power Pool revenues or costs. OPCo as a member of the AEP Power Pool shares in the revenues and costs of the AEP Power Pool's wholesale sales to and net forward trades with other utility systems and power marketers. Revenues from forward electricity trades are recorded net of purchases as operating revenues for transactions in AEP's traditional marketing area (up to two transmission systems from the AEP service territory) and as nonoperating income for transactions beyond two transmission systems from AEP. The AEP Power Pool also enters into power trading transactions for options, futures and swaps. OPCo's share of these transactions is recorded in nonoperating income.

Results of Operations

In February 2001 the U.S. District Court for the Southern District of Ohio ruled against AEP and certain of its subsidiaries, including OPCo, in a suit over deductibility of interest claimed in AEP's consolidated tax returns related to a corporate owned life insurance (COLI) program. In 1998 and 1999 OPCo paid the disputed taxes and interest attributable to the COLI interest deductions for taxable years 1991-98. The payments were included in Other Property and Investments pending the resolution of this matter. As a result of the Court's decision, net income was reduced by $118 million in 2000.

Income before extraordinary item decreased $110 million or 52% in 2000 due predominantly to the disallowance of COLI related tax deductions. An extraordinary loss related to the discontinuance of SFAS 71 regulatory accounting, of approximately $19 million after tax, was recorded in September 2000 in connection with the PUCO's approval of a plan to transition OPCo's generation business from cost based rate regulation to customer choice and market pricing.

Net income increased $2 million or 1% in 1999 primarily due to a decline in operation and maintenance costs reflecting cost containment efforts.

Operating Revenues and Energy Sales

Operating revenues increased 9% in 2000 following a decrease of 3% in 1999. The changes in the components of revenues were as follows:

(Dollars in Millions)	Increase (Decrease) From Previous Year			
	2000		1999	
	Amount	%	Amount	%
Retail:				
Residential	$ (4.2)		$ 7.5	
Commercial	1.7		0.4	
Industrial	(126.0)		(5.0)	
Other	0.2		-	
	(128.3)	(9)	2.9	-
Wholesale	322.1	56	(71.9)	(11)
Transmission and Other	(5.2)	(6)	2.7	3
Total	$ 188.6	9	$(66.3)	(3)

The increase in operating revenues in 2000 resulted from increased wholesale sales to the AEP Power Pool and the Company's share of increased Power Pool wholesale sales to and net revenues from trading of electricity with other utility systems and power marketers. As a result of one of OPCo's major industrial customers deciding not to continue its power purchase agreement, OPCo was able to deliver additional power to the AEP Power Pool accounting for part of the increase in wholesale revenues. Wholesale revenues also benefited from the growth in AEP's marketing and trading operation, favorable wholesale market conditions and increased availability of AEP Power Pool generation for wholesale sales. The increase in AEP Power Pool generation availability was due to the return to service of one of an affiliate's nuclear units in June 2000 and improved generating unit outage management.

Operating revenues declined 3% in 1999 primarily due to a decline in margins on wholesale sales and net power trading transactions and decreased sales to the AEP Power Pool.

Operating Expenses

Operating expenses increased by 14% in 2000 mostly due to increases in fuel expense, purchased power expense, other operation expense and federal income taxes.

Operating expenses decreased 4% in 1999 from cost containment efforts and lower fuel costs due mainly to a decrease in generation reflecting lower demand for wholesale energy. Changes in the components of operating expenses were as follows:

(dollars in millions)	Increase (Decrease) From Previous Year			
	2000		1999	
	Amount	%	Amount	%
Fuel	$ 84.3	12	$(50.8)	(7)
Purchased Power	20.9	13	12.4	8
Other Operation	80.2	25	(26.1)	(7)
Maintenance	3.4	3	(18.3)	(13)
Depreciation and Amortization	6.9	5	4.6	3
Taxes Other Than Federal Income Taxes	(0.3)	-	(3.5)	(2)
Federal Income Taxes	55.2	41	16.0	13
Total Operating Expenses	$250.6	14	$(65.7)	(4)

Fuel expense increased in 2000 due to increases in generation and the average cost of fuel consumed reflecting shutdown costs included in the cost of coal delivered from affiliated mining operations. Fuel expense decreased in 1999 due to a 6% decrease in generation reflecting the decline in wholesale sales.

The increase in purchased power expense was due to a significant increase in AEP Power Pool transactions.

Other operation expense increased in 2000 mainly due to increased power generation costs. Increased emission allowance consumption and allowance prices and increased costs of AEP's growing power marketing and trading operation, including incentive compensation, accounted for the increase in generation costs. The increase in emission allowance usage and prices resulted from the stricter air quality standards of Phase II of the 1990 Clean Air Act Amendments which became effective on January 1, 2000. The decrease in other operation expense in 1999 was due to lower coal-fired power plant expenses reflecting cost containment efforts, and an increase in gains on emission allowance sales. The cost containment efforts included staff reductions in transmission and distribution operations, at the power plants and within the engineering and maintenance group of AEP Service Corporation which bills OPCo for operations support services. These cost containment efforts were the primary reason for the decrease in maintenance expense in 1999.

The increase in federal income tax expense in 2000 was primarily due to the unfavorable ruling relating to AEP's COLI program. Federal income taxes attributable to operations increased in 1999 due to changes in certain book/tax differences accounted for on a flow-through basis for rate-making purposes and an increase in pre-tax operating income.

Nonoperating Income

The decrease in nonoperating income in 2000 is due to the disallowance of COLI-related tax deductions for coal-mining operations that are no longer operating.

Extraordinary Loss

An extraordinary loss was recorded in the third quarter of 2000 when OPCo discontinued the application of SFAS 71 regulatory accounting for the generation portion of its business due to the approval in September 2000 of a stipulation agreement by the PUCO providing for a transition from cost based rate regulation for OPCo's generation business to customer choice and market pricing.

OHIO POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Income

	Year Ended December 31,		
	2000	1999	1998
		(in thousands)	
OPERATING REVENUES	$2,227,902	$2,039,263	$2,105,547
OPERATING EXPENSES:			
Fuel	771,969	687,672	738,522
Purchased Power	184,004	163,143	150,733
Other Operation	407,375	327,132	353,194
Maintenance	124,735	121,299	139,611
Depreciation and Amortization	155,944	149,055	144,493
Taxes Other Than Federal Income Taxes	165,552	165,891	169,353
Federal Income Taxes	191,496	136,242	120,269
Total Operating Expenses	2,001,075	1,750,434	1,816,175
OPERATING INCOME	226,827	288,829	289,372
NONOPERATING INCOME (LOSS)	(5,004)	7,000	588
INCOME BEFORE INTEREST CHARGES	221,823	295,829	289,960
INTEREST CHARGES	119,210	83,672	80,035
INCOME BEFORE EXTRAORDINARY ITEM	102,613	212,157	209,925
EXTRAORDINARY LOSS - Discontinuance of Regulatory Accounting for Generation (inclusive of Tax Benefit of $21,281,000)	(18,876)	-	-
NET INCOME	83,737	212,157	209,925
PREFERRED STOCK DIVIDEND REQUIREMENTS	1,266	1,417	1,474
EARNINGS APPLICABLE TO COMMON STOCK	$ 82,471	$ 210,740	$ 208,451

See Notes to Consolidated Financial Statements beginning on page L-1.

OHIO POWER COMPANY AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 2000	December 31, 1999
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,764,155	$2,713,421
Transmission	870,033	857,420
Distribution	1,040,940	999,679
General (including mining assets)	707,417	713,882
Construction Work in Progress	195,086	116,515
Total Electric Utility Plant	5,577,631	5,400,917
Accumulated Depreciation and Amortization	2,764,130	2,621,711
NET ELECTRIC UTILITY PLANT	2,813,501	2,779,206
OTHER PROPERTY AND INVESTMENTS	109,124	221,756
LONG-TERM ENERGY TRADING CONTRACTS	256,455	31,912
CURRENT ASSETS:		
Cash and Cash Equivalents	31,393	157,138
Advances to Affiliates	92,486	-
Accounts Receivable:		
Customers	139,732	246,310
Affiliated Companies	126,203	89,215
Miscellaneous	39,046	22,055
Allowance for Uncollectible Accounts	(1,054)	(2,223)
Fuel - at average cost	82,291	129,022
Materials and Supplies - at average cost	96,053	95,967
Accrued Utility Revenues	264	45,575
Energy Trading Contracts	1,617,660	134,567
Prepayments and Other	32,882	38,472
TOTAL CURRENT ASSETS	2,256,956	956,098
REGULATORY ASSETS	714,710	594,385
DEFERRED CHARGES	101,690	93,852
TOTAL	$6,252,436	$ 4,677,209

See Notes to Consolidated Financial Statements beginning on page L-1.

	December 31, 2000	December 31, 1999
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - No Par Value:		
Authorized - 40,000,000 Shares		
Outstanding - 27,952,473 Shares	$ 321,201	$ 321,201
Paid-in Capital	462,483	462,376
Retained Earnings	398,086	587,424
Total Common Shareholder's Equity	1,181,770	1,371,001
Cumulative Preferred Stock:		
Not Subject to Mandatory Redemption	16,648	16,937
Subject to Mandatory Redemption	8,850	8,850
Long-term Debt	1,077,987	1,139,834
TOTAL CAPITALIZATION	2,285,255	2,536,622
OTHER NONCURRENT LIABILITIES	542,017	414,837
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	117,506	11,677
Short-term Debt	-	194,918
Accounts Payable - General	179,691	180,383
Accounts Payable - Affiliated Companies	121,360	64,599
Customer Deposits	39,736	8,196
Taxes Accrued	223,101	179,112
Interest Accrued	20,458	16,863
Obligations Under Capital Leases	32,716	34,284
Energy Trading Contracts	1,662,315	131,844
Other	151,934	88,249
TOTAL CURRENT LIABILITIES	2,548,817	910,125
DEFERRED INCOME TAXES	621,941	676,460
DEFERRED INVESTMENT TAX CREDITS	25,214	35,838
LONG-TERM ENERGY TRADING CONTRACTS	206,187	24,677
DEFERRED CREDITS	23,005	78,650
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$6,252,436	$4,677,209

See Notes to Consolidated Financial Statements beginning on page L-1.

OHIO POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	Year Ended December 31, 2000	1999 (in thousands)	1998
OPERATING ACTIVITIES:			
Net Income	$ 83,737	$ 212,157	$ 209,925
Adjustments for Noncash Items:			
Depreciation, Depletion and Amortization	200,350	193,780	172,085
Deferred Income Taxes	(65,956)	3,666	3,042
Deferred Investment Tax Credits	(3,399)	(3,458)	(3,525)
Deferred Fuel Costs (net)	(56,869)	(76,978)	(44,694)
Extraordinary Loss - Discontinuance of SFAS 71	18,876	-	-
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	51,430	(49,309)	(12,376)
Fuel, Materials and Supplies	46,645	(60,500)	18,612
Accrued Utility Revenues	45,311	(2,074)	(5,915)
Accounts Payable	56,069	9,195	51,040
Disputed Tax and Interest Related to COLI	110,494	(6,272)	(104,222)
Change in Operating Reserves	145,573	66,573	77,811
Other (net)	6,232	48,718	42,981
Net Cash Flows From Operating Activities	638,493	335,498	404,764
INVESTING ACTIVITIES:			
Construction Expenditures	(254,016)	(193,870)	(185,036)
Proceeds from Sales of Property and Other	6,354	5,900	5,910
Net Cash Flows Used For Investing Activities	(247,662)	(187,970)	(179,126)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	74,748	222,308	186,126
Changes in Advances to Affiliates (net)	(92,486)	-	-
Retirement of Cumulative Preferred Stock	(182)	(3,392)	(133)
Retirement of Long-term Debt	(30,663)	(158,638)	(197,911)
Change in Short-term Debt (net)	(194,918)	71,913	44,305
Dividends Paid on Common Stock	(271,813)	(210,813)	(211,101)
Dividends Paid on Cumulative Preferred Stock	(1,262)	(1,420)	(1,475)
Net Cash Flows Used For Financing Activities	(516,576)	(80,042)	(180,189)
Net Increase (Decrease) in Cash and Cash Equivalents	(125,745)	67,486	45,449
Cash and Cash Equivalents January 1	157,138	89,652	44,203
Cash and Cash Equivalents December 31	$ 31,393	$ 157,138	$ 89,652

Supplemental Disclosure:
Cash paid for interest net of capitalized amounts was $87,120,000, $78,739,000 and $79,667,000 and for income taxes was $142,710,000, $94,606,000 and $118,548,000 in 2000, 1999 and 1998, respectively. Noncash acquisitions under capital leases were $17,005,000, $28,561,000 and $29,938,000 in 2000, 1999 and 1998, respectively.

See Notes to Consolidated Financial Statements beginning on page L-1.

OHIO POWER COMPANY AND SUBSIDIARIES
Consolidated Statement of Retained Earnings

	Year Ended December 31,		
	2000	1999	1998
		(in thousands)	
Retained Earnings January 1	$587,424	$587,500	$590,151
Net Income	83,737	212,157	209,925
	671,161	799,657	800,076
Deductions:			
Cash Dividends Declared:			
Common Stock	271,813	210,813	211,101
Cumulative Preferred Stock:			
4.08% Series	59	61	63
4.20% Series	96	97	97
4.40% Series	139	142	143
4-1/2% Series	442	460	467
5.90% Series	428	472	487
6.02% Series	66	156	186
6.35% Series	32	32	32
Total Dividends	273,075	212,233	212,576
Retained Earnings December 31	$398,086	$587,424	$587,500

See Notes to Consolidated Financial Statements beginning on page L-1.

OHIO POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Capitalization

Series(a)	Call Price December 31, 2000	Par Value	Number of Shares Redeemed Year Ended December 31, 2000	1999	1998	Shares Outstanding December 31, 2000	December 31, 2000 (in thousands)	1999
COMMON SHAREHOLDER'S EQUITY							$1,181,770	$1,371,001
PREFERRED STOCK - authorized shares 3,762,403 $100 par value; authorized shares 4,000,000 $25 par value								
Not Subject to Mandatory Redemption:								
4.08%	$103	$100	-	373	425	14,595	1,460	1,460
4.20%	103.20	100	276	-	-	22,824	2,282	2,310
4.40%	104	100	432	330	200	31,512	3,151	3,194
4-1/2%	110.00	100	2,181	3,631	1,096	97,546	9,755	9,973
							16,648	16,937
Subject to Mandatory Redemption:								
5.90% (b)	-	$100	-	10,000	-	72,500	7,250	7,250
6.02% (c)	-	100	-	20,000	-	11,000	1,100	1,100
6.35% (c)	-	100	-	-	-	5,000	500	500
							8,850	8,850
LONG-TERM DEBT (See Schedule of Long-term Debt):								
First Mortgage Bonds							316,294	323,772
Installment Purchase Contracts							233,130	233,025
Senior Unsecured Notes							471,583	408,671
Notes Payable							30,000	30,000
Junior Debentures							131,980	131,860
Other Long-term Debt							12,506	24,183
Less Portion Due Within One Year							(117,506)	(11,677)
Long-term Debt Excluding Portion Due Within One Year							1,077,987	1,139,834
TOTAL CAPITALIZATION							$2,285,255	$2,536,622

(a) The series subject to mandatory redemption are not callable until after 2002. The sinking fund provisions of each series subject to mandatory redemption have been met by purchase of shares in advance of the due date.

(b) Commencing in 2004 and continuing through the year 2008, a sinking fund for the 5.90% cumulative preferred stock will require the redemption of 22,500 shares each year and the redemption of the remaining shares outstanding on January 1, 2009, in each case at $100 per share. Shares previously redeemed may be applied to meet sinking fund requirements.

(c) Commencing in 2003 and continuing through 2007 cumulative preferred stock sinking funds will require the redemption of 20,000 shares each year of the 6.02% series and 15,000 shares each year of the 6.35% series, in each case at $100 per share. All remaining outstanding shares must be redeemed in 2008. Shares previously redeemed may be applied to meet the sinking fund requirements.

See Notes to Consolidated Financial Statements beginning on page L-1.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
6.75	2003 - April 1	$ 38,850	$ 40,000
6.55	2003 - October 1	32,135	32,135
6.00	2003 - November 1	25,000	25,000
6.15	2003 - December 1	50,000	50,000
8.80	2022 - February 10	50,000	50,000
7.75	2023 - April 1	40,000	40,000
7.375	2023 - October 1	40,000	40,000
7.10	2023 - November 1	20,000	23,000
7.30	2024 - April 1	21,500	25,000
Unamortized Discount		(1,191)	(1,363)
Total		$316,294	$323,772

Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
Mason County, West Virginia:		
5.45% 2016 - December 1	$ 50,000	$ 50,000
Marshall County, West Virginia:		
5.45% 2014 - July 1	50,000	50,000
5.90% 2022 - April 1	35,000	35,000
6.85% 2022 - June 1	50,000	50,000
Ohio Air Quality Development		
5.15% 2026 - May 1	50,000	50,000
Unamortized Discount	(1,870)	(1,975)
Total	$233,130	$233,025

Under the terms of the installment purchase contracts, OPCo is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
(a)	2001 - May 16	$ 75,000	$ -
6.75	2004 - July 1	100,000	100,000
7.00	2004 - July 1	75,000	75,000
6.73	2004 - November 1	48,000	48,000
6.24	2008 - December 4	37,225	50,000
7-3/8	2038 - June 30	140,000	140,000
Unamortized Discount		(3,642)	(4,329)
Total		$471,583	$408,671

(a) A floating interest rate is determined monthly. The rate on December 31, 2000 was 7.26%.

Notes payable outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
6.20	2001 - January 31	$ 5,000	$ 5,000
6.20	2001 - January 31	7,000	7,000
6.20	2001 - January 31	18,000	18,000
Total		$30,000	$30,000

Junior debentures outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
8.16	2025 - September 30	$ 85,000	$ 85,000
7.92	2027 - March 31	50,000	50,000
Unamortized Discount		(3,020)	(3,140)
Total		$131,980	$131,860

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of the Company.

Finance obligations were entered into by the Company's coal mining subsidiaries for mining facilities and equipment through sale and leaseback transactions. In accordance with SFAS 98, the transactions did not qualify as sales and leasebacks for accounting purposes and therefore are shown as other long-term debt. The terms on the remaining long-term debt obligation including renewals end on December 24, 2001 and contain a bargain purchase option at expiration of the agreement. At December 31, 2000, the interest rate was 6.98%.

At December 31, 2000, future annual long-term debt payments are as follows:

	Amount (in thousands)
2001	$ 117,506
2002	-
2003	145,985
2004	223,000
2005	-
Later Years	718,725
Total Principal Amount	1,205,216
Unamortized Discount	(9,723)
Total	$1,195,493

OHIO POWER COMPANY AND SUBSIDIARIES
Index to Notes to Consolidated Financial Statements

The notes listed below are combined with the notes to financial statements for AEP and its other subsidiary registrants. The combined footnotes begin on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES
Selected Consolidated Financial Data

	Year Ended December 31,				
	2000	1999	1998 (in thousands)	1997	1996
INCOME STATEMENTS DATA:					
Operating Revenues	$ 962,609	$749,390	$780,159	$712,690	$735,265
Operating Expenses	865,940	650,677	665,085	630,666	635,527
Operating Income	96,669	98,713	115,074	82,024	99,738
Nonoperating Income (Loss)	8,974	946	(91)	1,649	(35,511)
Income Before Interest Charges	105,643	99,659	114,983	83,673	64,227
Interest Charges	38,980	38,151	38,074	37,218	34,748
Net Income	66,663	61,508	76,909	46,455	29,479
Preferred Stock Dividend Requirements	212	212	213	364	816
Gain On Reacquired Preferred Stock	-	-	-	4,211	-
Earnings Applicable to Common Stock	$ 66,451	$ 61,296	$ 76,696	$ 50,302	$ 28,663

	December 31,				
	2000	1999	1998 (in thousands)	1997	1996
BALANCE SHEETS DATA:					
Electric Utility Plant	$2,604,670	$2,459,705	$2,391,722	$2,339,908	$2,290,175
Accumulated Depreciation and Amortization	1,150,253	1,114,255	1,082,081	1,031,322	987,283
Net Electric Utility Plant	$1,454,417	$1,345,450	$1,309,641	$1,308,586	$1,302,892
Total Assets	$2,142,156	$1,524,726	$1,470,939	$1,464,562	$1,447,107
Common Stock and Paid-in Capital	$ 337,230	$ 337,230	$ 337,230	$ 337,230	$ 337,230
Retained Earnings	137,688	139,237	142,941	135,245	143,944
Total Common Shareholder's Equity	$ 474,918	$ 476,467	$ 480,171	$ 472,475	$ 481,174
Cumulative Preferred Stock: Not Subject to Mandatory Redemption	$ 5,283	$ 5,286	$ 5,287	$ 5,287	$ 19,826
Preferred Securities of Subsidiary Trust	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ -
Long-term Debt (a)	$ 470,822	$ 384,516	$ 384,064	$ 438,703	$ 438,369
Total Capitalization and Liabilities	$2,142,156	$1,524,726	$1,470,939	$1,464,562	$1,447,107

(a) Including portion due within one year.

PSO is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power to approximately 499,000 retail customers in eastern and southwestern Oklahoma. PSO also sells electric power at wholesale to other utilities, municipalities and rural electric cooperatives. PSO participates in power marketing and trading activities conducted on its behalf by the AEP System.

PSO shares in the revenues and costs of the AEP Power Pool wholesale sales to and net forward trades with other utility systems and power marketers. Revenues from trading of electricity are recorded net of purchases as operating revenues.

Results of Operations Rise

Net income increased $5.2 million or 8.4% in 2000 due mainly to a gain from the sale of a minority interest in Scientech, Inc. Scientech provides services, systems and instruments, which describe, regulate, monitor and enhance the safety and reliability of power plant operations and their environmental impact.

Operating Revenues

Operating revenues rose 28% due to an increase in fuel and purchased power revenues, reflecting price increases in fuel and purchased power expenses, and an increase in power sales to neighboring utilities and power marketers. Changes in the components of operating revenues were as follows:

(dollars in millions)	Increase From Previous Year Amount	%
Retail:		
Residential	$ 65.8	22
Commercial	52.2	23
Industrial	37.4	23
Other	1.9	20
	157.3	
Wholesale	54.8	140
Transmission and Other	1.1	6
Total	$213.2	28

Revenues from retail customers increased as a result of an increase in fuel-related revenues that reflect rising prices for natural gas used for generation and higher purchased power prices. The Oklahoma fuel clause recovery mechanism provides for the accrual of fuel-related revenues until reviewed and approved for billing to customers by the Oklahoma Corporation Commission. The accrual of additional fuel and purchased power revenues is offset by increases in fuel and purchased power expenses. As a result, accrued fuel-related revenues do not impact results of operations.

The increase in wholesale revenues is attributable to increased sales volumes to other utilities and prices reflecting the increase in gas prices and PSO's participation in the AEP System's power marketing and trading operations. The volume of electricity sales to other utilities, both affiliated and unaffiliated, increased as demand for energy rose in response to warmer summer weather. Since PSO became a subsidiary of AEP in June 2000 as a result of a merger with CSW, PSO shares in the AEP System's power marketing and trading transactions with other entities. Trading involves the purchase and sale of substantial amounts of electricity at wholesale to non-affiliated parties. Revenues from trading are recorded net of purchases.

Operating Expenses Increase

Operating expenses were $215.3 million more in 2000 than in 1999 largely as a result of increased fuel and purchased power expenses. Changes in the components of operating expenses were as follows:

(dollars in millions)	Increase (Decrease) From Previous Year Amount	%
Fuel Expense	$133.6	50
Purchased Power Expense	80.2	107
Other Operation	(0.2)	N.M.
Depreciation and Amortization	1.7	2
Taxes Other Than Federal Income Taxes	(1.7)	(5)
Federal Income Taxes	1.7	6
Total	$215.3	33

N.M. = Not Meaningful

The increases in fuel and purchased power were due primarily to a rise in the average unit fuel cost and higher prices for economy energy purchases reflecting an increase in natural gas prices. As discussed above, changes in fuel and purchased power expenses are generally reflected in revenues on an accrual basis and as such did not impact results of operations.

Nonoperating Income

Nonoperating income increased $8 million primarily due to the gain from the sale of PSO's minority interest in Scientech, Inc. in 2000.

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES
Consolidated Statements of Income

	Year Ended December 31, 2000	1999	1998
	(in thousands)		
OPERATING REVENUES	$962,609	$749,390	$780,159
OPERATING EXPENSES:			
Fuel	402,933	269,316	309,969
Purchased Power	155,087	74,893	57,222
Other Operation	121,697	121,896	109,285
Maintenance	45,858	45,809	36,981
Depreciation and Amortization	76,418	74,736	72,671
Taxes Other Than Federal Income Taxes	33,235	34,970	36,733
Federal Income Taxes	30,712	29,057	42,224
Total Operating Expenses	865,940	650,677	665,085
OPERATING INCOME	96,669	98,713	115,074
NONOPERATING INCOME (LOSS)	8,974	946	(91)
INCOME BEFORE INTEREST CHARGES	105,643	99,659	114,983
INTEREST CHARGES	38,980	38,151	38,074
NET INCOME	66,663	61,508	76,909
PREFERRED STOCK DIVIDEND REQUIREMENTS	212	212	213
EARNINGS APPLICABLE TO COMMON STOCK	$ 66,451	$ 61,296	$ 76,696

Consolidated Statements of Retained Earnings

	Year Ended December 31, 2000	1999	1998
	(in thousands)		
BALANCE AT BEGINNING OF PERIOD AS PREVIOUSLY REPORTED	$142,019	$144,626	$136,996
CONFORMING CHANGE IN ACCOUNTING POLICY	(2,782)	(1,685)	(1,751)
ADJUSTED BALANCE AT BEGINNING OF PERIOD	139,237	142,941	135,245
NET INCOME	66,663	61,508	76,909
DEDUCTIONS:			
Cash Dividends Declared:			
Common Stock	68,000	65,000	69,000
Preferred Stock	212	212	213
BALANCE AT END OF PERIOD	$137,688	$139,237	$142,941

See Notes to Consolidated Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 2000	December 31, 1999
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$ 914,096	$ 916,889
Transmission	396,695	392,029
Distribution	938,053	897,516
General	206,731	217,368
Construction Work in Progress	149,095	35,903
Total Electric Utility Plant	2,604,670	2,459,705
Accumulated Depreciation and Amortization	1,150,253	1,114,255
NET ELECTRIC UTILITY PLANT	1,454,417	1,345,450
OTHER PROPERTY AND INVESTMENTS	38,211	46,205
LONG-TERM ENERGY TRADING CONTRACTS	52,629	-
CURRENT ASSETS:		
Cash and Cash Equivalents	11,301	3,173
Accounts Receivable:		
Customers	60,424	32,301
Affiliated Companies	3,453	2,283
Allowance for Uncollectible Accounts	(467)	-
Fuel - at LIFO cost	28,113	24,143
Materials and Supplies - at average cost	29,642	34,289
Under-recovered Fuel Costs	43,267	6,469
Energy Trading Contracts	382,380	-
Prepayments	1,559	1,572
TOTAL CURRENT ASSETS	559,672	104,230
REGULATORY ASSETS	29,338	16,717
DEFERRED CHARGES	7,889	12,124
TOTAL	$2,142,156	$1,524,726

See Notes to Consolidated Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES

	December 31, 2000	December 31, 1999
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - $15 Par Value:		
Authorized Shares: 11,000,000		
Issued Shares: 10,482,000		
Outstanding Shares: 9,013,000	$ 157,230	$ 157,230
Paid-in Capital	180,000	180,000
Retained Earnings	137,688	139,237
Total Common Shareholder's Equity	474,918	476,467
Cumulative Preferred Stock Not Subject To Mandatory Redemption	5,283	5,286
PSO-Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of PSO	75,000	75,000
Long-term Debt	450,822	364,516
TOTAL CAPITALIZATION	1,006,023	921,269
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	20,000	20,000
Advances from Affiliates	81,120	79,169
Accounts Payable - General	104,379	44,088
Accounts Payable - Affiliated Companies	64,556	35,517
Customer Deposits	19,294	17,751
Taxes Accrued	1,659	18,480
Interest Accrued	8,336	5,420
Energy Trading Contracts	389,279	-
Other	12,137	8,059
TOTAL CURRENT LIABILITIES	700,760	228,484
DEFERRED INCOME TAXES	312,060	281,916
DEFERRED INVESTMENT TAX CREDITS	35,783	37,574
REGULATORY LIABILITIES AND DEFERRED CREDITS	35,292	55,483
LONG-TERM ENERGY TRADING CONTRACTS	52,238	-
CONTINGENCIES (Note 8)		
TOTAL	$2,142,156	$1,524,726

See Notes to Consolidated Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	2000	1999	1998
	Year Ended December 31, (in thousands)		
OPERATING ACTIVITIES:			
Net Income	$ 66,663	$ 61,508	$ 76,909
Adjustments for Noncash Items:			
Depreciation and Amortization	76,418	74,736	72,671
Deferred Income Taxes	25,453	14,521	(1,651)
Deferred Investment Tax Credits	(1,791)	(1,791)	(1,795)
Changes in Certain Assets and Liabilities:			
Accounts Receivable (net)	(28,826)	(1,668)	(13,308)
Fuel, Materials and Supplies	677	(8,985)	(5,809)
Other Property and Investments	7,994	(2,108)	(2,835)
Accounts Payable	89,330	(8,000)	2,196
Taxes Accrued	(16,821)	(4,615)	23,095
Fuel Recovery	(36,798)	(21,709)	30,605
Transmission Coordination Agreement Settlement	(15,063)	15,063	-
Other (net)	(1,621)	(5,509)	13,035
Net Cash Flows From Operating Activities	165,615	111,443	193,113
INVESTING ACTIVITIES:			
Construction Expenditures	(176,851)	(103,122)	(68,897)
Proceeds from Sales of Property and Other Items	-	(8,659)	(8,271)
Net Cash Flows Used For Investing Activities	(176,851)	(111,781)	(77,168)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	105,625	33,232	-
Retirement of Long-term Debt	(20,000)	(33,700)	(55,231)
Change in Advances from Affiliates (net)	1,951	63,277	11,018
Dividends Paid on Common Stock	(68,000)	(65,000)	(69,000)
Dividends Paid on Cumulative Preferred Stock	(212)	(212)	(213)
Net Cash Flows From (Used For) Financing Activities	19,364	(2,403)	(113,426)
Net Increase (Decrease) in Cash and Cash Equivalents	8,128	(2,741)	2,519
Cash and Cash Equivalents January 1	3,173	5,914	3,395
Cash and Cash Equivalents December 31	$ 11,301	$ 3,173	$ 5,914

Supplemental Disclosure:
Cash paid for interest net of capitalized amounts was $33,732,000, $37,081,000 and $37,772,000 and for income taxes was $25,786,000, $23,871,000 and $37,712,000 in 2000, 1999, and 1998, respectively.

See Notes to Consolidated Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA AND SUBSIDIARIES
Consolidated Statements of Capitalization

						December 31, 2000	December 31, 1999
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						$ 474,918	$ 476,467
PREFERRED STOCK - authorized shares 700,000, cumulative $100 par value redeemable at the option of PSO upon 30 days notice.							
Series	Call Price December 31, 2000	Number of Shares Redeemed Year Ended December 31, 2000	1999	1998	Shares Outstanding December 31, 2000		
Not Subject to Mandatory Redemption:							
4.00%	$105.75	25	9	-	44,606	4,460	4,463
4.24%	103.19	-	-	-	8,069	807	807
Premium						16	16
						5,283	5,286
TRUST PREFERRED SECURITIES							
PSO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of PSO, 8.00%, due April 30, 2037						75,000	75,000
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						317,465	337,160
Installment Purchase Contracts						47,357	47,356
Senior Unsecured Notes						106,000	-
Less Portion Due Within One Year						(20,000)	(20,000)
Long-term Debt Excluding Portion Due Within One Year						450,822	364,516
TOTAL CAPITALIZATION						$1,006,023	$ 921,269

See Notes to Consolidated Financial Statements beginning on page L-1.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2000	December 31, 1999
		(in thousands)	
6.43	2000 - March 30	$ -	$ 10,000
5.89	2000 - December 15	-	10,000
5.91	2001 - March 1	6,000	6,000
6.02	2001 - March 1	5,000	5,000
6.02	2001 - March 1	9,000	9,000
6.25	2003 - April 1	35,000	35,000
7.25	2003 - July 1	65,000	65,000
7.38	2004 - December 1	50,000	50,000
6.50	2005 - June 1	50,000	50,000
7.38	2023 - April 1	100,000	100,000
Unamortized Discount		(2,535)	(2,840)
		$317,465	$337,160

Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	December 31, 2000	December 31, 1999
		(in thousands)	
Oklahoma Environmental Finance Authority (OEFA):			
5.90	2007 - December 1	$ 1,000	$ 1,000
Oklahoma Development Finance Authority (ODFA):			
4.875	2014 - June 1	33,700	33,700
Red River Authority of Texas:			
6.00	2020 - June 1	12,660	12,660
Unamortized Discount		(3)	(4)
Total		$47,357	$47,356

Under the terms of the installment purchase contracts, PSO is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2000	December 31, 1999
		(in thousands)	
(a)	2002 - November 21	$106,000	$ -

(a) A floating interest rate is determined monthly. The rate on December 31, 2000 was 7.376%.

At December 31, 2000, future annual long-term debt payments are as follows:

	Amount (in thousands)
2001	$ 20,000
2002	106,000
2003	100,000
2004	50,000
2005	50,000
Later Years	147,360
Total Principal Amount	473,360
Unamortized Discount	(2,538)
Total	$470,822

The notes listed below are combined with the notes to financial statements for AEP and its other subsidiary registrants. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Public Service Company of Oklahoma:

We have audited the accompanying consolidated balance sheet and consolidated statement of capitalization of Public Service Company of Oklahoma and subsidiaries as of December 31, 2000, and the related consolidated statements of income, retained earnings, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The consolidated financial statements of the Company for the years ended December 31, 1999 and 1998, before the restatement described in Note 3 to the consolidated financial statements, were audited by other auditors whose report, dated February 25, 2000, expressed an unqualified opinion on those statements.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provide a reasonable basis for our opinion.

In our opinion, the 2000 consolidated financial statements present fairly, in all material respects, the financial position of Public Service Company of Oklahoma and subsidiaries as of December 31, 2000, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

We also audited the adjustments described in Note 3 that were applied to restate the 1999 and 1998 consolidated financial statements to give retroactive effect to the conforming change in the method of accounting for vacation pay accruals. In our opinion, such adjustments are appropriate and have been properly applied.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 26, 2001

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES

-This page intentionally left blank.-

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES
Selected Consolidated Financial Data

	Year Ended December 31,				
	2000	1999	1998	1997	1996
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	$1,124,210	$971,527	$952,952	$939,869	$920,786
Operating Expenses	995,932	824,465	802,274	800,396	786,669
Operating Income	128,278	147,062	150,678	139,473	134,117
Nonoperating Income (Loss)	3,851	(1,965)	2,451	4,029	(21,178)
Income Before Interest Charges	132,129	145,097	153,129	143,502	112,939
Interest Charges	59,457	58,892	55,135	50,536	50,349
Income Before Extraordinary Item	72,672	86,205	97,994	92,966	62,590
Extraordinary Loss	-	(3,011)	-	-	-
Net Income	72,672	83,194	97,994	92,966	62,590
Preferred Stock Dividend Requirements	229	229	705	2,467	3,053
Gain (Loss) on Reacquired Preferred Stock	-	-	(856)	1,819	-
Earnings Applicable to Common Stock	$ 72,443	$ 82,965	$ 96,433	$ 92,318	$ 59,537

	December 31,				
	2000	1999	1998	1997	1996
			(in thousands)		
BALANCE SHEETS DATA:					
Electric Utility Plant	$3,319,024	$3,231,431	$3,157,911	$3,081,443	$3,044,314
Accumulated Depreciation and Amortization	1,457,005	1,384,242	1,317,057	1,225,865	1,192,356
Net Electric Utility Plant	$1,862,019	$1,847,189	$1,840,854	$1,855,578	$1,851,958
Total Assets	$2,662,534	$2,106,215	$2,081,454	$2,134,618	$2,141,999
Common Stock and Paid-in Capital	$ 380,660	$ 380,660	$ 380,660	$ 380,660	$ 380,660
Retained Earnings	293,989	283,546	296,581	320,148	317,835
Total Common Shareholder's Equity	$ 674,649	$ 664,206	$ 677,241	$ 700,808	$ 698,495
Preferred Stock	$ 4,704	$ 4,706	$ 4,707	$ 30,639	$ 48,496
Trust Preferred Securities	$ 110,000	$ 110,000	$ 110,000	$ 110,000	$ -
Long-term Debt (a)	$ 645,963	$ 541,568	$ 587,673	$ 589,980	$ 642,555
Total Capitalization and Liabilities	$2,662,534	$2,106,215	$2,081,454	$2,134,618	$2,141,999

(a) Including portion due within one year.

SWEPCo is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power to approximately 428,000 retail customers in northeastern Texas, northwestern Louisiana, and western Arkansas. SWEPCo also sells electric power at wholesale to other utilities, municipalities and rural electric cooperatives. SWEPCo participates in power marketing and trading activities conducted on its behalf by the AEP System.

SWEPCo shares in the revenues and costs of the AEP Power Pool's wholesale sales to and net forward trades with other utility systems and power marketers. Revenues from trading of electricity are recorded net of purchases as operating revenues.

Results of Operations

The $10.5 million or 13% decrease in net income in 2000 is due to increased operating expenses. While the $14.8 million or 15% decrease in 1999 is primarily the result of increased other operation and maintenance expenses, the write-off of acquisition expenses attributable to CSW's efforts to acquire the non-nuclear assets of Cajun Power Cooperative, increased interest charges and the effect of an extraordinary loss from the discontinued regulatory accounting for SWEPCo's Texas and Arkansas generating business.

Operating Revenues

Operating revenues significantly increased in 2000 from higher fuel and purchased power revenues due to increased fuel and purchased power expense, increased retail energy sales, the post merger favorable impact of AEP's power marketing and trading operations, which added new wholesale revenues, and the effect of an unfavorable revenue adjustment in 1999 as a result of FERC's approval of a transmission coordination agreement. The transmission coordination agreement provides the means by which the AEP West electric operating companies plan, operate and maintain their separate transmission assets as a single system. The agreement also establishes the method by which these companies allocate transmission revenues received under open access transmission tariffs. In 1999 the AEP West electric operating companies filed a revised transmission coordination agreement which included changes that ensure a revenue allocation in proportion to each company's respective revenue requirement for service it provides under a revised open access transmission tariff. In the third quarter of 1999, SWEPCo and the other AEP West electric operating companies recorded the estimated impact of the reallocation of open access transmission tariff revenues to 1997 which caused SWEPCo to record a reduction to revenues in the third quarter of 1999.

The following analyzes the changes in operating revenues:

(dollars in millions)	Increase (Decrease) From Previous Year			
	2000		1999	
	Amount	%	Amount	%
Retail:				
Residential	$ 32.7		$(19.9)	
Commercial	21.1		0.5	
Industrial	18.4		1.6	
Other	3.3		1.0	
	75.5	10	(16.8)	(2)
Wholesale	68.7	40	32.2	23
Transmission	32.1	N.M.	(5.3)	N.M.
Other	(23.6)	(86)	8.5	44
Total	$152.7	16	$ 18.6	2

N.M. = Not Meaningful

Revenues from retail customers increased in 2000 as a result of an increase in fuel and purchased power revenues and a rise in sales volume caused by warmer summer temperatures. The increase in fuel and purchased power revenues reflects rising prices for natural gas used for generation and related higher costs for purchased power. The Texas and Arkansas fuel clause recovery mechanisms provide for the accrual of fuel-related revenues until reviewed and approved for billing to customers by the regulator. The accrual of additional fuel-related revenues is generally offset by increases in fuel and purchased power expenses. As a result fuel-related revenues do not impact results of operations.

The significant increase in wholesale revenues in 2000 is attributable to increased sales to other utilities and SWEPCo's initial participation in the AEP System's power marketing and trading operations after the merger of CSW and AEP. The volume of wholesale electricity sales to other utilities, both affiliated and unaffiliated, increased as demand for energy rose in response to warmer summer weather. Since SWEPCo became a subsidiary of AEP as a result of the merger in June 2000, SWEPCo shares in the AEP System's power marketing and trading transactions with other entities. Trading transactions involve the purchase and sale of substantial amounts of electricity which are accounted for as revenues net of purchases.

Wholesale revenues increased 23% in 1999 due mainly to an increase in sales to other utilities as a result of increased demand.

Operating Expenses Increase

Total operating expenses increased 21% in 2000 primarily due to significant increases in the cost of fuel and purchased power. In 1999 the operating expenses increased 3% primarily due to increased maintenance expense. The changes in the components of operating expenses were:

(dollars in millions)	Increase (Decrease) From Previous Year			
	2000		1999	
	Amount	%	Amount	%
Fuel	$119.2	31	$ 8.2	2
Purchased Power	40.4	108	1.9	5
Other Operation	17.1	12	1.8	1
Maintenance	10.9	17	13.0	25
Depreciation and Amortization	(4.2)	(4)	10.3	11
Taxes Other Than Federal Income Taxes	(2.2)	(4)	(3.7)	(6)
Federal Income Taxes	(9.8)	(29)	(9.3)	(22)
Total	$171.4	21	$22.2	3

Fuel expense increased in 2000 and 1999 due to an increase in the average unit cost of fuel as a result of an increase in the spot market price for natural gas and an increase in generation to meet the rise in retail and wholesale demand for electricity. The modest increase in fuel expense in 1999 resulted from an increase in the generation of electricity to meet the rising wholesale demand for electricity.

The major increase in purchased power expense in 2000 was primarily caused by an increase in firm energy contract purchases, increased capacity charges and increased economy energy purchases. Purchased power expense for 1999 increased due primarily to an increase in economy energy purchases.

Other operation expense increased in 2000 due primarily to increased regulatory and consulting expenses.

Maintenance expense increased in 2000 as a result of costs to restore service and make repairs following a severe ice storm in December. The increase in 1999 can be attributed to higher power station maintenance, increased tree-trimming and additional overhead line maintenance.

The increase in depreciation and amortization in 1999 is the result of increased depreciable plant and a provision for excess earnings. The Texas Legislation provides that each year during the 1999 through 2001 rate freeze period, electric utilities are subject to an earnings test. See description of earnings test in Note 7 of the Notes to Consolidated Financial Statements.

A decline in franchise taxes in 2000 and ad valorem taxes in 1999 led to the reduction in taxes other than federal income taxes in 2000 and 1999.

The decreases in federal income tax expense attributable to operations in 2000 and 1999 were primarily due to decreases in pre-tax operating income and an unfavorable tax accrual adjustment made in 1998.

Nonoperating Income

The increase in nonoperating income in 2000 was due to the effect of a 1999 write off of Cajun Electric Power Cooperative acquisition expenses following CSW's decision not to continue to pursue the acquisition of Cajun Electric Power Cooperative non-nuclear assets. SWEPCo had deferred approximately $13 million in acquisition costs related to its attempt to acquire Cajun's non-nuclear assets.

Interest Charges

Interest charges for 1999 increased primarily due to increased levels of short-term borrowings and additional interest expenses in connection with changes to the transmission coordination agreements.

Extraordinary Loss

An extraordinary loss of $3 million net of tax was recorded in the third quarter of 1999 when SWEPCo discontinued the application of SFAS 71 regulatory accounting for the generation portion of its business in Texas and Arkansas as a result of legislation passed in those states providing for a transition from cost based rate regulation for SWEPCo's generation business to customer choice market pricing.

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Income

	Year Ended December 31, 2000	1999 (in thousands)	1998
OPERATING REVENUES	$1,124,210	$971,527	$952,952
OPERATING EXPENSES:			
Fuel	498,805	379,597	371,414
Purchased Power	77,792	37,371	35,483
Other Operation	159,459	142,385	140,627
Maintenance	75,123	64,241	51,219
Depreciation and Amortization	104,679	108,831	98,479
Taxes Other Than Federal Income Taxes	56,283	58,458	62,207
Federal Income Taxes	23,791	33,582	42,845
Total Operating Expenses	995,932	824,465	802,274
OPERATING INCOME	128,278	147,062	150,678
NONOPERATING INCOME (LOSS)	3,851	(1,965)	2,451
INCOME BEFORE INTEREST CHARGES	132,129	145,097	153,129
INTEREST CHARGES	59,457	58,892	55,135
INCOME BEFORE EXTRAORDINARY ITEM	72,672	86,205	97,994
EXTRAORDINARY LOSS (net of tax of $1,621,000)	-	(3,011)	-
NET INCOME	72,672	83,194	97,994
PREFERRED STOCK DIVIDEND REQUIREMENTS	229	229	705
LOSS ON REACQUIRED PREFERRED STOCK	-	-	(856)
EARNINGS APPLICABLE TO COMMON STOCK	$ 72,443	$ 82,965	$ 96,433

Consolidated Statements of Retained Earnings

	2000	1999	1998
BALANCE AT BEGINNING OF PERIOD AS PREVIOUSLY REPORTED	$288,019	$300,592	$324,050
Conforming Change in Accounting Policy	(4,473)	(4,011)	(3,902)
ADJUSTED BALANCE AT BEGINNING OF PERIOD	283,546	296,581	320,148
NET INCOME	72,672	83,194	97,994
LOSS ON REACQUIRED PREFERRED STOCK	-	-	(856)
DEDUCTIONS:			
Cash Dividends Declared:			
Common Stock	62,000	96,000	120,000
Preferred Stock	229	229	705
BALANCE AT END OF PERIOD	$293,989	$283,546	$296,581

See Notes to Consolidated Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 2000	December 31, 1999
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$1,414,527	$1,402,062
Transmission	519,317	484,327
Distribution	1,001,237	958,318
General	325,948	333,949
Construction Work in Progress	57,995	52,775
Total Electric Utility Plant	3,319,024	3,231,431
Accumulated Depreciation and Amortization	1,457,005	1,384,242
NET ELECTRIC UTILITY PLANT	1,862,019	1,847,189
OTHER PROPERTY AND INVESTMENTS	39,627	37,080
LONG-TERM ENERGY TRADING CONTRACTS	63,028	-
CURRENT ASSETS:		
Cash and Cash Equivalents	1,907	3,043
Accounts Receivable:		
Customers	42,310	49,939
Affiliated Companies	11,419	6,053
Allowance for Uncollectible Accounts	(911)	(4,428)
Fuel Inventory - at average cost	40,024	60,844
Materials and Supplies - at average cost	25,137	26,420
Under-recovered Fuel Costs	35,469	-
Energy Trading Contracts	457,936	-
Prepayments	16,780	15,953
TOTAL CURRENT ASSETS	630,071	157,824
REGULATORY ASSETS	57,082	47,180
DEFERRED CHARGES	10,707	16,942
TOTAL	$2,662,534	$2,106,215

See Notes to Consolidated Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES

	December 31, 2000	December 31, 1999
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - $18 Par Value:		
Authorized - 7,600,000 Shares		
Outstanding - 7,536,640 Shares	$ 135,660	$ 135,660
Paid-in Capital	245,000	245,000
Retained Earnings	293,989	283,546
Total Common Shareholder's Equity	674,649	664,206
Preferred Stock	4,704	4,706
SWEPCO - obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of SWEPCO	110,000	110,000
Long-term Debt	645,368	495,973
TOTAL CAPITALIZATION	1,434,721	1,274,885
OTHER NONCURRENT LIABILITIES	11,290	9,255
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	595	45,595
Advances from Affiliates	16,823	140,897
Accounts Payable - General	107,747	60,689
Accounts Payable - Affiliated Companies	36,021	39,117
Customer Deposits	16,433	14,236
Taxes Accrued	11,224	24,374
Interest Accrued	13,198	9,792
Energy Trading Contracts	466,198	-
Other	15,064	12,623
TOTAL CURRENT LIABILITIES	683,303	347,323
DEFERRED INCOME TAXES	399,204	376,504
DEFERRED INVESTMENT TAX CREDITS	53,167	57,649
REGULATORY LIABILITIES AND DEFERRED CREDITS	18,288	40,599
LONG-TERM ENERGY TRADING CONTRACTS	62,561	-
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$2,662,534	$2,106,215

See Notes to Consolidated Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	Year Ended December 31, 2000	1999	1998
	(in thousands)		
OPERATING ACTIVITIES:			
Net Income	$ 72,672	$ 83,194	$ 97,994
Adjustments for Noncash Items:			
Depreciation and Amortization	104,679	108,831	98,479
Deferred Income Taxes	14,653	(17,347)	(11,909)
Deferred Investment Tax Credits	(4,482)	(4,565)	(4,631)
Changes in Certain Assets and Liabilities:			
Accounts Receivable (net)	(1,254)	(11,134)	41,077
Fuel, Materials and Supplies	22,103	(21,891)	(14,436)
Accounts Payable	43,962	(12,953)	(25,852)
Taxes Accrued	(13,150)	1,185	10,305
Transmission Coordination Agreement Settlement	(24,406)	24,406	-
Fuel Recovery	(38,357)	(2,490)	18,391
Other (net)	25,208	8,731	17,045
Net Cash Flows From Operating Activities	201,628	155,967	226,463
INVESTING ACTIVITIES:			
Construction Expenditures	(120,671)	(111,019)	(83,120)
Other	446	(4,167)	(5,202)
Net Cash Flows Used For Investing Activities	(120,225)	(115,186)	(88,322)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	149,360	-	-
Retirement of Cumulative Preferred Stock	(1)	(1)	(27,988)
Retirement of Long-term Debt	(45,595)	(46,144)	(2,354)
Change in Advances from Affiliates (net)	(124,074)	100,192	15,530
Dividends Paid on Common Stock	(62,000)	(96,000)	(120,000)
Dividends Paid on Cumulative Preferred Stock	(229)	(229)	(1,183)
Net Cash Flows Used For Financing Activities	(82,539)	(42,182)	(135,995)
Net Increase (Decrease) in Cash and Cash Equivalents	(1,136)	(1,401)	2,146
Cash and Cash Equivalents January 1	3,043	4,444	2,298
Cash and Cash Equivalents December 31	$ 1,907	$ 3,043	$ 4,444

Supplemental Disclosure:
Cash paid for interest net of capitalized amounts was $51,110,611, $55,254,000 and $50,341,000 and for income taxes was $27,993,879, $55,677,000 and $57,977,000 in 2000, 1999, and 1998, respectively.

See Notes to Consolidated Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES
Consolidated Statements of Capitalization

						December 31, 2000	December 31, 1999
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						$ 674,649	$ 664,206
PREFERRED STOCK - authorized 1,860,000 shares $100 par value							
Series	Call Price December 31, 2000	Number of Shares Redeemed Year Ended December 31, 2000	1999	1998	Shares Outstanding December 31, 2000		
Not Subject to Mandatory Redemption:							
4.28%	$103.90	-	-	-	7,386	739	739
4.65%	$102.75	-	1	-	1,907	190	191
5.00%	$109.00	12	2	20	37,715	3,771	3,772
Premium						4	4
						4,704	4,706
TRUST PREFERRED SECURITIES SWEPCo-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of SWEPCo, 7.875%, due April 30, 2037						110,000	110,000
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						315,477	360,430
Installment Purchase Contracts						180,486	181,138
Senior Unsecured Notes						150,000	-
Less Portion Due Within One Year						(595)	(45,595)
Long-term Debt Excluding Portion Due Within One Year						645,368	495,973
TOTAL CAPITALIZATION						$1,434,721	$1,274,885

See Notes to Consolidated Financial Statements beginning on page L-1.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2000	December 31, 1999
		(in thousands)	
5-1/4	2000 - April 1	$ -	$ 45,000
6-5/8	2003 - February 1	55,000	55,000
7-3/4	2004 - June 1	40,000	40,000
6.20	2006 - November 1	5,795	5,940
6.20	2006 - November 1	1,000	1,000
7.00	2007 - September 1	90,000	90,000
7-1/4	2023 - July 1	45,000	45,000
6-7/8	2025 - October 1	80,000	80,000
Unamortized Discount		(1,318)	(1,510)
		$315,477	$360,430

Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	December 31, 2000	December 31, 1999
		(in thousands)	
DeSoto:			
7.60	2019 - January 1	$ 53,500	$ 53,500
Sabine:			
6.10	2018 - April 1	81,700	81,700
Titus County:			
6.90	2004 - November 1	12,290	12,290
6.00	2008 - January 1	13,520	13,970
8.20	2011 - August 1	17,125	17,125
Unamortized Premium		2,351	2,553
		$180,486	$181,138

Under the terms of the installment purchase contracts, SWEPCo is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 2000	December 31, 1999
		(in thousands)	
(a)	2002 - March 1	$150,000	$ -

(a) A floating interest rate is determined monthly. The rate on December 31, 2000 was 6.97%.

At December 31, 2000, future annual long-term debt payments are as follows:

	Amount (in thousands)
2001	$ 595
2002	150,595
2003	55,595
2004	52,885
2005	595
Later Years	384,665
Total Principal Amount	644,930
Unamortized Premium	1,033
Total	$645,963

SOUTHWESTERN ELECTRIC POWER COMPANY AND SUBSIDIARIES
Index to Notes to Consolidated Financial Statements

The notes listed below are combined with the notes to financial statements for AEP and its other subsidiary registrants. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Southwestern Electric Power Company:

We have audited the accompanying consolidated balance sheet and consolidated statement of capitalization of Southwestern Electric Power Company and subsidiaries as of December 31, 2000, and the related consolidated statements of income, retained earnings, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The consolidated financial statements of the Company for the years ended December 31, 1999 and 1998, before the restatement described in Note 3 to the consolidated financial statements, were audited by other auditors whose report, dated February 25, 2000, expressed an unqualified opinion on those statements.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the 2000 consolidated financial statements present fairly, in all material respects, the financial position of Southwestern Electric Power Company and subsidiary as of December 31, 2000, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

We also audited the adjustments described in Note 3 that were applied to restate the 1999 and 1998 consolidated financial statements to give retroactive effect to the conforming change in the method of accounting for vacation pay accruals. In our opinion, such adjustments are appropriate and have been properly applied.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 26, 2001

WEST TEXAS UTILITIES COMPANY

WEST TEXAS UTILITIES COMPANY
Selected Financial Data

	Year Ended December 31,				
	2000	1999	1998 (in thousands)	1997	1996
INCOME STATEMENTS DATA:					
Operating Revenues	$ 572,794	$ 445,709	$ 424,953	$ 397,779	$ 377,057
Operating Expenses	520,453	391,910	365,677	353,195	327,499
Operating Income	52,341	53,799	59,276	44,584	49,558
Nonoperating Income (Loss)	(1,675)	2,488	2,712	1,463	(9,922)
Income Before Interest Charges	50,666	56,287	61,988	46,047	39,636
Interest Charges	23,216	24,420	24,263	24,570	25,241
Income Before Extraordinary Item	27,450	31,867	37,725	21,477	14,395
Extraordinary Loss	-	(5,461)	-	-	-
Net Income	27,450	26,406	37,725	21,477	14,395
Preferred Stock Dividend Requirements	104	104	104	144	264
Gain on Reacquired Preferred Stock	-	-	-	1,085	-
Earnings Applicable to Common Stock	$ 27,346	$ 26,302	$ 37,621	$ 22,418	$ 14,131

	December 31,				
	2000	1999	1998 (in thousands)	1997	1996
BALANCE SHEETS DATA:					
Electric Utility Plant	$1,229,339	$1,182,544	$1,146,582	$1,108,845	$1,088,141
Accumulated Depreciation and Amortization	515,041	495,847	473,503	441,281	414,777
Net Electric Utility Plant	$ 714,298	$ 686,697	$ 673,079	$ 667,564	$ 673,364
Total Assets	$1,088,932	$ 861,205	$ 819,446	$ 826,858	$ 837,412
Common Stock and Paid-in Capital	$ 139,450	$ 139,450	$ 139,450	$ 139,450	$ 139,450
Retained Earnings	122,588	113,242	114,940	117,319	120,901
Total Common Shareholder's Equity	$ 262,038	$ 252,692	$ 254,390	$ 256,769	$ 260,351
Cumulative Preferred Stock: Not Subject to Mandatory Redemption	$ 2,482	$ 2,482	$ 2,482	$ 2,483	$ 6,291
Long-term Debt (a)	$ 255,843	$ 303,686	$ 303,518	$ 303,351	$ 303,182
Total Capitalization and Liabilities	$1,088,932	$ 861,205	$ 819,446	$ 826,858	$ 837,412

(a) Including portion due within one year.

WTU is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power and provides electric power to approximately 190,000 retail customers in west and central Texas. WTU also sells electric power at wholesale to other utilities, municipalities and rural electric cooperatives. WTU participates in power marketing and trading activities conducted on its behalf by the AEP System.

WTU shares in the revenues and costs of the AEP Power Pool's wholesale sales to and net forward trades with other utility systems and power marketers. Revenues from trading of electricity are recorded net of purchases as operating revenues.

Results of Operations

Income before extraordinary items decreased $4.4 million or 14%. The decrease was primarily due to a decrease in nonoperating income, as a result of the termination of merchandise sales and the cost of phasing out the merchandise sales program. The decrease in nonoperating income is partially offset by a decrease in interest charges.

An extraordinary loss related to the discontinuance of SFAS 71 regulatory accounting for WTU's generation business of $5.5 million after tax was recorded in September 1999.

Operating Revenues

A 29% increase in operating revenues was due to increased fuel and purchases power revenues, reflecting higher fuel and purchased power expenses, and an increase in weather-related demand for electricity. Under the operation of a fuel and purchase power clause mechanism in Texas, revenues are accrued to reflect fuel and purchased power cost increases. The accrued revenues are subsequently reviewed and approved for recovery by the PUCT. As a result changes in fuel and purchase power revenues do not generally impact results of operations.

Changes in the components of operating revenues were as follows:

(dollars in millions)	Increase (Decrease) From Previous Year Amount	%
Retail:		
Residential	$ 31.7	24
Commercial	18.9	24
Industrial	13.3	26
Other	9.3	25
	73.2	
Wholesale	47.8	46
Transmission	3.7	11
Other	2.4	128
Total	$127.1	29

Revenues from retail customers increased significantly as a result of an increase in fuel and purchase power related revenues reflecting rising prices for natural gas used for generation and related higher purchased power prices. Since the Texas fuel and purchase power clause recovery mechanism provides for the accrual of revenues to recover fuel and purchase power cost changes until reviewed and approved for billing to customers by the PUCT, increases in fuel and purchased power expenses and related accrued revenues do not adversely effect results of operations.

The significant increase in wholesale revenues is attributable to increased sales to other utilities and WTU's participation in the AEP System's power marketing and trading operations. The volume of electricity sales to other utilities, both affiliated and unaffiliated, increased as demand for energy rose in response to warmer summer weather. Since WTU became a subsidiary of AEP as a result of the merger in June 2000, WTU shares in the AEP System's power marketing and trading transactions with other non-affiliated entities. Trading involves the purchase and sale of substantial amounts of electricity to non-affiliated parties. Revenues from trading are recorded net of purchases.

Operating Expenses

Operating expenses were $520.5 million or 33% more than in 1999 largely as a result of increased fuel and purchased power expenses. Changes in the components of operating expenses were as follows:

(dollars in millions)	Increase (Decrease) From Previous Year Amount	%
Fuel	$ 59.8	48
Purchased Power	66.1	107
Other Operation	(1.2)	(1)
Maintenance	1.6	8
Depreciation and Amortization	4.4	9
Taxes Other Than Federal Income	(2.9)	(10)
Federal Income Taxes	0.8	6
Total	$128.6	33

The substantial increase in fuel expense was primarily due to a rise in the average cost of fuel resulting from an increase in spot market prices of natural gas. WTU uses natural gas as fuel for 72% of its generating capacity. The nature of the natural gas market is such that both long-term and short-term contracts are generally based on the current spot market price. Consequently, changes in natural gas prices affect WTU's fuel expense. However, as explained above they generally do not impact results of operations.

Purchased power expense increased due primarily to an increase in the cost per MWH purchased to replace generation at a power plant which was out of service for 90 days as a result of a control room fire and to the adverse impact of natural gas prices on wholesale purchased power prices.

The increase in maintenance expense was due to an increase in power plant maintenance and overhead line maintenance. The increase in power plant maintenance was partly due to repair of the fire damaged control room.

Depreciation and amortization expense increased due to the recordation of increased accruals for estimated excess earnings under the Texas Legislation.

The decrease in taxes other than federal income taxes was primarily due to lower ad valorem and state franchise taxes.

Nonoperating Income

Nonoperating income decreased $4.2 million primarily due to the termination of merchandise sales and the cost of phasing out the merchandise sales program.

Interest Charges

The decrease in interest charges of $1.2 million or 5% resulted from a reduction in long-term borrowings.

Extraordinary Loss

The extraordinary loss of $5.5 million was recorded in the third quarter of 1999 when WTU discontinued the application of SFAS 71 regulatory accounting for the generation portion of its business as a result of Texas Jurisdictional Legislation which provides for a transition from cost based rate regulation for WTU's generation business to customer choice and market based pricing for the supply of electricity at retail.

WEST TEXAS UTILITIES COMPANY
Statements of Income

	Year Ended December 31, 2000	1999	1998
		(in thousands)	
OPERATING REVENUES	$ 572,794	$ 445,709	$ 424,953
OPERATING EXPENSES:			
Fuel	183,154	123,348	122,836
Purchased Power	127,583	61,532	48,131
Other Operation	93,078	94,290	90,061
Maintenance	21,241	19,604	16,666
Depreciation and Amortization	55,172	50,789	42,750
Taxes Other Than Federal Income Taxes	25,321	28,267	24,638
Federal Income Taxes	14,904	14,080	20,595
Total Operating Expenses	520,453	391,910	365,677
OPERATING INCOME	52,341	53,799	59,276
NONOPERATING INCOME (LOSS)	(1,675)	2,488	2,712
INCOME BEFORE INTEREST CHARGES	50,666	56,287	61,988
INTEREST CHARGES	23,216	24,420	24,263
INCOME BEFORE EXTRAORDINARY ITEMS	27,450	31,867	37,725
EXTRAORDINARY LOSS - (net of tax of $2,941,000)	-	(5,461)	-
NET INCOME	27,450	26,406	37,725
PREFERRED STOCK DIVIDEND REQUIREMENTS	104	104	104
EARNINGS APPLICABLE TO COMMON STOCK	$ 27,346	$ 26,302	$ 37,621

Statements of Retained Earnings

	Year Ended December 31, 2000	1999	1998
		(in thousands)	
BALANCE AT BEGINNING OF PERIOD AS PREVIOUSLY REPORTED	$115,856	$117,189	$119,479
CONFORMING CHANGE IN ACCOUNTING POLICY	(2,614)	(2,249)	(2,160)
ADJUSTED BALANCE AT BEGINNING OF PERIOD	113,242	114,940	117,319
NET INCOME	27,450	26,406	37,725
DEDUCTIONS:			
Cash Dividends Declared:			
Common Stock	18,000	28,000	40,000
Preferred Stock	104	104	104
BALANCE AT END OF PERIOD	$122,588	$113,242	$114,940

See Notes to Financial Statements beginning on page L-1.

WEST TEXAS UTILITIES COMPANY
Balance Sheets

	December 31, 2000	December 31, 1999
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$ 431,793	$ 429,783
Transmission	235,303	220,479
Distribution	416,587	403,206
General (including nuclear fuel)	110,832	113,945
Construction Work in Progress	34,824	15,131
Total Electric Utility Plant	1,229,339	1,182,544
Accumulated Depreciation and Amortization	515,041	495,847
NET ELECTRIC UTILITY PLANT	714,298	686,697
OTHER PROPERTY AND INVESTMENTS	23,154	21,570
ENERGY TRADING CONTRACTS - LONG-TERM	20,944	-
CURRENT ASSETS:		
Cash and Cash Equivalents	6,941	6,074
Accounts Receivable:		
Customers	36,217	45,928
Affiliated Companies	16,095	4,837
Allowance for Uncollectible Accounts	(288)	(186)
Fuel - at average cost	12,174	17,133
Materials and Supplies - at average cost	10,510	14,029
Underrecovered Fuel Costs	67,655	14,652
Energy Trading Contracts	152,174	-
Prepayments	851	619
TOTAL CURRENT ASSETS	302,329	103,086
REGULATORY ASSETS	24,808	29,745
DEFERRED CHARGES	3,399	20,107
TOTAL	$1,088,932	$ 861,205

See Notes to Financial Statements beginning on page L-1.

WEST TEXAS UTILITIES COMPANY

	December 31, 2000	December 31, 1999
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - $25 Par Value:		
Authorized - 7,800,000 Shares		
Outstanding - 5,488,560 Shares	$ 137,214	$137,214
Paid-in Capital	2,236	2,236
Retained Earnings	122,588	113,242
Total Common Shareholder's Equity	262,038	252,692
Cumulative Preferred Stock:		
Not Subject to Mandatory Redemption	2,482	2,482
Long-term Debt	255,843	263,686
TOTAL CAPITALIZATION	520,363	518,860
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	-	40,000
Advances from Affiliates	58,578	21,408
Accounts Payable - General	45,562	39,611
Accounts Payable - Affiliated Companies	42,212	19,770
Customer Deposits	2,659	2,396
Taxes Accrued	18,901	12,458
Interest Accrued	3,717	4,165
Energy Trading Contracts	154,919	-
Other	7,906	5,510
TOTAL CURRENT LIABILITIES	334,454	145,318
DEFERRED INCOME TAXES	157,038	148,992
DEFERRED INVESTMENT TAX CREDITS	24,052	25,323
REGULATORY LIABILITIES AND DEFERRED CREDITS	32,236	22,712
ENERGY TRADING CONTRACTS - LONG-TERM	20,789	-
COMMITMENTS AND CONTINGENCIES (Note 8)		
TOTAL	$1,088,932	$861,205

See Notes to Financial Statements beginning on page L-1.

WEST TEXAS UTILITIES COMPANY
Statements of Cash Flows

	Year Ended December 31, 2000	1999	1998
	(in thousands)		
OPERATING ACTIVITIES:			
Net Income	$ 27,450	$ 26,406	$ 37,725
Adjustments for Noncash Items:			
Depreciation and Amortization	55,172	50,789	42,750
Deferred Federal Income Taxes	8,164	12,026	(6,626)
Deferred Investment Tax Credits	(1,271)	(1,275)	(1,321)
Extraordinary Loss - Discontinuance of SFAS 71	-	5,461	-
CHANGES IN CERTAIN ASSETS AND LIABILITIES:			
Accounts Receivable (net)	(1,445)	(18,890)	(21,119)
Fuel, Materials and Supplies	8,478	(3,785)	(660)
Accounts Payable	28,393	7,229	305
Taxes Accrued	6,443	2,427	(1,344)
Fuel Recovery	(53,003)	(10,672)	7,988
Other Property and Investments	(1,584)	(2,057)	(1,344)
Transmission Coordination Agreement Settlement	15,465	(15,465)	-
Other (net)	2,016	10,448	4,972
Net Cash Flows From Operating Activities	94,278	62,642	61,326
INVESTING ACTIVITIES:			
Construction Expenditures	(64,477)	(49,443)	(36,867)
Other	-	(3,832)	(5,782)
Net Cash Flows Used For Investing Activities	(64,477)	(53,275)	(42,649)
FINANCING ACTIVITIES:			
Retirement of Long-term Debt	(48,000)	-	-
Change in Advances from Affiliates (net)	37,170	16,835	4,573
Dividends Paid on Common Stock	(18,000)	(28,000)	(40,000)
Dividends Paid on Cumulative Preferred Stock	(104)	(105)	(104)
Net Cash Flows From (Used For) Financing Activities	(28,934)	(11,270)	(35,531)
Net Increase (Decrease) in Cash and Cash Equivalents	867	(1,903)	(16,854)
Cash and Cash Equivalents at Beginning of Period	6,074	7,977	24,831
Cash and Cash Equivalents at End of Period	$ 6,941	$ 6,074	$ 7,977

Supplemental Disclosure:
Cash paid (received) for interest net of capitalized amounts was $19,088,000, $17,577,000 and $17,250,000 and for income taxes was $(906,000), $3,309,000 and $29,533,000 in 2000, 1999 and 1998, respectively.

See Notes to Financial Statements beginning on page L-1.

WEST TEXAS UTILITIES COMPANY
Statements of Capitalization

						December 31, 2000	December 31, 1999
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						$262,038	$252,692
PREFERRED STOCK - authorized 810,000 shares $100 par value							
Series	Call Price December 31, 2000	Number of Shares Redeemed Year Ended December 31, 2000	1999	1998	Shares Outstanding December 31, 2000		
Not Subject to Mandatory Redemption:							
4.40%	$107.00	1	2	-	23,672	2,367	2,367
Premium						115	115
						2,482	2,482
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						211,533	259,376
Installment Purchase Contracts						44,310	44,310
Less Portion Due Within One Year						-	(40,000)
Long-term Debt Excluding Portion Due Within One Year						255,843	263,686
TOTAL CAPITALIZATION						$520,363	$518,860

See Notes to Financial Statements beginning on page L-1.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
7-3/4	2007 - June 1	$ 25,000	$ 25,000
6-7/8	2002 - October 1	35,000	35,000
7	2004 - October 1	40,000	40,000
6-1/8	2004 - February 1	40,000	40,000
7-1/2	2000 - April 1	-	40,000
6-3/8	2005 - October 1	72,000	80,000
Unamortized Discount		(467)	(624)
		$211,533	$259,376

Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into, in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	December 31, 2000 (in thousands)	December 31, 1999 (in thousands)
Red River Authority of Texas:			
6	2020 - June 1	$44,310	$44,310

Under the terms of the installment purchase contracts, WTU is required to pay amounts sufficient to enable the payment of interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

At December 31, 2000, future annual long-term debt payments are as follows:

	Amount (in thousands)
2001	$ -
2002	35,000
2003	-
2004	80,000
2005	72,000
Later Years	69,310
Total	$256,310

WEST TEXAS UTILITIES COMPANY

Index to Notes to Financial Statements

The notes listed below are combined with the notes to financial statements for AEP and its other subsidiary registrants. The combined footnotes begin on page L-1.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of West Texas Utilities Company:

We have audited the accompanying balance sheet and statement of capitalization of West Texas Utilities Company as of December 31, 2000, and the related statements of income, retained earnings, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The financial statements of the Company for the years ended December 31, 1999 and 1998, before the restatement described in Note 3 to the financial statements, were audited by other auditors whose report, dated February 25, 2000, expressed an unqualified opinion on those statements.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the 2000 financial statements present fairly, in all material respects, the financial position of West Texas Utilities Company as of December 31, 2000, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

We also audited the adjustments described in Note 3 that were applied to restate the 1999 and 1998 financial statements to give retroactive effect to the conforming change in the method of accounting for vacation pay accruals. In our opinion, such adjustments are appropriate and have been properly applied.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 26, 2001

NOTES TO FINANCIAL STATEMENTS

The notes to financial statements that follow are a combined presentation for AEP and its subsidiary registrants. The following list of footnotes shows the registrant to which they apply:

1. Significant Accounting Policies	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
2. Extraordinary Items	AEP, APCo, CPL, CSPCo, OPCo, SWEPCo, WTU
3. Merger	AEP, CPL, I&M, KPCo, PSO, SWEPCo, WTU
4. Nuclear Plant Restart	AEP, I&M
5. Rate Matters	AEP, APCo, CPL, CSPCo, I&M, KPCo, OPCo, OPCo, SWEPCo, WTU
6. Effects of Regulation	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, KPCo, OPCo, PSO, SWEPCo, WTU
7. Industry Restructuring	AEP, APCo, CPL, CSPCo, I&M, OPCo, PSO, SWEPCo, WTU
8. Commitments and Contingencies	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
9. Acquisitions	AEP
10. International Investments	AEP
11. Staff Reductions	AEP, APCo, CSPCo, I&M, KPCo, OPCo
12. Benefit Plans	AEP, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
13. Stock Based Compensation	AEP
14. Business Segments	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
15. Financial Instruments, Credit and Risk Management	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
16. Income Taxes	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, KPCo, OPCo, PSO, SWEPCo, WTU
17. Supplementary Information	AEP, APCo, CSPCo, I&M, OPCo
18. Leases	AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo
19. Lines of Credit and Commitment Fees	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
20. Unaudited Quarterly Financial Information	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
21. Trust Preferred Securities	AEP, CPL, PSO, SWEPCo,

22. Jointly Owned Electric Utility Plant	CPL, CSPCo, PSO, SWEPCo, WTU
23. Related Party Transactions	AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU

1. Significant Accounting Policies:

Business Operations – AEP's principal business conducted by its eleven domestic electric utility operating companies is the generation, transmission and distribution of electric power. Nine of AEP's eleven domestic electric utility operating companies, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU, are SEC registrants. AEGCo is a domestic generating company wholly-owned by AEP that is an SEC registrant. These companies are subject to regulation by the FERC under the Federal Power Act and follow the Uniform System of Accounts prescribed by FERC. They are subject to further regulation with regard to rates and other matters by state regulatory commissions.

Wholesale marketing and trading of electricity and gas is conducted in the United States and Europe. In addition AEP's domestic operations includes non-regulated independent power and cogeneration facilities and an intra-state midstream natural gas operation in Louisiana.

AEP's international operations include regulated supply and distribution of electricity and other non-regulated power generation projects in the United Kingdom, Australia, Mexico, South America and China.

In addition to the above energy related operations, AEP is also involved in domestic factoring of accounts receivable, investing in leveraged leases and providing energy services worldwide and communications related services domestically.

Rate Regulation – The AEP System is subject to regulation by the SEC under the PUHCA. The rates charged by the domestic utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale electricity operations and transmission rates and the state commissions regulate retail generation and distribution rates. The prices charged by foreign subsidiaries located in the UK, Australia, China, Mexico and Brazil are regulated by the authorities of that country and are generally subject to price controls.

Principles of Consolidation – AEP's consolidated financial statements include AEP Co., Inc. and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned subsidiaries. The consolidated financial statements for APCo, CPL, CSPCo, I&M, OPCo, PSO and SWEPCo include the registrant and its wholly-owned subsidiaries. Significant intercompany items are eliminated in consolidation. Equity investments that are 50% or less owned are accounted for using the equity method with their equity earnings included in Other Income, net for AEP and nonoperating income for the registrant subsidiaries.

Basis of Accounting - As cost-based rate-regulated electric public utility companies, the financial statements for AEP and each of the registrant subsidiaries reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues. Application of SFAS 71 for the generation portion of the business was discontinued as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June 2000, in Texas by CPL, WTU, and SWEPCo in September 1999 and in Arkansas by SWEPCo in September 1999. See Note 7, "Industry Restructuring" for additional information.

Use of Estimates - The preparation of these financial statements in conformity with generally accepted accounting principles requires in certain instances the use of estimates and assumptions that affect the reported amounts of assets and liabilities along with the disclosure of contingent liabilities at the date of financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Property, Plant and Equipment – Domestic electric utility property, plant and equipment are stated at original cost of the acquirer. The property, plant and equipment of SEEBOARD, CitiPower and LIG are stated at their fair market value at acquisition plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate regulated operations retirements from the plant accounts and associated removal costs, net of salvage, are deducted from accumulated depreciation. The costs of labor, materials and overheads incurred to operate and maintain plant are included in operating expenses.

Allowance for Funds Used During Construction (AFUDC) - AFUDC is a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For domestic regulated electric utility plant, it represents the estimated cost of borrowed and equity funds used to finance construction projects. The amounts of AFUDC for 2000, 1999 and 1998 were not significant. Effective with the discontinuance of the application of SFAS 71 regulatory accounting for domestic generating assets in Arkansas, Ohio, Texas, Virginia and West Virginia and for AEP's other nonregulated operations interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs." The amounts of interest capitalized was not material in 2000, 1999, and 1998.

Depreciation, Depletion and Amortization - Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of property, other than coal-mining property, and is calculated largely through the use of composite rates by functional class as follows:

Functional Class of Property	Annual Composite Depreciation Rates Ranges 2000
Production:	
Steam-Nuclear	2.8% to 3.4%
Steam-Fossil-Fired	2.3% to 4.5%
Hydroelectric-Conventional and Pumped Storage	2.7% to 3.4%
Transmission	1.7% to 3.1%
Distribution	3.3% to 4.2%
Other	2.5% to 20.0%

Functional Class of Property	Annual Composite Depreciation Rates Ranges 1999
Production:	
Steam-Nuclear	2.8% to 3.4%
Steam-Fossil-Fired	3.2% to 5.0%
Hydroelectric-Conventional and Pumped Storage	2.7% to 3.4%
Transmission	1.7% to 2.7%
Distribution	2.8% to 4.2%
Other	2.0% to 20.0%

Functional Class of Property	Annual Composite Depreciation Rates Ranges 1998
Production:	
Steam-Nuclear	2.8% to 3.4%
Steam-Fossil-Fired	3.2% to 4.4%
Hydroelectric-Conventional and Pumped Storage	2.7% to 3.4%
Transmission	1.7% to 2.7%
Distribution	3.3% to 4.2%
Other	2.5% to 20.0%

The following table provides the annual composite depreciation rates generally used by the AEP registrant subsidiaries for the years 2000, 1999 and 1998 which were as follows:

	Nuclear	Steam	Hydro	Transmission	Distribution	General
AEGCo	- %	3.5%	- %	- %	- %	2.8%
APCo	-	3.4	2.9	2.2	3.3	3.2
CPL	2.8	2.3	-	2.3	3.5	4.2
CSPCo	-	3.2	-	2.3	3.6	3.3
I&M	3.4	4.5	3.4	1.9	4.2	3.8
KPCo	-	3.8	-	1.7	3.5	2.5
OPCo	-	3.4	2.7	2.3	4.0	2.7
PSO	-	2.7	-	2.3	3.4	6.4
SWEPCo	-	3.3	-	2.7	3.6	4.6
WTU	-	2.7	-	3.1	3.3	6.8

Depreciation, depletion and amortization of OPCo's coal-mining assets is provided over each asset's estimated useful life or the estimated life of the mine, whichever is shorter, and is calculated using the straight-line method for mining structures and equipment. The units-of-production method is used to amortize coal rights and mine development costs based on estimated recoverable tonnages at a current average rate of \$5.07 per ton in 2000, \$2.32 per ton in 1999 and \$1.85 per ton in 1998. These costs are included in the cost of coal charged to fuel expense. See Note 5 "Rate Matters" regarding the closure and possible sale of affiliated mines.

Cash and Cash Equivalents - Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Inventory – Except for CPL, PSO and WTU, the domestic utility companies value fossil fuel inventories using a weighted average cost method. CPL, PSO and WTU, utilize the LIFO method to value fossil fuel inventories. SWEPCo continues to use the weighted average cost method pending approval of its request to the Arkansas Commission to utilize the LIFO method. Natural gas inventories held by LIG are marked-to-market.

Accounts Receivable – AEP Credit Inc. (formerly CSW Credit) factors accounts receivable for the domestic utility subsidiaries, except APCo, and unaffiliated companies.

Foreign Currency Translation - The financial statements of subsidiaries outside the U.S. which are included in AEP's consolidated financial statements are measured using the local currency as the functional currency and translated into U.S. dollars in accordance with SFAS 52 "Foreign Currency Translation". Assets and liabilities are translated to U.S. dollars at year-end rates of exchange and revenues and expenses are translated at monthly average exchange rates throughout the year. Currency translation gain and loss adjustments are recorded in shareholders' equity as "Accumulated Other Comprehensive Income (Loss)". The non-cash impact of the changes in exchange rates on cash, resulting from the translation of items at different exchange rates is shown on AEP's Consolidated Statement of Cash Flows in "Effect of Exchange Rate Change on Cash." Actual currency transaction gains and losses are recorded in income.

Energy Marketing and Trading Transactions - The AEP System engages in wholesale electricity and natural gas marketing and trading transactions (trading activities). Trading activities involve the sale of energy under physical forward contracts at fixed and variable prices and the trading of energy contracts including exchange traded futures and options, over-the-counter options and swaps. The majority of these transactions represent physical forward electricity contracts in AEP's traditional marketing area (up to two transmission systems from AEP's service territory) and are typically settled by entering into offsetting contracts. The net revenues from these transactions in AEP's traditional marketing area are included in revenues from domestic electric utility operations on AEP's consolidated statements of income.

The AEP System also purchases and sells electricity and gas options, futures and swaps, and enters into forward purchase and sale contracts for electricity (outside its traditional marketing area) and gas. These transactions represent non-regulated trading activities that are included in revenues from worldwide electric and gas operations on AEP's consolidated statements of income.

All of the registrant subsidiaries except AEGCo participate in the AEP System's wholesale marketing and trading of electricity. APCo, CSPCo, I&M, KPCo and OPCo record revenues from trading of electricity net of purchases as operating revenues for forward electricity trades in AEP's traditional marketing area and as nonoperating income for forward electricity trades beyond two transmission systems from AEP and for speculative financial transactions (options, futures and swaps). CPL, PSO, SWEPCo and WTU record revenues from trading of electricity net of purchases as operating revenues.

The AEP System follows EITF 98-10 and EITF 00-17, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" and "Measuring the Fair Value of Energy-Related Contracts in Applying Issue 98-10", respectively. EITF 98-10 requires that all energy trading contracts be marked-to-market. The effect on AEP's consolidated statements of income of marking open trading contracts to market in the regulated jurisdictions are deferred as regulatory assets or liabilities for those open electricity trading transactions within AEP's marketing area that are included in cost of service on a settlement basis for ratemaking purposes. Non-regulated jurisdictions with open electricity trading transactions within AEP's marketing area are marked-to-market and included in domestic electric utility operations revenues on AEP's consolidated statements of income. Non-regulated and regulated jurisdictions open electricity trading contracts outside the traditional marketing area are accounted for on a mark-to-market basis and included in worldwide electric and gas operations revenues on AEP's consolidated statements of income. Open gas trading contracts are accounted for on a mark-to-market basis and included in worldwide electric and gas operations on AEP's consolidated statements of income.

APCo, CSPCo and OPCo account for open forward electricity trading contracts on a mark-to-market basis and include the mark-to-market change in revenues for open contracts in AEP's traditional marketing area and in nonoperating income for open contracts beyond AEP's traditional marketing area.

I&M and KPCo account for open forward electricity trading contracts on a mark-to-market basis and defer the mark-to-market change as regulatory assets or liabilities for those open contracts in AEP's traditional marketing area and include the mark-to-market change in nonoperating income for open contracts beyond AEP's traditional marketing area.

CPL, PSO, SWEPCo and WTU account for open forward electricity trading contracts on a mark-to-market basis. CPL includes the mark-to-market change for open electricity trading contracts in revenues. PSO defers as regulatory assets or liabilities the mark-to-market change for open forward electricity trading contracts that are included in cost of service on a settlement basis for ratemaking purposes. SWEPCo and WTU include the jurisdictional share of the mark-to-market change in revenues for open electricity trading contracts for those jurisdictions that are not subject to SFAS 71 cost based rate regulation and defer as regulatory assets or liabilities the jurisdictional share of the mark-to-market change for open contracts that are included in cost of service on a settlement basis for ratemaking purposes.

Unrealized mark-to-market gains and losses from all trading activity are reported as assets and liabilities, respectively.

Hedging and Related Activities – In order to mitigate the risks of market price and interest rate fluctuations, AEP's foreign subsidiaries, SEEBOARD and CitiPower, utilize interest swaps, currency swaps and forward contracts to hedge such market fluctuations. Changes in the market value of these swaps and contracts are deferred until the gain or loss is realized on the underlying hedged asset, liability or commodity. To qualify as a hedge, these transactions must be designated as a hedge and changes in their fair value must correlate with changes in the price and interest rate movement of the underlying asset, liability or commodity. This in effect reduces AEP's exposure to the effects of market fluctuations related to price and interest rates.

AEP, APCo, CSPCo, I&M, and OPCo enter into contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory debt instruments are entered into in order to manage the change in interest rates between the time a debt offering is initiated and the issuance of the debt (usually a period of 60 days). Gains or losses from these transactions are deferred and amortized over the life of the debt issuance with the amortization included in interest charges. There were no such forward contracts outstanding at December 31, 2000 or 1999. See Note 15 – "Financial Instruments, Credit and Risk Management" for further discussion of the accounting for risk management transactions.

Revenues and Fuel Costs - Domestic revenues include the accrual of service provided but unbilled at month-end as well as billed revenues. The cost of fuel consumed is charged to expense as incurred. Under governing regulatory commission retail rate orders, any resulting fuel cost over or under-recoveries are deferred as regulatory liabilities or regulatory assets in accordance with SFAS 71. These deferrals generally are billed or refunded to customers in later months with the regulator's review and approval. Wholesale jurisdictional fuel cost increases and decreases over amounts included in base rates are expensed and billed as incurred. See Note 5 "Rate Matters" and Note 7 "Industry Restructuring" for further information about fuel recovery.

Levelization of Nuclear Refueling Outage Costs - In order to match costs with regulated revenues, which include outage costs on a normalized basis, incremental operation and maintenance costs associated with periodic refueling outages at I&M's Cook Plant are deferred and amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage.

Amortization of Cook Plant Deferred Restart Costs - Pursuant to settlement agreements approved by the IURC and the MPSC to resolve all issues related to an extended outage of the Cook Plant, I&M deferred $200 million of incremental operation and maintenance costs during 1999. The deferred amount is being amortized to expense on a straight-line basis over five years from January 1, 1999 to December 31, 2003. I&M amortized $40 million in 1999 and 2000, leaving $120 million as an SFAS 71 regulatory asset at December 31, 2000 on the Consolidated Balance Sheets of AEP and I&M.

Income Taxes - The AEP System follows the liability method of accounting for income taxes as prescribed by SFAS 109, "Accounting for Income Taxes." Under the liability method, deferred income taxes are provided for all temporary differences between the book cost and tax basis of assets and liabilities which will result in a future tax consequence. Where the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established in accordance with SFAS 71 to match the regulated revenues and tax expense.

Investment Tax Credits - Investment tax credits have been accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are being amortized over the life of the regulated plant investment.

Debt and Preferred Stock – Where appropriate gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plant are generally deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment. If the debt is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost based regulatory accounting under SFAS 71 are generally deferred and amortized over the term of the replacement debt commensurate with their recovery in rates. Gains and losses on the reacquisition of debt for operations not subject to SFAS 71 are reported as a component of net income.

Debt discount or premium and debt issuances expenses are deferred and amortized over the term of the related debt, with the amortization included in interest charges.

Where rates are regulated redemption premiums paid to reacquire preferred stock of the domestic utility subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and amortized to retained earnings consistent with the timing of its recovery in rates in accordance with SFAS 71.

Goodwill – The amount of acquisition cost in excess of the fair value allocated to tangible assets obtained through an acquisition accounted for as a purchase combination is recorded as goodwill on AEP's consolidated balance sheet. Amortization of goodwill is on a straight-line basis generally over 40 years except for the portion of goodwill associated with gas trading and marketing activities which is being amortized on a straight-line basis over 10 years. The recoverability of goodwill (evaluated on undiscounted operating cash flow analysis) is reviewed when events or changes in circumstances indicate that the carrying amount may exceed fair value.

Other Assets - Other assets on AEP's consolidated balance sheet are comprised primarily of nuclear decommissioning and spent nuclear fuel disposal trust funds and licenses for CitiPower operating franchises. Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Other Assets at market value in accordance with SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities." Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Under the provisions of SFAS 71, unrealized gains and losses from securities in these trust funds are not reported in equity but result in adjustments to the liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates.

Comprehensive Income - Comprehensive income is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. There were no material differences between net income and comprehensive income for AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, and WTU.

Components of Other Comprehensive Income – The following table provides the components that comprise the balance sheet amount in Accumulated Other Comprehensive Income for AEP.

	December 31,		
Components	2000	1999	1998
	(millions)		
Foreign Currency Adjustments	$ (99)	$ 20	$ 33
Unrealized Losses on Securities	-	(20)	(20)
Minimum Pension Liability	(4)	(4)	(6)
	$(103)	$ (4)	$ 7

Segment Reporting – The AEP System has adopted SFAS No. 131, which requires disclosure of selected financial information by business segment as viewed by the chief operating decision-maker. See Note 14 "Business Segments" for further discussion and details regarding segments.

Common Stock Options – AEP follows Accounting Principles Board Opinion 25 to account for stock options. Compensation expense is not recognized at the date of grant, because the exercise price of stock options awarded under the stock option plan equals the market price of the underlying stock on the date of grant.

EPS – AEP's basic earnings per share is determined based upon the weighted average number of common shares outstanding during the years presented. Diluted earnings per share for AEP is based upon the weighted average number of common shares and stock options outstanding during the years presented. Basic and diluted are the same in 2000, 1999 and 1998.

AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, and WTU are wholly-owned subsidiaries of AEP and are not required to report EPS.

Reclassification - Certain prior year financial statement items have been reclassified to conform to current year presentation. Such reclassification had no impact on previously reported net income.

2. Extraordinary Items:

Extraordinary Items – Extraordinary items were recorded for the discontinuance of regulatory accounting under SFAS 71 for the generation portion of the business in the Ohio, Virginia, West Virginia, Texas and Arkansas state jurisdictions. See Note 7 "Industry Restructuring" for descriptions of the restructuring plans and related accounting effects. The following table shows the components of the extraordinary items reported on AEP's consolidated statements of income:

	Year Ended December 31, 2000	Year Ended December 31, 1999
	(in millions)	
Extraordinary Items:		
Discontinuance of Regulatory Accounting for Generation:		
Ohio Jurisdiction (Net of Tax of $35 Million)	$(44)	$ -
Virginia and West Virginia Jurisdictions (Inclusive of Tax Benefit of $8 Million)	9	-
Texas and Arkansas Jurisdictions (Net of Tax of $5 Million)	-	(8)
Loss on Reacquired Debt (Net of Tax of $3 Million)	-	(6)
Extraordinary Items	$(35)	$(14)

There were no extraordinary items in 1998.

3. Merger:

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. Under the terms of the merger agreement, approximately 127.9 million shares of AEP Common Stock were issued in exchange for all the outstanding shares of CSW Common Stock based upon an exchange ratio of 0.6 share of AEP Common Stock for each share of CSW Common Stock. Following the exchange, former shareholders of AEP owned approximately 61.4 percent of the corporation, while former CSW shareholders owned approximately 38.6 percent of the corporation.

The merger was accounted for as a pooling of interests. Accordingly, AEP's consolidated financial statements give retroactive effect to the merger, with all periods presented as if AEP and CSW had always been combined. Certain reclassifications have been made to conform the historical financial statement presentation of AEP and CSW.

The following table sets forth revenues, extraordinary items and net income previously reported by AEP and CSW and the combined amounts shown in the accompanying financial statements for 1999 and 1998:

	Year Ended December 31, 1999	Year Ended December 31, 1998
	(in millions)	
Revenues:		
AEP	$ 6,870	$ 6,358
CSW	5,537	5,482
AEP After Pooling	$12,407	$11,840

	Year Ended December 31, 1999	1998
	(in millions)	
Extraordinary Items:		
AEP	$ -	$ -
CSW	(14)	-
AEP After Pooling	$(14)	$ -
Net Income:		
AEP	$520	$536
CSW	455	440
Conforming Adjustment	(3)	(1)
AEP After Pooling	$972	$975

The combined financial statements include an adjustment to conform CSW's accounting for vacation pay accruals with AEP's accounting. The effect of the conforming adjustment was to reduce net assets by $16 million at December 31, 1999 and reduce net income by $3 million and $1 million for the years ended December 31, 1999 and 1998, respectively.

The following table shows the vacation accrual conforming adjustment for CSW's registrant utility subsidiaries:

	Net Asset Reduction At December 31, 1999	Net Income Reductions Year Ended December 31, 1999	1998
	(in millions)	(in millions)	
CPL	$5.3	$0.7	$0.1
PSO	2.8	1.1	-
SWEPCo	4.5	0.5	0.1
WTU	2.6	0.4	0.1

In connection with the merger, $203 million ($180 million after tax) of non-recoverable merger costs were expensed by AEP through December 31, 2000. Such costs included transaction and transition costs not recoverable from ratepayers. Also included in the merger costs were non-recoverable change in control payments. Merger transaction and transition costs of $45 million recoverable from ratepayers were deferred pursuant to state regulator approved settlement agreements. The deferred merger costs are being amortized over five to eight year recovery periods depending on the specific terms of the settlement agreements, with the amortization ($4 million for AEP for the year 2000) included in depreciation and amortization expense.

The following table shows the deferred merger cost and amortization expense of the applicable subsidiary registrants:

	Merger Cost Deferral at December 31, 2000	Amortization Expense for the Year Ended December 31, 2000
	(in millions)	
CPL	$15.7	$1.3
I&M	7.6	0.7
KPCo	2.7	0.3
PSO	8.3	0.5
SWEPCo	6.6	0.5
WTU	4.6	0.4

Merger transition costs are expected to continue to be incurred for several years after the merger and will be expensed or deferred for amortization as appropriate. The state settlement agreements provide for, among other things, a sharing of net merger savings with certain regulated customers over periods of up to eight years through rate reductions beginning in the third quarter of 2000. In connection with the merger, the PUCT approved a settlement agreement that provides for, among other things, sharing net merger savings with Texas customers of CPL, SWEPCo and WTU over six years after consummation of the merger through rate reduction riders. The settlement agreement results in rate reductions for Texas customers totaling $221 million over a six-year period commencing with the merger's consummation. The rate reduction was composed of $84 million of net merger savings and $137 million to resolve issues associated with CPL's, SWEPCo's and WTU's rate and fuel reconciliation proceedings in Texas. Under the terms of the settlement agreement, base rates cannot be increased until three years after consummation of the merger.

The IURC and MPSC approved merger settlement agreements that, among other things, provide for sharing net merger savings with I&M's retail customers over eight years through reductions to customers' bills. The terms of the Indiana settlement require reductions in customers' bills of approximately $67 million over eight years. Under the Michigan settlement, billing credits will be used to reduce customers' bills by approximately $14 million over eight years for net guaranteed merger savings. The Indiana settlement extends the base rate freeze in the Cook Plant extended outage settlement agreement until January 1, 2005 and requires additional annual deposits of $6 million to the nuclear decommissioning trust fund for the

Indiana jurisdiction for the years 2001 through 2003. As a result of an appeal of the Indiana settlement agreement by a consumer group, I&M has not reflected the reductions in Indiana jurisdictional customers' bills. Instead, pending the result of the appeal, I&M recorded a liability ($1 million at December 31, 2000) for the reduction due to its Indiana customers under the settlement.

The KPSC approved a settlement agreement that, among other things, provides for sharing net merger savings with KPCo's customers over eight years through reductions to customers' bills and prohibits a general increase in base rates or other charges for three years following consummation of the merger. The Kentucky customers' share of the net merger savings is expected to be approximately $28 million.

A merger settlement agreement for PSO was approved by the Oklahoma Corporation Commission that, among other things, provides for sharing approximately $28 million in guaranteed net merger savings over five years with Oklahoma customers, prohibits an increase in Oklahoma base rates prior to January 1, 2003 and requires an application to join an RTO be filed with FERC by December 31, 2001.

The Arkansas Commission approved an agreement related to the merger which, among other things, provides for $6 million of net merger savings to reduce SWEPCo customers rates over five years in Arkansas and prohibits a base rate increase being effective prior to January 1, 2002.

SWEPCo's Louisiana customers will receive approximately $18 million of merger savings over eight years according to a merger approval order issued by the Louisiana Public Service Commission. In addition, the order capped base rates for five years after the consummation of the merger (until June 2005) and required that benefits from off-system sales be shared with ratepayers.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the eight-year period following consummation of the merger, future results of operations, cash flows and possibly financial condition could be adversely affected.

Most of the merger settlement agreements approved by the regulatory commissions require the electric operating companies to join regional transmission organizations. APCo, CSPCo, I&M, KPCo, OPCo and several other unaffiliated utilities formed the Alliance RTO before the consummation of the merger. As a condition of FERC's approval of the merger, CPL, PSO, SWEPCo and WTU were required to join an RTO prior to December 31, 2000 and to transfer the operation and control of their transmission facilities to that RTO by December 15, 2001. CPL and WTU are members of ERCOT. PSO and SWEPCo are members of SPP. ERCOT and SPP are transmission pooling organizations in certain geographic areas of the U.S. whose goals include enhancement of bulk electric transmission reliability. The SPP has filed with FERC to be approved as an RTO. Due to the FERC's inaction on approving the SPP RTO, in December 2000 PSO and SWEPCo filed with the FERC requesting an extension of time to join an RTO until 75 days following the FERC's approval of an RTO for the SPP service area. Initial filings to gain FERC approval for the Alliance RTO were made and conditional approval was granted by the FERC. The Alliance RTO made compliance filings as requested by the FERC and these were accepted in January 2001. Final FERC approval of the SPP RTO is pending.

The divestiture of 1,904 MW of generating capacity was required as a condition of regulatory approval of the merger by the FERC and PUCT. Under the FERC-approved merger agreement the divestiture of 550 MW of generating capacity comprised of 300 MW of capacity in SPP and 250 MW of capacity in ERCOT is required. The FERC is requiring AEP and CSW to divest their entire ownership interest in and operational control of the entire generating facilities that produce the capacity to be divested. The FERC required divestiture of the identified ERCOT capacity must be completed by March 15, 2001 and for the SPP capacity by July 1, 2002. The FERC found that certain energy sales in SPP and ERCOT would be a reasonable and effective interim mitigation measure until the required SPP and ERCOT divestitures could be completed. In February 2001, AEP announced the sale of Frontera, one of the plants required to be divested by the settlement agreements approved by the FERC. The Texas settlement calls for the divestiture of a total of 1,604 MW of generating capacity within

Texas inclusive of 250 MW ordered to be divested by FERC. The Texas divestiture cannot proceed until two years after the merger closes to satisfy the requirements to use pooling-of-interests accounting treatment. The FERC divestiture is not limited by the pooling rules because it is regulatory ordered.

The current annual dividend rate per share of AEP Common Stock is $2.40. The dividends per share reported on the statements of income for prior periods represent pro forma amounts and are based on AEP's historical annual dividend rate of $2.40 per share. If the dividends per share reported for prior periods were based on the sum of the historical dividends declared by AEP and CSW, the annual dividend rate would be $2.60 per combined share for the years ended December 31, 1999 and 1998.

4. Nuclear Plant Restart:

The restart of both units of I&M's Cook Plant was completed with Unit 2 reaching 100% power on July 5, 2000 and Unit 1 achieving 100% power on January 3, 2001. Cook Plant is a 2,110 MW two-unit plant owned and operated by I&M under licenses granted by the NRC. I&M shut down both units of the Cook Plant in September 1997 due to questions regarding the operability of certain safety systems that arose during a NRC architect engineer design inspection.

Settlement agreements in the Indiana and Michigan retail jurisdictions that address recovery of Cook Plant related outage costs were approved in 1999. The IURC approved a settlement agreement in March 1999 that resolved all matters related to the recovery of replacement energy fuel costs and all outage/restart costs and related issues during the extended outage of the Cook Plant. The settlement agreement provided for, among other things, the deferral of unrecovered fuel revenues accrued between September 9, 1997 and December 31, 1999; the deferral of up to $150 million of restart related nuclear operation and maintenance costs in 1999 above the amount included in base rates; the amortization of the deferred fuel revenues and non-fuel operation and maintenance cost deferrals over a five-year period ending December 31, 2003; a freeze in base rates through December 31, 2003; and a fixed fuel recovery charge through March 1, 2004.

The regulatory approved deferrals were recorded in 1999 as a regulatory asset in accordance with SFAS 71.

In December 1999 the MPSC approved a settlement agreement for two open Michigan power supply cost recovery reconciliation cases that resolves all issues related to the Cook Plant extended outage. The settlement agreement limits I&M's ability to increase base rates and freezes the power supply cost recovery factor until January 1, 2004; permits the deferral of up to $50 million in 1999 of jurisdictional non-fuel nuclear operation and maintenance expenses; authorizes the amortization of power supply cost recovery revenues accrued from September 9, 1997 to December 31, 1999 and non-fuel nuclear operation and maintenance cost deferrals over a five-year period ending December 31, 2003. The regulatory approved deferrals were recorded in the fourth quarter of 1999.

The amounts of restart costs charged to other operation and maintenance expenses were as follows:

	Year Ended December 31,		
	2000	1999	1998
Costs Incurred	$297	$ 289	$78
Deferred Pursuant to Settlement Agreements	-	(200)	-
Amortization of Deferrals	40	40	-
Charged to O&M Expense	$337	$ 129	$78

At December 31, 2000 and 1999, deferred restart costs of $120 million and $160 million, respectively, remained in regulatory assets to be amortized through 2003. Also pursuant to the settlement agreements, accrued fuel-related revenues of $38 million and $37 million in 2000 and 1999, respectively, were amortized. At December 31, 2000 and 1999, fuel-related revenues of $113 million and $150 million, respectively, were included in regulatory assets and will be amortized through December 31, 2003 for both jurisdictions.

The amortization of restart costs and fuel-related revenues deferred under Indiana and Michigan retail jurisdictional settlement agreements will adversely affect results of operations through December 31, 2003 when the amortization period ends. The annual amortization of restart cost and fuel-related revenue deferrals is $78 million.

5. Rate Matters:

Texas Jurisdictional Fuel Filings – AEP's Texas electric operating companies (CPL, SWEPCo and WTU) have been experiencing significant natural gas fuel price increases which have resulted in under-recoveries of fuel costs and the need to seek increases in fuel rates and surcharges to recover these under-recoveries.

CPL Fuel Filings - In July 2000 CPL filed with the PUCT an application to implement an increase in fuel factor revenues effective with the September 2000 billing month. Additionally, CPL proposed to implement an interim fuel surcharge to collect its under-recovered fuel costs, including accumulated interest, over a twelve-month period beginning in October 2000.

In September 2000 the PUCT approved a settlement. The settlement provided for an increase in fuel factor revenues of $173.5 million annually and provided for a two-phase surcharge totaling $86.4 million. The recovery of the first phase surcharge of $21.3 million for previously under-recovered fuel costs including accumulated interest for the period from December 1, 1999 through May 31, 2000 was authorized to be collected in September through December 2000. The second surcharge was not to exceed $65.1 million for projected under-recoveries for the period from June 2000 through August 2000 and was authorized to be collected January through September 2001. A September 2000 compliance filing showed the actual under-recovery for June 2000 through August 2000 to be $93.7 million. The remaining under-recovery amount of $28.6 was carried forward into a January 2001 filing.

In January 2001 CPL filed with the PUCT an application to implement an increase in fuel factors of $175.9 million, effective with the March 2001 billing month over the ten months March 2001 through December 2001. Additionally, CPL proposed to implement an interim fuel surcharge of $51.8 million, including accumulated interest, over a nine-month period beginning in April 2001 to collect its under-recovered fuel costs. Approval by the PUCT is pending.

SWEPCo Fuel Filings – In November 2000 SWEPCo filed with the PUCT an application for authority to implement an increase in fuel factor revenues effective with the January 2001 billing month. SWEPCo also proposed to implement an interim fuel surcharge to collect its under-recovered fuel costs, including accumulated interest, over a six-month period beginning in January 2001.

In January 2001 the PUCT approved SWEPCo's application. The order allows an increase in fuel factors of $12 million on an annual basis including accumulated interest beginning in January 2001 and a surcharge of $11.8 million for the billing months of February through July 2001.

In June 2000 SWEPCo filed with the PUCT an application for authority to reconcile fuel costs and to request authorization to carry the unrecovered balance forward into the next reconciliation period. During the reconciliation period of January 1, 1997 through December 31, 1999, SWEPCo incurred $347 million of Texas jurisdiction eligible fuel and fuel-related expenses.

On December 27, 2000, SWEPCo reached a settlement. The settlement resulted in a reduction of $2.25 million of eligible Texas jurisdictional fuel expense, which was prorated equally over thirty-six months of the reconciliation period. The settlement also provides that depreciation and lease expense associated with new aluminum railcars will qualify for treatment as eligible fuel expense from January 1, 2000 forward. Parties to the settlement will support SWEPCo in seeking to amend its 1999 excess earnings report to include 1999 railcar depreciation expense in the depreciation component of the calculation. In February 2001, the PUCT approved the settlement, which did not have a material effect on SWEPCo's results of operations.

WTU Fuel Filings. – In August 2000 WTU filed with the PUCT an application for authority to implement an increase in fuel factors effective with the October 2000 billing month. WTU also proposed to implement an interim fuel surcharge to collect its under-recovered fuel costs from August 1, 1999 through June 30, 2000 including accumulated interest, over a six-month period beginning in November 2000.

In December 2000, the PUCT approved WTU's application. The order allows an increase in fuel factors of $42.6 million on an annual basis including accumulated interest and provides for a surcharge of $19.6 million for previously under-recovered fuel costs.

In January 2001 WTU filed with the PUCT an application for authority to implement an increase in fuel factor revenues of $46.5 million effective with the March 2001 billing. Approval by the PUCT is pending.

In December 2000 WTU filed with the PUCT an application for authority to reconcile fuel costs. During the reconciliation period of July 1, 1997 through June 30, 2000, WTU incurred $348 million of Texas jurisdiction eligible fuel and fuel-related expenses. Approval by the PUCT is pending.

OPCo's Recovery of Fuel Costs – Pursuant to PUCO – approved stipulation agreements the cost of coal burned at the Gavin Plant was subject to a 15-year predetermined price of $1.575 per million Btu's with quarterly escalation adjustments through November 2009. To the extent the actual cost of coal burned at the Gavin Plant was below the predetermined prices, the stipulation agreement provided OPCo with the opportunity to recover over its term the Ohio jurisdictional share of OPCo's investment in and the liabilities and future shutdown costs of its affiliated mines as well as any fuel costs incurred above the pre-determined rate and deferred for future recovery under the agreements. As a result of the Ohio Act introducing customer choice and a transition to market based pricing for electricity supply in Ohio, these stipulation agreements were superseded effective January 1, 2001. OPCo filed under the provisions of the Ohio Act for recovery of all of its generation related regulatory assets including fuel costs deferred under these predetermined price stipulation agreements. Under the terms of OPCo's PUCO-approved stipulated transition plan, recovery of generation-related regulatory assets at December 31, 2000, which were $518 million, over seven years was approved.

The Muskingum coal strip mine and Windsor deep coal mine which supplied all of their output to OPCo have been closed. Efforts are underway to reclaim the properties, sell or scrap all mining equipment, terminate both capital and operating leases and perform other activities necessary to reclaim the mines. Mine reclamation activities should be completed within two to three years; postremediation monitoring is anticipated to continue for five years after completion of reclamation.

OPCo currently plans to close the Meigs deep coal mine by the end of 2001 unless ongoing efforts to sell it are successful. Currently efforts are being made to sell the active Meigs and shutdown Windsor and Muskingum mines.

FERC - The FERC issued orders 888 and 889 in April 1996 which required each public utility that owns or controls interstate transmission facilities to file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The orders also require utilities to functionally unbundle their services, and to pay their own transmission service tariffs in making off-system and third-party sales. As part of the orders, the FERC issued a pro-forma tariff, which reflects the Commission's views on the minimum non-price terms and conditions for non-discriminatory transmission service. The FERC orders also allow a utility to seek recovery of certain prudently-incurred stranded costs that result from unbundled transmission service.

On July 9, 1996, the AEP System companies filed an Open Access Transmission Tariff conforming with the FERC's pro-forma transmission tariff, subject to the resolution of certain pricing issues. The 1996 tariff incorporated transmission rates which were the result of a settlement of a pending rate case, but which were being collected subject to refund from certain customers who opposed the settlement and continued to litigate the reasonableness of AEP's transmission rates. On July 30, 1999, the FERC issued an order in the litigated rate case that would reduce AEP's rates for the affected customers below the settlement rate. AEP and certain of the affected customers sought rehearing of the Commission's Order.

On December 10, 1999, AEP filed a settlement agreement with the FERC resolving the issues on rehearing of the July 30, 1999 order. On March 16, 2000, the FERC approved the settlement agreement. Under terms of the settlement, the AEP System is required to make refunds retroactive to September 7, 1993 to certain customers affected by the July 30, 1999 FERC order. The refunds were made in two payments. Pursuant to FERC orders the first payment was made in February 2000 and the second payment was made on August 1, 2000. APCo, CSPCo, I&M, KPCo, and OPCo recorded provisions in 1999 and 2000 for the earnings impact of the required refunds including interest.

The settlement agreement also reduced the rates for transmission service. A new lower rate of $1.55 kw/month was made effective January 1, 2000, for all transmission service customers. Also as agreed, a new rate of $1.42 kw/month took effect on June 16, 2000 upon consummation of the AEP/CSW merger. Prior to January 1, 2000, the rate was $2.04 kw/month. Unless the market volume of physical power transactions grows to increase the utilization of the AEP System's transmission lines, the new open access transmission rate will adversely impact future results of operations and cash flows. Since the rate has been reduced the volume of transmission usage has increased on the AEP System mainly due to increased competition in the wholesale electricity market.

West Virginia

On May 12, 1999, APCo, an AEP subsidiary doing business in WV, filed with the WVPSC for a base rate increase of $50 million annually and a reduction in ENEC rates of $38 million annually. On February 7, 2000, APCo and other parties to the proceeding filed a Joint Stipulation with the WVPSC for approval.

The Joint Stipulation's main provisions include no change in either base or ENEC rates effective January 1, 2000 from those base and ENEC rates in effect from November 1, 1996 until December 31, 1999 (these rates provide for recovery of regulatory assets including any generation-related regulatory assets through frozen transition rates and a wires charge of 0.5 mills per KWH); the continued suspension of annual ENEC recovery proceedings and cessation of existing deferral accounting for all over or under recovery of fuel and purchased power costs net of system sales effective January 1, 2000; and the retention, as a regulatory liability, on the books of a net cumulative deferred ENEC overrecovery balance of $66 million as established by a WVPSC order on December 27, 1996. The Joint Stipulation also provides that when deregulation of generation occurs in WV, APCo will use this retained regulatory liability to reduce generation-related regulatory assets and, to the extent possible, any additional costs or obligations that restructuring and deregulation of APCo's generation business may impose. The elimination of ENEC recovery proceedings in WV will subject AEP and APCo to the risk of fuel market price increases and reductions in wholesale sales levels which could adversely affect results of operations and cash flows.

Also, under the Joint Stipulation, APCo's share of any net savings from the merger between AEP and CSW prior to December 31, 2004 shall be retained by APCo. As a result, all costs incurred in the merger that were allocated to APCo shall be fully charged to expense to partially offset merger savings through December 31, 2004 and shall not be included in any WV rate proceeding after that date. After December 31, 2004, current distribution savings related to the merger will be reflected in rates in any future rate proceeding before the WVPSC to establish distribution rates or to adjust rate caps during the transition to market based generation rates. When deregulation of generation occurs in WV, the net retained generation-related merger savings shall be used to recover any generation-related regulatory assets that are not recovered under the other provisions of the Joint Stipulation and the mechanisms provided for in the deregulation legislation and, to the extent possible, to recover any additional costs or obligations that deregulation may impose on APCo. Regardless of whether the net cumulative deferred ENEC overrecovery balance and the net merger savings are sufficient to offset all of APCo's generation-related regulatory assets, under the terms of the Joint Stipulation there will be no further explicit adjustment to APCo's rates to provide for recovery of generation-related regulatory assets beyond the above discussed specific adjustment provisions in the Joint Stipulation and the 0.5 mills per KWH wires charge in the WV Restructuring Plan (see Note 7 "Industry Restructuring" for discussion of WV Restructuring Plan). On June 2, 2000, the WVPSC issued an order approving the Joint Stipulation. Management expects that the stipulation agreement plus the provisions of pending restructuring legislation will, if the legislation becomes effective, provide for the recovery of existing regulatory assets, other stranded costs and the cost of such deregulation in WV.

6. Effects of Regulation:

In accordance with SFAS 71 the consolidated financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) recorded in accordance with regulatory actions in order to match expenses and revenues from cost-based rates in the same accounting period. Regulatory assets are expected to be recovered in future periods through the rate-making process and regulatory liabilities are expected to reduce future cost recoveries. Among other things, application of SFAS 71 requires that the AEP System's regulated rates be cost-based and the recovery of regulatory assets probable. Management has reviewed all the evidence currently available and concluded that the requirements to apply SFAS 71 continue to be met for all electric operations in Indiana, Kentucky, Louisiana, Michigan, Oklahoma and Tennessee.

When the generation portion of the business in Arkansas, Ohio, Texas, Virginia and WV no longer met the requirements to apply SFAS 71, net regulatory assets were written off for that portion of the business unless they were determined to be recoverable as a stranded cost through regulated distribution rates or wire charges in accordance with SFAS 101 "Regulated Enterprises – Accounting for the Discontinuation of FASB Statement No. 71" and EITF 97-4 "Deregulation of the Pricing of Electricity – Issues Related to the Application of FASB No. 71, Accounting for the Effects of Certain Types of Regulation, and No. 101, Regulated Enterprises – Accounting for the Discontinuation of the Application of FASB Statement No. 71." In the Ohio, Virginia and WV jurisdictions the generation-related regulated assets that are recoverable through transition rates have been transferred to the distribution portion of the business and are being amortized as they are recovered through charges to regulated distribution customers. In the Texas jurisdiction generation-related regulatory assets that have been tentatively approved for recovery through securitization have been classified as "regulatory assets designated for securitization." (See Note 7 "Industry Restructuring" for further details.)

AEP's recognized regulatory assets and liabilities are comprised of the following at:

	December 31, 2000	December 31, 1999
	(in millions)	
Regulatory Assets:		
Amounts Due From Customers For Future Income Taxes	$ 914	$1,450
Transition - Regulatory Assets	963	-
Regulatory Assets Designated for Securitization	953	953
Deferred Fuel Costs	407	477
Unamortized Loss on Reacquired Debt	113	154
Cook Plant Restart Costs	120	160
DOE Decontamination and Decommissioning Assessment	35	39
Other	193	231
Total Regulatory Assets	$3,698	$3,464
Regulatory Liabilities:		
Deferred Investment Tax Credits	$528	$580
Other	208	315
Total Regulatory Liabilities	$736	$895

The recognized regulatory assets and liabilities for the registrant subsidiaries are comprised of the following at:

December 31, 2000	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
Regulatory Assets:					
Amounts Due From Customers For Future Income Taxes		$217,540	$ 206,930	$ 31,853	$229,466
Transition - Regulatory Assets		191,469		247,852	
Excess Earnings			(39,700)		
Regulatory Assets Designated For Securitization			953,249		
Deferred Fuel Costs		14,669	127,295		112,503
Unamortized Loss on Reacquired Debt	$5,504	11,676	12,773	8,340	17,740
Deferred Storm Damage		1,244			
Cook Plant Restart Costs					120,000
DOE Decontamination and Decommissioning Assessment			3,622		31,744
Other		11,152	18,815	3,508	40,687
Total Regulatory Assets	$5,504	$447,750	$1,282,984	$291,553	$552,140
Regulatory Liabilities:					
Deferred Investment Tax Credits	$59,718	$ 43,093	$128,100	$41,234	$113,773
Amounts Due To Customers For Future Income Taxes	23,996				
WV Rate Stabilization		75,601			
Other		2,614		11,510	9,930
Total Regulatory Liabilities	$83,714	$121,308	$128,100	$52,744	$123,703

December 31, 2000	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
Regulatory Assets:					
Amounts Due From Customers For Future Income Taxes	$85,926	$180,602		$14,558	
Transition - Regulatory Assets		517,851			
Deferred Fuel Costs			$43,267	35,469	$67,655
Unamortized Loss on Reacquired Debt	459	6,106	13,600	22,626	11,204
Other	12,130	10,151	15,738	19,898	13,604
Total Regulatory Assets	$98,515	$714,710	$72,605	$92,551	$92,463
Regulatory Liabilities:					
Deferred Investment Tax Credits	$11,656	$25,214	$35,783	$53,167	$24,052
Excess Earnings				500	15,100
Amounts Due To Customers For Future Income Taxes			28,652		13,493
Other	3,172	10,994	2,015	8,140	
Total Regulatory Liabilities	$14,828	$36,208	$66,450	$61,807	$52,645

December 31, 1999	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
Regulatory Assets:					
Amounts Due From Customers For Future Income Taxes	-	$389,922	$212,364	$243,031	$236,783
Excess Earnings			(18,400)		
Regulatory Assets - Designated For Securitization			953,249		
Deferred Fuel Costs			30,423		150,004
Unamortized Loss on Reacquired Debt	$5,744	20,828	13,983	23,307	14,780
Deferred Zimmer Plant Carrying Charges				42,826	
Deferred Storm Damage		6,619			
Cook Plant Restart Costs					160,000
DOE Decontamination and Decommissioning Assessment			4,022		35,238
Other		19,525	11,390	29,939	28,005
Total Regulatory Assets	$5,744	$436,894	$1,207,031	$339,103	$624,810
Regulatory Liabilities:					
Deferred Investment Tax Credits	$63,114	$ 57,259	$ 133,306	$ 44,716	$121,627
Amounts Due To Customers For Future Income Taxes	26,266				
50% Share - Net WV ENEC		36,589			
Over Recovery - Fuel Costs		34,676			
Deferred Gains From Emission Allowance Sales		1,867		13,539	
Other		7,180		24,082	17,238
Total Regulatory Liabilities	$89,380	$137,571	$ 133,306	$ 82,337	$138,865

December 31, 1999	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
Regulatory Assets:					
Amounts Due From Customers For Future Income Taxes	$88,764	$331,164		$ 7,128	
Deferred Fuel Costs		197,631	$6,469		$14,652
Unamortized Loss on Reacquired Debt	711	15,666	14,880	25,539	14,700
Other	6,821	49,924	1,837	14,513	15,045
Total Regulatory Assets	$96,296	$594,385	$23,186	$47,180	$44,397
Regulatory Liabilities:					
Deferred Investment Tax Credits	$12,908	$ 35,838	$37,574	$57,649	$25,323
Excess Earnings				6,500	6,000
Amounts Due To Customers For Future Income Taxes			32,826		13,146
Deferred Gains From Emission Allowance Sales		53,738			
Other	2,792	13,043		2,480	
Total Regulatory Liabilities	$15,700	$102,619	$70,400	$66,629	$44,469

7. Industry Restructuring:

Restructuring legislation has been enacted in seven of the eleven state retail jurisdictions in which AEP's domestic electric utility companies operate. The legislation provides for a transition from cost-based regulation of bundled electric service to unbundled cost-based rate regulation of transmission and distribution service and customer choice market pricing for the supply of electricity. The enactment of restructuring legislation and the ability to determine transition rates, wires charges and any resultant extraordinary gain or loss under restructuring legislation enabled APCo, CPL, CSPCo, OPCo, SWEPCo and WTU to discontinue regulatory accounting for the generation portion of their business in those jurisdictions. Prior to restructuring, the electric utility companies accounted for their operations according to the cost-based regulatory accounting principles of SFAS 71. Under the provisions of SFAS 71, regulatory assets and regulatory liabilities are recorded to reflect the economic effects of regulation to account for the difference between regulatory accounting and GAAP and to match expenses with regulated revenues. The discontinuance of the application of SFAS 71 is in accordance with the provisions of SFAS 101. Pursuant to those provisions and further guidance provided in EITF Issue 97-4, a company is required to write-off regulatory assets and liabilities related to the deregulated operations, unless recovery of such amounts is provided through cost-based regulated rates to be collected in the portion of operations which continues to be rate regulated. Additionally, a company experiencing a discontinuance of cost-based rate regulation is required to determine if any plant assets are impaired under SFAS 121. A SFAS 121 accounting impairment analysis involves estimating cumulative future non-discounted net cash flows arising from the use of assets. If the cumulative undiscounted net cash flows exceed the net book value of the assets, then there is no impairment of the assets for accounting purposes. If there is any accounting impairment, it would be recorded on a discounted basis.

As legislative and regulatory proceedings evolve, the electric operating companies doing business in the seven states that have passed restructuring legislation are applying the standards discussed above to discontinue SFAS 71 regulatory accounting. The following is a summary of the restructuring legislation, the status of the transition plans and the status of the electric utility operating companies' accounting to comply with the changes in each of the seven state regulatory jurisdictions affected by restructuring legislation.

Ohio Restructuring – Affecting AEP, CSPCo and OPCo

Effective January 1, 2001, customer choice of electricity supplier began under the Ohio Act. In February 2001, one supplier announced its plan to offer service to CSPCo's residential customers. Currently for residential customers of OPCo, no alternative suppliers have registered with the PUCO as required by the Ohio Act. Two alternative suppliers have been approved to compete for CSPCo's and OPCo's commercial and industrial customers. Presently, customers continue to be served by CSPCo and OPCo with a legislatively required residential rate reduction of 5% for the generation portion of rates and a freezing of generation rates including fuel rates starting on January 1, 2001.

The Ohio Act provides for a five-year transition period to move from cost based rates to market pricing for generation services. It granted the PUCO broad oversight responsibility for promulgation of rules for competitive retail electric generation service, approval of a transition plan for each electric utility company and addressing certain major transition issues including unbundling of rates and the recovery of stranded costs including regulatory assets and transition costs.

The Ohio Act also provides for a reduction in property tax assessments, the imposition of replacement franchise and income taxes, and the replacement of a gross receipts tax with a KWH based excise tax. The property tax assessment percentage on generation property was lowered from 100% to 25% of value effective January 1, 2001 and Ohio electric utilities will become subject to the Ohio Corporate Franchise Tax and municipal income taxes on January 1, 2002. The last year for which Ohio electric utilities will pay the excise tax based on gross receipts is the tax year ending April 30, 2002. As of May 1, 2001 electric distribution companies will be subject to an excise tax based on KWH sold to Ohio customers. The gross receipts tax is paid at the beginning of the tax year (May 1), deferred by CSPCo and OPCo as a prepaid expense and amortized to expense during the tax year pursuant to the tax law whereby the payment of the tax results in the privilege to conduct business in the year following the payment of the tax. As a result a duplicate tax will be expensed from May 1, 2001 through April 30, 2002 adding approximately $90 million ($40 million for CSPCo and $50 million for OPCo) to tax expense during that period. Unless CSPCo and OPCo can recover the duplicate amount from ratepayers it will negatively impact results of operations.

On September 28, 2000, the PUCO approved, with minor modifications, a stipulation agreement between CSPCo, OPCo, the PUCO staff, the Ohio Consumers' Counsel and other concerned parties regarding transition plans filed by CSPCo and OPCo. The key provisions of this stipulation agreement are:

- Recovery of generation-related regulatory assets at December 31, 2000 over seven years for OPCo ($518 million) and over eight years for CSPCo ($248 million) through frozen transition rates for the first five years of the recovery period and a wires charge for the remaining years.
- A shopping incentive (a price credit) of 2.5 mills per KWH for the first 25% of CSPCo residential customers that switch suppliers. There is no shopping incentive for OPCo customers.
- The absorption of $40 million by CSPCo and OPCo ($20 million per company) of consumer education, implementation and transition plan filing costs with deferral of the remaining costs, plus a carrying charge, as a regulatory asset for recovery in future distribution rates.
- CSPCo and OPCo will make available a fund of up to $10 million to reimburse customers who choose to purchase their power from another company for certain transmission charges imposed by PJM and/or a Midwest ISO on generation originating in the Midwest ISO or PJM areas.
- The statutory 5% reduction in the generation component of residential tariffs will remain in effect for the entire five year transition period.
- CSPCo's and OPCo's request for a $90 million gross receipts tax rider to recover the duplicate gross receipts KWH based excise tax would be considered separately by the PUCO.

The approved stipulation agreement also accepted the following provisions contained in CSPCo's and OPCo's filed transition plans:

- a corporate separation plan to segregate generation, transmission and distribution assets into separate legal entities, and
- a plan for independent operation of transmission facilities.

The gross receipts tax issue was considered by the PUCO in hearings held in June 2000. In the September 28, 2000 order approving the stipulation agreement, the PUCO determined that there was no duplicate tax overlap period and denied the request for a $90 million gross receipts tax rider. CSPCo's and OPCo's request for rehearing of the gross receipts tax issue was denied. An appeal of this issue to the Ohio Supreme Court has been filed. Unless this issue is resolved in CSPCo's and OPCo's favor, it will have an adverse effect on future results of operations and financial position.

One of the intervenors at the hearings for approval of the settlement agreement (whose request for rehearing was denied by the PUCO) has filed with the Ohio Supreme Court for review of the settlement agreement including recovery of regulatory assets. Management is unable to predict the outcome of litigation but the resolution of this matter could negatively impact results of operation.

Beginning January 1, 2001, CSPCo's and OPCo's fuel costs will not be subject to PUCO fuel recovery proceedings. Deferred fuel costs at December 31, 2000 which represent under or over recoveries were one of the items included in the PUCO's final determination of net regulatory assets to be collected (recovered) during the transition period. The elimination of fuel clause recoveries in 2001 in Ohio will subject AEP, CSPCo and OPCo to the risk of fuel market price increases and could adversely affect their future results of operations and cash flows.

CSPCo and OPCo Discontinue Application of SFAS 71 Regulatory Accounting for the Ohio Jurisdiction

In September 2000 CSPCo and OPCo discontinued the application of SFAS 71 for their Ohio retail jurisdictional generation business since generation is no longer cost-based regulated in the Ohio jurisdiction and management was able to determine their transition rates and wires charges. The discontinuance in the Ohio jurisdiction was possible as a result of the PUCO's September 28, 2000 approval of the stipulation agreement which established rates, wires charges and net regulatory asset recovery procedures during the transition to market rates.

CSPCo's and OPCo's discontinuance of SFAS 71 for generation resulted in after tax extraordinary losses in the third quarter of 2000 of $25 million and $19 million, respectively, due to certain unrecoverable generation-related regulatory assets and transition expenses. Management believes that substantially all of the remaining net regulatory assets related to the Ohio generation business will be recovered under the PUCO's September 28, 2000 order. Therefore, under the provisions of EITF 97-4, CSPCo's and OPCo's generation-related recoverable net regulatory assets were transferred to the transmission and distribution portion of the business and will be amortized as they are recovered through transition rates to customers. CSPCo and OPCo performed an accounting impairment analysis on their generating assets under SFAS 121 as required when discontinuing the application of SFAS 71 and concluded there was no impairment of generation assets.

Virginia – Affecting AEP and APCo

In Virginia, a restructuring law provides for a transition to choice of electricity supplier for retail customers beginning on January 1, 2002. In February 2001 restructuring revision legislation was approved by the Virginia Legislature which could modify the terms of restructuring. Presently, the transition period is to be completed, subject to a finding by the Virginia SCC that an effective competitive market exists by January 1, 2004 but no later than January 1, 2005.

The restructuring law also provides an opportunity for recovery of just and reasonable net stranded generation costs. The mechanisms in the Virginia law for net stranded cost recovery are: a capping of rates until as late as July 1, 2007, and the application of a wires charge upon customers who depart the incumbent utility in favor of an alternative supplier prior to the termination of the rate cap. The restructuring law provides for the establishment of capped rates prior to January 1, 2001 based either on a request by APCo for a change in rates prior to January 1, 2001 or on the rates in effect at July 1, 1999 if no rate change request is made and the establishment of a wires charge by the fourth quarter of 2001. APCo did not request new rates; therefore, its current rates are the capped rates. In the third quarter of 2000, the Virginia SCC directed APCo to file a cost of service study using 1999 as a test year to review the reasonableness of APCo's capped rates. The cost of service study was filed on January 3, 2001. In the opinion of APCo's Virginia counsel, Virginia's restructuring law does not permit the Virginia SCC to change rates for the transition period except for changes in the fuel factor, changes in state gross receipts taxes, or to address the utility's financial distress. However, if the Virginia SCC were to reduce APCo's capped rates or deny recovery of regulatory assets, it would adversely affect results of operations if such action is ultimately determined to be legal.

The Virginia restructuring law also requires filings to be made that outline the functional separation of generation from transmission and distribution and a rate unbundling plan. On January 3, 2001, APCo filed its corporate separation plan and rate unbundling plan with the Virginia SCC which is based on the most recent rate case test year (1996). See the heading "Structural Separation" below in this footnote for a discussion of AEP's corporate separation plan filed with the SEC.

West Virginia – Affecting AEP and APCo

On January 28, 2000, the WVPSC issued an order approving an electricity restructuring plan for WV. On March 11, 2000, the WV Legislature approved the restructuring plan by joint resolution. The joint resolution provides that the WVPSC cannot implement the plan until the legislature makes necessary tax law changes to preserve the revenues of the state and local governments. The Joint Committee on Government and Finance of the WV Legislature hired a consultant to study and issue a report on the tax changes required to implement electric restructuring. Moreover, the committee also hired a consultant to study and issue a report on the electric restructuring plan in light of events occurring in California. The WV Legislature is not expected to consider these reports until the 2002 Legislative Session since the 2001 Legislative Session ends in April 2001. Since the WV Legislature has not yet passed the required tax law changes, the restructuring plan has not become effective. AEP subsidiaries, APCo and WPCo, provide electric service in WV.

The provisions of the restructuring plan provide for customer choice to begin after all necessary rules are in place (the "starting date"); deregulation of generation assets on the starting date; functional separation of the generation, transmission and distribution businesses on the starting date and their legal corporate separation no later than January 1, 2005; a transition period of up to 13 years, during which the incumbent utility must provide default service for customers who do not change suppliers unless an alternative default supplier is selected through a WVPSC-sponsored bidding process; capped and fixed rates for the 13 year transition period as discussed below; deregulation of metering and billing; a 0.5 mills per KWH wires charge applicable to all retail customers for a 10-year period commencing with the starting date intended to provide for recovery of any stranded cost including net regulatory assets; establishment of a rate stabilization deferred liability balance of $81 million ($76 million by APCo and $5 million by WPCo) by the end of year ten of the transition period to be used as determined by the WVPSC to offset market prices paid in the eleventh, twelfth, and thirteenth year of the transition period by residential and small commercial customers that do not choose an alternative supplier.

Default rates for residential and small commercial customers are capped for four years after the starting date and then increase as specified in the plan for the next six years. In years eleven, twelve and thirteen of the transition period, the power supply rate shall equal the market price of comparable power. Default rates for industrial and large commercial customers are discounted by 1% for four and a half years, beginning July 1, 2000, and then increased at pre-defined levels for the next three years. After seven years the power supply rate for industrial and large commercial customers will be market based. APCo's Joint Stipulation agreement, discussed in Note 5 "Rate Matters", which was approved by the WVPSC on June 2, 2000 in connection with a base rate filing, also provides additional mechanisms to recover regulatory assets.

APCo Discontinues Application of SFAS 71 Regulatory Accounting

In June 2000 APCo discontinued the application of SFAS 71 for its Virginia and WV retail jurisdictional portions of its generation business since generation is no longer considered to be cost-based regulated in those jurisdictions and management was able to determine APCo's transition rates and wires charges. The discontinuance in the WV jurisdiction was made possible by the June 2, 2000 approval of the Joint Stipulation which established rates, wires charges and regulatory asset recovery procedures for the transition period to market rates which was determined to be probable. APCo was also able to discontinue application of SFAS 71 for the generation portion of its Virginia retail jurisdiction after management decided that APCo would not request capped rates different from its current rates. The existence of effective restructuring legislation in Virginia and the probability that the WV legislation would become effective with the expected probable passage of required enabling tax legislation in 2001 supported management's decision in 2000 to discontinue SFAS 71 regulatory accounting for APCo's electricity generation and supply business.

APCo's discontinuance of SFAS 71 for generation resulted in an after tax extraordinary gain, in the second quarter of 2000, of $9 million. Management believes that it is probable that substantially all net regulatory assets related to the Virginia and WV generation business will be recovered. Therefore, under the provisions of EITF 97-4, APCo's generation-related net regulatory assets were transferred to the distribution portion of the business and are being amortized as they are recovered through charges to regulated distribution customers. As required by SFAS 101 when discontinuing SFAS 71 regulatory accounting, APCo performed an accounting impairment analysis on its generating assets under SFAS 121 and concluded that there was no accounting impairment of generation assets.

The studies requested by the WV Legislature, discussed above, could result in the WV Legislature deciding not to enact the required tax changes, thereby, effectively continuing cost based rate regulation in West Virginia or it could modify the restructuring plan. Modifications in the restructuring plan could adversely affect future results of operations if they were to occur. Management is carefully monitoring the situation in West Virginia and continues to work with all concerned parties to get approval to successfully transition APCo's generation business in West Virginia. Failure to pass the required enabling tax changes could ultimately require APCo to reinstate regulatory accounting principles under SFAS 71 for its generation operations in West Virginia.

Arkansas Restructuring – Affecting AEP and SWEPCo

In 1999 legislation was enacted in Arkansas that will ultimately restructure the electric utility industry. Its major provisions are:

- retail competition begins January 1, 2002 but can be delayed until as late as June 30, 2003 by the Arkansas Commission;
- transmission facilities must be operated by an ISO if owned by a company which also owns generation assets;
- rates will be frozen for one to three years;
- market power issues will be addressed by the Arkansas Commission; and
- an annual progress report to the Arkansas General Assembly on the development of competition in electric markets and its impact on retail customers is required.

In November 2000 the Arkansas Commission filed its annual progress report with the Arkansas General Assembly recommending a delay in the start date of retail competition to a date between October 1, 2003 and October 1, 2005. The report also asks the Arkansas General Assembly to delegate authority to the Arkansas Commission to determine the appropriate retail competition start date within the approved time frame. In February 2001 the Arkansas General Assembly passed legislation that was signed into law by the Governor that changes the date of electric retail competition to October 1, 2003, and provided the Arkansas Commission with the authority to delay that date for up to two years.

Texas Restructuring – Affecting AEP, CPL, SWEPCo and WTU

In June 1999 Texas restructuring legislation was signed into law which, among other things:

- gives Texas customers of investor-owned utilities the opportunity to choose their electricity provider beginning January 1, 2002;
- provides for the recovery of regulatory assets and of other stranded costs through securitization and non-bypassable wires charges;
- requires reductions in NOx and sulfur dioxide emissions;
- provides for a rate freeze until January 1, 2002 followed by a 6% rate reduction for residential and small commercial customers and a number of customer protections;

- provides for an earnings test for each of the three years of the rate freeze period (1999 through 2001) which will reduce stranded cost recoveries or if there is no stranded cost provides for a refund or their use to fund certain capital expenditures in the amount of the excess earnings;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution utility;
- provides for certain limits for ownership and control of generating capacity by companies;
- provides for elimination of the fuel clause reconciliation process beginning January 1, 2002; and
- provides for a 2004 true-up proceeding to determine recovery of stranded costs including final fuel recovery balances, net regulatory assets, certain environmental costs, accumulated excess earnings and other issues.

Under the Texas Legislation, delivery of electricity will continue to be the responsibility of the local electric transmission and distribution utility company at regulated prices. Each electric utility was required to submit a plan to structurally unbundle its business activities into a retail electric provider, a power generation company, and a transmission and distribution utility. In May 2000 CPL, SWEPCo and WTU filed a revised business separation plan that the PUCT approved on July 7, 2000 in an interim order. The revised business separation plans provided for CPL and WTU, which operate in Texas only, to establish separate companies and divide their integrated utility operations and assets into a power generation company, a transmission and distribution utility and a retail electric provider. SWEPCo will separate its Texas jurisdictional transmission and distribution assets and operations into a new Texas regulated transmission and distribution subsidiary. In addition, a retail electric provider will be formed by SWEPCo to provide retail electric service to SWEPCo's Texas jurisdictional customers.

Under the Texas Legislation, electric utilities are allowed, with the approval of the PUCT, to recover stranded generation costs including generation-related regulatory assets that may not be recoverable in a future competitive market. The approved stranded costs can be refinanced through securitization, which is a financing structure designed to provide lower financing costs than are available through conventional financings. Lower financing costs are achieved through the issuance of securitization bonds at a lower interest rate to finance 100% of the costs pursuant to a state pledge to ensure recovery of the bond principal and financing costs through a non-bypassable rate surcharge by the regulated transmission and distribution utility over the life of the securitization bonds.

In 1999 CPL filed an application with the PUCT to securitize approximately $1.27 billion of its retail generation-related regulatory assets and approximately $47 million in other qualified restructuring costs. On March 27, 2000, the PUCT issued an order permitting CPL to securitize approximately $764 million of net regulatory assets. The PUCT's order authorized issuance of up to $797 million of securitization bonds including the $764 million for recovery of net generation-related regulatory assets and $33 million for other qualified refinancing costs. The $764 million for recovery of net generation-related regulatory assets reflects the recovery of $949 million of generation-related regulatory assets offset by $185 million of customer benefits associated with accumulated deferred income taxes. CPL had previously proposed in its filing to flow these benefits back to customers over the 14-year term of the securitization bonds. On April 11, 2000, four parties appealed the PUCT's securitization order to the Travis County District Court. In July 2000 the Travis County District Court upheld the PUCT's securitization order. The securitization order is being appealed to the Supreme Court of Texas. One of these appeals challenges CPL's ability to recover securitization charges under the Texas Constitution. CPL will not be able to issue the securitization bonds until these appeals are resolved.

The remaining regulatory assets of $206 million originally included by CPL in its 1999 securitization request were included in a March

2000 filing with the PUCT, requesting recovery of an additional $1.1 billion of stranded costs. The March 2000 filing of $1.1 billion included recovery of approximately $800 million of STP costs included in property, plant and equipment-electric on AEP's Consolidated Balance Sheets and in electric utility plant-production on CPL's Consolidated Balance Sheets. These STP costs had previously been identified as excess cost over market (ECOM) by the PUCT for regulatory purposes and were earning a lower return and were being amortized on an accelerated basis for rate-making purposes in Texas. The March 2000 filing will determine the initial amount of stranded costs in addition to the securitized regulatory assets to be recovered beginning January 1, 2002.

CPL submitted a revised estimate of stranded costs on October 2, 2000 using assumptions developed in generic proceedings by the PUCT and an administrative model developed by the PUCT staff that reduced the amount of the initial stranded cost estimate to $361 million from the $1.1 billion requested by CPL. CPL subsequently agreed to accept adjustments proposed by intervenors that reduced ECOM to approximately $230 million. Hearings on CPL's requested ECOM were held in October 2000. In February 2001 the PUCT issued an interim decision determining an initial amount of CPL ECOM or stranded costs of negative $580 million. The decision indicated that CPL's costs were below market after securitization of regulatory assets. Management does not agree with the critical inputs to this model. Management believes CPL has a positive stranded cost exclusive of securitized regulatory assets. The final amount of CPL's stranded costs including regulatory assets and ECOM will be established by the PUCT in the legislatively required 2004 true-up proceeding. If CPL's total stranded costs determined in the 2004 true-up are less than the amount of securitized regulatory assets, the PUCT can implement an offsetting credit to transmission and distribution rates.

The PUCT ruled that prior to the 2004 true-up proceeding, no adjustments would be made to the amount of regulatory costs authorized by the PUCT to be securitized. However, the PUCT also ruled that excess earnings for the period 1999-2001 should be refunded through transmission and distribution rates to the extent of any over-mitigation of stranded costs represented by negative ECOM. In the event that CPL will be required to refund excess earnings in the future instead of applying them to reduce ECOM or regulatory assets, it will adversely affect future cash flow but not results of operations since excess earnings for 1999 and 2000 were accrued and expensed in 1999 and 2000. The Texas Legislation allows for several alternative methods to be used to value stranded costs in the final 2004 true-up proceeding including the sale or exchange of generation assets, the issuance of power generation company stock to the public or the use of PUCT staff's ECOM model. To the extent that the final 2004 true-up proceeding determines that CPL should recover additional stranded costs, the total amount recoverable can be securitized.

The Texas Legislation provides that each year during the 1999 through 2001 rate freeze period, electric utilities are subject to an earnings test. For electric utilities with stranded costs, such as CPL, any earnings in excess of the most recently approved cost of capital in its last rate case must be applied to reduce stranded costs. Utilities without stranded costs, such as SWEPCo and WTU, must either flow such excess earnings amounts back to customers or make capital expenditures to improve transmission or distribution facilities or to improve air quality. The Texas Legislation requires PUCT approval of the annual earnings test calculation.

The 1999 earnings test reports filed by CPL, SWEPCo and WTU showed excess earnings of $21 million, $1 million and zero, respectively. The PUCT staff issued its report on the excess earnings calculations filed by CPL, SWEPCo and WTU and calculated the excess earnings amounts to be $41 million, $3 million and $11 million for CPL, SWEPCo and WTU, respectively. The Office of Public Utility Counsel also filed exceptions to the companies' earnings reports. Several issues were resolved via settlement and the remaining open issues were submitted to the

PUCT. A final order was issued by the PUCT in February 2001 and adjustments to the accrued 1999 and 2000 excess earnings were recorded in results of operations in the fourth quarter of 2000. After adjustments the accruals for 1999 excess earnings for CPL and WTU were $24 million and $1 million, respectively. CPL and WTU also recorded an estimated provision for excess 2000 earnings of $16 million and $14 million, respectively.

A Texas settlement agreement in connection with the AEP and CSW merger permits CPL to apply for regulatory purposes up to $20 million of STP ECOM plant assets a year in 2000 and 2001 to reduce excess earnings, if any. For book and financial reporting purposes, STP ECOM plant assets will be depreciated in accordance with GAAP, on a systematic and rational basis unless impaired. CPL will establish a regulatory liability or reduce regulatory assets by a charge to earnings to the extent excess earnings exceed $20 million in 2000 and 2001.

Beginning January 1, 2002, fuel costs will not be subject to PUCT fuel reconciliation proceedings. Consequently, CPL, SWEPCo and WTU will file a final fuel reconciliation with the PUCT to reconcile their fuel costs through the period ending December 31, 2001. Fuel costs have been reconciled by CPL, SWEPCo and WTU through June 30, 1998, December 31, 1999 and June 30, 1997, respectively. WTU is currently reconciling its fuel through June 2000. See discussion in Note 5 "Rate Matters". At December 31, 2000, CPL's, SWEPCo's and WTU's Texas jurisdictional unrecovered deferred fuel balances were $127 million, $20 million and $59 million, respectively. Final unrecovered deferred fuel balances at December 31, 2001 will be included in each company's 2004 true-up proceeding. If the final fuel balances or any amount incurred but not yet reconciled were not recovered, they could have a negative impact on results of operations. The elimination of the fuel clause recoveries in 2002 in Texas will subject AEP, CPL, SWEPCo and WTU to greater risks of fuel market price increases and could adversely affect future results of operations beginning in 2002.

The affiliated retail electric provider of CPL, SWEPCo and WTU will be required to offer residential and small commercial customers (with a peak usage of less than 1000 KW) a rate 6% below rates in effect on January 1, 1999 adjusted for any changes in fuel cost recovery factors since January 1, 1999 (price to beat). The price to beat must be offered to residential and small commercial customers until January 1, 2007. Customers with a peak usage of more than 1000 KW are subject to market rates. The Texas restructuring legislation provides for the price to beat to be adjusted up to two times annually to reflect significant changes in fuel and purchased energy costs.

Discontinuance of the Application of SFAS 71 Regulatory Accounting in Arkansas and Texas

The financial statements of CPL, SWEPCo and WTU have historically reflected the economic effects of regulation by applying the requirements of SFAS 71. As a result of the scheduled deregulation of generation in Arkansas and Texas, the application of SFAS 71 for the generation portion of the business in those states was discontinued in the third quarter of 1999. Under the provisions of EITF 97-4, CPL's generation-related net regulatory assets were transferred to the distribution portion of the business and will be amortized as they are recovered through wires charges to customers. Management believes that substantially all of CPL's generation-related regulatory assets will be recovered under the Texas Legislation. CPL's recovery of generation-related regulatory assets and stranded costs are subject to a final determination by the PUCT in 2004. If future events were to make the recovery through securitization of CPL's generation-related regulatory assets no longer probable, CPL would write-off the portion of such regulatory assets deemed unrecoverable as a non-cash extraordinary charge to earnings.

The Texas Legislation provides that all finally determined stranded costs will be recovered. Since SWEPCo and WTU are not expected to have net stranded costs, all Arkansas and Texas jurisdictional generation-related net regulatory assets were written off as non-recoverable in 1999 when SWEPCo and WTU discontinued the application of SFAS 71 regulatory accounting. As required by SFAS 101 when SFAS 71 is discontinued, an accounting impairment analysis for generation assets under SFAS 121 was completed for CPL, SWEPCo and WTU. The analysis showed that there was no accounting impairment of generation assets when the application of SFAS 71 was discontinued. CPL, SWEPCo and WTU will test their generation assets for impairment under SFAS 121 if circumstances change. Management believes that on a discounted basis CPL's generation business net cash flows will likely be less than its generating assets' net book value and together with its generation-related regulatory assets should create a recoverable stranded cost for regulatory purposes under the Texas Legislation. Therefore, management continues to carry on the balance sheet at December 31, 2000, $953 million of generation-related regulatory assets already approved for securitization and $195 million of net generation-related regulatory assets pending approval for securitization in Texas. A final determination of whether they will be securitized and recovered will be made as part of the 2004 true-up proceeding.

CPL, SWEPCo, and WTU continue to analyze the impact of electric utility industry restructuring legislation on their Arkansas and Texas electric operations. Although management believes that the Texas Legislation provides for full recovery of stranded costs and that the companies do not have a recordable accounting impairment, a final determination of whether CPL will experience an accounting loss or whether SWEPCo and WTU will experience any additional accounting loss from an inability to recover generation-related regulatory assets and other restructuring related costs in Texas and Arkansas cannot be made until such time as the regulatory process is complete following the 2004 true-up proceeding in Texas and a determination by the Arkansas Commission. In the event CPL, SWEPCo, and WTU are unable after the 2004 true-up proceeding and after the Arkansas Commission proceedings to recover all or a portion of their generation-related regulatory assets, stranded costs and other restructuring related costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Although Arkansas' delay of retail competition may be having a negative effect on the progress of efforts to transition SWEPCo's generation in Arkansas to market based pricing of electricity, it appears that Texas is moving forward as planned. Management is carefully monitoring the situation in Arkansas and is working with all concerned parties to prudently quicken the pace of the transition. However, changes could occur due to concerns stemming from the California energy crisis and other events which could adversely affect future results of operations in Arkansas and possibly Texas.

Michigan Restructuring - Affecting AEP and I&M

On June 5, 2000, the Michigan Legislation became law. Its major provisions, which were effective immediately, applied only to electric utilities with one million or more retail customers. I&M, AEP's electric operating subsidiary doing business in Michigan, has less than one million customers in Michigan. Consequently, I&M was not immediately required to comply with the Michigan Legislation.

The Michigan Legislation gives the MPSC broad power to issue orders to implement retail customer choice of electric supplier no later than January 1, 2002 including recovery of regulatory assets and stranded costs. On October 2, 2000, I&M filed a restructuring implementation plan as required by a MPSC order. The plan identifies I&M's proposal to file with the MPSC on June 5, 2001 its unbundled rates, open access tariffs, terms of service and supporting schedules. Described in the plan are I&M's intentions and preparation for competition related to supplier transactions, customer transactions, rate unbundling, education programs, and regional transmission organization. The plan contains a proposed methodology to determine stranded costs and implementation costs and requests the continuation of a wires charge for recovery of nuclear decommissioning costs. Approval of the restructuring implementation plan is pending before the MPSC.

Management has concluded that as of December 31, 2000 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan will continue to be cost-based regulated until the MPSC approves rates and wires charges in 2001. The establishment of rates and wires charges under a MPSC approved transition plan will enable management to determine the ability to recover stranded costs including regulatory assets and other implementation costs, a requirement of EITF 97-4 to discontinue the application of SFAS 71. Upon the discontinuance of SFAS 71, I&M will, if necessary, have to write off its Michigan jurisdictional generation-related regulatory assets and record its unrecorded Michigan jurisdictional liability for decommissioning the Cook Plant to the extent that they cannot be recovered under the transition rates and wires charges. As required by SFAS 101 when discontinuing SFAS 71 regulatory accounting, I&M will have to perform an accounting impairment analysis under SFAS 121 to determine if the Michigan jurisdictional portion of its generating assets are impaired for accounting purposes.

The amount of regulatory assets recorded on the books at December 31, 2000 applicable to I&M's Michigan retail jurisdictional generation business is approximately $45 million before related tax effects. The estimated unrecorded liability for the Michigan jurisdiction to decommission the Cook Plant ranges from $114 million to $215 million in 2000 non-discounted dollars based upon studies completed during 2000. For the Michigan jurisdiction, I&M has accumulated approximately $100 million in trust funds to decommission the Cook Plant. Based on the current information available, management does not anticipate that I&M will experience any material tangible asset accounting impairment or regulatory asset write-offs. Ultimately, however, whether I&M will experience material regulatory asset write-offs will depend on whether the MPSC approves their recovery in future restructuring proceedings.

A determination of whether I&M will experience any asset impairment loss regarding its Michigan retail jurisdictional generating assets and any loss from a possible inability to recover Michigan generation-related regulatory assets, decommissioning obligations and transition costs cannot be made until such time as the rates and the wires charges are determined through the regulatory process. In the event I&M is unable to recover all or a portion of its generation-related regulatory assets, unrecorded decommissioning obligation, stranded costs and other implementation costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Oklahoma Restructuring – Affecting AEP and PSO

In 1997, the Oklahoma Legislature passed restructuring legislation providing for retail open access by July 1, 2002. That legislation called for a number of studies to be completed on a variety of restructuring issues, including an independent system operator, technical, financial, transition and consumer issues. During 1998 and 1999 several of the studies were completed.

The information from the studies was expected to be used in the development of additional industry restructuring legislation during the 2000 legislative session. Several additional electric industry restructuring bills were filed in the 2000 Oklahoma legislative session. The proposed bills generally supplemented the industry restructuring legislation previously enacted in Oklahoma which lacked specific procedures for a transition to market based competitive prices. The industry restructuring legislation previously passed did not delegate the establishment of transition procedures to the Oklahoma Corporation Commission. The 2000 Oklahoma legislative session adjourned in May without passing further restructuring legislation.

The 2001 Oklahoma legislative session convened in early February. No further electric restructuring legislation has passed and proposals have been made to delay the implementation of the transition to customer choice and market based pricing under the restructuring legislation. If the necessary legislation is not passed, PSO's generation and retail electric supply business will remain regulated in Oklahoma. If implementation legislation were to modify the original restructuring legislation in Oklahoma it could have a adverse effect on results of operations.

Management has concluded that as of December 31, 2000 the requirements to apply SFAS 71 continue to be met since PSO's rates for generation in Oklahoma will continue to be cost-based regulated until the Oklahoma Legislature approves further restructuring legislation and transition rates and wires charges are established under an approved transition plan. Until management is able to determine the ability to recover stranded costs which includes regulatory assets and other implementation costs, PSO cannot discontinue application of SFAS 71 accounting under GAAP.

When PSO discontinues application of SFAS 71, it will be necessary to write off Oklahoma jurisdictional generation-related regulatory assets to the extent that they cannot be recovered under the transition rates and wires charges, when determined, and record any asset accounting impairments in accordance with SFAS 121.

A determination of whether PSO will experience any asset impairment loss regarding its Oklahoma retail jurisdictional generating assets and any loss from a possible inability to recover Oklahoma generation-related regulatory assets and other transition costs cannot be made until such time as the rates and the wires charges are determined through the legislative and/or regulatory process. In the event PSO is unable to recover all or a portion of its generation-related regulatory assets and implementation costs, Oklahoma restructuring could have a material adverse effect on results of operations and cash flows.

Structural Separation

On November 1, 2000, AEP, AEPSC, APCo, CPL, CSPCo, OPCo, SWEPCo and WTU filed with the SEC for approval to form two separate legal holding company subsidiaries of AEP, the parent company. The purpose of these entities is to legally and functionally separate the competitive market business activities and the subsidiaries performing those competitive activities from the business activities which are cost-based regulated and the subsidiaries that perform those regulated activities. Corporate separation plans have also been filed with regulatory commissions in Arkansas, Ohio, Texas and Virginia to comply with requirements specified in their restructuring legislation. The Texas Legislation requires separate legal entities for generation and distribution assets by January 1, 2002. AEP, APCo, CPL, CSPCo, OPCo, SWEPCo and WTU will need approval from the SEC under PUHCA, FERC and certain state regulatory commissions to make these organization changes.

8. Commitments and Contingencies:

Construction and Other Commitments - The AEP System has substantial construction commitments to support its operations. Aggregate construction expenditures for 2001-2003 for consolidated domestic and foreign operations are estimated to be $7 billion.

The following table shows the estimated construction expenditures of the subsidiary registrants for 2001 – 2003:

	(in millions)
AEGCo	$ 9.1
APCo	1,164.3
CPL	770.2
CSPCo	422.2
I&M	439.6
KPCo	215.6
OPCo	1,085.2
PSO	310.8
SWEPCo	413.1
WTU	259.3

Long-term contracts to acquire fuel for electric generation have been entered into for various terms, the longest of which extends to the year 2014 for the AEP System. The expiration date of the longest fuel contract for APCo is 2006, CSPCo is 2007, I&M is 2014, KPCo is 2003, OPCo is 2012, PSO is 2014, SWEPCo is 2006 and WTU is 2006. The contracts provide for periodic price adjustments and contain various clauses that would release the subsidiaries from their obligations under certain force majeure conditions.

The AEP System has contracted to sell approximately 1,174 MW of capacity domestically on a long-term basis to unaffiliated utilities. Certain of these contracts totaling 250 mw of capacity are unit power agreements requiring the delivery of energy only if the unit capacity is available. The power sales contracts expire from 2001 to 2010.

Nuclear Plants – Affecting AEP, CPL and I&M

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. CPL owns 25.2% of the two-unit 2,500 MW STP. STPNOC operates STP on behalf of the joint owners under licenses granted by the NRC. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the U.S., the resultant liability could be substantial. By agreement I&M and CPL are partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery in rates is not possible, results of operations, cash flows and financial condition would be adversely affected.

Nuclear Incident Liability – Affecting AEP, CPL and I&M

The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at $9.5 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance provides $200 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S. the remainder of the liability would be provided by a deferred premium assessment of $88 million on each licensed reactor in the U.S. payable in annual installments of $10 million. As a result, I&M could be assessed $176 million per nuclear incident payable in annual installments of $20 million. CPL could be assessed $44 million per nuclear incident payable in annual installments of $5 million as its share of a STPNOC assessment. The number of incidents for which payments could be required is not limited.

Insurance coverage for property damage, decommissioning and decontamination at the Cook Plant and STP is carried by I&M and STPNOC in the amount of $1.8 billion each. Cook Plant and STPNOC jointly purchase $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage.

SNF Disposal – Affecting AEP, CPL, and I&M

Federal law provides for government responsibility for permanent SNF disposal and assesses nuclear plant owners fees for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at Cook Plant and STP is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $211 million for fuel consumed prior to April 7, 1983 at Cook Plant have been recorded as long-term debt. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 2000, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and approximate the liability. CPL is not liable for any assessments for nuclear fuel consumed prior to April 7, 1983 since the STP units began operation in 1988 and 1989.

Decommissioning and Low Level Waste Accumulation Disposal – Affecting AEP, CPL and I&M

Decommissioning costs are accrued over the service lives of the Cook Plant and STP. The licenses to operate the two nuclear units at Cook Plant expire in 2014 and 2017. After expiration of the licenses, Cook Plant is expected to be decommissioned through dismantlement. The estimated cost of decommissioning and low level radioactive waste accumulation disposal costs for Cook Plant ranges from $783 million to $1,481 million in 2000 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. I&M is recovering estimated Cook Plant decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The amount recovered in rates for decommissioning the Cook Plant and deposited in the external fund was $28 million in 2000, $28 million in 1999 and $29 million in 1998.

The licenses to operate the two nuclear units at STP expire in 2027 and 2028. After expiration of the licenses, STP is expected to be decommissioned using the decontamination method. CPL estimates its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. CPL is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of $8 million per year.

Decommissioning costs recovered from customers are deposited in external trusts. In 2000 and 1999 I&M deposited in its decommissioning trust an additional $6 million and $4 million, respectively, related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and the recorded liability and decrease the amount needed to be recovered from ratepayers. Decommissioning costs including interest, unrealized gains and losses and expenses of the trust funds are recorded in other operation expense for Cook Plant. For STP, nuclear decommissioning costs are recorded in other operation expense, interest income of the trusts are recorded in nonoperating income and interest expense of the trust funds are included in interest charges. During 1999 and 1998 I&M withdrew $8 million and $3 million, respectively, from the trust funds for decommissioning of the original steam generators removed from Cook Plant Unit 2.

On the AEP Consolidated Balance Sheets, nuclear decommissioning trust assets are included in other assets and a corresponding nuclear decommissioning liability is included in other noncurrent liabilities. On CPL's balance sheets, the nuclear decommissioning liability is included in electric utility plant-accumulated depreciation and amortization. At December 31, 2000 and 1999, the decommissioning liability for Cook Plant and STP combined totals $654 million and $587 million, respectively.

Shareholders' Litigation – Affecting AEP

On June 23, 2000, a complaint was filed in the U.S. District Court for the Eastern District of New York seeking unspecified compensatory damages against AEP and four former or present officers. The individual plaintiff also seeks certification as the representative of a class consisting of all persons and entities who purchased or otherwise acquired AEP common stock between July 25, 1997, and June 25, 1999. The complaint alleges that the defendants knowingly violated federal securities laws by disseminating materially false and misleading statements concerning, among other things, the undisclosed materially impaired condition of the Cook Plant; AEP's inability to properly monitor, manage, repair, supervise and report on operations at the Cook Plant and the materially adverse conditions these problems were having, and would continue to have, on AEP's deteriorating financial condition, and ultimately on AEP's operations, liquidity and stock price. Four other similar class action complaints have been filed and the court has consolidated the five cases. The plaintiffs filed a consolidated complaint pursuant to this court order. This case has been transferred to the U.S. District Court for the Southern District of Ohio. Although management believes these shareholder actions are without merit and intends to oppose them vigorously, management cannot predict the outcome of this litigation or its impact on results of operations, cash flows or financial condition.

Municipal Franchise Fee Litigation – Affecting AEP and CPL

CPL has been involved in litigation regarding municipal franchise fees in Texas as a result of a class action suit filed by the City of San Juan, Texas in 1996. The City of San Juan claims CPL underpaid municipal franchise fees and seeks damage of up to $300 million plus attorney's fees. CPL filed a counterclaim for overpayment of franchise fees.

During 1997, 1998 and 1999 the litigation moved procedurally through the Texas Court System and was sent to mediation without resolution.

In 1999 a class notice was mailed to each of the cities served by CPL. Over 90 of the 128 cities declined to participate in the lawsuit. However, CPL has pledged that if any final, non-appealable court decision in the litigation awards a judgement against CPL for a franchise underpayment, CPL will extend the principles of that decision, with regard to any franchise underpayment, to the cities that declined to participate in the litigation. In December 1999, the court ruled that the class of plaintiffs would consist of approximately 30 cities. A trial date for June 2001 has been set.

Although management believes that it has substantial defenses to the cities' claims and intends to defend itself against the cities' claims and pursue its counterclaims vigorously, management cannot predict the outcome of this litigation or its impact on results of operations, cash flows or financial condition.

Texas Base Rate Litigation – Affecting AEP and CPL

In November 1995 CPL filed with the PUCT a request to increase its retail base rates by $71 million. In October 1997 the PUCT issued a final order which lowered CPL's annual retail base rates by $19 million from the rate level which existed prior to May 1996. The PUCT also included a "glide path" rate methodology in the final order pursuant to which annual rates were reduced by $13 million beginning May 1, 1998 with an additional annual reduction of $13 million commencing on May 1, 1999.

CPL appealed the final order to the Travis District Court. The primary issues being appealed include: the classification of $800 million of invested capital in STP as ECOM and assigning it a lower return on equity than other generation property; the use of the "glide path" rate reduction methodology; and an $18 million disallowance of service billings from an affiliate, CSW Services. As part of the appeal, CPL sought a temporary injunction to prohibit the PUCT from implementing the "glide path" rate reduction methodology. The temporary injunction was denied and the "glide path" rate reduction was implemented. In February 1999 the Travis District Court affirmed the PUCT order in regard to the three major items discussed above.

CPL appealed the Travis District Court's findings to the Texas Appeals Court which in July 2000, issued its opinion upholding the Travis District Court except for the disallowance of affiliated service company billings. Under Texas law, specific findings regarding affiliate transactions must be made by PUCT. In regards to the affiliate service billing issue, the findings were not complete in the opinion of the Texas Appeals Court who remanded the issue back to PUCT.

CPL has sought a rehearing of the Texas Appeals Court's opinion. The Texas Appeals Court has requested briefs related to CPL's rehearing request from interested parties. Management is unable to predict the final resolution of its appeal. If the appeal is unsuccessful the PUCT's 1997 order will continue to adversely affect results of operations and cash flows.

As part of the AEP/CSW merger approval process in Texas, a stipulation agreement was approved which resulted in the withdrawal of the appeal related to the "glide path" rate methodology. CPL will continue its appeal of the ECOM classification for STP property and the disallowed affiliated service billings.

Lignite Mining Agreement Litigation – Affecting AEP and SWEPCo

SWEPCo and CLECO are each a 50% owner of Dolet Hills Power Station Unit 1 and jointly own lignite reserves in the Dolet Hills area of northwestern Louisiana. In 1982, SWEPCo and CLECO entered into a lignite mining agreement with DHMV, a partnership for the mining and delivery of lignite from a portion of these reserves.

In April 1997, SWEPCo and CLECO sued DHMV and its partners in U.S. District Court for the Western District of Louisiana seeking to enforce various obligations of DHMV under the lignite mining agreement, including provisions relating to the quality of delivered lignite, pricing, and mine reclamation practices. In June 1997, DHMV filed an answer denying the allegations in the suit and filed a counterclaim asserting various contract-related claims against SWEPCo and CLECO. SWEPCo and CLECO have denied the allegations contained in the counterclaims. In January 1999, SWEPCo and CLECO amended the claims against DHMV to include a request that the lignite mining agreement be terminated.

In April 2000, the parties agreed to settle the litigation. As part of the settlement, DHMV's interest in the mining operations and related debt and other obligations will be purchased by SWEPCo and CLECO. The closing date for the settlement has been extended from December 31, 2000 to March 31, 2001. The litigation has been stayed until April 2001 to give the parties time to consummate the settlement agreement.

Management believes that the resolution of this matter will not have a material effect on results of operations, cash flows or financial condition.

Federal EPA Complaint and Notice of Violation – Affecting AEP, APCo, CSPCo, I&M, and OPCo

Under the Clean Air Act, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

AEP, APCo, CSPCo, I&M, and OPCo have been involved in litigation regarding generating plant emissions under the Clean Air Act. In 1999 Notices of Violation were issued and complaints were filed by Federal EPA in various U.S. District Courts alleging APCo, CSPCo, I&M, OPCo and a number of unaffiliated utilities made modifications to generating units at certain of their coal-fired generating plants over the course of the past 25 years that extended unit operating lives or increased unit generating capacity without a preconstruction permit in violation of the Clean Air Act. The complaint was amended in March 2000 to add allegations for certain generating units previously named in the complaint and to include additional generating units previously named only in the Notices of Violation in the complaint.

A number of northeastern and eastern states were granted leave to intervene in the Federal EPA's action against the AEP System under the Clean Air Act. A lawsuit against power plants owned by certain AEP System operating companies alleging similar violations to those in the Federal EPA complaint and Notices of Violation was filed by a number of special interest groups and has been consolidated with the Federal EPA action.

The Clean Air Act authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). Civil penalties, if ultimately imposed by the court, and the cost of any required new pollution control equipment, if the court accepts Federal EPA's contentions, could be substantial.

On May 10, 2000, the AEP System companies filed motions to dismiss all or portions of the complaints. Briefing on these motions was completed on August 2, 2000. On February 23, 2001, the government filed a motion for partial summary judgement seeking a determination that four projects undertaken on units at Sporn, Cardinal and Clinch River plants do not constitute "routine maintenance, repair and replacement" as used in the Clean Air Act. Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act and intends to vigorously pursue its defense.

In the event the AEP System companies do not prevail, any capital and operating costs of additional pollution control equipment that may be required as well as any penalties imposed would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates, and where states are deregulating generation, unbundled transition period generation rates, stranded cost wires charges and future market prices for electricity.

In December 2000 Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by CSPCo reached a tentative agreement with Federal EPA and other parties to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing between the parties in an attempt to reach final settlement terms. Cinergy's settlement could impact the operation of Zimmer Plant and W.C. Beckjord Generating Station Unit 6 which are owned 25.4% and 12.5%, respectively, by CSPCo. Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its future earnings and cash flows.

NOx Reductions – Affecting AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo and SWEPCo

Federal EPA issued a NOx rule that required substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located. A number of utilities, including several AEP System companies, filed petitions seeking a review of the final rule in the D.C. Circuit Court. In March 2000, the D.C. Circuit Court issued a decision generally upholding the NOx rule. The D.C. Circuit Court issued an order in August 2000 which extends the final compliance date to May 31, 2004. In September 2000 following denial by the D.C. Circuit Court of a request for rehearing, the industry petitioners, including the AEP System companies, petitioned the U.S. Supreme Court for review, which was denied.

In December 2000 Federal EPA ruled that eleven states, including states in which AEGCo's, APCo's, CSPCo's, I&M's, KPCo's and OPCo's generating units are located, failed to submit plans to comply with the mandates of the NOx rule. This determination means that those states could face stringent sanctions within the next 24 months including limits on construction of new sources of air emissions, loss of federal highway funding and possible Federal EPA takeover of state air quality management programs.

In January 2000 Federal EPA adopted a revised rule granting petitions filed by certain northeastern states under Section 126 of the Clean Air Act seeking significant reductions in nitrogen oxide emissions from utility and industrial sources. The rule imposes emissions reduction requirements comparable to the NOx rule beginning May 1, 2003, for most of AEP's coal-fired generating units. Certain AEP operating companies and other utilities filed petitions for review in the D.C. Circuit Court. Briefing has been completed and oral argument was held in December 2000.

In a related matter, on April 19, 2000, the Texas Natural Resource Conservation Commission adopted rules requiring significant reductions in NOx emissions from utility sources, including CPL and SWEPCo. The rule's compliance date is May 2003 for CPL and May 2005 for SWEPCo.

In June 2000 OPCo announced that it was beginning a $175 million installation of selective catalytic reduction technology (expected to be operational in 2001) to reduce NOx emissions on its two-unit 2,600 MW Gavin Plant. Construction of selective catalytic reduction technology on Amos Plant Unit 3, which is jointly owned by OPCo and APCo, and APCo's Mountaineer Plant is scheduled to begin in 2001. The Amos and Mountaineer projects (expected to be completed in 2002) are estimated to cost a total of $230 million ($145 million for APCo and $85 million for OPCo).

Preliminary estimates indicate that compliance with the NOx rule upheld by the D.C. Circuit Court as well as compliance with the Texas Natural Resource Conservation Commission rule and the Section 126 petitions could result in required capital expenditures of approximately $1.6 billion, including the amounts discussed in the previous paragraph, for AEP Consolidated. Estimated compliance costs by registrant subsidiaries are as follows:

	(in millions)
AEGCo	$125
APCo	365
CPL	57
CSPCo	106
I&M	202
KPCo	140
OPCo	606
SWEPCo	28

Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the preliminary estimates depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital and operating costs of additional pollution control equipment are recovered from customers through regulated rates and/or future market prices for electricity where generation is deregulated, they will have an adverse effect on future results of operations, cash flows and possibly financial condition.

COLI Litigation – Affecting AEP, APCo, CSPCo, I&M, KPCo and OPCo

On February 20, 2001, the U.S. District Court for the Southern District of Ohio ruled against the AEP System companies in their suit against the United States over deductibility of interest claimed in their consolidated federal income tax return related to a COLI program. The suit was filed to resolve the IRS' assertion that interest deductions for the COLI program should not be allowed. In 1998 and 1999 APCo, CSPCo, I&M, KPCo and OPCo paid the disputed taxes and interest attributable to COLI interest deductions for taxable years 1991-98 for APCo, CSPCo, I&M and OPCo and 1992-98 for KPCo to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in other assets on AEP's Consolidated Balance Sheet and in Other Property and Investment on the subsidiaries' balance sheets pending the resolution of this matter. As a result of the U.S. District Court's decision to deny the COLI interest deductions, net income was reduced for AEP Consolidated by $319 million in 2000. The appeal of this decision is planned. The earnings reductions for affected registrant subsidiaries are as follows:

	(in millions)
APCo	$ 82
CSPCo	41
I&M	66
KPCo	8
OPCo	118

Other – AEP and its registrant subsidiaries are involved in a number of other legal proceedings and claims. While management is unable to predict the ultimate outcome of these matters, it is not expected that their resolution will have a material adverse effect on results of operations, cash flows or financial condition.

9. Acquisitions:

AEP completed two energy related acquisitions in 1998 through a subsidiary, AEPR. Both acquisitions have been accounted for using the purchase method. On December 31, 1998 CitiPower, an Australian distribution utility, that serves approximately 250,000 customers in Melbourne with 3,100 miles of distribution lines in a service area of approximately 100 square miles was acquired. All of the stock of CitiPower was acquired for approximately $1.1 billion. The acquisition of CitiPower had no effect on the results of operations for 1998 and a full year of CitiPower's results of operations are included in the consolidated statements of income for 1999 and 2000. Assets acquired and liabilities assumed have been recorded at their fair values. Based on an independent appraisal, $616 million of the purchase price was allocated to retail and wholesale distribution licenses which are being amortized on a straight-line basis over 20 years and 40 years, respectively. The excess of cost over fair value of the net assets acquired was approximately $34 million and is recorded as goodwill and is being amortized on a straight-line basis over 40 years.

On December 1, 1998 AEPR acquired Louisiana Intrastate Gas (LIG) with midstream gas operations that include a fully integrated natural gas gathering, processing, storage and transportation operation in Louisiana and a gas trading and marketing operation. LIG was acquired for approximately $340 million, including working capital funds with one month of earnings reflected in AEP's consolidated results of operations for the year ended December 31, 1998. A full year of LIG's results of operations is included in AEP's consolidated statements of income for 1999 and 2000. Assets acquired and liabilities assumed have been recorded at their fair values. The excess of cost over fair value of the net assets acquired was approximately $158 million for the midstream gas storage operations and $17 million for the gas trading and marketing operation. The goodwill is being amortized on a straight-line basis over 40 years and 10 years, respectively.

10. International Investments:

CSW International owns a 44% equity interest in Vale, a Brazilian electric operating company which it had purchased for a total of $149 million. The investment is covered by a put option, which, if exercised, requires CSW International's partners in Vale to purchase CSW International's Vale shares at a minimum price equal to the U.S. dollar equivalent of CSW International's purchase price. As a result, management has concluded that CSW International's investment carrying amount will not be reduced below the put option value unless it is deemed to be a permanent impairment and CSW International's partners in Vale are deemed unable to fulfill their responsibilities under the put option. Vale has experienced losses from operations and CSW International's investment has been affected by the devaluation of the Brazilian Real. CSW International's cumulative equity share of these operating and foreign currency translation losses through December 31, 2000 is approximately $33 million, net of tax, and $49 million, net of tax, respectively. Pursuant to the put option arrangement, these losses have not been applied to reduce the carrying value of the Vale investment. As a result, CSW International will not recognize any future earnings from Vale until the operating losses are recovered.

In December 2000, CSW International sold its investment in a Chilean electric company for $67 million. A net loss on the sale of $13 million ($9 million after tax) is included in worldwide electric and gas expenses and includes $26 million ($17 million net of tax) of losses from foreign exchange rate changes that were previously reflected in other comprehensive income. In the second quarter of 2000 management determined that the then existing decline in market value of the shares was other than temporary. As a result the investment was written down by $33 million ($21 million after tax) in June 2000. The total loss from both the write down of the Chilean investment to market in the second quarter and from the sale in the fourth quarter was $46 million ($30 million net of tax).

In December 2000 AEPR entered into negotiations to sell its 50% investment in Yorkshire, a U.K. electricity supply and distribution company. On February 26, 2001 an agreement to sell AEPR's 50% interest in Yorkshire was signed. As a result a $43 million impairment writedown ($30 million after tax) was recorded in the fourth quarter of 2000 to reflect the net loss from the expected sale in the first quarter of 2001. The impairment writedown is included in other income (net) on AEP's Consolidated Statements of Income.

11. Staff Reductions:

During 1998 an internal evaluation of the power generation organization was conducted with a goal of developing an optimum organizational structure for a competitive generation market. The study was completed in October 1998 and called for the elimination of approximately 450 positions across the AEP System. In addition, a review of energy delivery staffing levels in 1998 identified 65 AEP System positions for elimination.

A provision for severance costs totaling $26 million was recorded in December 1998 for reductions in power generation and energy delivery staffs and was charged to maintenance and other operation expense. The power generation and energy delivery staff reductions were made in the first quarter of 1999. The amount of severance benefits paid was not significantly different from the amount accrued.

The following table shows the staff reductions information for the applicable registrant companies:

Company	Total Number of Employees	Severance Accrual Amount (in millions)
APCo	180	$7.6
CSPCo	70	3.4
I&M	80	3.7
KPCo	35	1.9
OPCo	150	8.6

12. Benefit Plans:

In the U.S. the AEP System sponsors two qualified pension plans and two nonqualified pension plans. All employees in the U.S., except participants in the UMWA pension plans are covered by one or both of the pension plans. OPEB plans are sponsored by the AEP System to provide medical and death benefits for retired employees in the U.S.

The foreign pension plans are for employees of SEEBOARD in the U.K. and CitiPower in Australia. The majority of SEEBOARD's employees joined a pension plan that is administered for the U.K.'s electricity industry. The assets of this plan are actuarially valued every three years. SEEBOARD and its participating employees both contribute to the plan. Subsequent to July 1, 1995, new employees were no longer able to participate in that plan and two new pension plans were made available to new employees of SEEBOARD. CitiPower sponsors a defined benefit pension plan that covers all employees.

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending December 31, 2000, and a statement of the funded status as of December 31 for both years:

	U.S. Pension Plans 2000	U.S. Pension Plans 1999	Foreign Pension Plans 2000	Foreign Pension Plans 1999	U.S. OPEB Plans 2000	U.S. OPEB Plans 1999
			(in millions)			
Reconciliation of benefit obligation:						
Obligation at January 1	$2,934	$3,117	$1,176	$1,147	$1,365	$1,297
Service Cost	60	71	13	15	29	33
Interest Cost	227	211	64	59	106	90
Participant Contributions	-	-	5	4	7	9
Plan Amendments	(71)(a)	7 (b)	-	7 (c)	(67) (d)	-
Foreign Currency Translation Adjustment	-	-	(95)	(26)	-	-
Actuarial (Gain) Loss	218	(300)	80	37	262	-
Benefit Payments	(207)	(172)	(64)	(67)	(85)	(74)
Curtailments	-	-	-	-	51 (e)	10 (e)
Obligation at December 31	$3,161	$2,934	$1,179	$1,176	$1,668	$1,365
Reconciliation of fair value of plan assets:						
Fair value of plan assets at January 1	$3,866	$3,665	$1,405	$1,338	$668	$560
Actual Return on Plan Assets	250	370	55	156	2	71
Company Contributions	2	2	-	7	112	103
Participant Contributions	-	-	5	4	7	9
Foreign Currency Translation Adjustment	-	-	(111)	(33)	-	-
Benefit Payments	(207)	(172)	(64)	(67)	(85)	(74)
Fair value of plan assets at December 31	$3,911	$3,865	$1,290	$1,405	$704	$669
Funded status:						
Funded status at December 31	$ 750	$ 931	$111	$ 229	$(964)	$(696)
Unrecognized Net Transition (Asset) Obligation	(23)	(31)	-	-	298	434
Unrecognized Prior-Service Cost	(12)	71	10	11	-	-
Unrecognized Actuarial (Gain) Loss	(628)	(954)	(67)	(177)	448	135
Prepaid Benefit (Accrued Liability)	$ 87	$ 17	$ 54	$ 63	$(218)	$(127)

(a) One of the qualified pension plans converted to the cash balance pension formula from a final average pay formula.
(b) Early retirement factors for one of the pension plans was changed to provide more generous benefits to participants retiring between ages 55 and 60.
(c) SEEBOARD made a one-time payment to all retired participants.
(d) Change to a service-related formula for retirement health care costs and a 50% of pay life insurance benefit for retiree life insurance.
(e) Related to the shutdown of OPCo's affiliated coal mine operations.

The following table provides the amounts recognized in AEP's consolidated balance sheets as of December 31 of both years:

	U.S. Pension Plan 2000	U.S. Pension Plan 1999	Foreign Pension Plans 2000	Foreign Pension Plans 1999	U.S. OPEB Plans 2000	U.S. OPEB Plans 1999
			(in millions)			
Prepaid Benefit Costs	$ 159	$ 145	$54	$63	$ -	$ -
Accrued Benefit Liability	(72)	(128)	-	-	(218)	(127)
Additional Minimum Liability	(24)	(14)	-	-	N/A	N/A
Intangible Asset	14	8	-	-	N/A	N/A
Accumulated Other Comprehensive Income	10	6	-	-	N/A	N/A
Net Amount Recognized	$ 87	$ 17	$54	$63	$(218)	$(127)
Other Comprehensive (Income) Expense Attributable to Change in Additional Pension Liability Recognition	$4	$(2)	-	-	N/A	N/A

N/A = Not Applicable

The AEP System's nonqualified pension plans had accumulated benefit obligations in excess of plan assets of $41 million and $26 million at December 31, 2000 and $29 million and $23 million at December 31, 1999. There are no plan assets in the nonqualified plans.

The AEP System's OPEB plans had accumulated benefit obligations in excess of plan assets of $964 million and $696 million at December 31, 2000 and 1999, respectively.

The following table provides the components of AEP's net periodic benefit cost for the plans for fiscal years 2000, 1999 and 1998:

	U.S. Pension Plans			Foreign Pension Plans			U.S. OPEB Plans		
	2000	1999	1998	2000	1999	1998	2000	1999	1998
				(in millions)					
Service cost	$ 60	$ 71	$ 67	$ 13	$ 15	$ 14	$ 29	$ 33	$ 26
Interest cost	227	211	202	64	59	68	106	90	76
Expected return on plan assets	(321)	(299)	(269)	(75)	(71)	(77)	(57)	(49)	(40)
Amortization of transition (asset) obligation	(8)	(8)	(8)	-	-	-	41	43	41
Amortization of prior-service cost	13	12	9	1	-	-	-	-	-
Amortization of net actuarial (gain) loss	(39)	(15)	(3)	-	-	-	4	5	(2)
Net periodic benefit cost	(68)	(28)	(2)	3	3	5	123	122	101
Curtailment loss(a)	-	-	-	-	-	-	79	18	24
Net periodic benefit cost after curtailments	$(68)	$ (28)	$ (2)	$ 3	$ 3	$ 5	$202	$140	$125

(a) Curtailment charges were recognized during 2000, 1999 and 1998 for the shutdown of affiliated coal mine operations.

The following table provides the net periodic benefit cost (credit) for the plans by the following AEP registrant subsidiaries for fiscal years 2000, 1999 and 1998:

	U.S. Pension Plans			U.S OPEB Plans		
	2000	1999	1998	2000	1999	1998
			(in thousands)			
APCo	$(14,047)	$(3,925)	$ 778	$ 22,139	$19,431	$16,569
CPL	(2,986)	(4,270)	(2,850)	6,656	7,595	6,599
CSPCo	(10,905)	(4,893)	(1,410)	9,643	8,623	7,467
I&M	(8,565)	(1,259)	2,104	14,155	13,664	11,994
KPCo	(2,075)	(393)	322	2,364	2,652	2,113
OPCo	(15,041)	(4,979)	26	116,205	52,518	54,578
PSO	(2,196)	(3,129)	(2,190)	4,277	5,516	4,369
SWEPCo	(2,606)	(3,734)	(2,581)	4,152	4,913	3,673
WTU	(1,585)	(2,221)	(1,478)	2,929	3,377	3,002

The assumptions used in the measurement of the AEP System's benefit obligations are shown in the following tables:

	U.S. Pension Plans			Foreign Pension Plans			U.S. OPEB Plans		
	2000 %	1999 %	1998 %	2000 %	1999 %	1998 %	2000 %	1999 %	1998 %
Weighted-average assumptions as of December 31:									
Discount rate	7.50	8.00	6.75	5-5.5	5.5-6	5-5.5	7.50	8.00	6.75
Expected return on plan assets	9.00	9.00	9.00	6-7.5	6.5-7.5	6.25-7	8.75	8.75	8.75
Rate of compensation increase	3.2	3.8	3.8	3.5-4.0	4-4.5	3.5-4	N/A	N/A	N/A

For measurement purposes, a 6.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2001. The rate was assumed to decrease gradually each year to a rate of 5.1% through 2005 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on total service and interest cost components of net periodic postretirement health care benefit cost	$ 15	$ (13)
Effect on the health care component of the accumulated postretirement benefit obligation	197	(162)

AEP System Savings Plans - The AEP System Savings Plans are defined contribution plans offered to non-UMWA U.S. employees. The cost for contributions to these plans totaled $37 million in 2000, $36 million in 1999 and $35 million in 1998. Beginning in 2001 AEP's contributions to the plans will increase to 4.5% of the initial 6% of employee pay contributed from the current 3% of the initial 6% of employee base pay contributed.

The following table provides the cost for contributions to the savings plans by the following AEP registrant subsidiaries for fiscal years 2000, 1999 and 1998:

	2000	1999	1998
	(in thousands)		
APCo	$3,988	$4,091	$4,276
CPL	3,161	3,284	3,078
CSPCo	1,638	1,679	1,830
I&M	4,231	3,996	4,017
KPCo	544	561	714
OPCo	3,713	3,744	3,978
PSO	2,306	2,435	2,230
SWEPCo	2,880	2,961	2,728
WTU	1,708	1,766	1,594

Other UMWA Benefits – AEP and OPCo provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. The benefits are administered by UMWA trustees and contributions are made to their trust funds. Contributions are based on hours worked and are expensed as paid as part of the cost of active mining operations and were not material in 2000, 1999 and 1998.

13. Stock-Based Compensation:

In 2000, AEP adopted a Long-term Incentive Plan under which a maximum of 15,700,000 shares of common stock can be issued to key employees. Under the plan, the exercise price of each option granted equals the market price of AEP's common stock on the date of grant. These options will vest in equal increments, annually, over a three-year period beginning on January 1, 2002 with a maximum exercise term of ten years.

CSW maintained a stock option plan prior to the merger with AEP. Effective with the merger, all CSW stock options outstanding were converted into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. The exercise price for each CSW stock option was adjusted for the exchange ratio. The provisions of the CSW stock option plan will continue in effect until all options expire or there are no longer options outstanding. Under the CSW stock option plan, the option exercise price was equal to the stock's market price on the date of grant. The grant vested over three years, one-third on each of the first three anniversary dates of the grant, and expires 10 years after the original grant date. All CSW stock options were fully vested at December 31, 2000.

The following table summarizes share activity in the above plans, and the weighted-average exercise price:

	2000		1999		1998	
	Options (in thousands)	Weighted Average Exercise Price	Options (in thousands)	Weighted Average Exercise Price	Options (in thousands)	Weighted Average Exercise Price
Outstanding at beginning of year	825	$40	866	$40	1,141	$40
Granted	6,046	$36	-	$ -	-	$ -
Exercised	(26)	$36	(22)	$38	(202)	$40
Forfeited	(235)	$39	(19)	$43	(73)	$40
Outstanding at end of year	6,610	$36	825	$40	866	$40
Options Exercisable at end of year	588	$41	707	$42	606	$43

The weighted-average fair value of options granted in 2000 is $36 per share. No options were granted in 1999 or 1998. Shares outstanding under the stock option plan have exercise prices ranging from $35 to $49 and a weighted-average remaining contractual life of 9.2 years.

If compensation expense for stock options had been determined based on the fair value at the grant date, net income and earnings per share would have been the pro forma amounts shown below:

	2000	1999	1998
Pro forma net income (in millions)	$264	$972	$975
Pro forma earnings per share (basic and diluted)	$0.82	$3.03	$3.06

The pro forma amounts are not representative of the effects on reported net income for future years.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used to estimate the fair value of options granted in 2000: dividend yield of 6.02%; expected stock price volatility of 24.75%; risk-free interest rate of 5.02% and expected life of option of 7 years.

14. Business Segments:

AEP's principal business segment is its cost-based rate regulated Domestic Electric Utility business consisting of eleven regulated utility operating companies providing generation, distribution and transmission electric services in eleven states. Also included in this segment are AEP's electric power wholesale marketing and trading activities conducted within two transmission systems of the AEP System.

The AEP consolidated income statement caption "Revenues-Domestic Electric Utility Operations" includes both the retail and wholesale domestic electricity supply businesses which are cost-based rate regulated on a bundled basis with transmission and distribution services in Kentucky, Indiana, Michigan, Louisiana, Oklahoma and Tennessee and are in the process of transitioning to customer choice market based pricing in Arkansas, Ohio, Texas, WV and Virginia. Since the domestic electric utility companies have not yet functionally or structurally separated their retail and wholesale electricity supply business from their regulated transmission and distribution service business, separate financial data is not available and the Domestic Electric Utilities business will continue to be reported as one business segment which is the only reportable segment for the domestic electric operating subsidiaries. Therefore all registrant subsidiaries have one reportable segment, a regulated vertically integrated electricity generation and energy delivery business. All other activities for these registrant subsidiaries are insignificant. In 2000, 1999 and 1998 all the registrant subsidiaries revenues are derived from the generation, sale and delivery of electricity in the U.S.

The AEP consolidated income statement caption "Revenues-Worldwide Electric and Gas Operations" includes three segments: Foreign Energy Delivery, Worldwide Energy Investments and other. The Foreign Energy Delivery segment includes investments in overseas electric distribution and supply companies (SEEBOARD and Yorkshire in the U.K. and CitiPower in Australia).

The Worldwide Energy Investments segment represents domestic and international investments in energy-related gas and electric projects including the development and management of those projects. Such investment activities include electric generation in Florida, Texas, Colorado, Brazil and Mexico, and natural gas pipeline, storage and other natural gas services in the U.S.

The other segment which is included in the AEP consolidated income statement as part of Worldwide Electric and Gas Operations includes non-regulated electric marketing and trading activities outside of AEP's marketing area (beyond two transmission systems from the AEP System) gas marketing and trading activities, telecommunication services, and the marketing of various energy related products and services.

In the fourth quarter of 2000, management announced its intent to functionally and structurally separate its operations into two main business segments, a non-regulated business and a regulated business. Separation of AEP's regulated bundled generation, distribution and transmission businesses into an unbundled non-regulated generation business and regulated unbundled distribution and transmission business will not be completed until the required regulatory approvals are obtained and the electric operating subsidiaries operating in states that are deregulating the generation business are structurally separated and the remaining subsidiaries functionally separated and the necessary changes are made to their accounting software, books, and records. Management expects to begin reporting certain segmented information by the new business segments in the near future.

Year	Domestic* Electric Utilities	Foreign Energy Delivery	Worldwide Energy Investments	Other	Reconciling Adjustments	AEP Consolidated
			(in millions)			
2000						
Revenues from:						
External unaffiliated customers	$10,827	$1,934	$ 836	$ 97	-	$13,694
Transactions with other operating segments	-	-	147	391	$(538)	-
Interest expense	734	163	129	91	(60)	1,057
Depreciation, depletion and amortization expense	1,062	149	25	13	(187)	1,062
Income tax expense (benefit)	641	(16)	(19)	(9)	-	597
Segment net income (loss)	211	125	(56)	(13)	-	267
Total assets	35,741	4,446	2,089	12,272	-	54,548
Investments in equity method subsidiaries	-	427	360	77	-	864
Gross property additions	1,386	177	149	61	-	1,773
1999						
Revenues from:						
External unaffiliated customers	$ 9,838	$2,023	$ 583	$ (37)	-	$12,407
Transactions with other operating segments	-	-	70	246	$(316)	-
Interest expense	688	172	109	55	(47)	977
Depreciation, depletion and amortization expense	1,011	166	26	9	(201)	1,011
Income tax expense (benefit)	490	18	(10)	(16)	-	482
Segment net income (loss)	794	170	34	(26)	-	972
Total assets	27,288	4,739	1,669	2,023	-	35,719
Investments in equity method subsidiaries	-	412	420	57	-	889
Gross property additions	1,215	206	205	54	-	1,680
1998						
Revenues from:						
External unaffiliated customers	$ 9,834	$1,769	$ 183	$ 54	-	$11,840
Transactions with other operating segments	-	-	-	49	$ (49)	-
Interest expense	682	116	68	51	(38)	879
Depreciation, depletion and amortization expense	989	95	13	7	(115)	989
Income tax expense (benefit)	532	4	(14)	(20)	-	502
Segment net income (loss)	884	155	(26)	(38)	-	975
Total assets	25,546	4,504	1,672	1,543	-	33,265
Investments in equity method subsidiaries	-	352	287	59	-	698
Gross property additions	729	1,259	712	90	-	2,790

*Includes the domestic generation retail and wholesale supply businesses a significant portion of which is undergoing a transition from regulated cost based bundled rates to open access market pricing but which have not yet been unbundled i.e., structurally separated from the distribution and transmission portions of the vertically integrated electric utility business.

Geographic Areas	Revenues			
	United States	United Kingdom	Other Foreign	AEP Consolidated
		(in millions)		
2000	$11,663	$1,632	$399	$13,694
1999	10,353	1,705	349	12,407
1998	10,063	1,769	8	11,840

	Long-Lived Assets			
	United States	United Kingdom	Other Foreign	AEP Consolidated
		(in millions)		
2000	$20,463	$1,220	$710	$22,393
1999	19,958	1,124	783	21,865
1998	19,752	1,102	665	21,519

15. Financial Instruments, Credit and Risk Management:

AEP and its subsidiaries are subject to market risk as a result of changes in commodity prices, foreign currency exchange rates, and interest rates. AEP has wholesale electricity and gas trading and marketing operations that manage the exposure to commodity price movements using physical forward purchase and sale contracts at fixed and variable prices, and financial derivative instruments including exchange traded futures and options, over-the-counter options, swaps and other financial derivative contracts at both fixed and variable prices.

In the first quarter of 1999 AEP adopted the Financial Accounting Standards Board's EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities". The EITF requires that all open energy trading contracts be marked-to-market. The effect on the Consolidated Statements of Income of marking open trading contracts to market in the AEP System's regulated jurisdictions are deferred as regulatory assets or liabilities in accordance with SFAS 71 for the portion of those open electricity trading transactions within AEP's marketing area that are included in cost of service on a settlement basis for ratemaking purposes. Open electricity trading transactions within AEP's marketing area allocated to non-regulated jurisdictions are marked-to-market and included in revenues from domestic electric utility operations. Open electricity trading contracts outside AEP's marketing area are accounted for on a mark-to-market basis and included in revenues from worldwide electric and gas operations. Open gas trading contracts are accounted for on a mark-to-market basis and included in revenues from worldwide electric and gas operations. Unrealized mark-to-market gains and losses from trading of financial instruments are reported as assets and liabilities, respectively.

The amounts of net revenues recorded in 2000 and 1999 for electric and gas trading activities were:

Revenues - Net Gain (Loss)	2000	1999
	(in millions)	
Domestic Electric Utility Operations	$ 43	$27
Worldwide Electric and Gas Operations	213	14

The amounts of net revenues recorded in 2000 and 1999 for the registrant subsidiaries were:

	2000	1999
	(in thousands)	
APCo	$23,712	$14,640
CPL	(3,809)	-
CSPCo	22,032	5,819
I&M	29,344	6,384
KPCo	11,792	2,182
OPCo	34,582	10,921
PSO	3,553	-
SWEPCo	(441)	-
WTU	(453)	-

Investment in foreign energy companies and projects exposes AEP to risk of foreign currency fluctuations. AEP is also exposed to changes in interest rates primarily due to short- and long-term borrowings used to fund its business operations. AEP does not presently utilize derivatives to manage its exposures to foreign currency exchange rate movements.

Market Valuation - The book values of cash and cash equivalents, accounts receivable, short-term debt and accounts payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates AEP and I&M's best estimate of its fair value.

The book values and fair values of AEP's and the registrant subsidiaries' significant financial instruments at December 31, 2000 and 1999 are summarized in the following table. The fair values of long-term debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments of the same remaining maturities. The fair value of those financial instruments that are marked-to-market are based on management's best estimates using over-the-counter quotations, exchange prices, volatility factors and a valuation methodology. The estimates presented herein are not necessarily indicative of the amounts that AEP and the registrant subsidiaries could realize in a current market exchange.

	2000		1999	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)		(in thousands)	
Non-Derivatives				
AEP Consolidated				
Long-term Debt	$10,754,000	$10,812,000	$11,524,000	$11,037,000
Preferred Stock	100,000	98,000	119,000	117,000
Trust Preferred Securities	334,000	326,000	335,000	290,000
AEGCo				
Long-term Debt	$45	$45	$45	$45
APCo				
Long-term Debt	$1,605,818	$1,601,313	$1,665,307	$1,580,600
Preferred Stock	10,860	10,725	20,310	19,700
CPL				
Long-term Debt	$1,454,559	$1,463,690	$1,454,541	$1,435,083
Trust Preferred Securities	148,500	147,431	150,000	129,360
CSPCo				
Long-term Debt	$899,615	$908,620	$925,000	$889,000
Preferred Stock	15,000	14,892	25,000	25,438
I&M				
Long-term Debt	$1,388,939	$1,377,230	$1,324,326	$1,283,300
Preferred Stock	64,945	63,941	64,945	63,500
KPCo				
Long-term Debt	$330,880	$335,408	$365,782	$359,100
OPCo				
Long-term Debt	$1,195,493	$1,176,367	$1,151,511	$1,027,000
Preferred Stock	8,850	8,780	8,850	8,500
PSO				
Long-term Debt	$470,822	$476,964	$384,516	$378,437
Trust Preferred Securities	75,000	72,180	75,000	63,390
SWEPCo				
Long-term Debt	$645,963	$651,586	$541,568	$537,354
Trust Preferred Securities	110,000	106,700	110,000	97,372
WTU				
Long-term Debt	$255,843	$261,315	$303,686	$298,220

Derivatives

	2000 Notional Amount	2000 Fair Value	2000 Average Fair Value	1999 Notional Amount	1999 Fair Value	1999 Average Fair Value
	GWH	(in millions)		GWH	(in millions)	
AEP Consolidated						
Trading Assets						
Electric						
Futures and Options-NYMEX (net)	-	$ -	$ -	224	$ 2	$ 1
Physicals	247,330	8,845	2,758	69,509	577	517
Options - OTC	8,981	215	99	6,203	39	62
Swaps	11,575	164	60	177	1	1
	MMMBTU			MMMBTU		
Gas						
Futures and Options-NYMEX (net)	-	$ -	$ -	-	$ -	$ -
Physicals	597,251	455	97	345,830	37	39
Options - OTC	698,392	1,266	355	192,593	54	40
Swaps	4,677,142	7,328	1,730	2,682,033	410	312
Trading Liabilities						
	GWH	(in millions)		GWH	(in millions)	
Electric						
Futures and Options-NYMEX (net)	-	$ -	$ -	-	$ -	$ -
Physicals	246,729	(8,906)	(2,712)	74,764	(536)	(498)
Options - OTC	10,368	(133)	(69)	8,907	(43)	(56)
Swaps	11,289	(144)	(47)	180	(2)	(2)
	MMMBTU			MMMBTU		
Gas						
Futures and Options-NYMEX (net)	23,110	$ (81)	$ (11)	69,840	$ (8)	$ (5)
Physicals	442,309	(420)	(91)	301,271	(32)	(26)
Options - OTC	666,304	(934)	(306)	227,225	(55)	(37)
Swaps	4,616,178	(7,592)	(1,762)	2,601,644	(379)	(303)

	2000 Notional Amount	2000 Fair Value	2000 Average Fair Value	1999 Notional Amount	1999 Fair Value	1999 Average Fair Value
	GWH	(in thousands)		GWH	(in thousands)	
APCo						
Trading Assets						
Electric						
Futures and Options-NYMEX (net)	-	$ -	$ -	64	$ 535	$ 254
Physicals	45,406	2,246,952	757,757	19,953	165,624	150,377
Options - OTC	1,924	59,814	25,015	1,781	11,766	18,461
Swaps	3,652	51,470	18,387	51	112	90
Trading Liabilities						
Electric						
Futures and Options-NYMEX (net)	-	$ -	$ -	-	$ -	$ -
Physicals	45,994	(2,271,026)	(747,567)	21,461	(154,364)	(144,876)
Options - OTC	3,130	(35,955)	(18,872)	2,557	(12,375)	(16,811)
Swaps	3,562	(44,855)	(14,103)	52	(103)	(85)
KPCo						
Trading Assets						
Electric						
Futures and Options-NYMEX (net)	-	$ -	$ -	15	$ 114	$ 49
Physicals	10,779	533,781	179,999	4,707	39,074	35,477
Options - OTC	456	14,207	5,938	420	2,773	4,353
Swaps	867	12,227	4,368	12	26	21
Trading Liabilities						
Electric						
Futures and Options-NYMEX (net)	-	$ -	$ -	-	$ -	$ -
Physicals	10,919	(539,465)	(177,581)	5,063	(36,422)	(34,180)
Options - OTC	743	(8,521)	(4,461)	603	(2,900)	(3,949)
Swaps	846	(10,656)	(3,350)	12	(24)	(20)

	2000			1999		
	Notional Amount GWH	Fair Value (in thousands)	Average Fair Value (in thousands)	Notional Amount GWH	Fair Value (in thousands)	Average Fair Value (in thousands)
I&M						
Trading Assets						
Electric						
Futures and Options-NYMEX (net)	-	$ -	$ -	43	$ 340	$ 171
Physicals	27,431	1,357,459	466,140	13,592	112,830	99,621
Options - OTC	1,162	36,139	15,464	1,213	8,010	12,125
Swaps	2,206	31,095	11,144	35	76	61
Trading Liabilities						
Electric						
Futures and Options-NYMEX (net)	-	$ -	$ -	-	$ -	$ -
Physicals	27,786	(1,379,302)	(460,348)	14,620	(105,169)	(95,948)
Options - OTC	1,891	(25,807)	(13,031)	1,742	(8,391)	(11,010)
Swaps	2,152	(27,099)	(8,552)	35	(70)	(58)
OPCo						
Trading Assets						
Electric						
Futures and Options-NYMEX (net)	-	$ -	$ -	61	$ 583	$ 286
Physicals	36,080	1,786,137	639,632	18,753	155,507	146,395
Options - OTC	1,529	46,731	20,403	1,673	9,672	9,936
Swaps	2,902	41,788	16,172	48	987	967
Trading Liabilities						
Electric						
Futures and Options-NYMEX (net)	-	$ -	$ -	-	$ -	$ -
Physicals	36,547	(1,802,295)	(627,137)	20,171	(143,440)	(135,015)
Options - OTC	2,487	(29,350)	(16,571)	2,403	(11,506)	(7,084)
Swaps	2,830	(37,398)	(13,447)	49	(1,846)	(1,829)
CSPCo						
Trading Assets						
Electric						
Futures and Options-NYMEX (net)	-	$ -	$ -	40	$ 312	$ 159
Physicals	24,221	1,198,835	420,090	12,503	103,794	91,570
Options - OTC	1,026	31,918	13,961	1,116	7,369	11,140
Swaps	1,948	27,461	9,914	32	70	56
Trading Liabilities						
Electric						
Futures and Options-NYMEX (net)	-	$ -	$ -	-	$ -	$ -
Physicals	24,535	(1,211,580)	(414,198)	13,449	(96,748)	(88,194)
Options - OTC	1,669	(19,220)	(10,629)	1,602	(7,717)	(10,114)
Swaps	1,900	(23,932)	(7,599)	32	(64)	(53)

	2000 Notional Amount GWH	Fair Value	Average Fair Value
		(in thousands)	
CPL			
Trading Assets			
Electric Physicals	31,040	$547,437	$ 210,189
Trading Liabilities			
Electric Physicals	31,442	(555,628)	(211,482)
PSO			
Trading Assets			
Electric Physicals	24,670	435,009	232,198
Trading Liabilities			
Electric Physicals	24,990	(441,517)	(234,082)
SWEPCo			
Trading Assets			
Electric Physicals	29,538	520,964	217,444
Trading Liabilities			
Electric Physicals	29,920	(528,759)	(220,171)
WTU			
Trading Assets			
Electric Physicals	9,821	173,118	58,048
Trading Liabilities			
Electric Physicals	9,948	(175,708)	(58,071)

There were no trading activities for CPL, PSO, SWEPCo, and WTU for the year ended 1999.

AEP routinely enters into exchange traded futures and options transactions for electricity and natural gas as part of its wholesale trading operations. These transactions are executed through brokerage accounts with brokers who are registered with the Commodity Futures Trading Commission. Brokers require cash or cash related instruments to be deposited on these accounts as margin calls against the customer's open position. The amount of these deposits at December 31, 2000 and 1999 was $95 million and $25 million, respectively.

Credit and Risk Management - In addition to market risk associated with price movements, AEP is also subject to the credit risk inherent in its risk management activities. Credit risk refers to the financial risk arising from commercial transactions and/or the intrinsic financial value of contractual agreements with trading counter parties, by which there exists a potential risk of non-performance. The AEP System has established and enforced credit policies that minimize or eliminate this risk. AEP accepts as counter parties to forwards, futures, and other derivative contracts primarily those entities that are classified as Investment Grade, or those that can be considered as such due to the effective placement of credit enhancements and/or collateral agreements. Investment Grade is the designation given to the four highest debt rating categories (i.e., AAA, AA, A, BBB) of the major rating services, e.g., ratings BBB- and above at Standard & Poor's and Baa3 and above at Moody's. When adverse market conditions have the potential to negatively affect a counter party's credit position, AEP will require further enhancements to mitigate risk. Since the formation of the trading business in July of 1997, AEP has not experienced a significant loss due to the credit risk; furthermore, AEP does not anticipate any future material effect on its results of operations, cash flow or financial condition as a result of counter party non-performance.

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value - The trust investments for decommission and SNF disposal, reported in other assets, are recorded at market value. At December 31, 2000 and 1999 the fair values of the trust investments were $873 million and $795 million, respectively, and had a cost basis of $768 million and $696 million, respectively. The change in market value in 2000, 1999, and 1998 was a net unrealized holding gain of $6 million, $18 million, and $32 million, respectively.

At December 31, 2000 and 1999 the fair value of CPL's trust investments for decommissioning were $94 million and $86 million, respectively, and had a cost basis of $70 million and $60 million, respectively. The change in market value for CPL was a net unrealized holding loss of $3 million in 2000 and a net unrealized holding gain of $10 million and $8 million in 1999 and 1998, respectively. At December 31, 2000 and 1999 the fair value of I&M's trust investments for decommissioning and SNF disposal were $779 million and $708 million, respectively, and had a cost basis of $698 million and $636 million, respectively. The change in market value for I&M in 2000, 1999, and 1998 was a net unrealized holding gain of $9 million, $8 million and $24 million, respectively.

CitiPower entered into several interest rate swap agreements for $425 million of borrowings under a credit facility. The swap agreements involve the exchange of floating-rate for fixed-rate interest payments. Interest is recognized currently based on the fixed rate of interest resulting from use of these swap agreements. Market risks arise from the movements in interest rates. If counter parties to an interest rate swap agreement were to default on contractual payments, CitiPower could be exposed to increased costs related to replacing the original agreement. However, CitiPower does not anticipate non-performance by any counter party to any interest rate swap in effect as of December 31, 2000. As of December 31, 2000, CitiPower was a party to interest rate swaps having an aggregate notional amount of $626 million, with $224 million maturing on December 31, 2003, and $201 million maturing on December 29, 2003, $201 million commencing on December 29, 2003 and maturing on December 30, 2005. The average fixed interest rate payable on the aggregate of the interest rate swaps is 5.84%. The average floating rate for interest rate swaps was 6.04% at December 31, 2000. The estimated fair value of the interest rate swaps, which represents the estimated amount CitiPower would receive to terminate the swaps at December 31, 2000, based on quoted interest rates, is a net receivable of less than a million dollars.

CitiPower entered into interest rate swap agreement for $112 million in January 2000, for the purpose of hedging a capital markets bond issue. The interest rate swap agreement exchanges a fixed-rate for a floating interest rate up to January 15, 2007. The $112 million interest rate swap agreement was terminated on December 18, 2000. The gain of $9 million earned upon termination of the swap agreement has been deferred and will be amortized through January 15, 2007.

The CSW UK Holdings Group (Group) entered into two currency swaps in 1996 in respect of two tranches of $200 million notes ("Yankee Bonds") repayable on August 1, 2001 and August 1, 2006. The swaps convert fixed rate semi-annual U.S. Dollar interest payments at 6.95% and 7.45% to fixed rate sterling. As a result of the swaps the effective fixed sterling interest rates, including fees, are 7.98% and 8.75%. The estimated fair value of these swaps at December 31, 2000 is a net payable of $1 million.

The Group also has an interest in two interest rate swaps entered into by its joint venture associate Power Asset Development Company Limited in 1998. The swaps convert floating rate interest payable on a $157 million bank project finance borrowing, maturing in 2021, to 6.00% fixed rate. The estimated fair value of these swaps at December 31, 2000 is a net payable of $3 million of which the Group's interest is $1 million.

In addition, at December 31, 2000, the Group has an interest in a currency swap and an interest rate swap entered into by another joint venture associate, South Coast Power Limited. The estimated fair value of these swaps is a net receivable of $3 million of which the Group's share is $1 million.

In accordance with the debt covenants included in the financing provisions of its credit facility, CitiPower must hedge at least 80% of its energy purchase requirements through energy trading derivative instruments entered into with market participants, predominantly generators. As of December 31, 2000, CitiPower had outstanding energy trading derivatives with a total contracted load of 10,144 GWH's. The maturities for these contracts range from three months to six years. Management's estimate of the fair value of these derivatives as of December 31, 2000 is $7 million in excess of net contract value.

SEEBOARD manages its energy purchase costs through energy trading derivative instruments entered into with market participants. The Company buys derivative instruments to hedge purchase costs only and does not enter into any speculative trades. As of December 31, 2000, SEEBOARD had outstanding energy trading derivatives with a total contracted volume of 14,059 GWH's excluding Medway Power Limited. These contracts have maturities in the range of 1 to 27 months. In addition SEEBOARD has a 15 year contract with Medway Power Limited which owns and operates a 675 MW combined cycle gas generating station. SEEBOARD also has a 37.5% equity interest in Medway Power Limited. There are 29,025 GWH remaining under the contract which has 10 years and 9 months to run.

Management's estimate of the fair value of these derivatives as of December 31, 2000 is $132 million below net contract value.

16. Income Taxes:

The details of AEP's consolidated income taxes as reported are as follows:

	Year Ended December 31,		
	2000	1999	1998
		(in millions)	
Federal:			
Current	$ 766	$308	$492
Deferred	(237)	129	(43)
Total	529	437	449
State:			
Current	50	25	30
Deferred	(9)	-	-
Total	41	25	30
International:			
Current	6	3	14
Deferred	21	17	9
Total	27	20	23
Total Income Tax as Reported	$ 597	$482	$502

The details of the registrant subsidiaries income taxes as reported are as follows:

Year Ended December 31, 2000	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$ 8,746	$129,165	$ 89,403	$120,494	$ 134,796
Deferred	(5,842)	3,838	16,263	(7,746)	(126,748)
Deferred Investment Tax Credits	-	(2,947)	(5,207)	(3,379)	(7,524)
Total	2,904	130,056	100,459	109,369	524
Charged (Credited) to Nonoperating Income (net):					
Current	(44)	327	(5,073)	3,777	2,950
Deferred	-	4,764	-	3,683	1,569
Deferred Investment Tax Credits	(3,396)	(1,968)	-	(103)	(330)
Total	(3,440)	3,123	(5,073)	7,357	4,189
Total Income Tax as Reported	$ (536)	$133,179	$95,386	$116,726	$ 4,713

Year Ended December 31, 2000	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$17,878	$259,608	$11,597	$16,073	$ 6,774
Deferred	2,521	(70,263)	25,453	14,653	9,401
Deferred Investment Tax Credits	(1,187)	(1,824)	(1,791)	(4,482)	(1,271)
Total	19,212	187,521	35,259	26,244	14,904
Charged (Credited) to Nonoperating Income (net):					
Current	(50)	15,426	(1,306)	(1,476)	(222)
Deferred	1,244	4,307	-	-	(1,237)
Deferred Investment Tax Credits	(65)	(1,575)	-	-	-
Total	1,129	18,158	(1,306)	(1,476)	(1,459)
Total Income Tax as Reported	$20,341	$205,679	$33,953	$24,768	$13,445

Year Ended December 31, 1999	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$ 7,713	$69,522	$ 89,112	$79,410	$(67,368)
Deferred	(5,282)	8,981	19,620	9,737	85,345
Deferred Investment Tax Credits	-	(2,659)	(5,207)	(3,432)	(7,547)
Total	2,431	75,844	103,525	85,715	10,430
Charged (Credited) to Nonoperating Income (net):					
Current	(146)	(1,548)	(5,604)	(3,122)	1,529
Deferred	-	4,052	318	744	382
Deferred Investment Tax Credits	(3,448)	(2,313)	-	(562)	(605)
Total	(3,594)	191	(5,286)	(2,940)	1,306
Total Income Taxes as Reported	$(1,163)	$76,035	$ 98,239	$82,775	$ 11,736

Year Ended December 31, 1999	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$14,897	$135,540	$20,777	$ 60,169	$ 3,328
Deferred	2,239	4,205	14,521	(17,347)	12,026
Deferred Investment Tax Credits	(1,193)	(1,825)	(1,791)	(4,565)	(1,275)
Total	15,943	137,920	33,507	38,257	14,079
Charged (Credited) to Nonoperating Income (net):					
Current	(424)	(3,256)	(2,215)	(4,826)	858
Deferred	357	(539)	-	-	-
Deferred Investment Tax Credits	(99)	(1,633)	-	-	-
Total	(166)	(5,428)	(2,215)	(4,826)	858
Total Income Taxes as Reported	$15,777	$132,492	$31,292	$ 33,431	$14,937

Year Ended December 31, 1998	AEGCo	APCo	CPL (in thousands)	CSPCo	I&M
Charged (Credited) to Operating Expenses (net):					
Current	$(2,556)	$63,291	$128,942	$62,123	$43,103
Deferred	5,544	(143)	(8,328)	17,612	21,073
Deferred Investment Tax Credits	-	(2,671)	(3,858)	(3,498)	(7,593)
Total	2,988	60,477	116,756	76,237	56,583
Charged (Credited) to Nonoperating Income (net):					
Current	(45)	(4,902)	(2,204)	(3,795)	(594)
Deferred	-	(2,195)	-	(511)	(3,168)
Deferred Investment Tax Credits	(3,454)	(2,594)	-	(726)	(673)
Total	(3,499)	(9,691)	(2,204)	(5,032)	(4,435)
Total Income Taxes as Reported	$ (511)	$50,786	$114,552	$71,205	$52,148

Year Ended December 31, 1998	KPCo	OPCo	PSO (in thousands)	SWEPCo	WTU
Charged (Credited) to Operating Expenses (net):					
Current	$10,788	$120,932	$52,587	$ 64,463	$28,542
Deferred	3,967	3,907	(1,651)	(11,909)	(6,626)
Deferred Investment Tax Credits	(1,202)	(1,827)	(1,795)	(4,631)	(1,321)
Total	13,553	123,012	49,141	47,923	20,595
Charged (Credited) to Nonoperating Income (net):					
Current	(794)	(5,619)	(93)	(1,868)	(454)
Deferred	(360)	(865)	-	-	-
Deferred Investment Tax Credits	(213)	(1,698)	-	-	-
Total	(1,367)	(8,182)	(93)	(1,868)	(454)
Total Income Taxes as Reported	$12,186	$114,830	$49,048	$ 46,055	$20,141

The following is a reconciliation for AEP Consolidated of the difference between the amount of federal income taxes computed by multiplying book income before federal income taxes by the statutory tax rate, and the amount of income taxes reported.

	Year Ended December 31,		
	2000	1999 (in millions)	1998
Net Income	$267	$ 972	$ 975
Extraordinary Items (net of income tax $44 million in 2000 and $8 million in 1999)	35	14	-
Preferred Stock Dividends	11	19	19
Income Before Preferred Stock Dividends of Subsidiaries	313	1,005	994
Income Taxes	597	482	502
Pre-Tax Income	$910	$1,487	$1,496
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$319	$520	$524
Increase (Decrease) in Income Tax Resulting from the Following Items:			
Depreciation	77	71	67
Corporate Owned Life Insurance	247	2	(16)
Foreign Tax Credits	(31)	(63)	(49)
Investment Tax Credits (net)	(36)	(38)	(37)
Merger Transaction Costs	49	-	-
State Income Taxes	26	16	19
International	18	13	15
Other	(72)	(39)	(21)
Total Income Taxes as Reported	$597	$482	$502
Effective Income Tax Rate	65.5%	32.5%	33.6%

Shown below is a reconciliation for each AEP registrant subsidiary of the difference between the amount of federal income taxes computed by multiplying book income before federal income taxes by the statutory rate, and the amount of income taxes reported.

	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
Year Ended December 31, 2000					
Net Income (Loss)	$7,984	$ 73,844	$189,567	$ 94,966	$(132,032)
Extraordinary (Gains) Loss		(1,066)		39,384	
Income Tax Benefit	-	(7,872)	-	(14,148)	-
Income Taxes	(536)	133,179	95,386	116,726	4,713
Pre-Tax Income (Loss)	$7,448	$198,085	$284,953	$236,928	$(127,319)
Income Tax on Pre-Tax Income (Loss) at Statutory Rate *(35%)*	$ 2,607	$ 69,330	$99,733	$ 82,925	$(44,561)
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	452	7,606	7,556	10,529	20,378
Corporate Owned Life Insurance	-	54,824	-	29,259	42,587
Nuclear Fuel Disposal Costs	-	-	-	-	(3,957)
Allowance for Funds Used During Construction	(1,070)	-	-	-	(2,211)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	(1,197)	-	-	-
Investment Tax Credits (net)	(3,396)	(4,915)	(5,207)	(3,482)	(7,854)
State Income Taxes	784	9,950	2,296	89	6,004
Other	(287)	(2,419)	(8,992)	(2,594)	(5,673)
Total Income Taxes as Reported	$ (536)	$133,179	$95,386	$116,726	$ 4,713
Effective Income Tax Rate	N.M.	67.2%	33.5%	49.3%	N.M.

	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
Year Ended December 31, 2000					
Net Income	$20,763	$ 83,737	$ 66,663	$72,672	$27,450
Extraordinary Loss		40,157			
Income Tax Benefit	-	(21,281)	-	-	-
Income Taxes	20,342	205,679	33,953	24,768	13,445
Pre-Tax Income	$41,105	$308,292	$100,616	$97,440	$40,895
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$14,387	$107,903	$35,216	$ 34,104	$14,313
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	1,827	27,577	-	-	1,204
Corporate Owned Life Insurance	5,149	84,453	-	-	-
Nuclear Fuel Disposal Costs	-	-	-	-	-
Allowance for Funds Used During Construction	-	-	-	-	-
Rockport Plant Unit 2 Investment Tax Credit	-	-	-	-	-
Removal Costs	(420)	-	-	-	-
Investment Tax Credits (net)	(1,252)	(3,398)	(1,791)	(4,482)	(1,271)
State Income Taxes	1,597	(1,988)	3,037	1,650	-
Other	(946)	(8,868)	(2,509)	(6,504)	(801)
Total Income Taxes as Reported	$20,342	$205,679	$33,953	$ 24,768	$13,445
Effective Income Tax Rate	49.5%	66.8%	33.8%	25.4%	32.9%

	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
Year Ended December 31, 1999					
Net Income	$ 6,195	$120,492	$182,201	$150,270	$32,776
Extraordinary Loss			8,488		
Income Tax Benefit	-	-	(2,971)	-	-
Income Taxes	(1,163)	76,035	98,239	82,775	11,736
Pre-Tax Income	$ 5,032	$196,527	$285,957	$233,045	$44,512
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$ 1,762	$ 68,785	$100,085	$ 81,566	$15,580
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	446	12,593	7,981	8,846	19,966
Corporate Owned Life Insurance	-	-	-	-	594
Nuclear Fuel Disposal Costs	-	-	-	-	(3,347)
Allowance for Funds Used During Construction	(1,069)	-	-	-	(2,174)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	(3,220)	-	-	-
Investment Tax Credits (net)	(3,448)	(4,972)	(5,207)	(3,994)	(8,152)
State Income Taxes	467	3,305	6,965	58	(4,635)
Other	305	(456)	(11,585)	(3,701)	(6,096)
Total Income Taxes as Reported	$(1,163)	$ 76,035	$ 98,239	$ 82,775	$11,736
Effective Income Tax Rate	N.M.	38.7%	34.4%	35.6%	26.4%

Year Ended December 31, 1999	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
Net Income	$25,430	$212,157	$61,508	$83,194	$26,406
Extraordinary Loss				4,632	8,402
Income Tax Benefit	-	-	-	(1,621)	(2,941)
Income Taxes	15,777	132,492	31,292	33,431	14,937
Pre-Tax Income	$41,207	$344,649	$92,800	$119,636	$46,804
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$14,423	$120,628	$ 32,480	$ 41,873	$16,382
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	1,843	17,517	-	-	1,120
Corporate Owned Life Insurance	-	198	-	-	-
Removal Costs	(420)	-	-	-	-
Investment Tax Credits (net)	(1,292)	(3,458)	(1,791)	(4,565)	(1,275)
State Income Taxes	1,809	1,090	3,054	2,924	-
Other	(586)	(3,483)	(2,451)	(6,801)	(1,290)
Total Income Taxes as Reported	$15,777	$132,492	$ 31,292	$ 33,431	$14,937
Effective Income Tax Rate	38.3%	38.5%	33.8%	28.0%	32.0%

Year Ended December 31, 1998	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
Net Income	$ 8,946	$ 93,330	$161,511	$133,044	$ 96,628
Income Taxes	(511)	50,786	114,552	71,205	52,148
Pre-Tax Income	$ 8,435	$144,116	$276,063	$204,249	$148,776
Income Tax on Pre-Tax Book Income at Statutory Rate *(35%)*	$ 2,953	$ 50,441	$ 96,623	$ 71,488	$ 52,072
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	1,105	11,667	8,170	8,604	17,257
Corporate Owned Life Insurance	-	(4,212)	-	-	(3,263)
Allowance for Funds Used During Construction	(1,070)	-	-	-	(2,184)
Rockport Plant Unit 2 Investment Tax Credits	374	-	-	-	-
Nuclear Fuel Disposal Costs	-	-	-	-	(3,397)
Removal Costs	-	(4,200)	-	-	-
Investment Tax Credits (net)	(3,454)	(5,265)	(3,858)	(4,224)	(8,266)
State Income Taxes	(203)	4,449	-	1	3,209
Mirror CWIP	-	-	10,055	-	-
Other	(216)	(2,094)	3,562	(4,664)	(3,280)
Total Income Taxes as Reported	$ (511)	$ 50,786	$114,552	$ 71,205	$52,148
Effective Income Tax Rate	N.M.	35.3%	41.5%	34.9%	35.1%

Year Ended December 31, 1998	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
Net Income	$21,676	$209,925	$ 76,909	$ 97,994	$37,725
Income Taxes	12,186	114,830	49,048	46,055	20,141
Pre-Tax Income	$33,862	$324,755	$125,957	$144,049	$57,866
Income Tax on Pre-Tax Book Income at Statutory Rate *(35%)*	$11,852	$113,665	$ 44,085	$ 50,418	$20,253
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	1,633	16,693	-	-	964
Corporate Owned Life Insurance	-	(5,238)	-	-	-
Removal Costs	(840)	-	-	-	-
Investment Tax Credits (net)	(1,415)	(3,525)	(1,795)	(4,631)	(1,321)
State Income Taxes	1,560	1,782	4,478	3,308	-
Other	(604)	(8,547)	2,280	(3,040)	245
Total Income Taxes as Reported	$12,186	$114,830	$ 49,048	$ 46,055	$20,141
Effective Income Tax Rate	36.0%	35.4%	39.0%	32.0%	34.9%

The following tables show the elements of the net deferred tax liability and the significant temporary differences for AEP Consolidated and each registrant subsidiary:

	December 31, 2000	December 31, 1999
	(in millions)	
Deferred Tax Assets	$ 1,248	$ 1,241
Deferred Tax Liabilities	(6,123)	(6,391)
Net Deferred Tax Liabilities	$(4,875)	$(5,150)
Property Related Temporary Differences	$(3,935)	$(4,109)
Amounts Due From Customers For Future Federal Income Taxes	(415)	(437)
Deferred State Income Taxes	(251)	(220)
Regulatory Assets Designated for Securitization	(332)	(332)
All Other (net)	58	(52)
Net Deferred Tax Liabilities	$(4,875)	$(5,150)

December 31, 2000	AEGCo	APCo	CPL (in thousands)	CSPCo	I&M
Deferred Tax Assets	$ 81,480	$ 178,487	$ 67,184	$ 88,198	$ 342,900
Deferred Tax Liabilities	(114,408)	(860,961)	(1,309,981)	(510,957)	(830,845)
Net Deferred Tax Liabilities	$ (32,928)	$(682,474)	$(1,242,797)	$(422,759)	$(487,945)
Property Related Temporary Differences	$ (78,113)	$(510,950)	$ (773,454)	$(343,045)	$(324,198)
Amounts Due From Customers For Future Federal Income Taxes	10,317	(95,639)	(72,426)	(79,959)	(55,218)
Deferred State Income Taxes	(5,478)	(86,351)	-	-	(69,982)
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	42,766	-	-	-	28,454
Accrued Nuclear Decommissioning Expense	-	-	-	-	34,702
Deferred Fuel and Purchased Power	-	-	-	-	(39,395)
Deferred Cook Plant Restart Costs	-	-	-	-	(42,000)
Nuclear Fuel	-	-	-	-	(28,319)
Regulatory Assets Designated for Securitization	-	-	(332,198)	-	-
All Other (net)	(2,420)	10,466	(64,719)	245	8,011
Net Deferred Tax Liabilities	$ (32,928)	$(682,474)	$(1,242,797)	$(422,759)	$(487,945)

December 31, 2000	KPCo	OPCo	PSO (in thousands)	SWEPCo	WTU
Deferred Tax Assets	$ 32,807	$ 330,878	$ 60,010	$ 47,615	$ 16,604
Deferred Tax Liabilities	(198,742)	(952,819)	(372,070)	(446,819)	(173,642)
Net Deferred Tax Liabilities	$(165,935)	$(621,941)	$(312,060)	$(399,204)	$(157,038)
Property Related Temporary Differences	$(116,109)	$(586,039)	$(313,248)	$(375,427)	$(150,264)
Amounts Due From Customers For Future Federal Income Taxes	(19,680)	(110,908)	11,082	(6,015)	4,723
Deferred State Income Taxes	(29,695)	(14,282)	(36,487)	-	-
Deferred Fuel and Purchased Power	-	(116,224)	-	-	-
Provision for Mine Shutdown Costs	-	63,995	-	-	-
Postretirement Benefits	-	93,306	-	-	-
All Other (net)	(451)	48,211	26,593	(17,762)	(11,497)
Net Deferred Tax Liabilities	$(165,935)	$(621,941)	$(312,060)	$(399,204)	$(157,038)

December 31, 1999	AEGCo	APCo	CPL (in thousands)	CSPCo	I&M
Deferred Tax Assets	$ 85,392	$ 173,038	$ 99,426	$ 79,510	$ 231,329
Deferred Tax Liabilities	(121,892)	(844,955)	(1,334,601)	(527,117)	(853,486)
Net Deferred Tax Liabilities	$ (36,500)	$(671,917)	$(1,234,175)	$(447,607)	$(622,157)
Property Related Temporary Differences	$ (84,149)	$(510,143)	$ (798,381)	$(352,805)	$(436,162)
Amounts Due From Customers For Future Federal Income Taxes	11,283	(109,846)	(74,328)	(85,078)	(61,311)
Deferred State Income Taxes	(5,970)	(76,073)	-	-	(61,700)
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	44,716	-	-	-	29,752
Accrued Nuclear Decommissioning Expense	-	-	-	-	32,097
Deferred Fuel and Purchased Power	-	-	-	-	(52,713)
Deferred Cook Plant Restart Costs	-	-	-	-	(56,000)
Nuclear Fuel	-	-	-	-	(27,512)
Regulatory Assets Designated for Securitization	-	-	(332,198)	-	-
All Other (net)	(2,380)	24,145	(29,268)	(9,724)	11,392
Net Deferred Tax Liabilities	$ (36,500)	$(671,917)	$(1,234,175)	$(447,607)	$(622,157)

December 31, 1999	KPCo	OPCo	PSO (in thousands)	SWEPCo	WTU
Deferred Tax Assets	$ 32,186	$ 234,826	$ 68,488	$ 79,056	$ 26,916
Deferred Tax Liabilities	(197,193)	(911,286)	(350,404)	(455,560)	(175,908)
Net Deferred Tax Liabilities	$(165,007)	$(676,460)	$(281,916)	$(376,504)	$(148,992)
Property Related Temporary Differences	$(114,903)	$(599,863)	$(308,497)	$(389,680)	$(153,027)
Amounts Due From Customers For Future Federal Income Taxes	(19,616)	(108,185)	12,697	(3,366)	4,569
Deferred State Income Taxes	(32,715)	(22,124)	(13,001)	-	-
Deferred Fuel and Purchase Power	-	(62,832)	-	-	-
Provision for Mine Shutdown Costs	-	33,105	-	-	-
Postretirement Benefits	-	44,483	-	-	-
All Other (net)	2,227	38,956	26,885	16,542	(534)
Net Deferred Tax Liabilities	$(165,007)	$(676,460)	$(281,916)	$(376,504)	$(148,992)

The AEP System has settled with the IRS all issues from the audits of its consolidated federal income tax returns for the years prior to 1991. Returns for the years 1991 through 1999 are presently being audited by the IRS. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

17. Supplementary Information:

	Year Ended December 31, 2000	1999 (in millions)	1998
AEP Consolidated Purchased Power - Ohio Valley Electric Corporation (44.2% owned by AEP System)	$86	$64	$43
Cash was paid for:			
Interest (net of capitalized amounts)	$842	$979	$859
Income Taxes	$449	$270	$540
Noncash Investing and Financing Activities:			
Acquisitions under Capital Leases	$118	$80	$119
Assumption of Liabilities Related to Acquisitions	-	-	$152

The amounts of power purchased by the registrant subsidiaries from Ohio Valley Electric Corporation, which is 44.2% owned by the AEP System, for the years ended December 31, 2000, 1999, and 1998 were:

Year Ended December 31,	APCo	CSPCo (in thousands)	I&M	OPCo
2000	$30,998	$8,706	$15,204	$31,134
1999	21,774	6,006	10,227	25,623
1998	10,388	5,947	14,271	12,006

18. Leases:

Leases of property, plant and equipment are for periods up to 35 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to operating expenses in accordance with rate-making treatment. The components of rental costs are as follows:

Year Ended December 31, 2000	AEP	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)				
Lease Payments on Operating Leases	$216,000	$73,858	$ 7,128	$ 7,683	$ 81,446	$1,978	$51,981
Amortization of Capital Leases	121,000	281	13,900	7,776	26,341	3,931	37,280
Interest on Capital Leases	38,000	55	3,930	2,690	10,908	1,054	9,584
Total Lease Rental Costs	$375,000	$74,194	$24,958	$18,149	$118,695	$6,963	$98,845

Year Ended December 31, 1999	AEP	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)				
Lease Payments on Operating Leases	$247,000	$74,269	$ 5,647	$ 5,687	$ 81,611	$ 199	$ 60,026
Amortization of Capital Leases	97,000	364	13,749	7,427	11,320	4,299	35,622
Interest on Capital Leases	35,000	64	4,267	2,720	9,338	1,162	9,552
Total Lease Rental Costs	$379,000	$74,697	$23,663	$15,834	$102,269	$5,660	$105,200

Year Ended December 31, 1998	AEP	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)				
Lease Payments on Operating Leases	$257,000	$76,387	$ 7,047	$ 8,107	$ 88,297	$ 931	$ 59,141
Amortization of Capital Leases	91,000	560	13,561	6,530	10,717	4,265	36,585
Interest on Capital Leases	37,000	97	3,541	2,626	10,302	1,173	14,309
Total Lease Rental Costs	$385,000	$77,044	$24,149	$17,263	$109,316	$6,369	$110,035

CPL, PSO, SWEPCo and WTU do not have any operating leases.

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

Year Ended December 31, 2000	AEP	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)				
Property, Plant and Equipment Under Capital Leases							
Production	$ 42,000	$2,017	$ 6,276	$ 2	$ 7,023	$ 1,730	$ 24,709
Distribution	151,000				14,595		
Other:							
Nuclear Fuel (net of amortization)	90,000				89,872		
Mining Assets and Other	619,000	177	93,437	$68,352	97,383	22,072	200,308
Total Property, Plant and Equipment	902,000	2,194	99,713	68,354	208,873	23,802	225,017
Accumulated Amortization	288,000	1,603	36,553	25,422	45,700	9,618	108,436
Net Property, Plant and Equipment Under Capital Leases	$614,000	$ 591	$63,160	$42,932	$163,173	$14,184	$116,581
Obligations Under Capital Leases:							
Noncurrent Liability	$419,000	$ 358	$50,350	$35,199	$ 62,325	$11,091	$ 83,866
Liability Due Within One Year	195,000	233	12,810	7,733	100,848	3,093	32,715
Total Obligations Under Capital Leases	$614,000	$ 591	$63,160	$42,932	$163,173	$14,184	$116,581

Year Ended December 31, 1999	AEP	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo	OPCo
Property, Plant and Equipment Under Capital Leases							
Production	$ 46,000	$2,350	$ 8,354		$ 8,348	$ 2,022	$ 24,428
Distribution	106,000				14,645		
Other:							
Nuclear Fuel (net of amortization)	108,000				108,140		
Mining Assets and Other	612,000	226	93,053	$63,386	99,367	24,225	205,209
Total Property, Plant and Equipment	872,000	2,576	101,407	63,386	230,500	26,247	229,637
Accumulated Amortization	262,000	1,708	36,762	23,116	42,535	11,106	93,094
Net Property, Plant and Equipment Under Capital Leases	$610,000	$ 868	$ 64,645	$40,270	$187,965	$15,141	$136,543
Obligations Under Capital Leases:							
Noncurrent Liability	$510,000	$ 592	$ 52,009	$33,031	$176,893	$11,830	$102,259
Liability Due Within One Year	100,000	276	12,636	7,239	11,072	3,311	34,284
Total Obligations Under Capital Leases	$610,000	$ 868	$ 64,645	$40,270	$187,965	$15,141	$136,543

Properties under operating leases and related obligations are not included in the Consolidated Balance Sheets.

CPL, PSO, SWEPCo and WTU do not lease property, plant and equipment under capital leases.

Future minimum lease payments consisted of the following at December 31, 2000:

	AEP	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo	OPCo
Capital (a)							
2001	$129,000	$255	$16,528	$10,480	$ 14,620	$ 3,929	$ 39,733
2002	99,000	217	15,526	9,426	13,535	3,501	21,332
2003	81,000	133	12,872	7,677	11,336	2,661	19,004
2004	63,000	20	10,336	6,331	9,397	2,004	15,445
2005	48,000	6	7,027	5,397	7,053	1,609	11,746
Later Years	397,000	1	13,748	15,376	25,427	3,417	38,710
Total Future Minimum Lease Payments	817,000(a)	632	76,037	54,687	81,368	17,121	145,970
Less Estimated Interest Element	293,000	41	12,876	11,755	8,067	2,937	29,389
Estimated Present Value of Future Minimum Lease Payments	524,000	$591	$63,161	$42,932	73,301	$14,184	$116,581
Unamortized Nuclear Fuel	90,000				89,872		
Total	$614,000				$163,173		

(a) Minimum lease payments do not include nuclear fuel payments. The payments are paid in proportion to heat produced and carrying charges on the unamortized nuclear fuel balance. There are no minimum lease payment requirements for leased nuclear fuel.

	AEP	AEGCo	APCo	CSPCo (in thousands)	I&M	KPCo	OPCo
Noncancellable Operating Leases							
2001	$ 244,000	$ 73,854	$ 726	$ 4,314	$ 99,249	$ 29	$ 62,560
2002	236,000	73,854	425	774	97,551	26	61,787
2003	235,000	73,854	412	735	97,385	23	61,109
2004	235,000	73,854	412	735	96,467	21	61,229
2005	243,000	73,854	412	735	95,201	21	71,304
Later Years	3,090,000	1,255,518	2,888	2,820	1,434,570	232	386,629
Total Future Minimum Lease Payments	$4,283,000	$1,624,788	$5,275	$10,113	$1,920,423	$352	$704,618

19. Lines of Credit and Factoring of Receivables:

The AEP System uses short-term debt, primarily commercial paper, to meet fluctuations in working capital requirements and other interim capital needs. AEP has established a money pool to coordinate short-term borrowings for certain subsidiaries, including AEGCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU, and also incurs borrowings outside the money pool for other subsidiaries. As of December 31, 2000, AEP had revolving credit facilities totaling $3.5 billion to backup its commercial paper program. At December 31, 2000, AEP had $2.7 billion outstanding in short-term borrowings. The maximum amount of such short-term borrowings outstanding during the year, which had a weighted average interest rate for the year of 7.5%, was $2.7 billion during December 2000.

The registrant subsidiaries incurred interest expense for amounts borrowed from the AEP money pool as follows

	Year Ended December 31,		
	2000	1999	1998
	(in millions)		
CPL	$16.9	$14.1	$8.8
CSPCo	1.4	-	-
I&M	0.8	-	-
KPCo	-	-	-
OPCo	9.2	-	-
PSO	7.5	2.0	1.0
SWEPCo	4.2	4.7	1.8
WTU	2.7	0.6	0.3

Interest income earned from amounts advanced to the AEP money pool by the registrant subsidiaries were:

	Year Ended December 31,		
	2000	1999	1998
	(in millions)		
CSPCo	$ 1.1	$ -	$ -
I&M	9.0	-	-
KPCo	1.8	-	-
OPCo	3.4	-	-
PSO	-	-	0.6
SWEPCo	-	0.1	0.1
WTU	-	0.2	0.4

AEP Credit, which does not participate in the money pool, issues commercial paper on a stand-alone basis. At December 31, 2000, AEP Credit had a $2.0 billion unsecured revolving credit agreement to back up its commercial paper program, which had $1.2 billion outstanding. The maximum amount of such commercial paper outstanding during the year, which had a weighted average interest rate for the year of 6.6% was $1.5 billion during September 2000.

Outstanding short-term debt for AEP Consolidated consisted of:

	December 31,	
	2000	1999
	(in millions)	
Balance Outstanding:		
Notes Payable	$ 193	$ 232
Commercial Paper	4,140	2,780
Total	$4,333	$3,012

In 2000 APCo did not participate in AEP's money pool. At December 31, 2000 and 1999, APCo had issued commercial paper in the amounts of $191.5 million and $123.5 million, respectively. At December 31, 2000, the weighted average interest rate for APCo's commercial paper borrowings was 8.24%. In January 2001 APCo became a participant in AEP's money pool and retired all outstanding short-term debt.

AEP Credit factors electric customer accounts receivable for affiliated operating companies and unaffiliated companies. AEP Credit issues commercial paper on a stand alone basis and does not participate in the money pool. In June 2000 the factoring of customer accounts receivable for affiliated companies was expanded as a result of the merger.

Under the factoring arrangement the registrant subsidiaries (excluding AEGCo and APCo) sell without recourse certain of their customer accounts receivable and accrued utility revenue balances to AEP Credit and are charged a fee based on AEP Credit financing costs, uncollectible accounts experience for each company's receivables and administrative costs. The costs of factoring customer accounts receivable is reported as an operating expense. At December 31, 2000, the amount of factored accounts receivable and accrued utility revenues for each registrant subsidiary was as follows:

Company	(in millions)
CPL	$153
CSPCo	116
I&M	103
KPCo	30
OPCo	104
PSO	108
SWEPCo	91
WTU	52

The fees paid by the registrant subsidiaries to AEP Credit for factoring customer accounts receivable were:

	Year Ended December 31,		
	2000	1999	1998
	(in millions)		
CPL	$15.7	$14.7	$12.8
CSPCo	10.8	-	-
I&M	6.8	-	-
KPCo	1.9	-	-
OPCo	8.4	-	-
PSO	8.3	6.5	7.7
SWEPCo	9.2	9.3	9.1
WTU	4.0	3.5	3.7

20. Unaudited Quarterly Financial Information:

The unaudited quarterly financial information for AEP Consolidated follows:

(In Millions - Except Per Share Amounts)	2000 Quarterly Periods Ended March 31	June 30	Sept. 30	Dec. 31
Operating Revenues	$3,021	$3,169	$3,915	$3,589
Operating Income	428	308	873	417
Income (Loss) Before Extraordinary Items	140	(18)	403	(223)
Net Income (Loss)	140	(9)	359	(223)
Earnings (Loss) per Share	0.43	(0.03)	1.11	(0.68)

Fourth quarter 2000 earnings decreased $415 million from the prior year. The decrease was primarily due to various unfavorable items including: a ruling disallowing interest deductions claimed by AEP relating to its COLI program of $319 million; $35 million of the Cook Plant restart costs; and a $30 million writedown for the proposed sale of Yorkshire. Additionally, the fourth quarter of 1999 includes a $33 million gain on the sale of Sweeney in October.

(In Millions - Except Per Share Amounts)	1999 Quarterly Periods Ended March 31	June 30	Sept. 30	Dec. 31
Operating Revenues	$2,902	$2,963	$3,528	$3,014
Operating Income	525	552	802	446
Income Before Extraordinary Items	195	190	403	198
Net Income	195	190	395	192
Earnings per Share	0.61	0.59	1.23	0.60

The unaudited quarterly financial information for each AEP registrant subsidiary follows:

Quarterly Periods Ended	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
2000					
March 31					
Operating Revenues	$56,866	$455,595	$316,328	$298,306	$343,986
Operating Income	2,395	78,246	38,650	44,124	(15,251)
Income (Loss) Before Extraordinary Items	2,445	47,664	8,139	27,471	(36,553)
Net Income (Loss)	2,445	47,664	8,139	27,471	(36,553)
June 30					
Operating Revenues	$56,928	$430,000	$437,911	$330,914	$362,272
Operating Income	1,746	58,208	95,717	50,798	(18,599)
Income (Loss) Before Extraordinary Items	1,653	30,240	67,553	35,335	(39,181)
Net Income (Loss)	1,653	39,178	67,553	35,335	(39,181)
September 30					
Operating Revenues	$55,658	$475,092	$601,369	$386,583	$423,217
Operating Income	2,209	65,750	120,653	83,562	36,056
Income Before Extraordinary Items	1,972	36,112	89,974	65,542	15,190
Net Income	1,972	36,112	89,974	40,306	15,190
December 31					
Operating Revenues	$59,064	$499,478	$415,569	$340,605	$419,001
Operating Income	2,074	(1,050)	52,078	17,393	(36,908)
Income (Loss) Before Extraordinary Items	1,914	(49,110)	23,901	(8,146)	(71,488)
Net Income (Loss)	1,914	(49,110)	23,901	(8,146)	(71,488)

Quarterly Periods Ended	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
2000					
March 31					
Operating Revenues	$ 97,204	$545,411	$161,329	$212,156	$ 96,535
Operating Income	15,557	65,113	10,860	22,731	9,781
Income Before Extraordinary Items	8,052	46,216	1,165	7,663	3,833
Net Income	8,052	46,216	1,165	7,663	3,833
June 30					
Operating Revenues	$ 97,759	$540,321	$209,172	$272,409	$130,742
Operating Income	9,456	79,968	24,502	33,296	16,938
Income Before Extraordinary Items	2,449	58,233	14,700	18,786	8,070
Net Income	2,449	58,233	14,700	18,786	8,070
September 30					
Operating Revenues	$106,698	$582,702	$358,710	$377,442	$201,191
Operating Income	13,790	96,652	56,437	61,312	16,565
Income Before Extraordinary Items	6,761	77,061	54,329	47,537	10,670
Net Income	6,761	58,185	54,329	47,537	10,670
December 31					
Operating Revenues	$108,742	$559,468	$233,398	$262,203	$144,326
Operating Income	10,935	(14,906)	4,870	10,939	9,057
Income (Loss) Before Extraordinary Items	3,501	(78,897)	(3,531)	(1,314)	4,877
Net Income (Loss)	3,501	(78,897)	(3,531)	(1,314)	4,877

In the fourth quarter of 2000 earnings for APCo, CSPCo, I&M, and OPCo were effected by a ruling disallowing interest deductions claimed by AEP relating to its COLI program. The unfavorable amounts are $82 million for APCo, $41 million for CSPCo, $66 million for I&M, $8 million for KPCo and $118 million for OPCo. Additionally I&M incurred costs in the fourth quarter of 2000 for the Cook Plant restart of $35 million.

Quarterly Periods Ended	AEGCo	APCo	CPL	CSPCo	I&M
			(in thousands)		
1999					
March 31					
Operating Revenues	$52,827	$427,702	$282,278	$279,067	$334,113
Operating Income	2,360	71,607	46,091	46,047	38,838
Income Before Extraordinary Items	2,614	39,261	17,020	27,418	20,070
Net Income	2,614	39,261	17,020	27,418	20,070
June 30					
Operating Revenues	$51,612	$373,766	$383,783	$301,419	$336,553
Operating Income	1,002	43,099	79,679	54,473	26,966
Income Before Extraordinary Items	1,222	11,036	51,024	34,559	9,745
Net Income	1,222	11,036	51,024	34,559	9,745
September 30					
Operating Revenues	$57,235	$441,435	$495,653	$368,946	$411,248
Operating Income	921	66,309	127,499	83,478	26,085
Income Before Extraordinary Items	958	35,661	103,989	63,719	8,084
Net Income	958	35,661	103,989	63,719	8,084
December 31					
Operating Revenues	$55,515	$408,034	$320,761	$280,562	$312,205
Operating Income	1,057	60,221	40,716	38,792	16,763
Income (Loss) Before Extraordinary Items	1,401	34,534	15,685	24,574	(5,123)
Net Income (Loss)	1,401	34,534	10,168	24,574	(5,123)

Quarterly Periods Ended	KPCo	OPCo	PSO	SWEPCo	WTU
			(in thousands)		
1999					
March 31					
Operating Revenues	$ 90,741	$518,221	$151,030	$197,064	$ 81,052
Operating Income	15,360	78,956	12,031	25,810	6,922
Income Before Extraordinary Items	8,209	60,821	2,423	12,095	932
Net Income	8,209	60,821	2,423	12,095	932
June 30					
Operating Revenues	$ 86,231	$498,587	$178,699	$242,888	$107,782
Operating Income	10,233	73,328	23,172	35,269	16,361
Income Before Extraordinary Items	2,995	51,865	13,955	21,411	10,116
Net Income	2,995	51,865	13,955	21,411	10,116
September 30					
Operating Revenues	$ 94,939	$544,451	$258,656	$312,035	$164,104
Operating Income	14,244	72,858	57,720	61,541	27,030
Income Before Extraordinary Items	7,197	56,233	50,257	44,908	21,413
Net Income	7,197	56,233	50,257	41,897	15,952
December 31					
Operating Revenues	$102,071	$478,004	$161,005	$219,540	$ 92,771
Operating Income	14,838	63,687	5,790	24,442	3,486
Income (Loss) Before Extraordinary Items	7,029	43,238	(5,127)	7,791	(594)
Net Income (Loss)	7,029	43,238	(5,127)	7,791	(594)

21. Trust Preferred Securities:

The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of CPL, PSO and SWEPCo were outstanding at December 31, 2000 and December 31, 1999. They are classified on the balance sheets as certain subsidiaries Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of such subsidiaries. The Junior Subordinated Debentures mature on April 30, 2037. CPL reacquired 60,000 trust preferred units during 2000.

Business Trust	Security	Units issued/ outstanding at 12/31/00	2000 Amount (millions)	1999 Amount (millions)	Description of Underlying Debentures of Registrant
CPL Capital I	8.00%, Series A	5,940,000	$149	$150	CPL, $153 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	3,000,000	75	75	PSO, $77 million, 8.00%, Series A
SWEPCo Capital I	7.875%, Series A	4,400,000	110	110	SWEPCO, $113 million, 7.875%, Series A
		13,340,000	$334	$335	

Each of the business trusts is treated as a subsidiary of its parent company. The only assets of the business trusts are the subordinated debentures issued by their parent company as specified above. In addition to the obligations under their subordinated debentures, each of the parent companies has also agreed to a security obligation which represents a full and unconditional guarantee of its capital trust obligation.

22. Jointly Owned Electric Utility Plant:

CPL, CSP, PSO, SWEPCo and WTU have generating units that are jointly owned with unaffiliated companies. Each of the participating companies is obligated to pay its share of the costs of any such jointly owned facilities in the same proportion as its ownership interest. Each AEP registrant subsidiary's proportionate share of the operating costs associated with such facilities is included in its statements of income and the investments are reflected in its balance sheets under utility plant as follows:

		Company's Share December 31,			
		2000		1999	
	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Utility Plant in Service	Construction Work in Progress
		(in thousands)		(in thousands)	
CPL:					
Oklaunion Generating Station (Unit No. 1)	7.8	$ 37,236	$ 395	$ 37,236	$ -
South Texas Project Generating Station (Units No. 1 and 2)	25.2	2,373,575	19,292	2,351,795	56,021
		$2,410,811	$19,687	$2,389,031	$56,021
CSP:					
W.C. Beckjord Generating Station (Unit No. 6)	12.5	$ 14,108	$ 178	$ 13,919	$ 390
Conesville Generating Station (Unit No. 4)	43.5	80,103	261	80,433	80
J.M. Stuart Generating Station	26.0	191,875	10,086	184,168	3,620
Wm. H. Zimmer Generating Station	25.4	706,549	5,265	701,054	6,030
Transmission	(a)	61,820	451	60,333	1,210
		$1,054,455	$16,241	$1,039,907	$11,330
PSO:					
Oklaunion Generating Station (Unit No. 1)	15.6	$ 81,185	$ 817	$ 81,185	$ -
SWEPCo:					
Dolet Hills Generating Station (Unit No. 1)	40.2	$ 231,442	$ 1,984	$ 230,971	$ 1,771
Flint Creek Generating Station (Unit No. 1)	50.0	82,899	852	81,895	286
Pirkey Generating Station (Unit No. 1)	85.9	437,069	435	434,960	1,777
		$ 751,410	$ 3,271	$ 747,826	$ 3,834
WTU:					
Oklaunion Generating Station (Unit No. 1)	54.7	$ 277,624	$ 3,295	$ 281,777	$ -

(a) Varying percentages of ownership.

The accumulated depreciation with respect to each AEP registrant subsidiary's share of jointly owned facilities is shown below:

	December 31, 2000	1999
	(in thousands)	
CPL	$834,722	$758,460
CSPCo	389,558	361,113
PSO	33,669	36,374
SWEPCo	367,558	354,360
WTU	98,045	93,807

23. Related Party Transactions

AEP System Power Pool

APCo, CSPCo, I&M, KEPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio," which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KEPCo and OPCo have been parties to the AEP System Interim Allowance Agreement which provides, among other things, for the transfer of SO2 Allowances associated with transactions under the Interconnection Agreement.

Power marketing and trading transactions (trading activities) are conducted by the AEP Power Pool and shared among the parties under the Interconnection Agreement.

In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

CPL, PSO, SWEPCo, WTU and AEP Service Corporation are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement). The CSW Operating Agreement requires the operating companies of the west zone to maintain specified annual planning reserve margins and requires the subsidiaries that have capacity in excess of the required margins to make such capacity available for sale to other AEP subsidiaries as capacity commitments. The CSW Operating Agreement also delegates to AEP Service Corporation the authority to coordinate the acquisition, disposition, planning, design and construction of generating units and to supervise the operation and maintenance of a central control center. The CSW Operating Agreement has been accepted for filing and allowed to become effective by FERC.

AEP's System Integration Agreement provides for the integration and coordination of AEP's east and west zone operating subsidiaries, joint dispatch of generation within the AEP System, and the distribution, between the two operating zones, of costs and benefits associated with the System's generating plants. It is designed to function as an umbrella agreement in addition to the AEP Interconnection Agreement and the CSW Operating Agreement, each of which will continue to control the distribution of costs and benefits within each zone.

The following table shows the revenues derived from sales to the Pools and direct sales to affiliates for years ended December 31, 2000, 1999 and 1998:

Related Party Revenues		APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
				(in thousands)			
2000	Sales to East System Pool	$ 81,013	$36,884	$200,474	$36,554	$502,140	$ -
	Sales to West System Pool	7,697	4,095	4,614	1,829	6,356	-
	Direct Sales To East Affiliates	59,106	-	-	-	66,487	227,983
	Direct Sales To West Affiliates	4,092	2,262	2,510	972	3,421	-
	Total Revenues	$151,908	$43,241	$207,598	$39,355	$578,404	$227,983
1999	Sales to East System Pool	$41,869	$15,136	$50,624	$43,157	$337,699	$ -
	Direct Sales To East Affiliates	57,201	-	-	-	50,968	152,559
	Total Revenues	$99,070	$15,136	$50,624	$43,157	$388,667	$152,559
1998	Sales to East System Pool	$36,930	$20,128	$37,561	$43,543	$363,343	$ -
	Direct Sales To East Affiliates	56,753	-	-	-	55,167	153,537
	Total Revenues	$93,683	$20,128	$37,561	$43,543	$418,510	$153,537

Related Party Revenues		CPL	PSO	SWEPCo	WTU
			(in thousands)		
2000	Sales to East System Pool	$ -	$ -	$ -	$ -
	Sales to West System Pool	23,421	7,323	5,546	194
	Direct Sales To East Affiliates	(3,348)	(1,990)	(3,008)	(1,116)
	Direct Sales To West Affiliates	12,516	21,995	62,178	7,645
	Total Revenues	$32,589	$27,328	$64,716	$ 6,723
1999	Sales to West System Pool	$ 6,124	$ 3,097	$ 4,527	$ 401
	Direct Sales To West Affiliates	7,470	7,968	49,542	2,576
	Total Revenues	$13,594	$11,065	$54,069	$2,977
1998	Sales to West System Pool	$ 7,853	$ 3,223	$ 5,660	$ 270
	Direct Sales To West Affiliates	9,798	10,196	29,811	2,190
	Total Revenues	$17,651	$13,419	$35,471	$2,460

The following table shows the purchased power expense incurred from purchases from the Pools and affiliates for the years ended December 31, 2000, 1999, and 1998:

Related Party Purchases		APCo	CSPCo	I&M	KPCo	OPCo
				(in thousands)		
2000	Purchases from East System Pool	$355,305	$287,482	$106,644	$ 58,150	$50,339
	Purchases from West System Pool	455	260	285	108	390
	Direct Purchases from East Affiliates	-	-	158,537	69,446	-
	Direct Purchases from West Affiliates	14	8	9	3	12
	Total Purchases	$355,774	$287,750	$265,475	$127,707	$50,741
1999	Purchases from East System Pool	$130,991	$199,574	$112,350	$19,502	$ 20,864
	Direct Purchases from East Affiliates	-	-	88,022	64,498	-
	Total Purchases	$130,991	$199,574	$200,372	$84,000	$ 20,864
1998	Purchases from East System Pool	$180,762	$167,619	$125,240	$ 9,673	$ 18,211
	Direct Purchases from East Affiliates	-	-	86,246	67,291	-
	Total Purchases	$180,762	$167,619	$211,486	$76,964	$ 18,211

Related Party Purchases		CPL	PSO	SWEPCo	WTU
			(in thousands)		
2000	Purchases from East System Pool	$ -	$20,100	$ -	$ -
	Purchases from West System Pool	1,696	5,386	4,379	18,444
	Direct Purchases from East Affiliates	251	2,117	-	71
	Direct Purchases from West Affiliates	30,644	33,185	8,264	39,258
	Total Purchases	$32,591	$60,788	$12,643	$57,773
1999	Purchases from West System Pool	$ 895	$ 6,992	$1,295	$ 7,266
	Direct Purchases from West Affiliates	15,778	27,627	6,256	19,325
	Total Purchases	$16,673	$34,619	$7,551	$26,591
1998	Purchases from West System Pool	$1,091	$ 5,022	$ 2,579	$ 8,314
	Direct Purchases from West Affiliates	8,636	15,970	7,576	20,935
	Total Purchases	$9,727	$20,992	$10,155	$29,249

AEP System Transmission Pool

APCo, CSPCo, I&M, KEPCo and OPCo are parties to the Transmission Agreement, dated April 1, 1984, as amended (the Transmission Agreement), defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kw and above) and certain facilities operated at lower voltages (138 kv and above). Like the Interconnection Agreement, this sharing is based upon each company's "member-load-ratio."

The following table shows the net (credits) or charges allocated among the parties to the Transmission Agreement during the years ended December 31, 1998, 1999 and 2000:

	1998	1999 (in thousands)	2000
APCo	$ (2,400)	$ (8,300)	$ (3,400)
CSPCo	35,600	39,000	38,300
I&M	(44,100)	(43,900)	(43,800)
KEPCo	(6,000)	(4,300)	(6,000)
OPCo	16,900	17,500	14,900

CPL, PSO, SWEPCo, WTU and AEP Service Corporation are parties to a Transmission Coordination Agreement originally dated as of January 1, 1997 (TCA). The TCA established a coordinating committee, which is charged with the responsibility of overseeing the coordinated planning of the transmission facilities of the west zone operating subsidiaries, including the performance of transmission planning studies, the interaction of such subsidiaries with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the Open Access Transmission Tariff (OATT) filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the west zone operating subsidiaries have delegated to AEP Service Corporation the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The TCA also provides for the allocation among the west zone operating subsidiaries of revenues collected for transmission and ancillary services provided under the OATT. In December 1999, the FERC approved the TCA filing based on the revised revenue allocation ratios effective as of January 1, 1997. In January 2000, the west zone operating companies settled among themselves, including interest, under the revised TCA.

The following table shows the net (credits) or charges, excluding interest, allocated among the west zone operating companies during the years ended December 31, 1998, 1999 and 2000:

	1998	1999 (in thousands)	2000
CPL	$ -	$ -	$(15,498)
WTU	1,139	(28)	(23,443)
SWEPCo	3,572	1,058	22,115
PSO	(4,711)	(1,030)	16,826

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP's east and west zone operating subsidiaries. Like the System Integration Agreement, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the AEP Transmission Agreement and the Transmission Coordination Agreement. The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues.
- The allocation of third-party transmission costs and revenues and System dispatch costs.

The Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

Unit Power Agreements and Other

A unit power agreement between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) such amounts, as when added to amounts received by AEGCo from any other sources, will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by FERC, currently 12.16%. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KEPCo, and a unit power agreement between KEPCo and AEGCo, AEGCo sells KEPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KEPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KEPCo unit power agreement expires on December 31, 2004.

APCo and OPCo, jointly own two power plants. The costs of operating these facilities are apportioned between the owners based on ownership interests. Each company's share of these costs is included in the appropriate expense accounts on each company's consolidated statements of income. Each company's investment in these plants is included in electric utility plant on its consolidated balance sheets.

I&M provides barging services to AEGCo, APCo and OPCo. I&M records revenues from barging services as nonoperating income. AEGCo, APCo and OPCo record costs paid to I&M for barging services as fuel expense. The amount of affiliated revenues and affiliated expenses were:

Company	Year Ended December 31,		
	2000	1999	1998
	(in millions)		
I&M - revenues	$23.5	$28.1	$24.8
AEGCo - expense	8.8	8.5	8.8
APCo - expense	7.8	10.5	8.5
OPCo - expense	6.9	9.1	7.5

American Electric Power Service Corporation (AEPSC) provides certain managerial and professional services to AEP System companies. The costs of the services are billed to its affiliated companies by AEPSC on a direct-charge basis, whenever possible, and on reasonable bases of proration for shared services. The billings for services are made at cost and include no compensation for the use of equity capital, which is furnished to AEPSC by AEP Co., Inc. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered. AEPSC and its billings are subject to the regulation of the SEC under the 1935 Act.

The following is a combined presentation of management's discussion and analysis of financial condition, contingencies and other matters for AEP and certain of its registrant subsidiaries. Management's discussion and analysis of results of operations for AEP and each of its subsidiary registrants is presented with their financial statements earlier in this document. The following is a list of sections of management's discussion and analysis of financial condition, contingencies and other matters and the registrant to which they apply:

Financial Condition	AEP, APCo, CPL, I&M, OPCo, SWEPCo
Market Risks	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU
Industry Restructuring	AEP, APCo, CPL, CSPCo, I&M, OPCo, PSO, SWEPCo, WTU
Litigation	AEP, APCo, CPL, CSPCo, I&M, KPCo, OPCo, SWEPCo, WTU
Environmental Concerns and Issues	AEP, APCo, CPL, CSPCo, I&M, OPCo, SWEPCO
Foreign Energy Delivery, Worldwide Energy Investments and Other Business Operations	AEP
Other Matters	AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU

Financial Condition – Affecting AEP, APCo, CPL, I&M, OPCo and SWEPCo

The Cook Plant extended outage and related restart expenditures negatively affected AEP's 2000 earnings and cash flows and the write-off related to COLI and non-regulated subsidiaries further depressed earnings. Although the 2000 dividend payout ratio was 289%, it is expected that the ratio will improve significantly as a result of earnings growth in 2001. It has been a management objective to reduce the payout ratio by increasing earnings. Management expects to grow future earnings by growing the wholesale business and by controlling operations and maintenance costs.

AEP's common equity to total capitalization, including long-term debt due within one year and short-term debt, decreased from 37% in 1999 to 34% in 2000. Preferred stock at 1% remained unchanged. Long-term debt decreased from 50% to 47%, while short-term debt increased from 12% to 18%. AEP's intention is to maintain flexibility during corporate separation by issuing floating rate debt. In 2000, AEP did not issue any shares of common stock to meet the requirements of the Dividend Reinvestment and Direct Stock Purchase Plan and the Employee Savings Plan. Sales of common stock and/or equity linked securities may be necessary in the future to support AEP's plan to grow the business.

Expenditures by the AEP System for domestic electric utility construction are estimated to be $6 billion for the next three years. Approximately 70% of those construction expenditures are expected to be financed by internally generated funds.

Construction expenditures for the registrant subsidiaries for the next three years excluding AFUDC are:

	Projected Construction Expenditures (in millions)	Construction Expenditures Financed with Internal Funds
APCo	$1,122.8	79%
I&M	427.2	ALL
OPCo	1,044.5	ALL
CPL	745.1	NONE
SWEPCo	405.6	70%

The year-end ratings of the subsidiaries' first mortgage bonds are listed in the following table:

Company	Moody's	S&P	Fitch
APCo	A3	A	A-
CSPCo	A3	A-	A
I&M	Baa1	A-	BBB+
KPCo	Baa1	A-	BBB+
OPCo	A3	A-	A-
CPL	A3	A-	A
PSO	A1	A	A+
SWEPCo	A1	A	A+
WTU	A2	A-	A

The ratings at the end of the year for senior unsecured debt issued by the subsidiaries are listed in the following table:

Company	Moody's	S&P	Fitch
AEP Resources*	Baa2	BBB+	BBB+
APCo	Baa1	BBB+	BBB+
CSPCo	Baa1	BBB+	A-
I&M	Baa2	BBB+	BBB
KPCo	Baa2	BBB+	BBB
OPCo	Baa1	BBB+	BBB+
CPL	Baa1	BBB+	A-
PSO	A2	BBB+	A
SWEPCo	A2	BBB+	A
WTU	A3	BBB+	-

- The rating is for a series of senior notes issued with a Support Agreement from AEP.

Financing Activity

Debt was issued in 2000 for the funding of debt maturities, for construction programs and for the growth of the wholesale business. AEP and its subsidiaries issued $1.1 billion principal amount of long-term obligations in 2000 at variable interest rates with due dates ranging from 2001 to 2007. The principal amount of long-term debt retirements, including maturities, totaled $1.6 billion with interest rates ranging from 5.25% to 9.6%.

The principal amount of long-term obligations issued and retired in 2000 by the registrant subsidiaries was:

	Issuance	Retirements
	(in thousands)	
APCo	$ 75,000	$136,000
I&M	200,000	148,000
OPCo	75,000	32,102
CPL	150,000	150,000
SWEPCo	150,000	45,595

The domestic electric utility subsidiaries generally issue short-term debt to provide for interim financing of capital expenditures that exceed internally generated funds. They periodically reduce their outstanding short-term debt through issuances of long-term debt and additional capital contributions by the parent company. The sources of funds available to the parent company, AEP, are dividends from its subsidiaries, short-term and long-term borrowings and proceeds from the issuance of common stock.

The subsidiaries formed to pursue worldwide electric and gas opportunities use short-term debt and capital contributions from the parent company for interim financing of working capital and acquisitions. Short-term debt is replaced with long-term debt when financial market conditions are favorable. Some acquisitions of existing business entities include the assumption of their outstanding debt.

The AEP System uses short-term debt, primarily commercial paper, to meet fluctuations in working capital requirements and other interim capital needs. AEP has established a system money pool to meet the short-term borrowings for certain of its subsidiaries, including AEGCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU. In January 2001 APCo became a participant in AEP's money pool and retired all outstanding short-term debt. In addition, AEP also funds the short-term debt requirements of other subsidiaries that are not included in the money pool. As of December 31, 2000, AEP had back up credit facilities totaling $3.5 billion to support its commercial paper program. At December 31, 2000, AEP had $2.7 billion outstanding in short-term borrowings. The maximum amount of short-term borrowings outstanding during the year, which had a weighted average interest rate for the year of 7.5%, was $2.7 billion during December 2000.

AEP Credit purchases, without recourse, the accounts receivable of most of the domestic utility operating companies and certain non-affiliated electric utility companies. The sale of accounts receivable provides the domestic electric utility operating companies with cash immediately, thereby reducing working capital needs and revenue requirements. In addition, AEP Credit's capital structure contains greater leverage than that of the domestic electric utility operating companies, so cost of capital is lowered. AEP Credit issues commercial paper to meet its financing needs. At December 31, 2000, AEP Credit had a $2.0 billion unsecured back up credit facility to support its commercial paper program, which had $1.2 billion outstanding. The maximum amount of such commercial paper outstanding during the year, which had a weighted average interest rate of 6.6%, was $1.5 billion during September 2000.

Market Risks – Affecting AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU

AEP as a major power producer and a trader of wholesale electricity and natural gas has certain market risks inherent in its business activities. The trading of electricity and natural gas and related financial derivative instruments exposes AEP to market risk. Market risk represents the risk of loss that may impact due to changes in commodity market prices and rates. Policies and procedures have been established to identify, assess, and manage market risk exposures including the use of a risk measurement model which calculates Value at Risk (VaR). The VaR is based on the variance - covariance method using historical prices to estimate volatilities and correlations and assuming a 95% confidence level and a one-day holding period. Throughout the year ending December 31, 2000 the average, high, and low VaRs in the wholesale electricity and gas trading portfolio were $10 million, $32 million, and $1 million, respectively. The average, high, and low VaRs for the year ending December 31, 1999 were $4 million, $8 million, and $1 million, respectively. Based on this VaR analysis, at December 31, 2000 a near term typical change in commodity prices is not expected to have a material effect on AEP's results of operations, cash flows or financial condition. The following table shows the high and average U.S. electricity market risk as measured by VaR allocated to the AEP registrant subsidiaries based upon the AEP System's trading activities in the U.S. Low VaR is excluded because all companies are under $1 million.

VaR for Registrant Subsidiaries:

	December 31,			
	2000		1999	
	High	Average	High	Average
	(in millions)			
APCo	$2	$6	$1	$2
CPL	1	4	-	-
CSPCo	1	3	1	1
I&M	1	4	1	2
KPCo	-	1	-	1
OPCo	2	5	1	2
PSO	1	3	-	-
SWEPCo	1	4	-	-
WTU	-	1	-	-

Investments in foreign ventures expose AEP to risk of foreign currency fluctuations. AEP's exposure to changes in foreign currency exchange rates related to these foreign ventures and investments is not expected to be significant for the foreseeable future.

AEP is exposed to changes in interest rates primarily due to short-and long-term borrowings to fund its business operations. AEP measures interest rate market risk exposure utilizing a VaR model. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one year holding period. The volatilities and correlations were based on three years of weekly prices. The risk of potential loss in fair value attributable to AEP's exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $998 million at December 31, 2000 and $966 million at December 31, 1999. The following table shows the potential loss in fair value as measured by VaR allocated to the AEP registrant subsidiaries based upon debt outstanding:

VaR for Registrant Subsidiaries:

Company	December 31, 2000	1999
	(in millions)	
AEGCo	$ 4	$ 4
APCo	149	144
CPL	135	131
CSPCo	84	81
I&M	129	125
KPCo	31	30
OPCo	112	109
PSO	44	42
SWEPCo	60	58
WTU	24	23

AEP and its registrant subsidiaries would not expect to liquidate its entire debt portfolio in a one year holding period. Therefore, a near term change in interest rates should not materially affect results of operations or the consolidated financial position of AEP and its registrant subsidiaries. AEP is currently utilizing interest rate swaps as a hedge to manage its exposure to interest rate fluctuations in the U.K. and Australia.

AEP has investments in debt and equity securities which are held in nuclear trust funds. The trust investments and their fair value are discussed in Note 15 of the Notes to Consolidated Financial Statements. Instruments in the trust funds have not been included in the market risk calculation for interest rates as these instruments are marked-to-market and changes in market value are reflected in a corresponding decommissioning liability. Any differences between the trust fund assets and the ultimate liability should be recoverable from ratepayers.

AEGCo is not exposed to risk from changes in interest rates on short-term and long-term borrowings used to finance operations since financing costs are recovered through the unit power agreements.

Inflation affects the AEP's System's cost of replacing utility plant and the cost of operating and maintaining its plant. The rate-making process limits recovery to the historical cost of assets, resulting in economic losses when the effects of inflation are not recovered from customers on a timely basis. However, economic gains that result from the repayment of long-term debt with inflated dollars partly offset such losses.

Industry Restructuring

In 2000 California's deregulated energy market suffered problems including high energy prices, short energy supply, and financial difficulties for retail energy suppliers whose prices to customers are controlled. This energy crisis has highlighted the importance of risk management and has contributed to certain state regulatory and legislative actions which could delay the start of customer choice and the transition to competitive, market based pricing for retail electricity supply in some of the states in which the AEP System companies operate. Seven of the eleven state retail jurisdictions in which the domestic electric utility companies operate have enacted restructuring legislation. In general, the legislation provides for a transition from cost-based regulation of bundled electric service to customer choice and market pricing for the supply of electricity. As legislative and regulatory proceedings evolve, six of the electric operating companies (APCo, CPL, CSPCo, OPCo, SWEPCo and WTU) doing business in five of the seven states that have passed restructuring legislation have discontinued the application of SFAS 71 regulatory accounting for generation. The seven states in various stages of restructuring to transition generation to market based pricing are Arkansas, Michigan, Ohio, Oklahoma, Texas, Virginia, and West Virginia. PSO and I&M have not discontinued regulatory accounting for their generation business in Oklahoma and Michigan, respectively, pending the implementation of the legislation. The following is a summary of restructuring legislation, the status of the transition plans and the status of the electric utility companies' accounting to comply with the changes in each of the AEP System's seven state regulatory jurisdictions affected by restructuring legislation.

Ohio Restructuring – Affecting AEP, CSPCo and OPCo

Effective January 1, 2001, customer choice of electricity supplier began under the Ohio Act. In February 2001, one supplier announced its plan to offer service to

CSPCo's residential customers. Currently for residential customers of OPCo, no alternative suppliers have registered with the PUCO as required by the Ohio Act. Two alternative suppliers have been approved to compete for CSPCo's and OPCo's commercial and industrial customers. Presently, customers continue to be served by CSPCo and OPCo with a legislatively required residential rate reduction of 5% for the generation portion of rates and a freezing of generation rates including fuel rates starting on January 1, 2001.

The Ohio Act provides for a five-year transition period to move from cost based rates to market pricing for generation services. It granted the PUCO broad oversight responsibility for promulgation of rules for competitive retail electric generation service, approval of a transition plan for each electric utility company and addressing certain major transition issues including unbundling of rates and the recovery of stranded costs including regulatory assets and transition costs.

The Ohio Act also provides for a reduction in property tax assessments, the imposition of replacement franchise and income taxes, and the replacement of a gross receipts tax with a KWH based excise tax. The property tax assessment percentage on generation property was lowered from 100% to 25% of value effective January 1, 2001 and Ohio electric utilities will become subject to the Ohio Corporate Franchise Tax and municipal income taxes on January 1, 2002. The last year for which Ohio electric utilities will pay the excise tax based on gross receipts is the tax year ending April 30, 2002. As of May 1, 2001 electric distribution companies will be subject to an excise tax based on KWH sold to Ohio customers. The gross receipts tax is paid at the beginning of the tax year (May 1), deferred by CSPCo and OPCo as a prepaid expense and amortized to expense during the tax year pursuant to the tax law whereby the payment of the tax results in the privilege to conduct business in the year following the payment of the tax. As a result a duplicate tax will be expensed from May 1, 2001 through April 30, 2002 adding approximately $90 million to AEP consolidated tax expense ($40 million for CSPCo and $50 million for OPCo) during that period. Unless the companies can recover the duplicate amount from ratepayers it will negatively impact results of operations.

On September 28, 2000, the PUCO approved, with minor modifications, a stipulation agreement between CSPCo, OPCo, the PUCO staff, the Ohio Consumers' Counsel and other concerned parties regarding transition plans filed by CSPCo and OPCo. The key provisions of this stipulation agreement are:

- Recovery of generation-related regulatory assets at December 31, 2000 over seven years for OPCo ($518 million) and over eight years for CSPCo ($248 million) through frozen transition rates for the first five years of the recovery period and a wires charge for the remaining years.
- A shopping incentive (a price credit) of 2.5 mills per KWH for the first 25% of CSPCo residential customers that switch suppliers. There is no shopping incentive for OPCo customers.
- The absorption of $40 million by CSPCo and OPCo ($20 million per company) of consumer education, implementation and transition plan filing costs with deferral of the remaining costs, plus a carrying charge, as a regulatory asset for recovery in future distribution rates.
- CSPCo and OPCo will make available a fund of up to $10 million to reimburse customers who choose to purchase their power from another company for certain transmission charges imposed by PJM and/or a Midwest ISO on generation originating in the Midwest ISO or PJM areas.
- The statutory 5% reduction in the generation component of residential tariffs will remain in effect for the entire five year transition period.
- The companies' request for a $90 million ($40 million for CSPCo and $50 million for OPCo) gross receipts tax rider to recover the duplicate gross receipts KWH based excise tax would be considered separately by the PUCO.

The approved stipulation agreement also accepted the following provisions contained in CSPCo's and OPCo's filed transition plans:

- a corporate separation plan to segregate generation, transmission and distribution assets into separate legal entities, and
- a plan for independent operation of transmission facilities.

The gross receipts tax issue was considered by the PUCO in hearings held in June 2000. In the September 28, 2000 order approving the stipulation agreement, the PUCO determined that there was no duplicate tax overlap period and denied the request for a $90 million ($40 million for CSPCo and $50 million for OPCo) gross receipts tax rider. CSPCo's and OPCo's request for rehearing of the gross receipts tax issue was denied. An appeal of this issue to the Ohio Supreme Court has been filed. Unless this issue is resolved in the companies' favor, it will have an adverse effect on future results of operations and financial position.

One of the intervenors at the hearings for approval of the settlement agreement (whose request for rehearing was denied by the PUCO) has filed with the Ohio Supreme Court for review of the settlement agreement including recovery of regulatory assets. Management is unable to predict the outcome of litigation but the resolution of this matter could negatively impact results of operations.

Beginning January 1, 2001, CSPCo's and OPCo's fuel costs will not be subject to PUCO fuel recovery proceedings. Deferred fuel costs at December 31, 2000 which represent under or over recoveries were one of the items included in the PUCO's final determination of net regulatory assets to be collected (recovered) during the transition period. The elimination of fuel clause recoveries in 2001 in Ohio will subject AEP, CSPCo and OPCo to the risk of fuel market price increases and could adversely affect their future results of operations and cash flows.

CSPCo and OPCo Discontinue Application of SFAS 71 Regulatory Accounting for the Ohio Jurisdiction

In September 2000 CSPCo and OPCo discontinued the application of SFAS 71 for their Ohio retail jurisdictional generation business since generation is no longer cost-based regulated in the Ohio jurisdiction and management was able to determine their transition rates and wires charges. The discontinuance in the Ohio jurisdiction was possible as a result of the PUCO's September 28, 2000 approval of the stipulation agreement which established rates, wires charges and net regulatory asset recovery procedures during the transition to market rates.

CSPCo's and OPCo's discontinuance of SFAS 71 for generation resulted in after tax extraordinary losses in the third quarter of 2000 of $25 million and $19 million, respectively, due to certain unrecoverable generation-related regulatory assets and transition expenses. Management believes that substantially all of the remaining net regulatory assets related to the Ohio generation business will be recovered under the PUCO's September 28, 2000 order. Therefore, under the provisions of EITF 97-4, CSPCo's and OPCo's generation-related recoverable net regulatory assets were transferred to the transmission and distribution portion of the business and will be amortized as they are recovered through transition rates to customers. CSPCo and OPCo performed an accounting impairment analysis on their generating assets under SFAS 121 as required when discontinuing the application of SFAS 71 and concluded there was no impairment of generation assets.

Virginia Restructuring – Affecting AEP and APCo

In Virginia, a restructuring law provides for a transition to choice of electricity supplier for retail customers beginning on January 1, 2002. In February 2001, restructuring revision legislation was approved by the Virginia Legislature which could modify the terms of restructuring. Presently, the transition period is to be completed, subject to a finding by the Virginia SCC that an effective competitive market exists by January 1, 2004 but no later than January 1, 2005.

The restructuring law also provides an opportunity for recovery of just and reasonable net stranded generation costs. The mechanisms in the Virginia law for net stranded cost recovery are: a capping of rates until as late as July 1, 2007, and the application of a wires charge upon customers who depart the incumbent utility in favor of an alternative supplier prior to the termination of the rate cap. The restructuring law provides for the establishment of capped rates prior to January 1, 2001 based either on a request by APCo for a change in rates prior to January 1, 2001 or on the rates in effect at July 1, 1999 if no rate change request is made and the establishment of a wires charge by the fourth quarter of 2001. APCo did not request new rates; therefore, its current rates are the capped rates. In the third quarter of 2000, the Virginia SCC directed APCo to file a cost of service study using 1999 as a test year to review the reasonableness of APCo's capped rates. The cost of service study was filed on January 3, 2001. In the opinion of APCo's Virginia counsel, Virginia's restructuring law does not permit the Virginia SCC to change rates for the transition period except for changes in the fuel factor, changes in state gross receipts taxes, or to address the utility's financial distress. However, if the Virginia SCC were to reduce APCo's capped rates or deny recovery of regulatory assets, it would adversely affect results of operations if such action is ultimately determined to be legal.

The Virginia restructuring law also requires filings to be made that outline the functional separation of generation from transmission and distribution and a rate unbundling plan. On January 3, 2001, APCo filed its corporate separation plan and rate unbundling plan with the Virginia SCC which is based on the most recent rate case test year (1996). See Note 7 of the Notes to Consolidated Financial Statements for a discussion of AEP's corporate separation plan filed with the SEC.

West Virginia Restructuring – Affecting AEP and APCo

On January 28, 2000, the WVPSC issued an order approving an electricity restructuring plan for WV. On March 11, 2000, the WV Legislature approved the restructuring plan by joint resolution. The joint resolution provides that the WVPSC cannot implement the plan until the legislature makes necessary tax law changes to preserve the revenues of the state and local governments. The Joint Committee on Government and Finance of the WV Legislature hired a consultant to study and issue a report on the tax changes required to implement electric restructuring. Moreover, the committee also hired a consultant to study and issue a report on the electric restructuring plan in light of events occurring in California. The WV Legislature is not expected to consider these reports until the 2002 Legislative Session since the 2001 Legislative Session ends in April 2001. Since the WV Legislature has not yet passed the required tax law changes, the restructuring plan has not become effective. AEP subsidiaries, APCo and WPCo, provide electric service in WV.

The provisions of the restructuring plan provide for customer choice to begin after all necessary rules are in place (the "starting date"); deregulation of generation assets on the starting date; functional separation of the generation, transmission and distribution businesses on the starting date and their legal corporate separation no later than January 1, 2005; a transition period of up to 13 years, during which the incumbent utility must provide default service for customers who do not change suppliers unless an alternative default supplier is selected through a WVPSC-sponsored bidding process; capped and fixed rates for the 13 year transition period as discussed below; deregulation of metering and billing; a 0.5 mills per KWH wires charge applicable to all retail customers for a 10-year period commencing with the starting date intended to provide for recovery of any stranded cost including net regulatory assets; establishment of a rate stabilization deferred liability balance of $81 million ($76 million by APCo and $5 million by WPCo) by the end of year ten of the transition period to be used as determined by the WVPSC to offset market prices paid in the eleventh, twelfth, and thirteenth year of the transition period by residential and small commercial customers that do not choose an alternative supplier.

Default rates for residential and small commercial customers are capped for four years after the starting date and then increase as specified in the plan for the next six years. In years eleven, twelve and thirteen of the transition period, the power supply rate shall equal the market price of comparable power.

Default rates for industrial and large commercial customers are discounted by 1% for four and a half years, beginning July 1, 2000, and then increased at pre-defined levels for the next three years. After seven years the power supply rate for industrial and large commercial customers will be market based. APCo's Joint Stipulation agreement, discussed in Note 5 of the Notes to Consolidated Financial Statements, which was approved by the WVPSC on June 2, 2000 in connection with a base rate filing, also provides additional mechanisms to recover regulatory assets.

APCo Discontinues Application of SFAS 71 Regulatory Accounting

In June 2000 APCo discontinued the application of SFAS 71 for its Virginia and WV retail jurisdictional portions of its generation business since generation is no longer considered to be cost-based regulated in those jurisdictions and management was able to determine APCo's transition rates and wires charges. The discontinuance in the WV jurisdiction was made possible by the June 2, 2000 approval of the Joint Stipulation which established rates, wires charges and regulatory asset recovery procedures for the transition period to market rates which was determined to be probable. APCo was also able to discontinue application of SFAS 71 for the generation portion of its Virginia retail jurisdiction after management decided that APCo would not request capped rates different from its current rates. The existence of effective restructuring legislation in Virginia and the probability that the WV legislation would become effective with the expected probable passage of required enabling tax legislation in 2001 supported management's decision in 2000 to discontinue SFAS 71 regulatory accounting for APCo's electricity generation and supply business.

APCo's discontinuance of SFAS 71 for generation resulted in an after tax extraordinary gain, in the second quarter of 2000, of $9 million. Management believes that it is probable that substantially all net regulatory assets related to the Virginia and WV generation business will be recovered. Therefore, under the provisions of EITF 97-4, APCo's generation-related net regulatory assets were transferred to the distribution portion of the business and are being amortized as they are recovered through charges to regulated distribution customers. As required by SFAS 101 when discontinuing SFAS 71 regulatory accounting, APCo performed an accounting impairment analysis on its generating assets under SFAS 121 and concluded that there was no accounting impairment of generation assets.

The recent energy crisis in California, discussed above, may be having a chilling effect on efforts to enact the required tax change legislation in West Virginia. The WV Legislature could decide not to enact the required tax changes, thereby, effectively continuing cost based rate regulation in West Virginia or it could modify the restructuring plan. Modifications in the restructuring plan could adversely affect future results of operations if they were to occur. Management is carefully monitoring the situation in West Virginia and continues to work with all concerned parties to get approval to successfully transition our generation business in West Virginia. Failure to pass the required enabling tax changes could ultimately require APCo to re-instate regulatory accounting principles under SFAS 71 for its generation operations in West Virginia.

Arkansas Restructuring – Affecting AEP and SWEPCo

In 1999 legislation was enacted in Arkansas that will ultimately restructure the electric utility industry. Its major provisions are:

- retail competition begins January 1, 2002 but can be delayed until as late as June 30, 2003 by the Arkansas Commission;
- transmission facilities must be operated by an ISO if owned by a company which also owns generation assets;
- rates will be frozen for one to three years;
- market power issues will be addressed by the Arkansas Commission; and
- an annual progress report to the Arkansas General Assembly on the development of competition in electric markets and its impact on retail customers is required.

In November 2000 the Arkansas Commission filed its annual progress report with the Arkansas General Assembly recommending a delay in the start date of retail competition to a date between October 1, 2003 and October 1, 2005. The report also asks the Arkansas General Assembly to delegate authority to the Arkansas Commission to determine the appropriate retail competition start date within the approved time frame. In February 2001 the Arkansas General Assembly passed legislation that was signed into law by the Governor that changes the date of electric retail competition to October 1, 2003, and provides the Arkansas Commission with the authority to delay that date for up to two years.

Texas Restructuring – Affecting AEP, CPL, SWEPCo and WTU

In June 1999 Texas restructuring legislation was signed into law which, among other things:

- gives Texas customers of investor-owned utilities the opportunity to choose their electricity provider beginning January 1, 2002;
- provides for the recovery of regulatory assets and of other stranded costs through securitization and non-bypassable wires charges;
- requires reductions in NOx and sulfur dioxide emissions;
- provides for a rate freeze until January 1, 2002 followed by a 6% rate reduction for residential and small commercial customers and a number of customer protections;
- provides for an earnings test for each of the three years of the rate freeze period (1999 through 2001) which will reduce stranded cost recoveries or if there is no stranded cost provides for a refund or their use to fund certain capital expenditures in the amount of the excess earnings;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution utility;
- provides for certain limits for ownership and control of generating capacity by companies;
- provides for elimination of the fuel clause reconciliation process beginning January 1, 2002; and
- provides for a 2004 true-up proceeding to determine recovery of stranded costs including final fuel recovery balances, net regulatory assets, certain environmental costs, accumulated excess earnings and other issues.

Under the Texas Legislation, delivery of electricity will continue to be the responsibility of the local electric transmission and distribution utility company at regulated prices. Each electric utility was required to submit a plan to structurally unbundle its business activities into a retail electric provider, a power generation company, and a transmission and distribution utility. In May 2000 CPL, SWEPCo and WTU filed a revised business separation plan that the PUCT approved on July 7, 2000 in an interim order. The revised business separation plans provided for CPL and WTU, which operate in Texas only, to establish separate companies and divide their integrated utility operations and assets into a power generation company, a transmission and distribution utility and a retail electric provider. SWEPCo will separate its Texas jurisdictional transmission and distribution assets and operations into a new Texas regulated transmission and distribution subsidiary. In addition, a retail electric provider will be formed by SWEPCo to provide retail electric service to SWEPCo's Texas jurisdictional customers.

Under the Texas Legislation, electric utilities are allowed, with the approval of the PUCT, to recover stranded generation costs including generation-related regulatory assets that may not be recoverable in a future competitive market. The approved stranded costs can be refinanced through securitization, which is a financing structure designed to provide lower financing costs than are available through conventional financings. Lower financing costs are achieved through the issuance of securitization bonds at a lower interest rate to finance 100% of the costs pursuant to a state pledge to ensure recovery of the bond principal and financing costs through a non-bypassable rate surcharge by the regulated transmission and distribution utility over the life of the securitization bonds.

In 1999 CPL filed an application with the PUCT to securitize approximately $1.27 billion of its retail generation-related regulatory assets and approximately $47 million in other qualified restructuring costs. On March 27, 2000, the PUCT issued an order permitting CPL to securitize approximately $764 million of net regulatory assets. The PUCT's order authorized issuance of up to $797 million of securitization bonds including the $764 million for recovery of net generation-related regulatory assets and $33 million for other qualified refinancing costs. The $764 million for recovery of net generation-related regulatory assets reflects the recovery of $949 million of generation-related regulatory assets offset by $185 million of customer benefits associated with accumulated deferred income taxes. CPL had previously proposed in its filing to flow these benefits back to customers over the 14-year term of the securitization bonds. On April 11, 2000, four parties appealed the PUCT's securitization order to the Travis County District Court. In July 2000 the Travis County District Court upheld the PUCT's securitization order. The securitization order is being appealed to the Supreme Court of Texas. One of these appeals challenges CPL's ability to recover securitization charges under the Texas Constitution. CPL will not be able to issue the securitization bonds until these appeals are resolved.

The remaining regulatory assets of $206 million originally included by CPL in its 1999 securitization request were included in a March 2000 filing with the PUCT, requesting recovery of an additional $1.1 billion of stranded costs. The March 2000 filing of $1.1 billion included recovery of approximately $800 million of STP costs included in property, plant and equipment-electric on AEP's Consolidated Balance Sheets and in electric utility plant-production on CPL's Consolidated Balance Sheets. These STP costs had previously been identified as excess cost over market (ECOM) by the PUCT for regulatory purposes and were earning a lower return and were being amortized on an accelerated basis for rate-making purposes in Texas. The March 2000 filing will determine the initial amount of stranded costs in addition to the securitized regulatory assets to be recovered beginning January 1, 2002.

CPL submitted a revised estimate of stranded costs on October 2, 2000 using assumptions developed in generic proceedings by the PUCT and an administrative model developed by the PUCT staff that reduced the amount of the initial stranded cost estimate to $361 million from the $1.1 billion requested by CPL. CPL subsequently agreed to accept adjustments proposed by intervenors that reduced ECOM to approximately $230 million. Hearings on CPL's requested ECOM were held in October 2000. In February 2001 the PUCT issued an interim decision determining an initial amount of CPL ECOM or stranded costs of negative $580 million. The decision indicated that CPL's costs were below market after securitization of regulatory assets. Management does not agree with the critical inputs to this model. Management believes CPL has a positive stranded cost exclusive of securitized regulatory assets. The final amount of CPL's stranded costs including regulatory assets and ECOM will be established by the PUCT in the legislatively required 2004 true-up proceeding. If CPL's total stranded costs determined in the 2004 true-up are less than the amount of securitized regulatory assets, the PUCT can implement an offsetting credit to transmission and distribution rates.

The PUCT ruled that prior to the 2004 true-up proceeding, no adjustments would be made to the amount of regulatory costs authorized by the PUCT to be securitized. However, the PUCT also ruled that excess earnings for the period 1999-2001 should be refunded through transmission and distribution rates to the extent of any over-mitigation of stranded costs represented by negative ECOM. In the event that CPL will be required to refund excess earnings in the future instead of applying them to reduce ECOM or regulatory assets, it will adversely affect future cash flow but not results of operations since excess earnings for 1999 and 2000 were accrued and expensed in 1999 and 2000. The Texas Legislation allows for several alternative methods to be used to value stranded costs in the final 2004 true-up proceeding including the sale or exchange of generation assets, the issuance of power generation company stock to the public or the use of PUCT staff's ECOM model. To the extent that the final 2004 true-up proceeding determines that CPL should recover additional stranded costs, the total amount recoverable can be securitized.

The Texas Legislation provides that each year during the 1999 through 2001 rate freeze period, electric utilities are subject to an earnings test. For electric utilities with stranded costs, such as CPL, any earnings in excess of the most recently approved cost of capital in its last rate case must be applied to reduce stranded costs. Utilities without stranded costs, such as SWEPCo and WTU, must either flow such excess earnings amounts back to customers or make capital expenditures to improve transmission or distribution facilities or to improve air quality. The Texas Legislation requires PUCT approval of the annual earnings test calculation.

The 1999 earnings test reports filed by CPL, SWEPCo and WTU showed excess earnings of $21 million, $1 million and zero, respectively. The PUCT staff issued its report on the excess earnings calculations filed by CPL, SWEPCo and WTU and calculated the excess earnings amounts to be $41 million, $3 million and $11 million for CPL, SWEPCo and WTU, respectively. The Office of Public Utility Counsel also filed exceptions to the companies' earnings reports. Several issues were resolved via settlement and the remaining open issues were submitted to the PUCT. A final order was issued by the PUCT in February 2001 and adjustments to the accrued 1999 and 2000 excess earnings were recorded in results of operations in the fourth quarter of 2000. After adjustments the accruals for 1999 excess earnings for CPL and WTU were $24 million and $1 million, respectively. CPL and WTU also recorded an estimated provision for excess 2000 earnings of $16 million and $14 million, respectively.

A Texas settlement agreement in connection with the AEP and CSW merger permits CPL to apply for regulatory purposes up to $20 million of STP ECOM plant assets a year in 2000 and 2001 to reduce excess earnings, if any. For book and financial reporting purposes, STP ECOM plant assets will be depreciated in accordance with GAAP, on a systematic and rational basis unless impaired. CPL will establish a regulatory liability or reduce regulatory assets by a charge to earnings to the extent excess earnings exceed $20 million in 2000 and 2001.

Beginning January 1, 2002, fuel costs will not be subject to PUCT fuel reconciliation proceedings. Consequently, CPL, SWEPCo and WTU will file a final fuel reconciliation with the PUCT to reconcile their fuel costs through the period ending December 31, 2001. Fuel costs have been reconciled by CPL, SWEPCo and WTU through June 30, 1998, December 31, 1999 and June 30, 1997, respectively. WTU is currently reconciling its fuel through June 2000. See discussion in Note 5 of the Notes to Consolidated Financial Statements. At December 31, 2000, CPL's, SWEPCo's and WTU's Texas jurisdictional unrecovered deferred fuel balances were $127 million, $20 million and $59 million, respectively. Final unrecovered deferred fuel balances at December 31, 2001 will be included in each company's 2004 true-up proceeding. If the final fuel balances or any amount incurred but not yet reconciled were not recovered, they could have a negative impact on results of operations. The elimination of the fuel clause recoveries in 2002 in Texas will subject AEP, CPL, SWEPCo and WTU to greater risks of fuel market price increases and could adversely affect future results of operations beginning in 2002.

The affiliated retail electric provider of CPL, SWEPCo and WTU will be required to offer residential and small commercial customers (with a peak usage of less than 1000 KW) a rate 6% below rates in effect on January 1, 1999 adjusted for any changes in fuel cost recovery factors since January 1, 1999 (price to beat). The price to beat must be offered to residential and small commercial customers until January 1, 2007. Customers with a peak usage of more than 1000 KW are subject to market rates. The Texas restructuring legislation provides for the price to beat to be adjusted up to two times annually to reflect significant changes in fuel and purchased energy costs.

CPL, SWEPCo and WTU Discontinue Application of SFAS 71 Regulatory Accounting in Arkansas and Texas

The financial statements of CPL, SWEPCo and WTU have historically reflected the economic effects of regulation by applying the requirements of SFAS 71. As a result of the scheduled deregulation of generation in Arkansas and Texas, the application of SFAS 71 for the generation portion of the business in those states was discontinued in the third quarter of 1999. Under the provisions of EITF 97-4, CPL's generation-related net regulatory assets were transferred to the distribution portion of the business and will be amortized as they are recovered through wires charges to customers. Management believes that substantially all of CPL's generation-related regulatory assets will be recovered under the Texas Legislation. CPL's recovery of generation-related regulatory assets and stranded costs are subject to a final determination by the PUCT in 2004. If future events were to make the recovery through securitization of CPL's generation-related regulatory assets no longer probable, CPL would write-off the portion of such regulatory assets deemed unrecoverable as a non-cash extraordinary charge to earnings.

The Texas Legislation provides that all finally determined stranded costs will be recovered. Since SWEPCo and WTU are not expected to have net stranded costs, all Arkansas and Texas jurisdictional generation-related net regulatory assets were written off as non-recoverable in 1999 when they discontinued application of SFAS 71 regulatory accounting. As required by SFAS 101 when SFAS 71 is discontinued, an accounting impairment analysis for generation assets under SFAS 121 was completed for CPL, SWEPCo and WTU. The analysis showed that there was no accounting impairment of generation assets when the application of SFAS 71 was discontinued. CPL, SWEPCo and WTU will test their generation assets for impairment under SFAS 121 if circumstances change. Management believes that on a discounted basis CPL's generation business net cash flows will likely be less than its generating assets' net book value and together with its generation-related regulatory assets should create a recoverable stranded cost for regulatory purposes under the Texas Legislation. Therefore, management continues to carry on the balance sheet at December 31, 2000, $953 million of generation-related regulatory assets already approved for securitization and $195 million of net generation-related regulatory assets pending approval for securitization in Texas. A final determination of whether they will be securitized and recovered will be made as part of the 2004 true-up proceeding.

CPL, SWEPCo, and WTU continue to analyze the impact of electric utility industry restructuring legislation on their Arkansas and Texas electric operations. Although management believes that the Texas Legislation provides for full recovery of stranded costs and that the companies do not have a recordable accounting impairment, a final determination of whether CPL will experience an accounting loss or whether SWEPCo and WTU will experience any additional accounting loss from an inability to recover generation-related regulatory assets and other restructuring related costs in Texas and Arkansas cannot be made until such time as the regulatory process is complete following the 2004 true-up proceeding in Texas and a determination by the Arkansas Commission. In the event CPL, SWEPCo, and WTU are unable after the 2004 true-up proceeding and after the Arkansas

Commission proceedings to recover all or a portion of their generation-related regulatory assets, stranded costs and other restructuring related costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Although Arkansas' delay of retail competition may be having a negative effect on the progress of efforts to transition SWEPCo's generation in Arkansas to market based pricing of electricity, it appears that Texas is moving forward as planned. Management is carefully monitoring the situation in Arkansas and is working with all concerned parties to prudently quicken the pace of the transition. However, changes could occur due to concerns stemming from the California energy crisis and other events which could adversely affect future results of operations in Arkansas and possibly Texas.

Michigan Restructuring – Affecting AEP and I&M

On June 5, 2000, the Michigan Legislation became law. Its major provisions, which were effective immediately, applied only to electric utilities with one million or more retail customers. I&M, AEP's electric operating subsidiary doing business in Michigan, has less than one million customers in Michigan. Consequently, I&M was not immediately required to comply with the Michigan Legislation.

The Michigan Legislation gives the MPSC broad power to issue orders to implement retail customer choice of electric supplier no later than January 1, 2002 including recovery of regulatory assets and stranded costs. On October 2, 2000, I&M filed a restructuring implementation plan as required by a MPSC order. The plan identifies I&M's proposal to file with the MPSC on June 5, 2001 its unbundled rates, open access tariffs, terms of service and supporting schedules. Described in the plan are I&M's intentions and preparation for competition related to supplier transactions, customer transactions, rate unbundling, education programs, and regional transmission organization. The plan contains a proposed methodology to determine stranded costs and implementation costs and requests the continuation of a wires charge for recovery of nuclear decommissioning costs. Approval of the restructuring implementation plan is pending before the MPSC.

Management has concluded that as of December 31, 2000 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan will continue to be cost-based regulated until the MPSC approves rates and wires charges in 2001. The establishment of rates and wires charges under a MPSC approved transition plan will enable management to determine the ability to recover stranded costs including regulatory assets and other implementation costs, a requirement of EITF 97-4 to discontinue the application of SFAS 71.

Upon the discontinuance of SFAS 71, I&M will, if necessary, have to write off its Michigan jurisdictional generation-related regulatory assets and record its unrecorded Michigan jurisdictional liability for decommissioning the Cook Plant to the extent that they cannot be recovered under the transition rates and wires charges. As required by SFAS 101 when discontinuing SFAS 71 regulatory accounting, I&M will have to perform an accounting impairment analysis under SFAS 121 to determine if the Michigan jurisdictional portion of its generating assets are impaired for accounting purposes.

The amount of regulatory assets recorded on the books at December 31, 2000 applicable to I&M's Michigan retail jurisdictional generation business is approximately $45 million before related tax effects. The estimated unrecorded liability for the Michigan jurisdiction to decommission the Cook Plant ranges from $114 million to $215 million in 2000 non-discounted dollars based upon studies completed during 2000. For the Michigan jurisdiction, I&M has accumulated approximately $100 million in trust funds to decommission the Cook Plant. Based on the current information available, management does not anticipate that I&M will experience any material tangible asset accounting impairment or regulatory asset write-offs. Ultimately, however, whether I&M will experience material regulatory asset write-offs will depend on whether the MPSC approves their recovery in future restructuring proceedings.

A determination of whether I&M will experience any asset impairment loss regarding its Michigan retail jurisdictional generating assets and any loss from a possible inability to recover Michigan generation-related regulatory assets, decommissioning obligations and transition costs cannot be made until such time as the rates and the wires charges are determined through the regulatory process. In the event I&M is unable to recover all or a portion of its generation-related regulatory assets, unrecorded decommissioning obligation, stranded costs and other implementation costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Oklahoma Restructuring – Affecting AEP and PSO

In 1997, the Oklahoma Legislature passed restructuring legislation providing for retail open access by July 1, 2002. That legislation called for a number of studies to be completed on a variety of restructuring issues, including an independent system operator, technical, financial, transition and consumer issues. During 1998 and 1999 several of the studies were completed.

The information from the studies was expected to be used in the development of additional industry restructuring legislation during the 2000 legislative session. Several additional electric industry restructuring bills were filed in the 2000 Oklahoma legislative session. The proposed bills generally supplemented the industry restructuring legislation previously enacted in Oklahoma which lacked specific procedures for a transition to market based competitive prices. The industry restructuring legislation previously passed did not delegate the establishment of transition procedures to the Oklahoma Corporation Commission. The 2000 Oklahoma legislative session adjourned in May without passing further restructuring legislation.

The 2001 Oklahoma legislative session convened in early February. No further electric restructuring legislation has passed and proposals have been made to delay the implementation of the transition to customer choice and market based pricing under the restructuring legislation. These proposals are a reaction to California's recent energy crisis. Management is working with all concerned parties to reassure them that what happened in California will not occur in Oklahoma. If the necessary legislation is not passed, PSO's generation and retail electric supply business will remain regulated in Oklahoma. If implementation legislation were to modify the original restructuring legislation in Oklahoma it could have a adverse effect on results of operations.

Management has concluded that as of December 31, 2000 the requirements to apply SFAS 71 continue to be met since PSO's rates for generation in Oklahoma will continue to be cost-based regulated until the Oklahoma Legislature approves further restructuring legislation and transition rates and wires charges are established under an approved transition plan. Until management is able to determine the ability to recover stranded costs which includes regulatory assets and other implementation costs, PSO cannot discontinue application of SFAS 71 accounting under GAAP.

When PSO discontinues application of SFAS 71, it will be necessary to write off Oklahoma jurisdictional generation-related regulatory assets to the extent that they cannot be recovered under the transition rates and wires charges, when determined, and record any asset accounting impairments in accordance with SFAS 121.

A determination of whether PSO will experience any asset impairment loss regarding its Oklahoma retail jurisdictional generating assets and any loss from a possible inability to recover Oklahoma generation-related regulatory assets and other transition costs cannot be made until such time as the rates and the wires charges are determined through the legislative and/or regulatory process. In the event PSO is unable to recover all or a portion of its generation-related regulatory assets and implementation costs, Oklahoma restructuring could have a material adverse effect on results of operations and cash flows.

Restructuring In Other Jurisdictions

The remaining four states (Indiana, Kentucky, Louisiana and Tennessee) making up AEP's service territory have initiatives to implement or review customer choice, although the timing of any implementation is uncertain and may be further delayed due to the California situation. AEP supports customer choice and deregulation of generation and is proactively involved in discussions regarding the best competitive market structure and transition method to arrive at a fair, competitive marketplace. As the pricing of generation in these markets evolves from regulated cost-of-service rates to market-based pricing, the recovery of stranded costs including net regulatory assets and other transition costs must be addressed. The amount of stranded costs the AEP subsidiaries could experience when and if restructuring occurs in their state jurisdictions depends on the timing and extent to which competition is introduced to their business and the future market prices of electricity. The recovery of stranded cost is dependent on the terms of future legislation and, if required, related regulatory proceedings.

Customer choice and the transition to market based competition if restructuring is implemented in Indiana, Kentucky, Louisiana and Tennessee could also ultimately result in adverse impacts on results of operations and cash flows depending on the future market prices of electricity and the ability of the subsidiaries to recover their stranded costs including net regulatory assets during a transition or subsequent period through a wires charge or other recovery mechanism. Management believes that state restructuring legislation and the regulatory process should provide for full recovery of generation-related net regulatory assets and other reasonable stranded costs if these states decide to deregulate generation. However, if in the future any portion of the generation business in these other jurisdictions were to no longer be cost-based regulated and if it were not possible to demonstrate probability of recovery of resultant stranded costs including regulatory assets, results of operations, cash flows and financial condition would be adversely affected.

Amortization of Transition Regulatory Assets and Other Deferred Costs – Affecting AEP, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU

Future earnings will be negatively impacted by amortization of certain deferred costs and regulatory assets related to I&M's Cook Plant extended outage, transition plans to discontinue SFAS 71 regulatory accounting for generation with the beginning of customer choice in certain states and the merger of AEP and CSW.

During 1999, the IURC and MPSC approved settlement agreements which provided for the deferral in 1999 and amortization of restart costs and fuel-related revenues from the extended Cook Plant outage. The amortization period is for five years ending in December 2003. Annual amortization is $78 million for I&M. See Note 4 of the Notes to Consolidated Financial Statements.

Beginning in 2001 under the Ohio Act, CSPCo and OPCo began amortizing their transition regulatory assets over eight and seven years, respectively. The annual amortization in 2001 for CSPCo and OPCo is estimated to be $20 million and $74 million, respectively. The amount of amortization is based upon KWH sold.

APCo began amortization of its West Virginia jurisdictional regulatory assets over an eleven year period in July 2000. In the Virginia jurisdiction, APCo started straight line amortization of regulatory assets over a seven year period in July 2000. The annual amortization for 2001 is $9 million for APCo's West Virginia jurisdiction and $9 million for APCo's Virginia jurisdiction.

In June 2000 AEP merged with CSW. In connection with securing approval for the merger, AEP and certain of its subsidiaries signed agreements, approved by regulatory authorities, which included rate reductions to share estimated merger savings with customers. The agreements provide for rate reductions for periods up to eight years beginning in the third quarter of 2000.

Certain merger related costs recoverable from ratepayers were deferred pursuant to the settlement agreements and will be amortized over five to eight years depending upon the terms of the respective agreements. The annual amortization of the deferred merger costs for the AEP System is estimated to total $8 million in 2001. The merger amortization will be recorded as follows: $2.6 million by CPL, $1.7 million by I&M, $600,000 by KPCo, $1.2 million by PSO, $1.1 million by SWEPCo and $800,000 by WTU. If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements and the amortization of deferred merger-related costs, future results of operations, cash flows and possibly financial condition could be adversely affected. See Note 3 of the Notes to Consolidated Financial Statements for further discussion of the merger.

Amortization of the above described deferred costs and regulatory assets could negatively affect future earnings to the extent that they exceed cost savings or revenues growth.

Litigation

COLI – Affecting AEP, APCo, CSPCo, I&M, KPCo and OPCo

On February 20, 2001, the U.S. District Court for the Southern District of Ohio ruled against AEP in its suit against the United States over deductibility of interest claimed by AEP in its consolidated federal income tax return related to its COLI program. AEP had filed suit to resolve the IRS' assertion that interest deductions for AEP's COLI program should not be allowed. In 1998 and 1999 AEP and the impacted subsidiaries paid the disputed taxes and interest attributable to COLI interest deductions for taxable years 1991-98 for APCo, CSPCo, I&M and OPCo and 1992-98 for KPCo to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in other assets on AEP Consolidated Balance Sheet and Other Property and Investments on the subsidiaries' balance sheets pending the resolution of this matter. As a result of the U.S. District Court's decision to deny the COLI interest deductions, net income was reduced by $319 million for the AEP System in 2000. Management plans to appeal the decision.

The earnings reductions for affected registrant subsidiaries are as follows:

	(in millions)
APCo	$ 82
CSPCo	41
I&M	66
KPCo	8
OPCo	118

Shareholders' Litigation – Affecting AEP

On June 23, 2000, a complaint was filed in the U.S. District Court for the Eastern District of New York seeking unspecified compensatory damages against AEP and four former or present officers. The individual plaintiff also seeks certification as the representative of a class consisting of all persons and entities who purchased or otherwise acquired AEP common stock between July 25, 1997, and June 25, 1999. The complaint alleges that the defendants knowingly violated federal securities laws by disseminating materially false and misleading statements concerning, among other things, the undisclosed materially impaired condition of the Cook Plant, AEP's inability to properly monitor, manage, repair, supervise and report on operations at the Cook Plant and the materially adverse conditions these problems were having, and would continue to have, on AEP's deteriorating financial condition, and ultimately on AEP's operations, liquidity and stock price. Four other similar class action complaints have been filed and the court has consolidated the five cases. The plaintiffs filed a consolidated complaint pursuant to this court order. This case has been transferred to the U.S. District Court for the Southern

District of Ohio. Although, management believes these shareholder actions are without merit and intends to oppose them vigorously, management cannot predict the outcome of this litigation or its impact on results of operations, cash flows or financial condition.

Municipal Franchise Fee Litigation – Affecting AEP and CPL

CPL has been involved in litigation regarding municipal franchise fees in Texas as a result of a class action suit filed by the City of San Juan, Texas in 1996. The City of San Juan claims CPL underpaid municipal franchise fees and seeks damages of up to $300 million plus attorney's fees. CPL filed a counterclaim for overpayment of franchise fees.

During 1997, 1998 and 1999 the litigation moved procedurally through the Texas Court System and was sent to mediation without resolution.

In 1999 a class notice was mailed to each of the cities served by CPL. Over 90 of the 128 cities declined to participate in the lawsuit. However, CPL has pledged that if any final, non-appealable court decision awards a judgement against CPL for a franchise underpayment, CPL will extend the principles of that decision, with regard to any franchise underpayment, to the cities that declined to participate in the litigation. In December 1999, the court ruled that the class of plaintiffs would consist of approximately 30 cities. A trial date for June 2001 has been set.

Although management believes that it has substantial defenses to the cities' claims and intends to defend itself against the cities' claims and pursue its counterclaim vigorously, management cannot predict the outcome of this litigation or its impact on results of operations, cash flows or financial condition.

Texas Base Rate Litigation – Affecting AEP and CPL

In November 1995 CPL filed with the PUCT a request to increase its retail base rates by $71 million. In October 1997 the PUCT issued a final order which lowered CPL's annual retail base rates by $19 million from the rate level which existed prior to May 1996. The PUCT also included a "glide path" rate methodology in the final order pursuant to which annual rates were reduced by $13 million beginning May 1, 1998 with an additional annual reduction of $13 million commencing on May 1, 1999.

CPL appealed the final order to the Travis District Court. The primary issues being appealed include: the classification of $800 million of invested capital in STP as ECOM and assigning it a lower return on equity than other generation property; the use of the "glide path" rate reduction methodology; and an $18 million disallowance of service billings from an affiliate, CSW Services. As part of the appeal, CPL sought a temporary injunction to prohibit the PUCT from implementing the "glide path" rate reduction methodology. The temporary injunction was denied and the "glide path" rate reduction was implemented. In February 1999 the Travis District Court affirmed the PUCT order in regard to the three major items discussed above.

CPL appealed the Travis District Court's findings to the Texas Appeals Court which in July 2000, issued its opinion upholding the Travis District Court except for the disallowance of affiliated service company billings. Under Texas law, specific findings regarding affiliate transactions must be made by PUCT. In regards to the affiliate service billing issue, the findings were not complete in the opinion of the Texas Appeals Court who remanded the issue back to PUCT.

CPL has sought a rehearing of the Texas Appeals Court's opinion. The Texas Appeals Court has requested briefs related to CPL's rehearing request from interested parties. Management is unable to predict the final resolution of its appeal. If the appeal is unsuccessful the PUCT's 1997 order will continue to adversely affect results of operations and cash flows.

As part of the AEP/CSW merger approval process in Texas, a stipulation agreement was approved which resulted in the withdrawal of the appeal related to the "glide path" rate methodology. CPL will continue its appeal of the ECOM classification for STP property and the related loss of return on equity and the disallowed affiliated service billings.

Lignite Mining Agreement Litigation – Affecting AEP and SWEPCo

SWEPCo and CLECO are each a 50% owner of Dolet Hills Power Station Unit 1 and jointly own lignite reserves in the Dolet Hills area of northwestern Louisiana. In 1982, SWEPCo and CLECO entered into a lignite mining agreement with DHMV, a partnership for the mining and delivery of lignite from a portion of these reserves.

In April 1997, SWEPCo and CLECO sued DHMV and its partners in U.S. District Court for the Western District of Louisiana seeking to enforce various obligations of DHMV under the lignite mining agreement, including provisions relating to the quality of delivered lignite, pricing, and mine reclamation practices. In June 1997, DHMV filed an answer denying the allegations in the suit and filed a counterclaim asserting various contract-related claims against SWEPCo and CLECO. SWEPCo and CLECO have denied the allegations contained in the counterclaims. In January 1999, SWEPCo and CLECO amended the claims against DHMV to include a request that the lignite mining agreement be terminated.

In April 2000, the parties agreed to settle the litigation. As part of the settlement, DHMV's interest in the mining operations and related debt and other obligations will be purchased by SWEPCo and CLECO. The closing date for the settlement has been extended from December 31, 2000 to March 31, 2001. The litigation has been stayed until April 2001 to give the parties time to consummate the settlement agreement.

Management believes that the resolution of this matter will not have a material effect on results of operations, cash flows or financial condition.

AEP and its registrant subsidiaries are involved in a number of other legal proceedings and claims. While management is unable to predict the outcome of such litigation, it is not expected that the ultimate resolution of these matters will have a material adverse effect on the results of operations, cash flows or financial condition.

Environmental Concerns and Issues

As 2001 begins, the U.S. continues to debate an array of environmental issues affecting the electric utility industry. Most of the policies are aimed at reducing air emissions citing alleged impacts of such emissions on public health, sensitive ecosystems or the global climate.

AEP and its subsidiaries' policy on the environment continues to be the development and application of long-term economically feasible measures to improve air and water quality, limit emissions and protect the health of employees, customers, neighbors and others impacted by their operations. In support of this policy, AEP and its subsidiaries continue to invest in research through groups like the Electric Power Research Institute and directly through demonstration projects for new technology for the capture and storage of carbon dioxide, mercury, NOx and other emissions. The AEP System intends to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to customers at fair prices.

AEP and its subsidiaries have a proven record of efficiently producing and delivering electricity and gas while minimizing the impact on the environment. AEP and its subsidiaries have spent billions of dollars to equip their facilities with the latest cost effective clean air and water technologies and to research new technologies. Award winning efforts to reclaim our mining properties is a proud accomplishment.

The introduction of multi-pollutant control legislation is being discussed by members of Congress and the Bush Administration. The legislation being considered may regulate carbon dioxide, NOx, sulfur dioxide, mercury and other emissions from electric generating plants. Management will continue to support solutions which are based on sound science, economics and demonstrated control technologies. Management is unable to operations, cash flows and possibly financial condition.

Superfund – Affecting AEP, APCo, CPL, CSPCo, I&M, OPCo and SWEPCo

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, the AEP System's generating plants and transmission and distribution facilities have used asbestos, PCBs and other hazardous and non-hazardous materials. The AEP System companies are currently incurring costs to safely dispose of these substances. Additional costs could be incurred to comply with new laws and regulations if enacted.

Superfund addresses clean-up of hazardous substances at disposal sites and authorized Federal EPA to administer the clean-up programs. As of year-end 2000, subsidiaries of AEP have been named by the Federal EPA as a PRP for five sites. APCo, CSPCo, and OPCo each have one PRP site and I&M has two PRP sites. There are five additional sites for which AEP, APCo, CSPCo, I&M, OPCo and SWEPCo have received information requests which could lead to PRP designation. CPL, OPCo and SWEPCo have also been named a PRP at three sites under state law. Liability has been resolved for a number of sites with no significant effect on the AEP subsidiaries' results of operations. In those instances where AEP or its subsidiaries have been named a PRP or defendant, their disposal or recycling activities were in accordance with the then-applicable laws and regulations. Unfortunately, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories.

While the potential liability for each Superfund site must be evaluated separately, several general statements can be made regarding AEP's and its subsidiaries' potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although liability is joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. Therefore, management's present estimates do not anticipate material cleanup costs for identified sites for which AEP System companies have been declared PRPs. If significant cleanup costs are attributed to AEP or its subsidiaries in the future under Superfund, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be recovered from customers.

Global Climate Change

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997 more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly carbon dioxide, which many scientists believe are contributing to global climate change. The treaty, which requires the advice and consent of the U.S. Senate for ratification, would require the U.S. to reduce greenhouse gas emissions seven percent below 1990 levels in the years 2008-2012. Although the U.S. has agreed to the treaty and signed it on November 12, 1998, the treaty has not been submitted to the Senate for consideration as it does not contain requirements for "meaningful participation by key developing countries" and the rules, procedures, methodologies and guidelines of the treaty's emissions trading and joint implementation programs and compliance enforcement provisions have not been negotiated. At the Fourth Conference of the Parties in November 1998, the parties agreed to a work plan to complete negotiations on outstanding issues with a view toward approving them at the Sixth Conference of the Parties to be held in November 2000. During the Sixth Conference of the Parties agreement was not reached on any of the outstanding issues requiring resolution in order to faciliate ratification of the Kyoto Protocol. There are several contentious issues and literally hundreds of pages of detailed, complex rules that remain to be negotiated. Discussions are expected to resume in July 2001. While a candidate for the presidency, George Bush had stated his opposition to U.S. ratification of the Kyoto Protocol. The Seventh Conference of the Parties is scheduled for October 2001 in Morocco. AEP does not support the Kyoto Treaty as presently drafted. Management will continue to work with the Administration and Congress to develop responsible public policy on this issue.

If the Kyoto treaty is approved by Congress as presently drafted, the costs for the AEP System to comply with the required emission reductions required by the treaty are expected to be substantial and would have a material adverse impact on results of operations, cash flows and possibly financial condition if not recovered from customers. It is management's belief that the Kyoto Protocol is unlikely to be ratified and implemented in the U.S. in its current form.

Costs for Spent Nuclear Fuel and Decommissioning – Affecting AEP, CPL and I&M

I&M, as the owner of the Cook Plant, and CPL, as a partial owner of STP, have a significant future financial commitment to safely dispose of SNF and decommission and decontaminate the plants. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law CPL and I&M participate in the DOE's SNF disposal program which is described in Note 8 of the Notes to Consolidated Financial Statements. Since 1983 I&M has collected $275 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. $116 million of these funds have been deposited in external trust funds to provide for the future disposal of SNF and $159 million has been remitted to the DOE. CPL has collected and remitted to the DOE, $44 million for the future disposal of SNF since STP began operation in the late 1980s. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. However, in 1996, the DOE notified the companies that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date DOE has failed to comply with the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, AEP on behalf of I&M and STPNOC on behalf of CPL and the other STP owners, along with a number of unaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other unaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOE's complete failure to perform its contract obligations, and that the utilities' suits against DOE may continue in court. AEP's and I&M suit has been stayed pending further action by the U.S. Court of Federal Claims. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage and the cost of decommissioning will continue to increase.

In January 2001, I&M and STPNOC, on behalf of STP's joint owners, joined a lawsuit against DOE, filed in November 2000 by unaffiliated utilities, related to DOE's nuclear waste fund cost recovery settlement with PECO Energy Corporation. The settlement allows PECO to skip two payments to the DOE for disposal of SNF due to the lack of progress towards development of a permanent repository for SNF. The companies believe the settlement is unlawful as the settlement would force other utilities to make up any shortfall in DOE's SNF disposal funds.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2000 estimate the cost to decommission the Cook Plant ranges from $783 million to $1,481 million in 2000 non-discounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2000, the total decommissioning trust fund balance for Cook Plant was $558 million which includes earnings on the trust investments. Studies completed in 1999 for STP estimate CPL's share of decommissioning cost to be $289 million in 1999 non-discounted dollars. Amounts collected from customers to decommission STP have been placed in an external trust. At December 31, 2000, the total decommissioning trust fund for CPL's share of STP was $94 million which includes earnings on the trust investments. Estimates from the decommissioning studies could continue to escalate due to the uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. We will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP through regulated rates and, where generation has been deregulated, through wires charges. However, AEP's, CPL's and I&M's future results of operations, cash flows and possibly their financial conditions would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Foreign Energy Delivery, Worldwide Energy Investments and Other Business Operations

Worldwide electric and gas operations on AEP's Consolidated Statements of Income include the foreign energy delivery, worldwide energy investments, and other segments of AEP's business. See Note 14 of the Notes to Consolidated Financial Statements for a discussion of segments.

AEP's investment in certain types of activities is limited by PUHCA. SEC authorization under PUHCA limits AEP to issuing and selling securities in an amount up to 100% of its average quarterly consolidated retained earnings balance for investment in EWGs and FUCOs. At December 31, 2000, AEP's investment in EWGs and FUCOs was $1.8 billion compared to AEP's limit of $3.4 billion by law.

SEC rules under PUHCA permit AEP to invest up to 15% of consolidated capitalization (such amount was $3.5 billion at December 31, 2000) in energy-related companies that engage in marketing and/or trading of electricity, gas and other energy commodities. AEP's gas trading business and its interests in domestic cogeneration projects are reported as investments under this rule and at December 31, 2000, AEP's investment was less than one million dollars.

Management continues to evaluate the U.S. and international energy markets for investment opportunities that complement AEP's wholesale operations. Management expects to continue to pursue new and existing energy supply projects and to provide energy related services worldwide. AEP's future consolidated earnings will be impacted by the performance of existing and any future investments.

The major business activities and subsidiaries of AEP's worldwide electric and gas operations are SEEBOARD, CitiPower, Yorkshire, European energy trading operations, U.S. power trading more than two transmission systems removed from the AEP transmission system and gas trading operations in the U.S., domestic and foreign generating facilities in China, Mexico and the U.S., electric distribution in South America and power plant construction. SEEBOARD's principal business is the distribution and supply of electricity in southeast England. CitiPower provides electricity and electric distribution service in the city of Melbourne, Australia. AEP owns 100% of SEEBOARD and CitiPower. The revenues and operating expenses for SEEBOARD and CitiPower are included in worldwide revenues and expenses on AEP's Consolidated Statements of Income. Interest, taxes and other nonoperating items for SEEBOARD and CitiPower are included in the appropriate income statement lines.

In 1998 SEEBOARD's 80% owned subsidiary, SEEBOARD Powerlink, signed a 30-year contract for $1.6 billion to operate, maintain, finance and renew the high-voltage power distribution network of the London Underground transportation system. SEEBOARD Powerlink will be responsible for distributing high voltage electricity to supply 270 London Underground stations and 250 miles of the rail system's track. SEEBOARD's partners in Powerlink are an international electrical engineering group and an international cable and construction group.

AEP has a 50% investment in Yorkshire, another U.K. regional electricity distribution and supply company. The investment is accounted for using the equity method of accounting with equity earnings included in other income (net) on the AEP Consolidated Statements of Income. In December 2000 AEP entered into negotiations to sell its investment in Yorkshire. On February 26, 2001, an agreement to sell AEP's 50% interest in Yorkshire was signed. The sale is expected to close by March 31, 2001. See Note 10 of the Notes to Consolidated Financial Statements.

In the U.K. all residential and commercial customers have been allowed to choose their electricity supplier since May 1999. Margins on retail electric sales have been generally declining due to competition. In April 2000 final proposals from the regulatory commission reduced distribution rates and electricity supply price caps. The distribution rate reductions and reduced price caps are expected to reduce AEP's earnings from SEEBOARD and its Yorkshire investment. In response to these final proposals and increasing competition, SEEBOARD and Yorkshire adopted an aggressive program of reducing controllable costs. Significant features of this program include staff reductions, outsourcing of certain functions and consolidation of facilities. Management intends to aggressively pursue this cost reduction program and continues to evaluate additional cost reduction measures to further mitigate the effects of the final proposals and increasing competition in the U.K. electricity supply business. Management expects that, despite the cost control measures, the rate reductions will negatively impact AEP's earnings.

The Utilities Act which became law in the U.K. in July 2000 includes a requirement for separate licensing of electricity supply and distribution and the introduction of a prohibition of electricity supply and distribution licenses being held by the same legal entity. This requirement effectively means that the electricity supply and distribution businesses of SEEBOARD and Yorkshire must be held by separate companies. However, AEP will not be required to divest its interest in either the supply entity or the distribution entity. The separation of the supply and distribution business into two entities each for SEEBOARD and Yorkshire is not expected to have a material impact on future results of operations or cash flows.

Beginning January 1, 2001 price reductions on the supply and distribution of electricity are being implemented in Victoria, Australia. The effect of these price reductions is expected to reduce CitiPower's results of operations to the extent that they cannot be offset by reduced expenses, improved efficiencies or increased sales.

A new, higher tariff rate for the electricity from two 250 MW coal-fired generating units located in Henan Province, China was approved by the Central Chinese government in January 2000. AEP owns 70% of these units, with the remaining 30% owned by two Chinese partners. As a result of the new tariff the units contributed positively to

AEP's results of operations for 2000 after incurring a loss in 1999.

Other foreign generating facilities include a 37.5% interest in 675 MW of capacity in the U.K. and a 50% interest in 118 MW of capacity in Mexico. AEP also has a 50% ownership interest in two generating plants under construction; a 600 MW facility in Mexico and a 400 MW facility in the U.K. All of these facilities sell their capacity under long-term contracts. The investment in these facilities is accounted for using the equity method.

AEP, through its CSW Energy subsidiary, has an ownership interest in seven operational domestic generation facilities in Colorado, Florida and Texas with one 440 MW facility under construction. These plants are EWGs or qualifying facilities (QF) as defined by law and not subject to cost-based rate regulation or the application of SFAS 71 regulatory accounting. The combined installed capacity of the operational facilities is 1,508 MW at December 31, 2000. The power from these QF facilities is sold under long-term power purchase agreements with the local host facility. Any merchant power is sold in the wholesale market generally under short-term contract. As a result, increases in the market price of natural gas used to generate electricity at these facilities may adversely impact results of operations.

In 1999 a 50% equity interest in one of the above facilities was sold to an unaffiliated company. The after-tax gain from the sale was approximately $33 million. An additional unit is under construction at this facility. Pursuant to the terms of the sale agreement, the unaffiliated company will make additional payments to CSW Energy upon completion of the additional unit.

Under terms of the FERC and Texas settlement agreements that approved the merger, the divestiture of certain generating units is required. The Frontera power plant, one of CSW Energy's facilities, is specifically identified as one of the plants where the entire ownership interest must be sold. On February 8, 2001, AEP announced that it had reached agreement with an unaffiliated company to sell the 500 MW Frontera power plant for $265 million in cash.

In 2000 an electricity and gas trading operation in Europe was added. This business requires minimal capital investment and offers an opportunity to employ our expertise in energy marketing and trading to a new market.

The domestic gas trading operation grew substantially in 2000 and is expected to benefit from the planned acquisition of the Houston Pipe Line Company which was announced in January 2001. The acquisition of Houston Pipe Line Company, which has more than 4,400 miles of natural gas transmission pipeline and operates one of the largest storage facilities, is expected to complement our intra-state gas transmission and storage facilities in Louisiana and extends AEP's strategy of linking physical energy asset operations with trading and marketing operations.

AEP's Louisiana gas operation is LIG, a midstream natural gas operation, that was purchased in December 1998 for approximately $340 million including working capital funds. LIG includes a fully integrated natural gas gathering, processing, storage and transportation operation in Louisiana and a gas trading and marketing operation. Assets include an intrastate pipeline system, natural gas liquids processing plants and natural gas storage facilities.

AEP's subsidiaries are engaged in the engineering and construction for third parties of three power plants in the U.S. with a capacity of 1,910 MW. These plants will be natural gas-fired facilities that are scheduled to be completed from 2001 to 2003. AEP intends to use its engineering, trading and marketing expertise on these projects some of which also include power purchase and power sale agreements to enhance its results of operations.

Other Matters – Affecting AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU

New Accounting Standards – SFAS 133, "Accounting for Derivative Instruments and Hedging Activities", as amended by SFAS 137 and SFAS 138, is effective for the AEP System beginning January 1, 2001. SFAS 133 requires that entities recognize all derivatives as either assets or liabilities and measure them at fair value. Changes in the fair value of derivative assets and liabilities must be recognized currently in net income. Changes in the derivatives that are effective cash flow hedges are recorded in other comprehensive income.

Pending the resolution of certain industry issues presently before the FASB's Derivatives Implementation Group (DIG), the effect of adoption of SFAS 133 will result in transition adjustment amounts which will have an immaterial effect on both net income and other comprehensive income.

The FASB's DIG, has issued tentative guidance, which has not yet been approved by the FASB, that option contracts cannot qualify as normal purchases and sales. In addition there are two industry issues pending resolution by the DIG related to whether electric capacity contracts that may have some characteristics of purchased and written options can qualify as normal sales, and whether contracts which do not result in physical delivery of power because of transmission constraints are derivatives.

While the Company believes the majority of the its fuel supply agreements should qualify as normal purchases and that the majority of its power sales agreements qualify as normal sales, the ultimate resolution of the above issues may result in accounting for certain power sales and fuel supply agreements as derivatives which may have a material effect on reported net income under SFAS 133. Whether the impact will be favorable or adverse will depend on the market prices compared to the contractual prices at the time of valuation.

INVESTOR INQUIRIES

Investors should direct inquiries to Investor Relations using the toll free number, 1-800-237-2667 or by writing to:

Bette Jo Rozsa
Managing Director of Investor Relations
American Electric Power Service Corporation
28th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

FORM 10-K ANNUAL REPORT

The Annual Report (Form 10-K) to the Securities and Exchange Commission will be available in April 2001 at no cost to shareholders. Please address requests for copies to:

Geoffrey C. Dean
Director of Financial Reporting
American Electric Power Service Corporation
26th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

TRANSFER AGENT AND REGISTRAR OF CUMULATIVE PREFERRED STOCK

Equiserve, First Chicago Division
P.O. Box 2500
Jersey City, NJ 07303-2500
Phone number: 1-800-328-6955

American Electric Power
101A Enterprise Drive
PO Box 5190
Frankfort, KY 40602-5190
www.aep.com

AEP
AMERICAN®
ELECTRIC
POWER

Mr. Thomas M. Dorman, Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RECEIVED
APR 18 2001
PUBLIC SERVICE
COMMISSION

16 April 2001

RE: AEP Request to SEC for Approval of New Cost Allocation Factors
(KPSC Case No. 99-149)

Dear Mr. Dorman:

Pursuant to the Commission's letter dated February 22, 2001, AEP is to provide the Commission with copies of any comments received from other state commissions or by the SEC in response to AEP's request to the SEC for approval of new cost allocation factors. Enclosed as requested are the original and four copies of AEP's response to the Arkansas Public Service Commission.

If you have any questions, please feel free to contact me at 502/696-7010.

Sincerely,

Errol K. Wagner

Errol K. Wagner
Director of Regulatory Services

jw

Enclosures

cc: K. Potts – AEP, Columbus

ARKANSAS PUBLIC SERVICE COMMISSION
STAFF'S FIRST DATA REQUEST TO
THE SECURITIES EXCHANGE COMMISSION

COMPANY NAME: American Electric Power Company, Inc. (AEP) NO.: JBF-1
Southwestern Electric Power Company (SWEPCO)

DATE REQUESTED: 03-29-01

DATE REQUIRED: 04-13-01

INFORMATION REQUESTED:

In its draft letter to SEC (a copy of which was sent to the Secretary of the Arkansas Public Service Commission, January 30, 2001), AEPSC states, "AEPSC requests authorization to utilize the twelve new attribution bases noted below which we believe will result in more equitable distribution of costs by applying better cost drivers." For each cost category listed below explain what precipitated the need to seek a more equitable distribution of these costs.

1. Costs of providing hydro plant services, including reservoir management.
2. Costs of managing forest resources.
3. Costs of biding, awarding and managing contracts and service orders.
4. Costs of ensuring safety compliance for dams.
5. Cost of providing fossil plant services.
6. Costs of processing nonelectric other accounts receivable (OAR) invoices.
7. Costs of managing the transformer inventory.
8. Costs to provide flue gas desulferization (FGD) service related to handling and disposal of FGD materials.
9. Costs of services related to planning, receiving and storing limestone (sorbent).
10. Costs to support and participate in industry, professional and trade associations, and managing/participating in public and community relations.
11. Costs to administer lease and rental agreements.
12. Costs in managing cash.

REQUESTED BY: Bret Franks, Financial Analysis Section
(501) 682-5734

RESPONSE NO. JBF-1:

The proposed changes in attribution bases are part of AEPSC's ongoing effort to use the most relevant allocation factors for billing costs to the companies it serves. The attribution bases which are being proposed for each of the noted cost categories provide a better and more equitable way of sharing and allocating costs among the applicable companies than the previous bases. The new bases are more closely associated with the specific drivers of those costs taking into account the scope of the services that are being performed. For example, number of dams is more reflective of the level of effort rerquired to perform dam safety compliance services than is a company's total MW generating capability from all sources, including hydro and other sources. In addition, the level of effort is less dependent on the size of a unit in terms of generating capability than it is on the number of units served. Likewise, the number of transformer transactions is a better measure of the relative effort required to manage each company's transformer inventory than is the number of transactions conducted for all of a company's stores transactions (i.e., transformer transactions as well as non-transformer transactions).

The response to the above information request provided to the Arkansas Public Service Commission is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Arkansas Public Service Commission, if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the information request.

RECORDS LISTED ABOVE:

_X_ May be retained
____ Must be returned

____
Signature of Company Representative

____
Company Representative

Date Provided:____________________

****

COMPLETE UPON RETURN OF THE RECORDS LISTED ABOVE

Date Returned:____________

____
Public Service Commission Representative

____
Company Representative

ARKANSAS PUBLIC SERVICE COMMISSION
STAFF'S FIRST DATA REQUEST TO
THE SECURITIES EXCHANGE COMMISSION

COMPANY NAME: American Electric Power Company, Inc. (AEP) NO.: JBF-2
Southwestern Electric Power Company (SWEPCO)

DATE REQUESTED: 03-29-01

DATE REQUIRED: 04-13-01

INFORMATION REQUESTED:

Prior to AEPSC's request to add new cost allocation factors, list the attribution base used to allocate each of the following costs:

M. Costs of providing hydro plant services, including reservoir management.
N. Costs of managing forest resources.
O. Costs of biding, awarding and managing contracts and service orders.
P. Costs of ensuring safety compliance for dams.
Q. Cost of providing fossil plant services.
R. Costs of processing nonelectric other accounts receivable (OAR) invoices.
S. Costs of managing the transformer inventory.
T. Costs to provide flue gas desulferization (FGD) service related to handling and disposal of FGD materials.
U. Costs of services related to planning, receiving and storing limestone (sorbent).
V. Costs to support and participate in industry, professional and trade associations, and managing/participating in public and community relations.
W. Costs to administer lease and rental agreements.
X. Costs in managing cash.

REQUESTED BY: Bret Franks, Financial Analysis Section
(501) 682-5734

RESPONSE NO. JBF-2:

The Attribution Basis/Allocation Factor currently being used by AEPSC vs. the new, requested Attribution Basis is indicated below in bold:

M. Costs of providing hydro plant services, including reservoir management.
Current: **Peak Load, Avg # Cust, KWH Sales Combination**
Requested: **Hydro MW Generating Capability**

N. Costs of managing forest resources.
Current: **MW Generating Capability**
Requested: **Number of Forest Acres**

O. Costs of biding, awarding and managing contracts and service orders.
Current: **Number of Purchase Orders Written**
Requested: **Number of Contracts & Service Orders Written**

P. Costs of ensuring safety compliance for dams.
Current: **MW Generating Capability**
Requested: **Number of Dams**

Q. Cost of providing fossil plant services.
Current: **MWH's Generation**
Requested: **Number of Licenses Obtained**

R. Costs of processing nonelectric other accounts receivable (OAR) invoices.
Current: **Total Gross Revenue**
Requested: **Number of Nonelectric OAR Invoices**

S. Costs of managing the transformer inventory.
Current: **Number of Stores Transactions**
Requested: **Number of Transformer Transactions**

T. Costs to provide flue gas desulferization (FGD) service related to handling and disposal of FGD materials.
Current: **Past 3 Mo. MMBTU's Burned (Coal Only)**
Requested: **Tons of FGD Material**

U. Costs of services related to planning, receiving and storing limestone (sorbent).
Current: **Past 3 Mo. MMBTU's Burned (Coal Only)**
Requested: **Tons of Limestone Received**

V. Costs to support and participate in industry, professional and trade associations, and managing/participating in public and community relations.
Current: **Total Assets**
Requested: **Total Assets + Total Revenues + Total Payroll**

W. Costs to administer lease and rental agreements.
Current: **Total Fixed Assets**
Requested: **Total Leased Assets**

X. Costs in managing cash.
Current: **Number of Bank Accounts**
Requested: **Number of Banking Transactions**

The response to the above information request provided to the Arkansas Public Service Commission is accurate and complete, and contains no material misrepresentations or omissions based upon present facts known to the undersigned. The undersigned agrees to immediately inform the Arkansas Public Service Commission, if any matters are discovered which would materially affect the accuracy or completeness of the information provided in response to the information request.

RECORDS LISTED ABOVE:

_X_ May be retained
____ Must be returned

____
Signature of Company Representative

____
Company Representative

Date Provided:____________________

****

COMPLETE UPON RETURN OF THE RECORDS LISTED ABOVE

Date Returned:__________

____
Public Service Commission Representative

____
Company Representative

Case No. 99-149

Paul E. Patton, Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Thomas M. Dorman
Executive Director
Public Service Commission

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BOULEVARD
POST OFFICE BOX 615
FRANKFORT, KENTUCKY 40602-0615
www.psc.state.ky.us
(502) 564-3940
Fax (502) 564-3460

Martin J. Huelsmann
Chairman

Edward J. Holmes
Vice Chairman

Gary W. Gillis
Commissioner

February 22, 2001

RECEIVED

FEB 22 2001

PUBLIC SERVICE
COMMISSION

Mr. Errol K. Wagner, Director of Regulatory Services
American Electric Power
101A Enterprise Drive
P. O. Box 5190
Frankfort, Kentucky 40602

RE: AEP Request to SEC for Approval of New Cost Allocation Factors

Dear Mr. Wagner,

In correspondence dated January 30, 2001, AEP notified the Commission of its intend to seek SEC approval of 12 new cost allocation factors. On February 6, 2001, the Commission Staff submitted a request to AEP for additional information concerning the new cost allocation factors. On February 16, 2001, AEP provided the requested information.

The Commission Staff has reviewed the new cost allocation factors and the additional information provided by AEP. Based on this review, Staff does not believe that we have any differences relative to the new cost allocation factors.

Therefore, the Commission will confirm that no differences exist relative to implementing the revised cost allocation factors for accounting purposes only. For rate-making purposes, AEP is bound by their commitment, as stated in the Appendix to the Commission's June 14, 1999 Order in Case No. 99-149, to not assert any claim under the Ohio Power vs. FERC decision, that the SEC's jurisdiction impairs the Commission's ability to examine and determine the reasonableness of non-power affiliate transaction costs to be passed to retail customers. However, AEP retains the right to assert that the costs are reasonable and appropriate.

To enable the Commission to properly monitor the status of the changes in cost allocation factors, AEP is requested to file copies of any comments received from other state commissions or by the SEC.

Sincerely,

Thomas M. Dorman
Executive Director

cc: Main Case File, Case No. 99-149

American Electric Power
101A Enterprise Drive
P.O. Box 5190
Frankfort, KY 40602
Fax: 502-696-7006

AMERICAN ELECTRIC POWER

RECEIVED
JAN 31 2001
PUBLIC SERVICE COMMISSION

Mr. Thomas M. Dorman, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, KY 40602

30 January 2001

Dear Mr. Dorman:

In accordance with the KPSC Stipulation and Settlement Agreement dated May 24, 1999 in Case No. 99-149, attached is a letter which American Electric Power Service Corporation ("AEPSC"), an affiliate of Kentucky Power Company, intends to submit to the Securities and Exchange Commission on March 2, 2001. The letter will request authorization for AEPSC to add new cost allocation factors.

The material is submitted for your information only and no action by you is required. If you have any questions about this filing, please contact me.

Very truly yours,

Errol K. Wagner/jw

Errol K. Wagner
Director of Regulatory Services

jw

Attachment

RECEIVED
JAN 31 2001
PUBLIC SERVICE
COMMISSION

Mr. Robert P. Wason
Chief Financial Analyst
Office of Public Utility Regulation
Securities and Exchange Commission
450 5th Street, N.W., Mail Stop 10-3
Washington, D.C. 20549

[Date]

Dear Mr. Wason:

In accordance with the provisions of the 60-day letter procedure authorized by the Securities and Exchange Commission (Commission), American Electric Power Service Corporation (AEPSC) is requesting authorization for a change, effective with the service company billings for _______ 2001 business, in the cost allocation methods previously established and authorized by the Commission. These cost allocation methods are utilized to allocate AEPSC's costs of providing service to American Electric Power Company, Inc. and its subsidiary companies, as applicable.

AEPSC requests authorization to utilize the twelve new attribution bases noted below which we believe will result in more equitable distribution of costs by applying better cost drivers. The SEC has previously authorized in HCAR No. 27186, File No. 70-9381, 64 attribution bases for AEPSC.

- <u>Hydro MW Generating Capability</u> – This attribution basis will be updated annually and will be used to allocate the costs of providing hydro plant services including reservoir management. It is calculated as follows:

$$\frac{\text{Hydro MW Generating Capability per Company}}{\text{Total Hydro MW Generating Capability}}$$

The approximate annualized amount that would utilize this new attribution Basis totals $100,000.

- <u>Number of Forest Acres</u> – This attribution basis will be updated annually and will be utilized to allocate the costs of managing forest resources. It is calculated as follows:

$$\frac{\text{Number of Forest Acres Per Company}}{\text{Total Number of Forest Acres}}$$

The approximate annualized amount that would utilize this new attribution Basis totals $203,000.

- Number of Contracts & Service Orders Written – This attribution basis will be updated monthly and will be utilized to allocate the costs of biding, awarding and managing contracts and service orders. It is calculated as follows:

$$\frac{\text{Number of Contracts \& Service Orders Written Per Company}}{\text{Total Number of Contracts \& Service Orders Written}}$$

The approximate annualized amount that would utilize this new attribution Basis totals $8,800,000.

- Number of Dams – This attribution basis will be updated annually and will be utilized to allocate the cost of ensuring safety compliance for dams. It is calculated as follows:

$$\frac{\text{Number of Dams Per Company}}{\text{Total Number of Dams}}$$

The approximate annualized amount that would utilize this new attribution Basis totals $100,000.

- Number of Licenses Obtained – This attribution basis will be updated annually and will be utilized to allocate the cost of providing Fossil Plant Services. It is calculated as follows:

$$\frac{\text{Number of Licenses Obtained Per Company}}{\text{Total Number of Licenses}}$$

The approximate annualized amount that would utilize this new attribution Basis totals $2,600,000.

- Number of Nonelectric OAR Invoices – This attribution basis will be updated semi-annually and will be utilized to allocate the costs of processing nonelectric other accounts receivable (OAR) invoices. It is calculated as follows:

$$\frac{\text{Number of Nonelectric OAR Invoices Per Company}}{\text{Total Number of Nonelectric OAR Invoices}}$$

The approximate annualized amount that would utilize this new attribution Basis totals $3.300,000.

- Number of Transformer Transactions – This attribution basis will be updated quarterly and will be utilized to allocate the costs of managing the transformer inventory. It is calculated as follows:

$$\frac{\text{Number of Transformer Transactions Per Company}}{\text{Total Number of Transformer Transactions}}$$

The approximate annualized amount that would utilize this new attribution Basis totals $100,000.

- Tons of FGD Material – This attribution basis will be updated semi-annually and will be utilized to allocate the costs to provide flue gas desulferization (FGD) service related to handling and disposal of FGD materials. It is calculated as follows:

$$\frac{\text{Tons of FGD Material Per Company}}{\text{Total Tons of FGD Material}}$$

The approximate annualized amount that would utilize this new attribution Basis totals $100,000.

- Tons of Limestone Received – This attribution basis will be updated semi-annually and will be utilized to allocate the costs of services related to planning, receiving and storing limestone (sorbent). It is calculated as follows:

$$\frac{\text{Tons of Limestone Received Per Company}}{\text{Total Tons of Limestone Received}}$$

The approximate annualized amount that would utilize this new attribution Basis totals $100,000.

- Total Assets/Total Gross Revenues/Total Payroll – This attribution basis will be updated quarterly and will be utilized to allocate the costs to support and participate in industry, professional and trade associations, and managing/participating in public and community relations. It is calculated as follows:

$$\frac{\text{Total Assets + Total Gross Revenues + Total Payroll Per Company}}{\text{Total Assets + Total Gross Revenues + Total Payroll}}$$

The approximate annualized amount that would utilize this new attribution Basis totals $27,300,000.

• Total Leased Assets – This attribution basis will be updated quarterly and will be utilized to allocate the costs to administer lease and rental agreements. It is calculated as follows:

$$\frac{\text{Total Leased Assets Per Company}}{\text{Total Assets}}$$

The approximate annualized amount that would utilize this new attribution Basis totals $1,700,000.

• Number of Banking Transactions – This attribution basis will be updated quarterly and will be utilized to allocate the costs in managing cash. It is calculated as follows:

$$\frac{\text{Number of Banking Transactions Per Company}}{\text{Total Number of Banking Transactions}}$$

The approximate annualized amount that would utilize this new attribution Basis totals $10,300,000.

If you have any questions, please feel free to contact the undersigned or Tom Berkemeyer.

Sincerely,

Leonard V. Assante
Vice President-Deputy Controller

STITES & HARBISON

ATTORNEYS

421 West Main Street
Post Office Box 634
Frankfort, KY 40602-0634
[502] 223-3477
[502] 223-4124 Fax
www.stites.com

Mark R. Overstreet
[502] 209-1219
moverstreet@stites.com

December 8, 2000

Thomas M. Dorman
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RECEIVED

DEC 08 2000

PUBLIC SERVICE
COMMISSION

RE: P.S.C. Case No. 99-149

Dear Mr. Dorman:

Please find enclosed and accept for filing the Response of Kentucky Power Company d/b/a American Electric Power to the Data Requests set forth in the Commission's Order dated June 14, 1999 in the above-styled action.

As indicated on the attached service list, copies have been served this day on the parties to the proceeding.

If you have any questions, please do not hesitate to contact me.

Very truly yours,

Mark R. Overstreet

KE057:KE131:4993:FRANKFORT

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that a copy of the foregoing Response of Kentucky Power Company d/b/a American Electric Power to Order Dated June 14, 1999 was served by first class mail, postage prepaid, on this 8th day of December, 2000 upon:

Elizabeth E. Blackford
Assistant Attorney General
Office of Rate Intervention
1024 Capital Center Drive
Frankfort, Kentucky 40601

David F. Boehm
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, Ohio 45202

William H. Jones, Jr.
VanAntwerp, Monge, Jones & Edwards, LLP
1544 Winchester Avenue
Fifth Floor
Ashland, Kentucky 41105-1111

Mark R. Overstreet

American Electric P[illegible]
1701 Central Avenue
P.O. Box 1428
Ashland, KY 41105-1428

AEP
AMERICAN
ELECTRIC
POWER

Mr. Thomas M. Dorman
Executive Director
Kentucky Public Service Commission
P.O. Box 615
211 Sower Boulevard
Frankfort, KY 40602-0615

RECEIVED
DEC 08 2000
PUBLIC SERVICE
COMMISSION

December 8, 2000

Dear Mr. Dorman:

Enclosed are five copies of the Company's responses to the information requests pursuant to the Commission's Order in Case No. 99-149 dated June 14, 1999.

The enclosed information is as of September 30, 2000. The December 31, 2000 information should be filed within 50 days after the close of the quarter due to the fact that the requested FERC reports are filed with the FERC 45 days after the close of the quarter.

Should you have any questions about the information please feel free to call me at (502)-696-7010

Sincerely,

Errol K. Wagner / JDV

Errol K. Wagner
Director of Regulatory Affairs

/d

Attachments

RECEIVED

DEC 08 2000

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:

JOINT APPLICATION OF KENTUCKY POWER	)	
COMPANY, AMERICAN ELECTRIC POWER	)	
COMPANY, INC. AND CENTRAL AND SOUTH	)	CASE NO. 99-149
WEST CORPORATION REGARDING A	)	
PROPOSED MERGER	)	

****

RESPONSE OF KENTUCKY POWER COMPANY
d/b/a
AMERICAN ELECTRIC POWER

8 December 2000

TABLE OF CONTENTS

TABLE OF CONTENTS

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF KENTUCKY POWER COMPANY, AMERICAN ELECTRIC POWER COMPANY, INC. AND CENTRAL AND SOUTH WEST CORPORATION REGARDING A PROPOSED MERGER	)	CASE NO. 99-149

ORDER

On April 15, 1999, Kentucky Power Company d/b/a American Electric Power ("Kentucky Power"), American Electric Power Company, Inc. ("AEP"), and Central and South West Corporation ("CSW") (collectively, the "Joint Applicants") applied to the Commission for an Order: (1) declaring that the merger of CSW and AEP, with AEP being the surviving entity, may be consummated without Commission approval or, alternatively, approving pursuant to KRS 278.020(4) and 278.020(5), the proposed regulatory plan and authorizing other steps necessary to implement the regulatory plan; (2) approving a tariff providing a net merger savings credit for Kentucky Power customers; and (3) making certain findings concerning the deferral of certain merger-related expenses in conformity with SFAS 71.

On April 20, 1999, the Commission established a procedural schedule that provided for discovery, an evidentiary hearing, and an opportunity for parties to file briefs. The Commission granted full intervention to the following entities: Attorney General's Office of Rate Intervention ("AG"), Kentucky Industrial Utility Customers ("KIUC"), and Kentucky Electric Steel Corporation (collectively, the "Intervenors").

Following several conferences held under the Commission's auspices, the parties resolved all disputed issues and executed a "Stipulation and Settlement Agreement" which they filed with the Commission on May 24, 1999. The Commission held a public hearing in this matter on May 28, 1999, at the Commission's offices in Frankfort, Kentucky.

OVERVIEW OF THE TRANSACTION

Kentucky Power, a Kentucky corporation, owns and operates facilities engaged in the generation, transmission, distribution and sale of electricity. It serves approximately 170,000 customers in the eastern Kentucky counties of Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Johnson, Knott, Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike, and Rowan. It also supplies electricity to public utilities and municipalities in Kentucky for resale. Kentucky Power is a utility subject to Commission jurisdiction. KRS 278.010(3)(a).

AEP, a New York corporation, is a holding company registered under the Public Utility Holding Company Act of 1935.[1] It owns, directly or indirectly, all of the outstanding common stock of seven domestic electric utility operating subsidiaries: Appalachian Power Company, Columbus Southern Power company, Indiana Michigan Power Company, Kentucky Power, Kingsport Power Company, Ohio Power Company and Wheeling Power Company. Its subsidiaries provide electricity to over 3 million customers in Kentucky, Indiana, Michigan, Ohio, Tennessee, Virginia, and West Virginia.

[1] 15 U.S.C. §79 *et seq.*

CSW, a Delaware corporation, is a holding company registered under the Public Utility Holding Company Act of 1935. It owns all of the outstanding common stock of four domestic electric utility operating subsidiaries: Central Power and Light Company, Public Service Company of Oklahoma, Southwestern Electric Power Company and West Texas Utilities Company. These subsidiaries provide electricity to over 1.7 million customers in areas of Texas, Oklahoma, Arkansas and Louisiana.

On December 21, 1997, AEP and CSW, with the approval of their respective Boards of Directors, executed a merger agreement. Under the terms of this agreement, shareholders of CSW will receive .6 of a share of AEP stock for each share of CSW common stock, resulting in CSW shareholders acquiring 40 percent of AEP's common stock. The four CSW domestic utility subsidiaries will become AEP subsidiaries. AEP's Board of Directors will be expanded from 12 to 15 members, with two AEP board members retiring. Five directors, formerly on the CSW Board of Directors, will be selected to serve upon AEP's Board.

The Joint Applicants estimate that the proposed merger will produce approximately $2.4 billion in non-fuel savings over a 10-year period. After considering the cost to achieve these savings and pre-merger initiatives, the proposed merger is estimated to produce net merger savings of $1.965 billion. Of this amount, Kentucky Power will be allocated $73.8 million. These savings are expected to result from the elimination of duplicative functions and positions and greater economies of scale the merger is expected to produce.

Because of the geographical area served by the Joint Applicants and their affiliates and the nature of their operations, the utility regulatory commissions of six states,[2] the Federal Energy Regulatory Commission ("FERC"), the Securities and Exchange Commission ("SEC"), the Federal Trade Commission ("FTC"), the United States Department of Justice ("DOJ"), and the Nuclear Regulatory Commission ("NRC") must approve the proposed merger. As of May 28, 1999, the NRC, Arkansas Public Service Commission, Indiana Utility Regulatory Commission, and Oklahoma Corporation Commission have granted their approval.

STIPULATION AND SETTLEMENT AGREEMENT

On May 24, 1999, the parties filed a "Stipulation and Settlement Agreement" ("Settlement Agreement") with the Commission. The most significant features of the Settlement Agreement are described below.

Merger Savings. The Settlement Agreement provides for the implementation of a Net Merger Savings Credit ("Merger Credit") tariff that will reduce customers' bills beginning in the first full billing month 30 days after the consummation of the merger. The Merger Credit will appear on each customer's monthly bill and will be based upon kWh consumption. The Merger Credit reflects non-fuel related merger savings and the associated merger costs based on estimated values included in AEP's merger filing with the FERC. Although the amounts are only estimates, the Joint Applicants have committed to guarantee their estimate of net merger savings. Associated merger costs

[2] Arkansas, Louisiana, Oklahoma, Texas, Indiana, and Kentucky. See Joint Applicants' Response to the Commission's Order of April 28, 1999, Item 2.

have been classified by AEP as either "Cost to Achieve" or "Change in Control Payments."[3]

The Merger Credit will be in effect for an initial eight-year period, with all associated merger costs amortized over the same eight years. The Cost to Achieve the merger will be shared by both customers and shareholders of AEP, while the Change in Control Payments will be borne solely by AEP shareholders. At the completion of the initial eight years, customers will have received 55 percent, or $28.365 million, of the total net merger savings for the period.[4] The Merger Credit will continue beyond the initial eight-year period, reflecting the gross merger savings estimated for the eighth year, and will be allocated between customers and shareholders in the same manner as was utilized during the initial eight-year period. This annual amount of customer savings will be $5.243 million and will continue until Kentucky Power's next base rate case which will allocate total gross merger savings to customers. Should Kentucky Power file a base rate case during the initial eight-year period, the Merger Credit will remain in effect. Any legislatively mandated rates that are part of any legislation enacted to deregulate the electric industry in Kentucky will not diminish or offset, but will be in addition to, the bill reductions established in the Settlement Agreement.

Rate Moratorium. The Settlement Agreement provides that Kentucky Power will not request a general increase in its existing base rates and charges that will be

[3] The Change in Control Payments relate to a special incentive plan adopted by CSW for 16 key employees in October 1996. See Joint Applicants' Response to Commission Staff's Information Request (requested at the informal conference of April 22, 1999), Item 4 at 61.

[4] See Settlement Agreement, Attachment A. The annual Merger Credit amount ranges from $1.464 million to $4.626 million during the initial eight-year period.

effective prior to January 1, 2003, or three years from the effective date of the merger, whichever is later. Kentucky Power's fuel adjustment clause, environmental surcharge, demand side management adjustment clause and system sales tracker are not included in this rate moratorium. Kentucky Power, moreover, may seek a general rate adjustment during the moratorium period if, after a public evidentiary hearing, the Commission determines that events constituting a force majeure as defined in the Settlement Agreement have occurred. The Intervenors have agreed not to seek a reduction in base rates during the rate moratorium period. The Settlement Agreement does not preclude the Commission from initiating proceedings to investigate Kentucky Power's rates should it find that circumstances warrant such proceedings.

Fuel Savings. The Settlement Agreement provides that all savings of fuel and purchase power expenses that result from the proposed merger will flow directly to Kentucky Power's retail customers through its existing fuel adjustment clause mechanism. AEP further agrees to hold Kentucky Power's native load customers harmless from higher replacement power costs or foregone revenues caused by current AEP operating companies supplying power to the service area of the CSW operating companies.

Environmental Surcharge Litigation. The Settlement Agreement seeks to resolve all outstanding matters involving Kentucky Power's environmental surcharge mechanism. It requires the dismissal of all appeals,[5] including the Commission's, now before the Kentucky Court of Appeals involving the Commission's Orders in Case No. 96-489.[6] All parties will dismiss their appeals without prejudice. The Settlement Agreement further provides that Kentucky Power may, beginning January 1, 2000, recover through its environmental surcharge mechanism the costs associated with the low NOx burners for Big Sandy Generating Units No. 1 and No. 2. Kentucky Power will forego any recovery of costs eligible for recovery prior to January 1, 2000.[7] The Settlement Agreement also provides that the Commission's most recent review[8] of Kentucky Power's environmental surcharge be closed without further adjustment.

---

[5] Kentucky Power Company d/b/a American Electric Power v. Kentucky Public Service Commission, et al., No. 1998-CA-001337 (filed July 25, 1998); Com. of Ky., ex rel., A. B. Chandler, III, Attorney General v. Kentucky Public Service Commission, et al., No.1998-CA-001344 (filed July 28, 1998); Kentucky Industrial Utility Customers, Inc. v. Com. of Ky., ex rel., A.B. Chandler, III, Attorney General, No. 1998-CA-001417 (filed July 25, 1998); Kentucky Public Service Commission v. Com. of Ky., ex rel., A.B. Chandler, III, Attorney General, No. 1998-CA-001455 (filed July 27, 1998); Kentucky Power Company v. Kentucky Public Service Commission, et al., 1998-CA-002476 (filed Oct. 1, 1998).

[6] Case No. 96-489, Application of Kentucky Power Company d/b/a American Electric Power to Assess a Surcharge under KRS 278.183 to Recover Costs of Compliance with the Clear Air Act and Those Environmental Requirements Which Apply to Coal Combustion Waste and By-Products.

[7] In Commonwealth of Kentucky ex rel. Chandler v. Kentucky Public Service Commission, Nos. 97-CI-01138, 97-CI-01144, 97-CI-01319 (Ky. Franklin Cir. Ct. May 14, 1998), the Franklin Circuit Court reversed in part the Commission's Order of May 27, 1997 and directed the Commission to permit Kentucky Power's recovery of low NOx burner costs incurred after May 19, 1997.

[8] Case No. 98-624, An Examination By The Public Service Commission of The Environmental Surcharge Mechanism of Kentucky Power Company d/b/a American Electric Power As Billed From January 1, 1998 to June 30, 1998.

Affiliated Standards. The Settlement Agreement provides for affiliate standards and guidelines that will apply to transactions between AEP operating companies and their affiliates. These standards will take effect upon the consummation of the merger and remain in effect "until new affiliate standards imposed by either the Commission or by the General Assembly."[9]

Quality of Service. The Settlement Agreement requires Kentucky Power and AEP to maintain service quality and reliability at existing levels. Kentucky Power and AEP agree to provide annually service reliability reports addressing the duration and frequency of customer disruptions and annual Call Center performance measures for those centers that handle Kentucky customer calls. They also commit to compile outage data detailing each circuit's reliability performance to identify and resolve reliability problems.

Most Favored Nations Provision. The Joint Applicants agree that if, in connection with the proposed merger, any state or federal regulatory commission imposes conditions on AEP that would benefit ratepayers in one jurisdiction, equivalent net benefits and conditions will be extended to Kentucky retail customers.

COMMISSION FINDINGS

Having thoroughly reviewed the Settlement Agreement, the Commission finds that the Settlement Agreement represents a reasonable resolution to the issues surrounding the proposed merger and should be approved. The Settlement Agreement allows for a fair and equitable distribution of the merger benefits between ratepayers

[9] Settlement Agreement at 6.

and shareholders and protects Kentucky Power ratepayers from many of the potential risks posed by the merger.

The Commission notes that the Settlement Agreement imposes new reporting requirements on Kentucky Power in the areas of service quality and reliability. While we recognize the difficulties presented by the terrain and topography in portions of Kentucky Power's service territory, the Commission reminds Kentucky Power that its top priority must be service quality and reliability. In the event that Kentucky Power's quality of service experiences a decline, the Commission is prepared to require additional measures be taken.

The Commission also notes that the Settlement Agreement will end the lengthy and extensive litigation surrounding Kentucky Power's environmental surcharge mechanism. By this Order, we approve in principle those provisions and authorize our legal counsel to take all actions necessary to implement the Settlement Agreement's provisions and to dismiss all outstanding appeals pending before the Kentucky Court of Appeals. Because the issues dealing with Kentucky Power's environmental surcharge mechanism are addressed in other Commission proceedings that have not been consolidated with this proceeding, however, the Commission must implement certain of the provisions related to that mechanism through Orders in those proceedings. The Commission will issue those Orders as soon as possible.[10]

[10] Within the next few days, the Commission will issue an Order in Case No. 98-624 to close Kentucky Power's current environmental surcharge proceedings. Implementing the provisions related to the recovery of the costs associated with the low NOx burners for Big Sandy Generating Units No. 1 and No. 2 will require the issuance of an Order in Case No. 96-489. That action will occur upon dismissal of all outstanding appeals.

REPORTING REQUIREMENTS

In previous cases,[11] the Commission has determined that to effectively monitor the activities of the jurisdictional utility, its parent company and related subsidiaries, and to protect ratepayers, certain additional reports should be furnished by the jurisdictional utility to the Commission on an annual, periodic, or other basis as appropriate. The Commission finds that similar requirements are appropriate in this case as well.[12]

Periodic Reports

The annual financial statements of AEP should be furnished, including consolidating adjustments of AEP and its subsidiaries with a brief explanation of each adjustment and all periodic reports filed with the SEC.[13] All subsidiaries should prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial statements for any non-consolidated subsidiaries of AEP should be furnished to the Commission.

---

[11] See, e.g., Case No. 10296, The Application of Kentucky Utilities Company to Enter Into an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith (Oct. 6, 1988); Case No. 89-374, Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith (May 25, 1990); Case No. 94-104, Application of the Cincinnati Gas & Electric Company and CINergy Corp. for Approval of the Acquisition of Control of The Union Light, Heat & Power Company by CINergy Corp. (May 13, 1994); Case No. 97-300, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of Merger (Sept.12,1997).

[12] The imposition of these requirements is consistent with KRS 278.020(5), KRS 278.230 and Paragraph 8 of the Stipulation and Settlement Agreement.

[13] The requested SEC reports include, but are not limited to, the U5S and U-13-60 reports.

AEP should also furnish the following reports on an annual basis:

1. A general description of the nature of intercompany transactions with specific identification of major transactions, and a description of the basis upon which cost allocations and transfer pricing have been established. This report should discuss the use of the cost or market standard for the sale or transfer of assets, the allocation factors used, and the procedures used to determine these factors if they are different from the procedures used in prior years.

2. A report that identifies professional personnel transferred from Kentucky Power to AEP or any of the non-utility subsidiaries and describes the duties performed by each employee while employed by Kentucky Power and to be performed subsequent to transfer.

AEP should file on a quarterly basis a report detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating and maintenance expenses, and number of employees.

Special Reports

Other special reports should be furnished to the Commission as necessary. In anticipation that transfers of utility assets and investments by AEP will occur in the future, AEP should file any contracts or other agreements concerning the transfer of such assets or the pricing of intercompany transactions with the Commission at the time the transfer occurs.

AEP should also file the following information:

1. A quarterly report of the number of employees of AEP and each subsidiary on the basis of payroll assignment.

2. An annual report containing the years of service at Kentucky Power and the salaries of professional employees transferred from Kentucky Power to AEP or its subsidiaries filed in conjunction with the annual transfer of employees report.

3. An annual report of cost allocation factors in use, supplemented upon significant change.

4. Summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation in effect.

5. An annual report of the methods used to update or revise the cost allocation factors in use, supplemented upon significant change.

6. Current Articles of Incorporation and bylaws of affiliated companies in businesses related to the electric industry or that would be doing business with AEP.

7. Current Articles of Incorporation of affiliated companies involved in non-related business.

After consummation of the merger, AEP will remain a registered holding company under the Public Utility Holding Company Act of 1935 and under the oversight of several regulatory bodies. Where the same information sought in these reports has been filed with the SEC, FERC, or another state regulatory commission, AEP may provide copies of that filing rather than prepare separate reports. Further, AEP may request the Commission to review these reporting requirements after the merger is completed to determine if the documentation being provided is either excessive or redundant.

The Commission recognizes that the proposed merger has not yet received all necessary regulatory approvals. Consequently, the form or substance of the anticipated benefits of the merger might ultimately vary from those reviewed in this case. To the extent that the merger is subject to conditions or changes not reviewed in this case, the Joint Applicants should amend their filing to allow the Commission and all parties an opportunity to review the revisions to ensure that Kentucky Power and its customers are not adversely affected and that any additional benefits flow through the favored nations clause.

MOTION FOR REHEARING

The Kentucky Association of Plumbing-Heating-Cooling Contractors, Inc. and Kentucky Propane Gas Association (collectively "Contractors") have moved for reconsideration of the Commission's Order of May 20, 1999 in which we denied their application for full intervention. In support of their motion, the Contractors state that they have an interest in this proceeding as the Joint Applicants have not expressly precluded the possibility of competing with their members or to refrain such competition pending completion of Administrative Case No. 369.[14]

Having considered the motion, the Commission does not find good cause to modify its May 20, 1999 Order. While the Commission acknowledges the Contractors' concerns regarding utility affiliate transactions, these concerns are more appropriately addressed in Administrative Case No. 369, which was initiated specifically to review these issues as they relate to all regulated utilities. Moreover, Commission approval of the Settlement Agreement neither binds nor limits our ability to deal with the issue of affiliated transactions. The Settlement Agreement contains no provision limiting the

[14] Administrative Case No. 369, An Investigation of The Need For Affiliate Transaction Rules and Cost Allocation Requirements For All Jurisdictional Utilities.

scope of our discretion in this area. It specifically provides that its affiliate standards "apply from the date of closing of the merger until new affiliate standards imposed by state legislation or State Commission action become effective." Settlement Agreement at 6.

SUMMARY

After consideration of the evidence and being otherwise sufficiently advised, the Commission finds that:

1. The proposed merger of AEP and CSW will result in an indirect change in control of Kentucky Power and therefore requires prior Commission approval. KRS 278.020(4) and (5).

2. The proposed merger of AEP and CSW and the resulting indirect change in control of Kentucky Power is in accordance with law, for a proper purpose, and with the conditions and assurances established herein consistent with the public interest.

3. AEP and Kentucky Power have and, upon completion of the proposed merger, will retain the financial, managerial and technical abilities to provide reasonable utility service.

4. The "Stipulation and Settlement Agreement," appended hereto, is reasonable, does not conflict with any regulatory principle and should be approved.

5. The Contractor's Motion for Reconsideration should be denied.

6. AEP and Kentucky Power should file the reports and other information as specifically set out in this Order.

7. The Joint Applicants should submit copies of final approval received from the FERC, SEC, FTC, DOJ, and all state regulatory commissions to the extent that

these documents have not been provided. With each submittal, the Joint Applicants shall further state whether Paragraph 10 of the Settlement Agreement requires changes to the regulatory plan approved herein.

IT IS THEREFORE ORDERED that:

1. The Joint Applicants' Application for an Order declaring that the merger of AEP and CSW is not subject to approval pursuant to KRS 278.020(4) or (5) is denied.

2. The terms and conditions set forth in the Settlement Agreement, a copy of which is appended hereto, are adopted and approved and are incorporated into this Order as if fully set forth herein.

3. The proposed merger transaction and resulting indirect transfer of control are approved, subject to additional review in the event that the merger or the anticipated benefits are changed or modified as a result of action by other regulatory agencies.

4. The proposed Net Merger Savings Credit Tariff is approved.

5. Within 20 days of the date of this Order, Kentucky Power shall file revised tariff sheets reflecting the approved Net Merger Savings Credit Tariff.

6. AEP and Kentucky Power shall comply with all reporting requirements described herein.

7. The Kentucky retail jurisdictional share of the estimated transaction, regulatory processing and transition costs incurred to merge and combine AEP and CSW shall be deferred and amortized for recovery over eight years. This amortization shall begin with the date of the combination and shall continue for eight years on a straight-line basis.

8. The Joint Applicants shall within five days of the consummation of the proposed merger file a written notice setting forth the date of merger and the effective date of the Net Merger Saving Credit Tariff.

9. The proposed settlement of outstanding litigation involving Kentucky Power's environmental surcharge mechanism, as set forth in the Settlement Agreement, is approved. Commission counsel is authorized to execute all necessary documents to dismiss all appeals identified in Footnote 6 of this Order.

10. The Contractors' Motion for Reconsideration is denied.

Done at Frankfort, Kentucky, this 14th day of June, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

1

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

Furnish annual financial statements of AEP, including consolidating adjustments of AEP and its subsidiaries with a brief explanation of each adjustment and all periodic reports filed with the SEC.[13] including but not limited to the U5S and U-13-60 reports. All subsidiaries should prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial statements for any non-consolidated subsidiaries of AEP should be furnished to the Commission.

RESPONSE:

The annual financial statements including consolidating adjustments of AEP will be furnished with the December 31, 2000 filing.

The Company's Form U-5-S and Form U-13-60 for 2000 will be furnished with the December 31, 2000 filing.

Attached is a list of AEP's non-consolidated subsidiaries at September 30, 2000. The list contains AEP's number of shares, percent of ownership, the initial investment in U.S. dollars, and the type of financial statement available if any.

WITNESS: Errol K. Wagner

AEP
Non-Consolidated Subsidiaries

September 30, 2000

Equity Investment	# Of Shares	%Of Ownership	Initial US $	I.S.	B.S.	C.F.
Ohio Valley Electric Company, Inc.	39,200	39.90%	4,082,365	Y	Y	Y
Integrated Communication System, Inc.	80,000	8.40%	200,000	NA	NA	NA
Cardinal Operating Company	250	50.00%	250*	Y	Y	Y
Ohio Valley Electric Company, Inc.	4,300	4.30%	430,000	Y	Y	Y
Yorkshire Power Group Limited	220,000,001	50.00%	362,959,383	Y	Y	Y
Pacific Hydro Limited	23,478,300	20.00%	10,082,000	Y	N	N
InterGen Denmark, Aps	Partnership	50.00%	47,101,431	Y	N	N
Operaciones Azteca VIII, S. de R.L. de C.V.	NA	50%	702	NA	NA	NA
Australian Energy International Pty Ltd	100	16.40%	507,929	NA	NA	NA
Virginia PCS Alliance, LLC	NA	17.00%	1,727,019	N	Y	N
West Virginia PCS Alliance, LLC	NA	19.00%	4,266,036	N	Y	N
American's Fiber Network, LLC		48.00%	54,380,937	N	Y	N
InterSource Technologies, Inc.***	895,000	9.90%	12,539,666	N	N	N
Enviro Tech Investment Fund I	**	9.90%	1,686,598	N	N	N
PHPK Tech Common - Voting	41	30.00%	72,183	Y	Y	N
PHPK Tech Common - NonVoting	300	30.00%	528,168	Y	Y	N
Dynelec - Common No Par	1	1%	50,000	N	N	N
Altra Energy Technologies, Inc.	952,381	less than 3%	5,000,100	N	N	N
Pantellos Corporation	540,000	5%	4,439,210	N	N	N
Power Span Corp	5,369,851	9.8%	5,000,000	N	N	N

* Excludes Advance $91,280

** Limited Partnership

*** Inactive

2

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a general description of the nature of intercompany transactions with specific identification of major transactions and a description of the basis upon which cost allocations and transfer pricing have been established. This report should discuss the use of the cost or market standard for the sale or transfer of assets, the allocation factors used, and the procedures used to determine these factors if they are different from the procedures used in prior years.

RESPONSE:

The subject matter covered by this request will be addressed through the Cost Allocation Manual (CAM) required by HB 897 and will be available by April 15, 2001.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

On an annual basis file a report that identifies professional personnel transferred from Kentucky Power to AEP or any of the non-utility subsidiaries and describes the duties performed by each employee while employed by Kentucky Power and to be performed subsequent to transfer.

RESPONSE:

A copy of the Kentucky Power employees transferred during the twelve months ending 9/30/2000 is attached.

WITNESS: Errol K. Wagner

Kentucky Power Tranferees - 12 months ending 09/30/2000

02 APPALACHIAN POWER COMPANY

Name	Eff Date	Job Title - Old	Job Title - New
FUGATE,MARVIN	08/16/2000	SENIOR CLERK	T&D DISPATCHER III
ROBINSON,MICHAEL R	08/26/2000	METER READER	EXPRESS DRIVER

04 INDIANA MICHIGAN POWER CO

Name	Eff Date	Job Title - Old	Job Title - New
COFFEY,JOHN A,,III	07/16/2000	MGR DISTRIBUTION SYSTEM	MGR DISTRIBUTION SYSTEM

07 OHIO POWER CO

Name	Eff Date	Job Title - Old	Job Title - New
DUMMITT,JEFFERY M	09/16/2000	TRANSMISSION LINE MECHANIC-A	TRANSMISSION LINE MECHANIC-A

10 COLUMBUS SOUTHERN POWER

Name	Eff Date	Job Title - Old	Job Title - New
COFFEY,MICHAEL W	01/16/2000	STATION CREW SUPERVISOR - NE	STATION SUPERVISOR
MAGGARD,JACKIE D	01/01/2000	DISTRIBUTION LINE COORDINATOR	TECHNICIAN I

61 AEP SERVICE CORP

Name	Eff Date	Job Title - Old	Job Title - New
COOKMAN,JOHN C	09/16/2000	SR ENGINEERING TECHNOLOGIST	SR ENGINEERING TECHNOLOGIST
FITZGERALD,MARY A	09/01/2000	TECHNICIAN SENIOR	TECHNICIAN SENIOR
KEYSER,LLOYD E	02/01/2000	TRADE ALLY TECHNICAL REP-SR	BUS SRVCS-SMALL BUS REP I
MCCLEAN,DONALD R,,JR	09/01/2000	PRODUCTION SERVICES LEADER	IT ARCHITECT II
SEAGRAVES,JOY M	01/29/2000	SENIOR CLERK	SR CALL CTR CUSTOMER SVCS REP

4

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file on a quarterly basis a report detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating revenues, operating and maintenance expenses, and number of employees.

RESPONSE:

Below is the information detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating and maintenance expense and the number of employees.

Kentucky Power Company
Report proportionate Share of AEP
(in millions, except number of employees)

	Three Months September 30, 2000			Nine Months September 30, 2000		
	AEP	KPCo	Share	AEP	KPCo	Share
Revenues	3,921	93	2.4%	10,134	270	2.7%
Operating & Maintenance Expenses	2,540	61	2.4%	7,017	170	2.4%
Number of Employees at 9/30/99 *				23,009	467	2.0%

*See Response To Item No. 6

WITNESS: Errol K. Wagner

5

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file any contracts or other agreements concerning the transfer of such assets or the pricing of intercompany transactions with the Commission at the time the transfer occurs.

RESPONSE:

During the three months ending September 30, 2000. There were only two transactions which results in a transfer of assets from Kentucky Power to an affiliated. The first transaction was from Kentucky Power to Ohio Power in August, 2000. This was a 69KV transformer at a cost of $86,751.00. The second transaction was from Kentucky Power to Appalachian Power in September, 2000. This was a 69KV transformer at a cost of $265,519.15.

WITNESS: Errol K. Wagner

9

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file a quarterly report of the number of employees of AEP and each subsidiary on the basis of payroll assignment.

RESPONSE:

Attached is the quarterly report of the number of employees of AEP and each subsidiary on the bases of payroll assigned.

WITNESS: Errol K. Wagner

EMPLOYEE COUNT BY LEGAL ENTITY

AS OF DATE 9/30/2000

KPSC Case No. 99-149
Order Dated June 14, 1999
Item No. 6

CO	COMPANY	Employee Count
01	KINGSPORT POWER COMPANY	58
02	APPALACHIAN POWER COMPANY	3072
03	KENTUCKY POWER COMPANY	467
04	INDIANA MICHIGAN POWER CO	2799
06	WHEELING POWER CO	73
07	OHIO POWER CO	2544
09	AEP FIBER VENTURE LLC	34
10	COLUMBUS SOUTHERN POWER	1316
36	LA INTRASTATE GAS CO, LLC	66
39	LIG LIQUIDS COMPANY, LLC	37
42	CENTRAL OHIO COAL CO	154
43	WINDSOR COAL CO	213
44	SOUTHERN OHIO COAL CO	744
48	RIVER TRANSPORTATION DIV - I&M	376
54	CONESVILLE COAL PREPARATION CO	37
59	ENERGY SERVICES	36
61	AEP SERVICE CORP	5856
69	AEP RESOURCES SERVICE COMPANY	3
CC	CENTRAL POWER & LIGHT	1506
EE	CSW ENERGY, INC	246
HH	ENERSHOP, INC	7
MM	C3 COMMUNICATIONS, INC	88
NN	CSW ENERGY SERVICES, INC	5
PP	PUBLIC SERVICE CO OF OK	1087
SS	SOUTHWESTERN ELEC POWER CO	1339
WW	WEST TEXAS UTILITIES	846
	TOTAL	23009

7

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report containing the years of service at Kentucky Power and the salaries of professional employees transferred from Kentucky Power to AEP or its subsidiaries filed in conjunction with the annual transfer of employees report.

RESPONSE:

A copy of the requested information is attached.

WITNESS: Errol K. Wagner

Kentucky Power Transferees - 12 months ending 09/30/2000

02 APPALACHIAN POWER COMPANY

Name	Eff Date	Total Years of Service	Salary	Frequency
FUGATE,MARVIN	·/16/2000	23	43500	A
ROBINSON,MICHAEL R	·/26/2000	14	16.11	H

04 INDIANA MICHIGAN POWER CO

Name	Eff Date	Total Years of Service	Salary	Frequency
COFFEY,JOHN A.,III	7/16/2000	13	88700	A

07 OHIO POWER CO

Name	Eff Date	Total Years of Service	Salary	Frequency
DUMMITT,JEFFERY M	·/16/2000	16	22.92	H

10 COLUMBUS SOUTHERN POWER

Name	Eff Date	Total Years of Service	Salary	Frequency
COFFEY,MICHAEL W	/16/2000	21	56000	A
MAGGARD,JACKIE D	/01/2000	24	935.77	W

61 AEP SERVICE CORP

Name	Eff Date	Total Years of Service	Salary	Frequency
COOKMAN,JOHN C	·/16/2000	23	69000	A
FITZGERALD,MARY A	·/01/2000	26	3800	M
KEYSER,LLOYD E	·/01/2000	21	54900	A
MCCLEAN,DONALD R.,JR	·/01/2000	19	64700	A
SEAGRAVES,JOY M	/29/2000	31	709.41	W

8

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of cost allocation factors in use, supplemented upon significant change.

RESPONSE:

The subject matter covered by this request will be addressed through the Cost Allocation Manual (CAM) required by HB 897 and will be available by April 15, 2001.

WITNESS: Errol K. Wagner

6

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation in effect.

RESPONSE:

If any cost allocation studies are conducted they will be provided. The basis for methods used to determine the cost allocations will be documented in the Company's Cost Allocation Manual (CAM).

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file an annual report of the methods used to update or revise the cost allocation factors in use supplemented upon significant change.

RESPONSE:

The subject matter covered by this request will be addressed through the Cost Allocation Manual (CAM) required by HB 897 and will be available by April 15, 2001. Significant changes to the method's of cost allocation will be documented in the Company's CAM in accordance with HB 897.

11

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation and bylaws of affiliated companies in businesses related to the electric industry or that would be doing business with AEP.

RESPONSE:

Due to the voluminous nature of this request the Company has provised a list of AEP's subsidiaries which describes the functions and business of each subsidiary. Once the Commission Staff has reviewed the list the Company will make available a copy of the Article of Incorporation and By Laws of the affiliates the Staff deem appropriate.

WITNESS: Errol K. Wagner

AEP's Subsudiaries and all Non-Utility Affiliates

American Electric Power Company, Inc. - A registered holding company under the provisions of the Public Utility Holding Company Act of 1935.

American Electric Power Service Corporation - Service company for AEP System.

Appalachian Power Company - Electric utility subsidiary of American Electric Power Compnay, Inc.

Cedar Coal Co. - Coal mining subsudiary of Appalacjian Power Company (inactive).

Central Appalachian Coal Company - Coal mining subsidiary of Appalachian Power Company (inactive).

Central Coal Company - Coal mining subsidiary of Appalachian Piwer Company (inactive).

Central Operating Company - Operated Sporn Plant on behalf od Appalachian Power Company and Ohio Power Company (inactive).

Southern Appalachian Coal Company - Coal mining sudsidiary of Appalachian Power Company (inactive).

West Virginia Power Company - Real estate subsidiary of Appalachian Power Company (Inactive).

Columbus Southern Power Company - Electric utility subsidiary of American Power Company, Inc.

Colomet, Inc. - Takes title to real estate as agent for Columbus Southern Power Company.

Conesville Coal Preparation Company - Owns coal preparation facilities.

Simco Inc. - Coal mining subsidiary of Columbus Southern Power Company (inactive).

Franklin Real Estate Company - Takes title to real estate as agent for AEP System companies.

Indiana Franklin Realty, Inc. - Takes titles to real estate in Indiana as agent for AEP System companies.

Indiana Michigan Power Company - Electric utility subsidiary of American Electric Power Company, Inc.

Blackhawk Coal Company - Coal mining subsidiary of Indiana Michigan Power Company (inactive).

Price River Coal Company - Coal mining subsidiary of Indiana Michigan Power Company (inactive).

Kentucky Power Company - Electric utility subsidiary of American Electric Power Company, Inc.

Kingsport Power Company - Electric utility subsidiary of American Electric Power Company, Inc.

Ohio Power Company - Electric utility subsidiary of American Electric Power Company, Inc.

Cardinal Operating Company - Operates Cardinal generating station on behalf of Ohio Power Company and Buckeye Power, Inc. an unaffiliated electric cooperative.

Central Ohio Coal Company - Coal Mining subsidiary of Ohio Power Company.

Soutern Ohio Coal Company - Coal mining subsidiary of Ohio Power Company.

Windsor Coal Company - -Coal mining subsidiary of Ohio Power Company.

Ohio Valley Electric Corporation - Elctric utility subsidiary of American Electric Power Company, Inc and Columbus Southerm Power Company (44.2% combined equity interest).

Indiana-Kentucky Electric Corporation - Electric utility subsidiary of Ohio Valley Elctric Company.

Wheeling Power Company - Electric utiltiy subsidiary of American Electric Power Company, Inc.

AEP Communications, Inc. - Telecommunications, Information and Other Services.

AEP Communications, LLC - Telecommunication, Information and Other Services.

AEP Energy Services, Inc. - Marketing natural gas and electricity.

AEP Energy Services International, Limited - Consulting and O&M services in international energy projects.

AEP Generating Company - Generates and sells power at wholesale to affiliated and non-affiliated utilities.

AEP Investments, Inc. - Invest in energy related technologies.

AEP Power Marketing, Inc. - Marketing natural gas and electricity.

AEP Resources Service Company - Consulting services in AEP's area of expertise and construction, engineering, operation and maintenance services.

AEP Resources, Inc. - Invest and participate in non-regulated energy projects.

AEP Resources Australia Investments, Inc. - Invest and participate in Australian energy projects.

AEP Resources Australia Ventures, Inc. - Invest and participate in Australian energy projects.

AEP Resources Australia Pty., Ltd. - Invest and partiicipate in Australian energy projects.

AEP Resources Delaware, Inc. - Provide loan funding to the Pushan Power joint venture company.

AEP Resources Limited - Invest and participate in European energy projects,

AEP Resources International, Limited - Invest and participate in international energy projects.

AEP Pushan Power, LDC - AEP investment company for Pushan Power joint venture.

Nanyang Genral Light Electric Company, Ltd. - Joint venture company for the Pushan Power project.

AEP Resources Mauritius Company - Investment company for energy projects in India.

AEP Resources Project Management Company - Investment company for foreign energy projects.

AEPR Global Holland Holding B.V. - Invest in Australian energy projects.

AEPR Golbal Investment B.V. - Invest in Australian energy projects.

AEPR Golbal Ventures B.V. - Invest in Australian energy projects.

Australian Energy Internaltional pty. Ltd. - Invest in Australian energy projects.

AEI (Loy Yang) Pty. Ltd. - Invest in Austaliam enrgy projects.

Pacific Hydro Limited - A developer of hydro electric facilities in Australia and the Philippines.

Virginia PCS Alliance - Invest in wireless telecommunication companies.

West Virginia PCS Alliance - Invest in wireless telecommunication companies.

Yorkshire Power Group Limited - Invest in Yorkshire Electricity Group plc (jointly-owned by AEP Resources, Inc. and New Century Energies, Inc.)

Yorkshire Holding plc - Holding company for Yorkshire Electricity Group plc.

Yorkshire Power Finance (Cayman) Limited - Provide financing for Yorkshire Electricity Group plc.

Yorkshire Electricity Group plc - United Kingdom electric distribution company.

12

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

AEP should file the current Articles of Incorporation of affiliated companies involved in non-related business.

RESPONSE:

See response to item no. 11.

WITNESS: Errol K. Wagner

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

To the extent that the merger is subject to conditions or changes not reviewed in this case, the Joint Applicants should amend their filing to allow the Commission and all parties an opportunity to review the revisions to ensure that Kentucky Power and its customers are not adversely affected and that any additional benefits flow through the favored nations clause.

RESPONSE:

There were no changes to the terms and conditions of the settlements in any jurisdiction which would adversely affect the settlement reached in the Commonwealth of Kentucky or cause additional benefits to flow through the favored nations clause.

Attached are copies of the Louisiana PSC, the Michigan PSC, the Missouri PSC and the PUC of Texas orders which were issued after the KPSC's order of June 14, 1999.

WITNESS: Errol K. Wagner

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

ORDER NO. U-23327

SOUTHWESTERN ELECTRIC POWER COMPANY "SWEPCO", CENTRAL AND SOUTH WEST CORPORATION "CSW" AND AMERICAN ELECTRIC POWER COMPANY, INC. "AEP"

EX PARTE.

Docket No. U-23327 - In re: The applicants jointly request a letter of non-opposition to a proposed Business Combination and Merger.

(Decided at Open Session held July 28, 1999)

I. INTRODUCTION

On May 15, 1998, Central and Southwest Corporation ("CSW"), Southwestern Electric Power Company ("SWEPCO"), and American Electric Power Company, Inc. ("AEP") (collectively, the "Applicants") filed an application with this Commission seeking approval of a merger between Central and Southwest Corporation and American Electric Power Company. The merger is proposed to be accomplished through the exchange of CSW common stock for AEP common stock at a ratio of 0.60 AEP share to one CSW share. Based upon the share price at closing on the last trading day before announcing the merger, the total value of the 127 million shares to be issued by AEP is $6.6 billion. If completed, the combined holding company will be the largest holding company in the United States in terms of total customers, generating capacity, and MW sold, and the fourth largest in terms of revenues. The Applicants believe that the merger is in the public interest, will provide savings to ratepayers by maintaining and improving efficiencies, and will result in a company with an improved financial position. In response to the filing, the Commission opened Docket No. U-23327, appointed an Administrative Law Judge who established a procedural schedule, and directed its expert consultants and Special Counsel to analyze the proposed combination.

This merger required the analysis of numerous complex technical and policy issues. Our consideration of proposed mergers is guided by the standards set forth in Commission General Order *In Re:* Commission Approval Required of Sales, Leases, Mergers, Consolidations, Stock Transfers, and All Other Changes of Ownership or Control of Public Utilities Subject to Commission Jurisdiction (March 18, 1994). This General Order enumerates eighteen standards that must be satisfied before the Commission will approve a merger. The planned asset transfer must also comply with Commission General Order *In Re:* Commission Approval of Security Issues and Assumptions of Liability (November 13, 1996).

Often conditions to the merger must be adopted to satisfy the standards in the Commission's General Orders and to ensure both that the merger is in the public interest and that Louisiana ratepayers are protected from any potential adverse consequences stemming from the merger. Of particular importance in this proceeding are the standards relating to whether the merger is in the public interest; whether the merger provides net benefits to ratepayers and a ratemaking method to ensure that these benefits are actually enjoyed by ratepayers; the ability of the acquiring utility to provide safe and reliable service; the financial condition of the resulting company; whether the transfer adversely affects competition; whether the transfer will improve the quality of management of the resulting public utility; whether the transfer is fair to the affected public utility employees; whether the transfer preserves the Commission's jurisdiction and ability to regulate effectively; and, whether it is necessary to attach conditions to prevent adverse consequences that may result from the merger.

After careful consideration of these issues, the Commission has determined that it will approve the merger but only subject to certain conditions required to protect ratepayers. These conditions are designed to (1) capture for ratepayers the actual savings resulting from the merger; (2) protect ratepayers from any adverse effect on rates or quality and reliability of service; and (3) ensure that transactions among the AEP affiliate companies do not result in cost increases to Louisiana customers. The specific conditions are set forth in the appendix to this Order, entitled "Stipulation and Settlement," and are discussed in more detail below. Subject to these conditions, the Commission approves the proposed merger.

A. The Applicants

1. American Electric Power Company, Inc.

AEP is a public utility holding company registered under the Public Utility Holding Company Act of 1935, with utility operating subsidiaries engaged primarily in the generation, transmission, distribution, and sale of electric energy to over 3 million customers in 7 states. AEP also owns non-utility subsidiaries. AEP is a New York corporation with its principal executive offices located in Columbus, Ohio. AEP owns all of the outstanding shares of common stock of seven domestic electric utility operating subsidiaries, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, and Wheeling Power Company.

The AEP operating companies serve nearly three million people in portions of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. The generation and transmission facilities of AEP's subsidiaries are physically interconnected, and their operations are coordinated as a single integrated electric utility system. The transmission networks are interconnected with extensive distribution facilities in the areas served by AEP's utility operating subsidiaries.

AEP also owns AEP Service Corporation ("AEPSC"), which primarily provides services to the regulated operating companies, and AEP Generating Company, which sells power and energy at wholesale to certain AEP operating companies and to unaffiliated purchasers. The AEP operating subsidiaries own several coal companies, including Conesville Coal Preparation Co., Southern Ohio Coal Company, Central Ohio Coal Company, Windsor Coal Company, and Cardinal Operating Co. (which is jointly owned with Buckeye Power, Inc.). AEP also owns interests in unregulated enterprises.

AEP owns 38 power plants with an aggregate generating capacity of 23,759 MW. This capacity is made up of the following generating sources:

Coal/Lignite	20,670 MW (87%)
Nuclear	2,138 MW (9%)
Hydro/Oil	950 MW (4%)

AEP owns roughly 22,000 miles of transmission lines and 119,000 miles of distribution lines.

The retail operations of the AEP operating companies are subject to the jurisdiction of the public service (or utilities) commissions of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. The Federal Energy Regulatory Commission ("FERC") regulates the wholesale purchases and sales of the operating companies and other AEP subsidiaries as well as the rates and service offerings of AEP's bulk transmission facilities. The Nuclear Regulatory Commission ("NRC") exercises regulatory authority over the operation of the nuclear unit owned by Indiana Michigan Power Company, one of the AEP operating subsidiaries. The AEP System is also subject to regulation by the Security and Exchange Commission ("SEC") under the Public Utility Holding Company Act of 1935.

2. **Central and Southwest Corporation**

CSW is also a registered public utility holding company that owns all of the common stock of four electric utility operating subsidiaries: SWEPCO, Central Power and Light Company ("CPL"), Public Service Company of Oklahoma ("PSO"), and West Texas Utilities Company ("WTU"). CSW indirectly owns all of the outstanding stock of Seeboard, a regulated regional electricity company in England and Wales. CSW also owns Central and South West Services, Inc. ("CSWS"), which provides administrative and general and other services to the four operating companies. CSW owns a number of other subsidiaries that are engaged in a variety of ventures. The basic structure of CSW parallels that of AEP, although some differences exist in the business functions of the non-operating company subsidiaries.

The CSW operating companies provide electric service to approximately 1.7 million customers in a widely diversified area covering 152,000 square miles. The CSW operating companies serve portions of the states of Louisiana, Texas, Oklahoma, and Arkansas. A majority of CSW's Texas operations take place within the Electric Reliability Council of Texas ("ERCOT") while the remainder of CSW's operations are within the Southwest Power Pool ("SPP"). On a combined basis, the CSW operating companies serve approximately 1,470,000 residential customers (sales of 17.9 billion kwh); approximately 214,000 commercial customers (sales of 14.5 billion kwh); over 22,000 industrial customers (sales of 21.0 billion kwh); and, over 14,000 customers in other categories such as municipal service and sales for resale (sales of 1.7 billion kwh). The CSW operating companies own 13,739 MW of installed generating capacity, fired by the following fuel sources:

Coal	5,358 MW (39%)
Gas and Oil	7,282 MW (53%)
Nuclear	1,099 MW (8%)

As previously mentioned, SWEPCO is one of the CSW operating companies. SWEPCO provides electric service in a 25,000 square mile territory covering the northwest portion of Louisiana, as well as in northwestern Texas and western Arkansas. SWEPCO serves nearly 414,000 customers in these three states, many of whom are located in the cities of Shreveport, Bossier City, Texarkana, Fayatteville, and Longview. SWEPCO provides service to approximately 169,000 customers in Louisiana.

The retail operations of SWEPCO-Louisiana ("SWEPCO-La.") are subject to the jurisdiction of the Louisiana Public Service Commission. SWEPCO's retail operations are also regulated by the Public Utility Commission of Texas and the Arkansas Public Service Commission. The retail operations of the other three CSW operating companies are regulated by the public service commissions of Texas and Oklahoma. The FERC regulates the wholesale transactions of SWEPCO and the other CSW operating companies and CSW subsidiaries as well as their bulk transmission rates and services. The NRC exercises jurisdiction over the CSW nuclear operations. The CSW System also is subject to regulation by the SEC under the Public Utility Holding Company Act of 1935.

B. **The Application**

AEP and CSW filed a joint application with this Commission seeking approval of the proposed merger of their two systems. CSW seeks permission to exchange all of the common stock for shares in AEP. If approved, all of CSW's accounts will be transferred to AEP, and the CSW electric utility operating companies will become operating subsidiaries of AEP. AEP and CSW also sought approval of a regulatory plan that contained the following elements:

1. Merger Savings -- Applicants proposed a 50/50 sharing between shareholders and ratepayers of an *estimated* amount of non-fuel savings to be realized through the merger. The amount to be shared would be calculated *after* all merger costs and costs to achieve the savings were deducted from the savings. Applicants sought to include in SWEPCO-La.'s cost of service the shareholders' portion of the estimated savings. Applicants also sought to capture in cost of service the ratepayers' share of savings by accelerating the depreciation rate of SWEPCO-La.'s distribution plant and accelerating recovery of the unamortized portion of certain debt and regulatory assets.

2. Fuel Savings -- Applicants proposed to pass all fuel savings to ratepayers through the fuel adjustment clause.

3. Rate Cap -- SWEPCO-La. offered to cap its rates at current levels through January 1, 2002, subject to certain exceptions designed principally to capture large cost increases.

4. Merger Costs -- Applicants sought to recover all of the merger and transition costs through deferral and amortization over 5 years.

5. Off-System Sales -- Applicants sought a sharing between customers and shareholders on a 50/50 basis of all off-system sales margins above recent historical levels.

Contemplating a June, 1999 closing date for the merger, the Applicants initially requested a decision from the Commission by the end of April, 1999. However, after the application was filed, the FERC denied the Applicants' request for summary approval of the merger and set the case for full, contested hearings, noting that the proposed merger raised serious concerns regarding the potential adverse effect on competition of the combined companies. [*In re: American Electric Power Co.*, 85 FERC ¶ 61, 201, pp. 21-22. (Nov. 10, 1998).] As a result, the Applicants filed a revised plan with the FERC, including proposed mitigation, addressing the FERC's market power concerns. The plan calls for the divestiture of certain generation assets that are part of the CSW System. Generation is to be divested in both the ERCOT and SPP areas of CSW.[1] This plan may be revised further by the FERC and could include the divestiture of additional generating assets.

The proposed plans for asset divestiture, along with the other issues being addressed at the FERC, are complex and have important potential ramifications for Louisiana ratepayers. As a result, the Commission believed it advisable to postpone the targeted decision date to allow these and other issues to be analyzed fully. This brief postponement also provided the parties with an opportunity to negotiate a settlement of the issues in our Docket. The Commission notes further that the proceedings in Texas are still pending, as are proceedings before state public service commissions in some of the AEP jurisdictions.

C. Necessary Regulatory Approvals

In addition to the Louisiana Commission, the merger requires approval from at least 8 regulatory agencies and one federal government department: the FERC, the Securities and Exchange Commission ("SEC"), the NRC, the Federal Communications Commission, the Federal Trade Commission, the state public service commissions of Arkansas, Texas, and Oklahoma, as well as the United States Department of Justice. AEP and CSW have made the required filings with each of the regulators and agencies, but final approval has not been obtained from any regulator other than the Arkansas Public Service Commission. Additionally, the Dockets pending in jurisdictions served by the AEP electric utility operating companies will have to be completed.

The status of the major proceedings before the federal and state regulatory agencies is discussed below.

1. Federal Approvals

a. FERC

On April 30, 1998, Applicants filed for approval of the merger with the FERC. Applicants contemporaneously requested approval of three related filings: (1) a System Integration Agreement, pursuant to which the combined system will operate on a coordinated basis after the merger; (2) a System Transmission Integration Agreement governing transmission system coordination; and (3) a

1 In connection with a non-unanimous settlement with the Texas Commission and certain Texas intervenors, CSW has committed to divest additional CP&L generation assets in ERCOT.

Transmission Reassignment Tariff providing for the sale and reassignment of unused transmission capacity. Applicants requested approval of the merger and related filings without an evidentiary hearing. Numerous parties intervened in the FERC Dockets, including this Commission. The FERC consolidated the Dockets addressing the merger and related filings.

The FERC has jurisdiction to determine whether a merger is consistent with the public interest. 16 U.S.C. §824b(a) (1994). To make this determination, the FERC examines the effect of the merger on competition, rates, and regulation. [*See* Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement, Order No. 592, 61 Fed. Reg. 68, 595 (1996), FERC Stats. and Regs. ¶31,044 (1996), *order on reconsideration*, Order No. 592-A, 62 Fed. Reg. ¶33,341 (1997), 79 FERC ¶61,321 (1997) ("Merger Policy Statement").") In this case, the screening analysis revealed an excessive concentration in the region served by CSW. According to Applicants, this concentration resulted from the need to purchase a 250 MW firm transmission contract path in order to link the AEP and CSW systems. These systems are not otherwise integrated, which is required under PUHCA before holding companies may merge.

Applicants proposed to mitigate their enhanced market power by dedicating into the market 250 MW of capacity for two, two-year periods. Applicants subsequently revised this proposal to require the divestiture of certain generating units located in Oklahoma on the CSW system. This mitigation plan may be amended further to include additional divestiture.

On November 10, 1998, the FERC denied Applicants' request to approve the merger and related filings without an evidentiary hearing. [*In re: American Electric Power Co.*, 85 FERC ¶ 61, 201 (Nov. 10, 1998).] The FERC found that the proposed merger failed the screening analysis. [65 FERC ¶ 61,201 at p. 21.] The FERC also rejected the Applicants' market power mitigation plan. [*Id.*] The FERC set these issues for a full evidentiary hearing. The FERC also set for hearing the effect of the merger on retail competition and rates and the need for ratepayer protection provisions. [*Id.* at pp. 23-29.] The System Integration Agreement and System Transmission Integration Agreement were also made subject to a full evidentiary hearing. [*Id.* at p. 32.]

The issues being addressed by the FERC, particularly those relating to the proposed mitigation plan, may have significant impact on Louisiana customers. As noted previously, Applicants have filed a revised mitigation plan that calls for divestiture of certain generating assets located in the SPP portion of the CSW System. The divestiture of generating units in the SPP portion of the CSW system may diminish the capacity available to satisfy the native load requirements of Louisiana customers and could cause significant increases in SWEPCO's purchased power costs. Because SWEPCO is projected to experience a capacity shortage by (or before) the 2001 summer cooling season, any generation divesture may have a material adverse impact on SWEPCO's costs and, therefore, the rates charged to Louisiana customers. This is an area of obvious concern to the Commission. The Commission is also concerned that the proposed system agreements not result in cost shifting from AEP to SWEPCO or be otherwise unjust or unreasonable.

Hearings on the merger approval application and the related Dockets commenced before a FERC administrative law judge on June 29, 1999 and concluded on July 19, 1999. The Louisiana Commission was an active participant in the proceedings and sponsored the testimony of Mr. Steve Baron of J. Kennedy and Associates, Inc. The Commission's testimony responded to proposals made by various intervenors to require CSW immediately to divest in excess of one thousand MW of generation in the CSW-SPP area. This is precisely the type of proposal that would cause SWEPCO to be short of capacity to serve its Louisiana native load customers and, at the very least, raise Louisiana ratepayer costs. The issues are currently being briefed and by order of the full FERC, the presiding Administrative Law Judge is required to issue his initial decision no later than November, 24, 1999.

b. <u>SEC</u>

On April 1, 1998, the SEC approved Applicants' Joint Proxy Statement, which requested authority to solicit proxies for shareholder approval of the proposed merger.

On October 1, 1998, Applicants filed for SEC approval of the merger. Applicants expect that the SEC will approve the merger thirty to sixty days after the FERC issues its decision. The October 1, 1999 filing also included cost allocation factors for the combined company. The SEC has not yet responded to this filing, and there is no determined date when action is expected.

Applicants also plan to file a proposed new service company agreement, which includes changes to the allocation methodologies for affiliate transactions. Applicants have agreed to provide this filing to the Commission, which will review the filing and determine whether to intervene and take action before the SEC. The allocation methodologies for affiliate transactions affect the level of costs charged by AEP to the electric utility operating companies, including SWEPCO. It is the Commission's position that these allocation factors do not determine the ratemaking treatment of the AEPSC or any other affiliate transaction costs. Applicants disagree with this position, although they have agreed that the Commission may disallow such costs if it finds the costs imprudent, unreasonable, or excessive.

c. <u>NRC</u>

Applicants filed a request with the Nuclear Regulatory Commission to obtain approval to transfer control of the South Texas Project nuclear facilities to AEP, Central Power & Light Co., which owns a portion of the unit is a subsidiary of CSW. These proceedings are still pending before the NRC, and no definitive date has been set for action.

d. <u>Other Approvals</u>

In addition to these regulatory approvals, both AEP and CSW were required to obtain shareholder approval for the merger. On May 28, 1998, CSW shareholders gave their approval. On May 27, 1998, AEP shareholders approved the issuance of the additional shares of AEP stock needed to consummate the merger.

2. <u>State Commission Approvals</u>

CSW serves retail customers in Louisiana, Arkansas, Texas, and Oklahoma, and the state public service commission of each of these states must approve the merger. AEP and CSW have therefore applied to each state commission for merger approval. The Arkansas Public Service Commission has approved the merger, subject to certain conditions. The proceedings in Texas are still pending.

a. <u>Arkansas</u>

In a series of orders, the Arkansas Public Service Commission approved the proposed merger, subject to a number of conditions. In its initial order, the Arkansas Commission found "no persuasive evidence that the proposed merger would adversely affect SWEPCO's Arkansas customers or the overall public interest if consummated subject to the express conditions set forth hereinafter." [*In the Matter of the Joint Application of American Electric Power Co., Inc.*, Docket No. 98-172-U, Order No. 5 at p. 7 (Aug. 13, 1998).] However, its approval is conditioned upon satisfactory resolution of the FERC proceedings. The Arkansas Commission remains an active participant in the FERC proceedings involving the Applicants' market power mitigation plan and proposed divestiture of generation assets.

The Arkansas Commission imposed conditions on the merger concerning quality and reliability of service, cost of capital protection, stranded cost recovery, *Ohio Power* issues, notice and filing requirements, and most favored nations protection. It also adopted a regulatory plan governing the treatment of and the manner in which the costs and benefits of the merger would be reflected in SWEPCO's Arkansas retail rates. [*In the matter of the Joint Application of American Electric Power Co.*, Docket No. 98-172-U, Order No. 9 (December 17, 1998).] The regulatory plan provides for a rate cap through 2002, the reflection of merger savings and costs in retail rates over 5 years; the flow through of fuel savings through the fuel adjustment clause; and, a hold harmless provision regarding the effects of any market power mitigation plan approved by the FERC. The Arkansas Commission also required most favored nations protection; notice requirements for certain filings;

and, a waiver of any requirement under the *Ohio Power* decision that the Arkansas Commission lacks authority to determine the reasonableness of non-power affiliate costs for retail ratemaking purposes.

b. **Oklahoma**

The Oklahoma Public Service Commission regulates the retail rates and service of Public Service Company of Oklahoma. In July, 1999, the Oklahoma Public Service Commission approved the proposed merger. The Order includes conditions similar to those imposed by the Arkansas Commission. The Order has been appealed by one customer group. However, in testimony before the Commission, AEP stated that it was prepared to proceed with the merger regardless of the pendency of the appeal. [07/07/99 Test., R. Munczinski.]

c. **Texas**

The Public Utility Commission of Texas ("PUCT") also regulates the retail operations of SWEPCO as well as those of West Texas Utilities Company and Central Power and Light Company, which are also CSW operating companies. On April 30, 1998, AEP and CSW filed an application with the PUCT requesting approval of the merger. Numerous parties intervened in the proceeding, including customers, competitors, and other regulatory authorities.

The parties have engaged in settlement negotiations and reached a settlement with the Staff of the Texas PUCT as well as the majority of the parties involved in the PUCT merger proceeding. Applicants filed a non-unanimous "Stipulation and Agreement," reflecting the terms of the proposed settlement. A number of parties objected to this agreement.

The non-unanimous Stipulation and Agreement contains provisions similar to those approved by the Arkansas Commission. The agreement also includes additional elements to the regulatory plan and provisions addressing off-system sales margins, affiliate transactions, and other issues. The Applicants have reached agreement with the Staff of the Texas Commission in which they have committed to divest additional generation assets (over and above those they committed to divest in the FERC proceeds) within ERCOT.

Hearings on the Applicants' petition in Texas were conducted before an administrative law judge appointed by the PUCT. Those hearings were concluded in August, 1999, and the parties are awaiting the ALJ's initial decision.

II. PROCEDURAL HISTORY BEFORE THIS COMMISSION

After receiving the merger application, the Commission docketed this matter and assigned the Honorable Valerie Meiners, Chief Administrative Law Judge, as the Presiding Administrative Law Judge. The Commission engaged J. Kennedy and Associates, Inc. and Stone, Pigman, Walther, Wittmann & Hutchinson, L.L.P. to assist the Commission's in-house Economics and Rate Analysis Division and in-house Staff legal counsel in representing the Commission in this matter. Interventions were filed on behalf of Entergy Gulf States, Inc., Entergy Louisiana, Inc., the Louisiana Energy Users Group ("LEUG"), Koch Refining Company, L.P., the Association of Louisiana Electric Cooperatives, Inc., Dixie Electric Membership Corporation, Beauregard Electric Cooperative, Inc., Claiborne Electric Cooperative, Inc., Valley Electric Cooperative, Inc., and the International Brotherhood of Electrical Workers ("IBEW").

On July 30, 1998, a status conference was conducted by Judge Meiners. A procedural schedule was established which included deadlines for discovery, the filing of testimony and exhibits, as well as hearing dates.

The Commission Staff engaged in extensive discovery from the Applicants, including multiple rounds of data requests and depositions of numerous Applicant witnesses who submitted pre-filed testimony. The IBEW also issued data requests to the Applicants. On November 20, 1998, the Commission Staff and IBEW submitted prefiled testimony in response to the direct testimony previously filed by the Applicants. The Applicants propounded discovery to the Staff and deposed the Commission's expert witnesses, Rick Baudino and Lane Kollen. On January 19, 1999, the Applicants filed rebuttal testimony to respond to the issues raised by the Staff and the IBEW.

During the course of discovery, the Applicants and the Commission Staff engaged in lengthy negotiations in an attempt to resolve the outstanding issues related to the merger. Ultimately, the Commission Staff and the Applicants reached agreement on a proposal to present to the Commission to resolve the matters in this Docket. A hearing was held before Chief Administrative Law Judge Meiners on July 7, 1999. The Commission Staff offered into evidence the "Proposed Stipulation and Settlement" that had been negotiated between the Applicants and the Staff. Commission Staff witnesses Richard A. Baudino and Lane Kollen offered testimony in support of the Proposed Stipulation and Settlement and were made available for cross-examination by all parties. The Applicants, SWEPCO, CSW, and AEP presented two witnesses, Richard E. Munczinski and David G. Carpenter, who also testified in support of the proposed settlement. Messrs. Munczinski and Carpenter were made available for cross-examination by all parties and were in fact cross-examined by the Commission Staff.

Counsel for several of the Intervenors, namely, the Association of Louisiana Electric Cooperatives, the Louisiana Energy Users Group, Dixie Electric Membership Corporation, Beauregard Electric Cooperative, Inc., Claiborne Electric Cooperative, Inc. and Valley Electric Cooperative, Inc., entered appearances at the hearing. However, none of the Intervenors presented evidence or testimony at the hearing. Following the testimony of the Commission Staff's and Applicants' witnesses, an opportunity was provided for other parties to state objections to the proposed settlement. There were no objections.[2]

Following the July 7, 1999 hearing, Chief Judge Meiners issued a Report of Proceedings. After outlining the history of the Docket and the participation of the parties at the hearing, the Report stated:

> In light of the proposed settlement, there are no disputed issues to be considered and addressed by the administrative law judge in the form of a Recommendation. Instead, the administrative law judge herewith submits a copy of the Proposed Stipulation and Settlement, together with a copy of a cover letter from Staff Counsel to all counsel of record, providing an overview of the terms of the Proposed Stipulation and Settlement.
>
> All parties are advised that the Proposed Stipulation and Settlement will be considered and voted on by the Commissioners at an upcoming monthly Commission meeting.
>
> Report of Proceedings, Docket No. U-23327 (July 13, 1999) at p. 3).

III. DISCUSSION OF THE ISSUES

A. Overview

In recent years, this Commission has considered a number of mergers involving electric utilities, including the Entergy/Gulf States Utilities merger (Order No. U-19904), the BREMCO/SWEPCO merger (Order No. U-20315) and the TECHE/CLECO merger (Order No. U-21128). Our experience with the earliest of these mergers influenced the Commission to adopt its March 18, 1994 General Order codifying the standards that all mergers must meet. In addition, however, the post-merger experience with these combinations has demonstrated some of the problems mergers may cause.

---

2 Prior to the hearing, two of the Intervenors, Koch Industries, Inc. and the International Brotherhood of Electrical Workers, had filed into the record statements of no opposition to the proposed merger of AEP and CSW.

Many of the conditions that we impose on this merger are designed to avoid past mistakes in other transactions The plan for capturing merger-related savings coupled with the conditions we require, as set forth in the Stipulation and Settlement attached hereto as Appendix A, will result in a merger that satisfies the eighteen standards contained in our March 18, 1994 General Order while ensuring that ratepayers will not be harmed, either financially or regarding service quality and reliability, as a result of the merger. In addition, this Commission will retain its jurisdiction and authority over SWEPCO and the transactions in which it engages.

B. <u>General Order Standards</u>

Our March 18, 1994 General Order, *In re: Commission Approval Required of Sales, Leases, Mergers, Consolidations, Stock Transfers, and All Other Changes of Ownership or Control of Public Utilities Subject to Commission Jurisdiction*, sets forth the eighteen factors to be considered by the Commission in analyzing proposed mergers:

1. Whether the transfer is in the public interest.

2. Whether the purchaser is ready, willing and able to continue providing safe, reliable and adequate service to the utility's ratepayers.

3. Whether the transfer will maintain or improve the financial condition of the resulting public utility.

4. Whether the proposed transfer will maintain or improve the quality of service to public utility ratepayers.

5. Whether the transfer will provide net benefits to ratepayers in both the short term and the long term and provide a ratemaking method that will ensure, to the fullest extent possible, that ratepayers will receive the forecasted short and long term benefit.

6. Whether the transfer will adversely affect competition.

7. Whether the transfer will maintain or improve the quality of management of the resulting public utility doing business in the State.

8. Whether the transfer will be fair and reasonable to the affected public utility employees.

9. Whether the transfer will be fair and reasonable to the majority of all affected public utility shareholders.

10. Whether the transfer will be beneficial on an overall basis to State and local economies and to the communities in the area served by the public utility.

11. Whether the transfer will preserve the jurisdiction of the Commission and the ability of the Commission to regulate and audit effectively the resulting public utility's operations in the State.

12. Whether conditions are necessary to prevent adverse consequences which may result from the transfer.

13. The history of compliance or noncompliance of the proposed acquiring entity or principals or affiliates have had with regulatory authorities in this State or other jurisdictions.

14. Whether the acquiring entity, persons, or corporations have the financial ability to operate the system and maintain or upgrade the quality of the physical system.

15. Whether any repairs and/or improvements are required and the ability of the acquiring entity to make those repairs and/or improvements.

16. The ability of the acquiring entity to obtain all necessary health, safety and other permits.

17 The manner of financing the transfer and any impact that may have on encumbering the assets of the entity and the potential impact on rates.

18. Whether there are any conditions which should be attached to the proposed acquisition.

Witnesses Dr. E. Linn Draper, Chairman, President, and CEO of AEP, and Mark D. Roberson, Vice President - Regulatory Affairs of CSW, presented the Applicants' view regarding how the terms and conditions of the merger satisfy the criteria set forth in our General Order. Commission Staff witness Rick Baudino specifically addressed the criteria set forth in the General Order, and Commission Staff witness Lane Kollen discussed the issue when proposing certain conditions to the proposed merger. Both Mr. Baudino and Mr. Kollen concluded that the proposed combination *could* satisfy our merger criteria *if* changes were made to the proposed regulatory plan to ensure that ratepayers enjoy the actual savings produced by the merger *and* a series of conditions and ratepayer protection mechanisms were attached to the merger. For the reasons more fully explained below, we believe that this merger should be approved, but only subject to the conditions contained in the Stipulation and Settlement. The Applicants have agreed to abide by all of these conditions. [07/07/99 Test., R. Munczinski and D. Carpenter.]

C. Terms of the Merger

This merger presents several unique problems for the Commission. In previous mergers considered by the Commission, there existed a likely prospect of significant ratepayer savings, making these mergers inherently attractive for ratepayers. Others mergers involved the takeover of a utility with major service problems by a more reliable company. The prospect of a significant upgrade in service quality is also desirable for ratepayers. This merger is somewhat different.

For the past several years, SWEPCO has been, on average, the lowest cost investor-owned electric utility providing service to retail ratepayers in Louisiana. Additionally, while the Company suffered some significant service quality problems in recent years, SWEPCO has generally been a relatively well-run, low cost provider of utility service. As such, we were concerned that the proposed merger not result in any increase in rates or degradation in service quality or reliability. Finally, the Commission is concerned that the proceedings at the FERC not result either in the absence of sufficient capacity to serve SWEPCO customers or increased costs resulting from the need to purchase power on the open market rather than obtaining it through native generation.

The need to ensure that rates do not rise and service does not deteriorate is reinforced by the apparent absence of significant merger savings as estimated by the Applicants. The non-fuel savings for SWEPCO's Louisiana operations are projected by the Applicants to be $50 million, over 10 years. These savings are in *nominal* dollars. The projected fuel savings over 10 years for SWEPCO-Louisiana are only $2.6 million, once again, in *nominal* dollars. (For comparison purposes, SWEPCO Louisiana's 1998 non-fuel revenues were $179 million, and fuel revenues for the same year were $96 million.) Because of the relatively modest non-fuel savings, the virtual absence of fuel savings, the planned divestiture of capacity, and the enhanced level of affiliate transactions, the Commission must adopt a variety of merger conditions, affiliate transaction conditions, and ratepayer protection mechanisms ("hold harmless" provisions) to ensure that SWEPCO's Louisiana ratepayers are no worse off as a result of the merger than they would have been had no merger occurred. These conditions and the ratepayer protection mechanisms are described below.

1. Merger Conditions

a. The Costs Of The Merger To Be Borne By Shareholders

The Applicants initially proposed to have *ratepayers* bear 100% of the costs to accomplish the merger. (This was to be accomplished through a sharing of merger savings *after* the costs of the merger and the costs to achieve the savings were netted out of the merger savings). However, we believe that AEP and CSW have agreed to merge, first and foremost, because those two companies believe that the merger is in the best interest of their shareholders. Consequently, the owners of the Company, not their customers, should bear the cost to achieve the merger. As the Staff recommended, the Applicants may not seek recovery of merger-related costs from ratepayers. Even if the FERC permits the costs of the merger to be assigned to the books of operating companies for accounting purposes, SWEPCO commits that it will not seek recovery of those costs from retail ratepayers, whether in traditional rate case proceedings or through any rider or automatic adjustment clause mechanism. The Applicants agreed to this condition. The Applicants shall be allowed to defer merger costs associated with transaction costs and other costs to achieve net of associated savings prior to the operation of the SSM. Ratemaking recovery of the deferred costs will not be permitted other than through SWEPCO's retained savings computed through the SSM. We find this treatment appropriate, and it will be adopted.

b. The Costs To Achieve The Projected Merger Savings Should be Borne By Shareholders

The Applicants proposed that *ratepayers* bear 100% of the costs to achieve the *projected* merger savings before sharing any of those savings with customers. The Staff recommended that these costs be treated in the same manner as the costs to achieve the merger, that is, they should be borne by shareholders, and any recovery will be out of the Company's retained savings computed pursuant to the SSM. The Applicants have agreed not to seek recovery of these costs from Louisiana retail ratepayers. This treatment is fair and consistent with our treatment of the costs of the merger and will be adopted.

c. All Fuel Savings Will Be Flowed Through Directly To SWEPCO's Louisiana Ratepayers

The Applicants have offered to flow through to Louisiana ratepayers all fuel savings generated by the merger. We agree that 100% of the fuel savings produced by the merger should be enjoyed by SWEPCO customers. This treatment is consistent with the Commission's directives in Order No. U-19904 requiring all fuel savings resulting from the merger of Entergy, Inc. ("Entergy") and Gulf States Utilities Company ("Gulf States") be flowed through to ratepayers.

d. Actual Non-Fuel Savings Will Be Flowed Through To SWEPCO's Louisiana Ratepayers

As previously discussed, the Applicants assert that non-fuel savings will result from cost reductions and other efficiencies associated with the merger. The Applicants offered to provide to Louisiana ratepayers, as merger savings, a predetermined dollar amount for a period of five years regardless of the level of actual savings. This *pre*-determined amount is obviously an estimate. The offered savings represented approximately one-half of the *projected* savings calculated *after* all merger related costs and all costs to achieve the savings were deducted. Stated otherwise, the Applicants proposed to split projected savings, with about 50% of savings benefitting ratepayers and 50% being retained by shareholders. This sharing would take place, however, only after ratepayers *paid* all merger-related costs and all costs to achieve the merger. If merger-related savings exceeded those projected by the Applicants, shareholders would enjoy 100% of those excess savings. Moreover, the Company sought to use the ratepayers' portion of the projected savings to fund accelerated depreciation of SWEPCO's distribution plant and the accelerated recovery of certain regulatory assets.

The Commission has previously addressed the appropriate treatment of merger savings. In the Entergy/Gulf States merger, the Commission required that *actual*, not projected, savings be refunded to ratepayers. In that case, we adopted a tracking mechanism designed to capture the actual savings resulting from the merger and required the ratepayer portion of those savings to be flowed through directly to consumers.

We find that the pass through of actual rather than projected savings is both fair and consistent with prior Commission precedent. To accomplish this pass through, the Applicants will implement a mechanism similar to that utilized in the Entergy merger to capture actual savings. The mechanism is known as the Savings Sharing Mechanism ("SSM"). The SSM will track the actual savings generated by the merger as well as any other cost of service reductions generated by productivity improvements implemented by SWEPCO. Fifty percent of all actual savings will be flowed through directly to Louisiana ratepayers via annual filings by SWEPCO. Unlike the Applicants' proposal, however, savings to be enjoyed by ratepayers will be calculated *before* any deduction of merger costs or costs to achieve the savings. Additionally, also unlike the Applicants' proposal, the savings will not be offset by any accelerated cost recovery but rather will be credited to ratepayer bills. The Company will be authorized to defer its merger costs, costs to achieve, transaction costs and change in control payments and to utilize its retained share of the SSM savings to amortize these costs. The SSM will be implemented 15 months after the merger is consummated.

In connection with the operation of the SSM, SWEPCO shall submit to and pay for an audit by the Commission which shall include an examination of affiliate transactions. The cost of the audit shall be reflected in SWEPCO's cost-of-service in the appropriate test year. The audit shall be conducted no less than six months and no more than eighteen months after the merger is consummated.

e. SWEPCO Ratepayers Shall Benefit From Any Increased Off-System Sales Margins

From time to time, CSW engages in off-system sales when it does not need its full capacity to serve its native load customers. Currently, 100% of the SWEPCO portion of the margins (profit) from the off-systems sales are credited to Louisiana ratepayers through the fuel adjustment clause. AEP also engages in off-system sales on behalf of its operating companies, but on a far more extensive basis. AEP has committed to increase significantly the off-system sales and margins for the former CSW operating companies.

To provide the Applicants with an incentive to pursue off-system sales (when profitable), while at the same time ensuring that Louisiana ratepayers continue to benefit from such sales, we will adopt to a tiered approach to sharing the benefit of the off-system sales margins. The proposal is as follows: (1) 100% of Louisiana jurisdictional off-system sales margins up to $874,000 shall be credited to customers. This figure is approximately 130% of current off-system sales margins. (2) 85% of off-system sales margins between $874,000 and $1,314,000 shall be flowed through to customers, with the remaining 15% to be retained by shareholders. (3) SWEPCO off-system sales margins above $1,314,000 shall be shared equally between ratepayers and shareholders. As a result, only if sales margins increase by over 30% of current levels will shareholders receive *any* benefit, and the 50/50 sharing mechanism is triggered only if off-system sales margins approximately double. Ratepayers thus continue to receive the principal benefit of any off-system sales while the Applicants have a significant incentive to increase margins. The Staff recommends that off-system sales margins shall continue to be flowed back to ratepayers through the fuel adjustment clause.

f. Any Stranded Costs That SWEPCO Seeks To Recover Must Be On A Stand Alone Basis

In comments filed in the Commission's Generic Restructuring Docket (Docket No. U-21453), SWEPCO indicated that it could not identify any generation-related stranded costs that would result if the Commission implemented retail competition. However, it is possible that some of the AEP operating companies may have stranded costs in the event of competition. In addition, at least one of SWEPCO's sister CSW operating companies has nuclear exposure and may have stranded costs.

- Assets with a net book value in excess of $1 million per transaction, purchased by SWEPCO from an unregulated affiliate, will be included in rate base at the *lesser* of the cost to the affiliate or its fair market value.

- For goods and services purchased by SWEPCO from unregulated affiliates, SWEPCO will reflect the *lower* of cost or fair market value in operating expenses for ratemaking purposes.

- Assets with a net book value in excess of $1 million per transaction sold by SWEPCO to an unregulated affiliate, will be valued for purposes of Louisiana retail rate base at the *greater* of the cost to SWEPCO or the fair market value.

- For goods and services sold by SWEPCO to unregulated affiliates, for ratemaking purposes, SWEPCO will reflect the *higher* of the cost or fair market value in operating income

- The Company shall comply with all requirements contained in the Commission's March, 1994 General Order (and any superseding General Order) regarding mergers, acquisitions and transfers of ownership and control regarding regulated utilities and their assets.

- SWEPCO shall notify the Commission in writing at least 90 days in advance of any proposed purchase, sale or transfer of assets with a net book value in excess of $1 million. With this notice, the Company shall identify the assets to be transferred, the proposed transferor and transferee, the value at which the assets will be transferred, the net book value of the assets, and the anticipated affect on Louisiana retail customers.

- SWEPCO shall have the burden of proof in any subsequent ratemaking proceeding to demonstrate that such purchase, sale or transfer of assets satisfies the requirements of applicable Commission and legal precedent and Commission General Orders, and will not harm ratepayers.

- The Commission reserves the right, in accordance with Commission and legal precedent and Commission General Orders, to determine the ratemaking treatment of any gains or losses from the sale or transfer of assets to affiliates.

- For ratemaking and regulatory reporting purposes, SWEPCO shall reflect the costs assigned or allocated from affiliate service companies on the same basis as if SWEPCO had incurred the costs directly.

- At least 30 days prior to the filing, and 90 days prior to the proposed effective date of any changes contained in those filings, the Company shall submit to the Commission any changes it proposes to the System Agreement, the System Integration Agreement (or successor agreements) and any other affiliate cost allocation agreements or methodologies that affect the allocation or assignment of costs to SWEPCO. The filing with the Commission shall include a description of the changes, the reason for the changes, and an estimate of the impact, on an annual basis, of such changes on SWEPCO's regulated costs.

- SWEPCO, or any entity on behalf of SWEPCO, may not make any non-emergency or scheduled maintenance procurement other than from American Electric Power Service Company in excess of $1 million from a non-regulated affiliate except through a competitive bidding process or as otherwise authorized by the Commission.

- To the extent that SWEPCO develops or pays for any product or service, all profits from the sale of the product or service shall be shared between SWEPCO and the non-regulated entity responsible for marketing and selling the product or service.

- Because of a decision of the United States Court of Appeals for the District of Columbia Circuit, *Ohio Power Co. v. FERC*, 954 F.2d 779 (D.C. Cir.) *cert. denied*, 498 U.S. 73 (1992), an issue has arisen as to whether authority of the Securities and Exchange Commission impairs the ability of state public service commissions to examine and determine the prudence, reasonableness and necessity of non-power affiliate transaction costs of public utilities subject to the state commissions' jurisdiction. A second issue is whether state public service commissions can challenge Securities and Exchange Commission-approved cost allocations. As to the first issue, the Applicants have agreed not to assert that the authority of the SEC impairs the ability of the Louisiana Commission to examine and determine the prudence, reasonableness and necessity of non-power affiliate transaction costs of SWEPCO. Regarding the second issue concerning cost allocations, the parties have simply agreed to disagree and litigate that issue if and when it arises.

3. Hold Harmless/Ratepayer Protection Mechanisms

In addition to the specific provisions described above, and because of the possibility that significant savings may *not* materialize as a result of the merger, we will adopt several provisions that are in the nature of "hold harmless" or ratepayer protection mechanisms. Fundamentally, these are designed to ensure that ratepayers will not be worse off after the merger than they would have been had CSW not been acquired by AEP. The specific hold harmless conditions that we require, which have already been agreed to by the Applicants are as follows:

a. SWEPCO's Rates Shall Be Capped For 5 Years After The Merger

SWEPCO shall function under a base rate ceiling, set at the level of current rates, for a period of 5 years after the merger closes This ceiling will protect ratepayers from base rate increases resulting from the merger or other causes. The level of the proposed cap is the level of current rates. This is a rate cap and *not* a rate freeze. Rates can be reduced *below* current levels, but they cannot rise. The rate cap is subject to certain limited *force majeure* type provisions described in the Stipulation and Settlement (Appendix A).

b. SWEPCO's Fuel Charges Shall Not Rise As A Result Of The Merger

As with base rates, it is important to ensure that SWEPCO's fuel charges are no higher after the merger than they would have been absent the merger. This is particularly important because as we previously discussed, SWEPCO is projecting only $2.5 million in merger-related fuel savings, over 10 years, in nominal dollars for its Louisiana jurisdictional operations. This indicates that fuel savings may not materialize and that fuel costs may increase as a result of the merger. Absent some action by the Commission, these increased fuel costs would be flowed through to ratepayers via the fuel adjustment clause.

To protect SWEPCO customers, we will require that ratepayers be held harmless from any increases in fuel costs resulting from the merger for a period of 10 years. This 10-year commitment captures the effective period of the Shared Savings Mechanism and is similar to the 10-year fuel protection mechanism we required in the Entergy/Gulf States merger. To ensure that fuel costs do not increase as a result of the merger, the Applicants have agreed to continue in place the current CSW System Operating Agreement and to make only *economic* exchanges of power between the AEP and CSW systems (that is, power will be exchanged only when the exchange will lower fuel or purchased power costs for the entire system). The Applicants have agreed to provide detailed data and calculations to verify compliance with the hold harmless commitment for fuel costs.

c. Cost Of Capital Protection Mechanism

In many respects, the cost of capital of a regulated operating subsidiary is determined (and viewed by the financial community) by the risk of the parent company. It is possible that AEP's risk would be greater than either CSW or SWEPCO as a stand-alone company. Any increased risk could translate into a higher cost of capital (or lower debt rating) for SWEPCO. The Commission seeks to ensure that the merger would not adversely affect SWEPCO's cost of capital, thereby causing higher rates to Louisiana customers. The Applicants are in agreement and have committed that the cost of capital as reflected in SWEPCO's rates shall not be adversely affected as a result of AEP's acquisition of CSW. We adopt that proposition and will require that subsequent to the completion of the merger, the cost of capital for SWEPCO will be set commensurate with the risk of SWEPCO, and the determination of the cost of capital will be based on the risk attendant to the regulated operations of SWEPCO and not to AEP's total operations.

d. SWEPCO's Ratepayers Shall Be Held Harmless From Any Increases Resulting From The Applicants Mitigation Plan

In connection with the application filed with the FERC seeking approval of the merger, the Applicants proposed (and subsequently amended) a mitigation plan to allay any market power concerns that might result from the merger. Under the current mitigation plan, a portion of a Public Service Company of Oklahoma coal-fired generating unit will be sold to third parties, along with the divestiture of additional CSW generating assets located within ERCOT. The sale of PSO generating capacity could cause SWEPCO's fuel and/or purchased power costs to increase. Therefore, we will require, and the Applicants have agreed to, a commitment that Louisiana ratepayers shall be held harmless from any net cost increases resulting from the Applicants' mitigation plan, measured on a calendar year basis. The specific formula for this hold harmless requirement will be developed after the final mitigation plan is ordered by the FERC. The Commission Staff and the Applicants are directed to work together to develop the hold harmless formula.

4. Additional Conditions

a. Commission Approval Of The Merger Will Not Be Final Until FERC Action Is Reviewed And Approved

If the Commission accepts the Staff's recommendation to approve the AEP/CSW merger subject to the conditions outlined in this letter, that approval will occur prior to the time that the proceedings are complete at the FERC. It is possible that the FERC may include certain conditions (particularly by way of mitigation) that would be unacceptable to the Louisiana Public Service Commission. For that reason, the Louisiana Commission's approval shall not become final until after we have had an opportunity to review any action by the Federal Energy Regulatory Commission and determined that such action will not be harmful to Louisiana ratepayers.

b. The Louisiana Commission Has Most Favored Nations Status

Consistent with the Entergy/Gulf States merger, the Commission will require a *most favored nations* provision as a condition to the merger. Thus, if any other regulator is able to negotiate an overall "better deal" for its ratepayers, Louisiana consumers will get the benefit of that better deal. The most favored nations clause is as follows:

> Applicants and the merged Company commit and agree that upon issuance of any final and non-appealable order from the FERC, SEC, or any state or federal commission addressing the merger, through stipulation or otherwise, providing any benefits to ratepayers of any jurisdiction or imposing any conditions on Applicants or the merged Company that would benefit the ratepayers of any jurisdiction, such benefits and conditions will be extended to Louisiana retail customers to the extent necessary to achieve equivalent net benefits and conditions to Louisiana retail customers, provided the proposed merger is ultimately consummated.

IV. CONCLUSION

Upon the unanimous vote of the Commission taken at its July 28, 1998 Open Session,

IT IS HEREBY DETERMINED AND ORDERED that the merger between AEP and CSW is in the public interest and complies with all of the provisions of the Commission's General Orders regarding transfers of ownership and control, subject to the conditions set forth in the Stipulation and Settlement attached as Appendix A to this Order, which are incorporated herein by reference, and subject to the Commission's approval of the capacity mitigation plan and the development of an appropriate methodology to hold SWEPCO's ratepayers harmless from any increased costs relating to the mitigation plan.

This Order will be effective upon its issuance.

BY ORDER OF THE COMMISSION
BATON ROUGE, LOUISIANA
SEPTEMBER 16, 1999

/S/ C. DALE SITTIG
DISTRICT IV
CHAIRMAN C. DALE SITTIG

/S/ JACK "JAY" A. BLOSSMAN, JR.
DISTRICT I
VICE CHAIRMAN JACK "JAY" A. BLOSSMAN, JR.

/S/ DON OWEN
DISTRICT V
COMMISSIONER DON OWEN

/S/ IRMA MUSE DIXON
DISTRICT III
COMMISSIONER IRMA MUSE DIXON

SECRETARY
LAWRENCE C. ST. BLANC

/S/ JAMES M. FIELD
DISTRICT II
COMMISSIONER JAMES M. FIELD

APPENDIX -A

Zones to lower fuel and purchased power costs for the West Zone. Applicants agree that they will not dispatch their system in a manner that will cause increased fuel costs to SWEPCO retail ratepayers as a result of the merger.

This provision shall function in connection with the hold harmless provision related to any mitigation sale as described in Paragraph 9 of the Merger Conditions/ Regulatory Plan of this Stipulation and Settlement. If AEP changes its System Integration Agreement, the notice provisions contained in Paragraph 12 of the Affiliate Transaction Conditions of this Stipulation and Settlement shall apply.

To allow the Commission to monitor the fuel costs of SWEPCO-La. to ensure that ratepayers do not pay higher fuel costs as a result of the merger and/or any mitigation measures undertaken by the Applicants, the Applicants agree that for a period of 10 years following consummation of the merger, SWEPCO shall file yearly fuel and purchase power cost reports with the Commission. These reports shall provide the following information:

a. Calendar year fuel and purchase power cost for SWEPCO and SWEPCO-La.

b. A detailed explanation (including detailed workpapers) of how the annual fuel and purchase power costs were derived.

c. A detailed explanation with supporting calculations showing how the Applicants incorporated the two hold-harmless merger conditions relating to any mitigation sale. The hold-harmless conditions include (1) the effect of any call-back provision; and (2) the effect on fuel and purchased power costs from any change in system dispatch from the operation of the mitigation sale.

d. The annual savings attributable to power interchanges with the East Zone, including detailed workpapers supporting the savings calculation. If fuel and purchase power costs increased due to power interchanges with the East Zone, this calculation shall be shown along with detailed supporting workpapers.

e. A sworn statement, consistent with current Commission requirements, with a supporting explanation, by a qualified representative of AEP stating that the fuel and purchase power costs of SWEPCO-La. did not increase as a result of the merger during the calendar year being reported.

7. SWEPCO shall continue to flow through the Louisiana jurisdictional portion of off-system sales margins to ratepayers in accordance with the following terms and conditions:

a. 100% of Louisiana-jurisdictional off-system sales margins up to $874,000 shall be credited to customers. 85% of off-system sales margins between $874,000 and $1,314,000 shall be flowed through to customers, with the remaining 15% to be retained by shareholders. The off-system sales margins of SWEPCO-La. above $1,314,000 shall be shared equally between ratepayers and shareholders. These dollar figures shall apply on a calendar-year basis and shall include margins associated with mitigation sales.

b. All off-system sales margins to be credited to the ratepayers of SWEPCO-La. under this subsection shall be made in the form of credits to the fuel adjustment clause of SWEPCO-La.

c. AEP shall report annually to the Commission the capital and operating costs allocable or assigned (directly or indirectly) to SWEPCO-La. of the AEP energy trading organization or operations, based upon the most recent composite allocation factor calculated. This report shall include, without limitation, the total AEP operating and capital costs for the energy trading organization and operations, allocation factors, and all supporting documentation and workpapers. To the extent that the Applicants deem any

AFFILIATE TRANSACTION CONDITIONS

CONFIDENTIAL DATA: **When the following obligations require the Company to produce competitively sensitive information, upon request of the Company, that information shall be maintained as confidential in accordance with the Commission's Rules of Practice and Procedure and applicable General Orders.**

1. CSW's domestic electric companies, including SWEPCO, will be core businesses for AEP. The Applicants commit, as part of their obligation to serve, to continue to meet the needs of SWEPCO's domestic regulated customers, including capital requirements, as long as SWEPCO is provided an opportunity to earn a fair return on its regulated investment in assets to provide service to customers, in accordance with regulatory precedent and applicable law.

2. AEP and SWEPCO will provide the Louisiana Commission access to their books and records, and to any records of their subsidiaries and affiliates that reasonably relate to regulatory concerns and that affect SWEPCO's cost of service and/or revenue requirement.

3. AEP will cooperate with audits ordered by the Louisiana Commission of affiliate transactions between SWEPCO and other AEP affiliates, including timely access to books and records and to persons knowledgeable regarding affiliate transactions, and will authorize and utilize its best efforts to obtain cooperation from its external auditor to make available the audit workpapers covering areas that affect the costs and pricing of affiliate transactions.

4. a. Assets with a net book value in excess of $1 million per transaction, purchased by or transferred to the regulated electric utility (SWEPCO) from an unregulated affiliate either directly or indirectly (through another affiliate), must be valued for purposes of the Louisiana retail rate base (but not necessarily for book accounting purposes) at the lesser of the cost to the originating entity and the affiliated group (CSW or AEP) or the fair market value, unless otherwise authorized by applicable Commission rules, Orders, or other Commission requirements.

   b. Assets with a net book value in excess of $1 million per transaction, sold by or transferred from the regulated electric utility (SWEPCO) to an unregulated affiliate either directly or indirectly (through another affiliate), with the exception of accounts receivable sold by SWEPCO to CSW Credit, must be valued for purposes of the Louisiana retail rate base (but not necessarily for book accounting purposes) at the greater of the cost to SWEPCO or the fair market value, unless otherwise authorized by applicable Commission rules, Orders, or other Commission requirements.

5. The Company shall comply with all requirements contained in the Commission's March, 1994 General Order (and any superseding General Order) regarding mergers, acquisitions and transfers of ownership and control regarding regulated utilities and their assets.

6. The Company shall notify the Commission in writing at least 90 days in advance of a proposed purchase, sale or transfer of assets with a net book value in excess of $1 million if such proposed purchase, sale or transfer is expected at least 90 days before the anticipated effective date of the transaction. With the notice, the Company shall provide such information as may be necessary to enable the Commission Staff to review the proposed transaction, including, without limitation, the identity of the asset to be transferred, the proposed transferor and transferee, the value at which the asset will be transferred, the net book value of the asset, and the anticipated effect on Louisiana retail customers. When such a transaction requires approval of a federal agency, under no circumstances shall such notification be less than 60 days in advance

or such longer advance period as the applicable federal agency may from time to time prescribe. If not provided with the initial notice, the Company will provide the Commission with a copy of its federal filing at the same time it is submitted to the federal agency.

7. Consistent with applicable Commission and legal precedents and Commission General Orders, the Company shall have the burden of proof in any subsequent ratemaking proceeding to demonstrate that such purchase, sale or transfer of assets satisfies the requirements of applicable Commission and legal precedent and Commission General Orders, and will not harm retail ratepayers.

8 The Commission reserves the right, in accordance with Commission and legal precedents and Commission General Orders, to determine the ratemaking treatment of any gains or losses from the sale or transfer of assets to affiliates.

9. For goods and services, including lease costs, sold by SWEPCO to unregulated affiliates either directly or indirectly (through another affiliate), SWEPCO agrees that it will reflect the higher of cost or fair market value in operating income (or as an offset to operating expenses) for ratemaking purposes, unless otherwise authorized by applicable Commission rules, Orders, or other Commission requirements (*e.g.*, Commission-approved tariffed rates).

10. With the exception of transactions between SWEPCO and CSW Credit, Inc. and AEPSC, for goods and services, including lease costs, purchased by SWEPCO from unregulated affiliates either directly or indirectly (through another affiliate), SWEPCO agrees that it will reflect the lower of cost or fair market value in operating expenses for ratemaking purposes, unless otherwise authorized by applicable Commission rules, Orders, or other Commission requirements.

11. For ratemaking and regulatory reporting purposes, SWEPCO shall reflect the costs assigned or allocated from affiliate service companies on the same basis as if SWEPCO had incurred the costs directly. This condition shall not apply to book accounting for affiliate transactions.

12. The Company shall submit in writing to the Commission any changes it proposes to the System Agreement, the System Integration Agreement and any other affiliate cost allocation agreements or methodologies that affect the allocation or assignment of costs to SWEPCO. The written submission to the Commission shall include a description of the changes, the reasons for such changes, and an estimate of the impact, on an annual basis, of such changes on SWEPCO's regulated costs. To the extent any such changes are filed with the SEC or FERC, the Company agrees to utilize its best efforts to notify the Commission at least 30 days prior to those filings, and at least 90 days prior to the proposed effective date of those changes or as early as reasonably practicable, to allow the Commission a timely opportunity to respond to such filings. If the documents to be filed with the SEC or the FERC are not finalized 30 days prior to the filing, the information required above may be provided by letter to the Commission with a copy of the SEC or FERC filing to be provided as soon as it is prepared. The filing by the Company of this information with the Commission shall not constitute acceptance of the proposed changes, the allocation or assignment methodologies, or the quantifications for ratemaking purposes.

13. SWEPCO or AEPSC on behalf of SWEPCO may not make any non-emergency procurement in excess of $1 million per transaction from an unregulated affiliate other than from AEPSC except through a competitive bidding process or as otherwise authorized by this Commission. Transactions involving the Company and CSW Credit, Inc. (or its successor) for the financing of accounts receivables are exempt from this condition. Records of all such affiliate transactions must be maintained until the Company's next comprehensive retail rate review. In addition, at the time of the next comprehensive rate review, all such affiliate transactions that were not competitively bid shall be separately identified for the Commission by the Company. This identification shall include all transactions between the Company and AEPSC in which AEPSC acquired the goods or services from another unregulated affiliate.

14. If an unregulated business markets a product or service that was developed by SWEPCO or paid for by SWEPCO directly or through an affiliate, and the product or service is actually used by SWEPCO, all profits on the sale of such product or service (based on Louisiana retail jurisdiction) shall be split evenly between SWEPCO, which was responsible for or shared the cost of developing the product, and the unregulated business responsible for marketing the product or service to third parties, after deducting all incremental costs associated with making such product or service available for sale, including the direct cost of marketing such product or service. However, in the event that such a product or service developed by SWEPCO to be used in its utility business is not actually so used, and subsequently is marketed by the unregulated business to third parties, SWEPCO shall be entitled to recover all of its costs to develop such product or service before any such net profits derived from its marketing shall be so divided. If SWEPCO jointly develops such product or service and shares the development with other entities, then the profits to be so divided shall be SWEPCO's *pro rata* share of such net profits based on SWEPCO's contribution to the development costs.

15. Subject to the provisions of Paragraph 6 of the Merger Conditions (fuel hold harmless), SWEPCO shall continue to purchase, treat, and allocate its fuel costs consistently with the Commission General Order dated November 6, 1997, *In re: Development of Standards Governing the Treatment and Allocation of Fuel Costs by Electric Utility Companies*, including any future amendments to this Order.

16. In the event of the implementation of electric generation open access for Commission-jurisdictional electric utilities, any rules, regulations or orders of general applicability adopted by the Commission regarding generation assets in an open access environment will apply to the company and, to the extent inconsistent with provisions of this Order, will govern. No later than six months prior to the mandated open access date, the company shall file with the Commission any proposed modifications to this Order to address any such inconsistencies.

17. If retail access for SWEPCO-La. is mandated by the Commission, or through action by the Federal Energy Regulatory Commission or federal legislation, then SWEPCO-La shall have the right to petition the Commission for modifications to the terms of this settlement, including the affiliate transaction conditions, that are made necessary by the mandating of retail access and its likely impact on the retail rates at SWEPCO-La. Any such petition must establish the necessity of the proposed modifications and provide appropriate protections to ensure that the benefits of this merger are preserved for SWEPCO-La. regulated customers, including merger savings and the hold harmless provisions set forth herein. The Commission will act upon the petition in accordance with its normal rules and procedures. This paragraph is not intended to limit SWEPCO's right to petition the Commission in the event that electric utility unbundling or retail access is ordered by a state commission regulating SWEPCO's retail rates, provided that SWEPCO must comply with the requirements set forth above in any such petition.

SAVINGS SHARING MECHANISM (SSM)

The savings in nonfuel operation and maintenance (O&M) expense resulting from the merger between CSW and AEP will be quantified in accordance with a formula based methodology, the SSM, and shared equally between customers and shareholders. The Louisiana retail jurisdictional share of nonfuel O&M savings quantified in accordance with the SSM will be flowed through to customers through an annual surcredit effective initially and for the period beginning on the first day of the fifteenth month after the consummation of the merger. The nonfuel savings quantification through the SSM and the surcredit will be updated for current information on each twelve month anniversary for a total of eight filings. The surcredit in effect after the eighth filing will remain in effect unless and until the Commission issues an order in a base rate proceeding. The annual surcredit will be computed and applied as a uniform percentage of base revenues.

After the base rate cap expires, the Company will be allowed to file a claim for a base rate revenue deficiency as an offset to the SSM savings surcredit, which will be subject to an expedited six month review by the Commission. However, the surcredit may only be reduced prospectively after the Commission determines and approves a revenue requirement offset. After the Company's base rate cap expires, but only through the effective dates of the Company's last required SSM filing, or in a base rate proceeding initiated by this Commission after the effective date of the merger, the Company may include its retained savings, computed pursuant to the SSM, as a cost of service expense in its revenue requirement filed in conjunction with a comprehensive base rate proceeding. The Company may not include its retained share of savings, computed pursuant to the SSM, as a cost of service item in any revenue requirement filing to offset the SSM. In any base revenue requirement filing through the effective date of the Company's last required SSM filing, the Company will exclude the test year amount of the SSM surcredit from its per books and pro forma revenues.

I. <u>Merger Costs To Achieve, Transaction Costs, And Change In Control Payments</u>.

The Company is authorized to defer its merger costs to achieve, transaction costs, and change in control payments as these terms have been defined in the testimony of the Applicants' witnesses in this proceeding. The Commission will allow the Company to retain its share of the SSM savings in order to amortize its deferred costs.

During the first fourteen months following the consummation of the merger, the Company will retain 100% of the merger savings and may utilize these savings to reduce the deferrals of its merger costs. Commencing in the fifteenth month following the consummation of the merger, the Company will retain 50% of the merger savings, computed pursuant to the SSM, and may utilize these savings or any portion of these savings to reduce the deferrals of its merger costs.

II. <u>Savings Sharing Mechanism Formula</u>.

The SSM surcredit and the Company's retained share of merger savings will be computed in accordance with the SSM formula. The SSM formula compares the Company's future year normalized O&M expense (FYNE) to the 1998 base year normalized O&M expense (BYNE) escalated for inflation and reduced for productivity improvements. The 1998 base year normalized O&M expense, prior to the inflation and productivity adjustments, is based upon the actual pre-merger level of the Company's nonfuel O&M expense adjusted to reflect certain ratemaking adjustments, to remove operating lease costs, and to remove certain nonrecurring expenses (specifically identifiable and in excess of $1 million during the twelve-month period), including all merger costs. The derivation of the 1998 base year normalized O&M expense is detailed on Attachment A.

For each year subsequent to 1998, the base year normalized O&M will be escalated by an inflation factor reflecting the annual increase in the Consumer Price Index - Urban (CPI-U) less a 1.1% annual productivity adjustment. For each subsequent year, the CYCPI-U will be for the month representing the mid-point of the twelve month future year period as published on the Consumer Price Indexes home page (http://stats.bls.gov/cpihome.htm).

The future year normalized O&M expense will be based upon the actual post merger level of the Company's nonfuel O&M expenses adjusted to reflect certain ratemaking adjustments, to remove operating lease costs, and to remove certain nonrecurring expenses (specifically identifiable and in excess of $1 million during the twelve-month period), including all merger related costs and amortizations, in a manner similar to that of the base year normalized O&M. The formula for the future year normalized O&M is detailed on Attachment B.

Merger savings will be computed as the difference between the future year normalized O&M and the base year normalized O&M, adjusted for inflation and productivity improvements as previously described. The merger savings then will be allocated to the Louisiana retail jurisdiction (LJA).

The merger savings for the Louisiana retail jurisdiction under the SSM will be computed in accordance with the following formula, consistent with the preceding description

Merger Savings = (FYNE - BYNE) * LJA
where:

FYNE – Future Year Normalized O&M, Computed According to Attachment B

BYNE = Base Year Normalized O&M, Computed According to Attachment A, escalated for inflation and reduced for productivity improvement in accordance with the following formula:

BYNE = 1998 BYNE O&M * (CYCPI-U/BYCPI-U) - ((1 + .011)^n - 1)

where:

CYCPI-U = Current Year CPI-U (as of the month representing the mid-point of 12-month future year period)

BYCPI-U = 1998 Base Year CPI-U (as of June 1998)

n = number of years (stated as a decimal to reflect partial years) computed as mid-point of current year less the mid-point of 1998

LJA = Louisiana retail jurisdiction allocation percentage based upon the most recent calendar year cost of service

Savings computed pursuant to the SSM formula beginning with the fifteenth month after the effective date of the merger will be allocated 50% to customers through the SSM surcredit mechanism and retained 50% by the Company.

Attachment C provides an example of the calculation of the SSM and the allocation of savings to customers through the surcredit and the savings retained by the Company.

III. Timing of SSM Surcredit Reductions to Customers and Commission Review.

The first twelve month (year) period for the computation of SSM savings will begin on the first day of the first calendar month after the consummation of the merger. Subsequent periods for the computation of SSM savings will follow the same twelve month cycle as the first period. SWEPCO will make the first SSM filing within the Merger Docket U-23327 and pursuant to the Merger Order in Docket U-23327 within 60 days after the completion of the first twelve month period (within fourteen months of the consummation of the merger). The first surcredit rate reductions will commence on the first day of the fifteenth month following the consummation of the merger, subject to the Commission's subsequent review and approval. Likewise, the subsequent surcredit rate reductions will commence on the twelve month anniversaries of the first surcredit rate reductions, subject to the Commission's subsequent review and approval. To implement the surcredit rate reductions, the Company's annual filings will include a tariff that will go into effect with no further action by the Commission, subject to the Commission's subsequent review and approval. Copies of the SSM filings will be provided to the Commission and, if directed, its consultants and Special Counsel for review, analysis, and recommendations to the Commission. In the event that the Commission ultimately determines that a larger surcredit rate reduction than the one filed by the Company is required, that additional reduction shall be effective as of the date the original filing became effective. The Company shall make such additional refunds or credit customer bills to reflect this effective date.

In conjunction with the second SSM filing, but within 120 days of the end of the second SSM period, the Company also will file detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service study. The filing of this detailed financial information also will be within the Merger Docket U-23327 and pursuant to the Merger Order in Docket U-23327. The detailed financial information will be for the most recent twelve months ending concurrent with the second SSM savings period. The detailed financial information will be provided in the format specified in Attachment D. However, the Company and other parties agree that the schedules filed pursuant to this provision will not be determinative for ratemaking purposes. Copies of the detailed financial information will be provided to the Commission's consultants and Special Counsel for review, analysis, and recommendations to the Commission. The Company agrees to cooperate with the Commission's Staff and/or its consultants and Special Counsel and to provide timely, accurate, and comprehensive responses to discovery.

Attachment A

BASE YEAR NORMALIZED (BYNE)
OPERATION AND MAINTENANCE EXPENSE
SWEPCO SAVINGS SHARING MECHANISM
(000)

			Twelve Months Ended December 31, 1998
I.	Total Actual 1998 Non-Fuel O&M Expense (Excluding Account Nos. 501, 518, 536, 547 and 555)		$191,833
II.	Less:		
	A.	Transmission Fees (Account 565)	(7,292)
	B.	Merger Costs (Costs to Achieve, Transaction Costs, Separation Payments)	0
	C.	Costs of Early Retirement or Other Cost Reductions	0
	D.	Operating Lease Expense***	(1,770)
III.	Other: Add/(Subtract)		
	A.	SFAS 106 Expense in Excess of Cash Pay-As-You-Go	(194)
	B.	Other Non-Recurring Adjustments	(13,870)
IV.	Total Base Year Normalized		$168,707

*** FERC Accounts 507, 525, 540, 550, 567, 589, and 931.

Attachment C

ILLUSTRATION OF OPERATION OF SWEPCO MERGER SAVINGS SHARING MECHANISM

Description	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Base Year O&M Expenses	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
Future Year CPI-U Base Year CPI-U	103,000 100,000	106,090 100,000	109,273 100,000	112,551 100,000	115,927 100,000	119,405 100,000	122,987 100,000	126,677 100,000
Future Year CPI-U/Base Year CPI-U	1.030	1.061	1.093	1.126	1.159	1.194	1.230	1.267
Productivity Factor Offset	-0.011	-0.022	-0.033	-0.045	-0.056	-0.068	-0.080	-0.091
SSM Base Year Escalation Factor	1.019	1.039	1.059	1.081	1.103	1.126	1.150	1.175
Base Year Normalized Expense, Esc & Prod Offset	$101,900	$103,878	$105,938	$108,078	$110,305	$112,621	$115,029	$117,531
Future Year Normalized Expenses	$101,000	$102,010	$103,080	$104,060	$105,101	$106,152	$107,214	$108,286
Total Company Savings (FYNE-BYNE)	($900)	($1,868)	($2,906)	($4,017)	($5,204)	($6,469)	($7,815)	($9,245)
Louisiana Jurisdictional Factor	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Louisiana Jurisdictional Merger Savings	($360)	($747)	($1,162)	($1,607)	($2,082)	($2,588)	($3,126)	($3,698)
Customers Allocation of Savings @50%	($180)	($374)	($581)	($803)	($1,041)	($1,294)	($1,563)	($1,849)

NOTE: Years in the column headings refers to the twelve month implementation periods commencing on the first day of the fifteenth month following consummation of the merger.

SOUTHWESTERN ELECTRIC POWER COMPANY
RATE BASE / RATE OF RETURN
FOR THE TEST YEAR ENDED DECEMBER 31, 1997

Exhibit B

	(1)	(2)	(3)	(4)	(5)
LINE NO.	Description	Schedule Reference	Total Company Per Books	Adjustments	Total Company Pro Forma Balance
1	Plant in service:				
2	Plant in service	W/P B-2	$ 3,005,002,647	(40,121,808)	2,964,880,839
3	Construction work in progress	W/P B-2	51,665,071	(8,281,517)	43,383,554
4	Plant acquisition adjustment	W/P B-2	18,043,976	0	18,043,976
5	Plant held for future use	W/P B-2	80,704	(80,704)	0
6	Gross Plant		$ 3,074,792,398	$ (48,484,029)	$ 3,026,308,369
7	Accumulated depreciation	W/P B-3	(1,225,864,541)	14,267,639	(1,211,596,902)
8	Net Plant		$ 1,848,927,857	$ (34,216,390)	$ 1,814,711,467
9					
10	Working capital:				
11	Cash working capital	W/P B-9	(90,078,456)	0	(90,078,456)
12	Prepayments	W/P B-6	38,498,880	(23,698,126)	14,800,754
13	Operating materials and supplies	W/P B-7	27,132,307	(2,840,083)	24,292,225
14	Fuel inventories	W/P B-8	26,415,233	30,699,587	57,114,820
15	Additions and deductions:				
16	Customer deposits	W/P B-13	(14,358,583)	0	(14,358,583)
17	Deferred credits	W/P B-11	(4,015,924)	1,939,285	(2,076,639)
18	Additional rate base items	W/P B-10	25,523,062	32,374,843	57,897,905
					0
19	Net total investment		$ 1,858,044,378	$ 4,259,116	$ 1,862,303,492
20	Accumulated deferred income taxes	W/P B-12	(410,575,785)	5,079,396	(405,496,389)
21	Deferred investment tax credit - pre 1971	W/P B-12	(345,089)	0	(345,089)
22	Rate Base		$ 1,447,123,502	$ 9,338,512	$ 1,456,462,014
23	Net operating income (current prices)		145,540,459	(28,706,042)	116,834,417
24	Rate of return (current prices)		10.057%		8.022%

Southwestern Electric Power Company
Electric Utility Plant
For the Test Year Ending December 31, 1997

Line No.	Description		FERC Account Number	Total Company Balance Dec. 31, 1997	Adjustments	Pro Forma Total Company Balance Dec 31, 1997
1	Electric Plant in Service		101, 106			
2	Intangible Plant					
3	Organization		301	12,201		12,201
4	Miscellaneous Intangible Plant		303	28,926,874		28,926,874
5	Total Miscellaneous Intangible Plant			28,939,075	0	28,939,075
6	PRODUCTION					
7	Steam Production Plant - Coal & Lignite					
8	Land and Land Rights		310	9,186,653		9,186,653
9	Structures and Improvements		311	226,605,778		226,605,778
10	Coal Unit Railroads		311	1,792,037		1,792,037
11	Boiler Plant Equipment		312	692,076,017		692,076,017
12	Rail Cars		312	31,947,035		31,947,035
13	Engines and Engine Driven Gener.		313	0		0
14	Turbogenerator Units		314	177,789,455		177,789,455
15	Accessory Electric Equipment		315	47,309,527		47,309,527
16	Misc. Power Equipment		316	34,084,763		34,084,763
17	AFUDC Rate Adjustment	W/P B-4		0	(38,201,579)	(38,201,579)
18	Total Steam Production Plant			1,220,791,265	(38,201,579)	1,182,589,686
19	Steam Production Plant - Gas & Oil					
20	Land and Land Rights		310	743,582		743,582
21	Structures and Improvements		311	21,809,310		21,809,310
22	Boiler Plant Equipment		312	72,031,354		72,031,354
23	Gas Unit Pipelines		312	1,259,681		1,259,681
24	Engines and Engine Driven Gener.		313	0		0
25	Turbogenerator Units		314	56,144,494		56,144,494
26	Accessory Electric Equipment		315	7,162,215		7,162,215
27	Misc. Power Equipment		316	4,963,273		4,963,273
28	Total Steam Production Plant			164,113,909	0	164,113,909
29	TRANSMISSION PLANT					
30	Land and Land Rights		350	1,147,105		1,147,105
31	Land and Land Rights		350.2	23,906,233		23,906,233
32	Structures and Improvements		352	7,411,953		7,411,953
33	Station Equipment		353	178,456,520		178,456,520
34	Towers and Fixtures		354	36,124,941		36,124,941
35	Poles and Fixtures		355	92,882,931		92,882,931
36	Overhead Conductors and Devices		356	115,893,914		115,893,914
37	Underground Conduit		357	0		0
38	Underground Conductors and Devices		358	295		295
39	Roads and Trails		359	132,266		132,266
40	AFUDC Rate Adjustment	W/P B-4		0	(1,893,630)	(1,893,630)
41	Total Transmission Plant			455,956,158	(1,893,630)	454,062,528

Southwestern Electric Power Company
Accumulated Provision for Depreciation, Amortization and Depletion
For the Test Period Ending December 31, 1997

Line No.	Description	FERC Account Number	Total Company Balance Dec. 31, 1997	W/P B-3 & W/P B-4 Adjustments	Pro Forma Balance Dec. 31, 1997
1	Accumulated Provision for				
2	Depreciation	108			
3	Production - Steam		$ 694,173,999	$ 23,172,551	$ 717,346,550
4	Transmission		152,328,547	(13,707,722)	138,620,825
5	Distribution		306,109,948	(20,700,365)	285,409,583
6	General		26,819,051	(3,032,103)	23,786,948
7	Lignite Depletion		20,496,682		20,496,682
8	Transportation		17,145,521		17,145,521
9	Retirement Work In Progress		(4,472,945)		(4,472,945)
			$ 1,212,600,803	$ (14,267,639)	$ 1,198,333,164
10	Accumulated Amortization for				
11	Intangible Plant	111	8,457,094		8,457,094
12	Accumulated Amortization for				
13	Plant Acquisition Adjustment	115	4,806,644		4,806,644
14	Total Accumulated Provision for				
15	Depreciation and Amortization		$ 1,225,864,541	$ (14,267,639)	$ 1,211,596,902

SWEPCO
CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 1997

Line No.	(1) Description	(2) Ref.	(3) Total Company Per Books	(4) Pro Forma Adjustment	(5) Adjusted Test Year Amount	(6) Revenue Lag Days	(7) Ref.	(8) Expense Lead Days	(9) Net Lag Days	(10) CWC Factor	(11) CWC Requirement
1	Fuel		383,007,632	(1,778,003)	381,228,629	3.93		32.77	(28.84)	-0.07681	(30,343,522)
2	Deferred Fuel		(603,883)	603,883	-	3.93			3.93	0.01073	-
3	Purchased Power		25,927,920	-	25,927,920	3.93		38.81	(34.89)	-0.09478	(2,457,356)
4	Total Fuel and Purchased Power		408,331,669	(1,175,120)	407,156,549						
5	Total Oper & maint		191,663,267	1,988,414	193,651,681	3.93		40.58	(36.65)	-0.10014	(19,392,129)
6	Taxes other than Income	A/C 84081	55,982,213	(350,497)	55,603,716	3.93		122.92	(119.00)	-0.32513	(18,078,295)
7	Federal Income Tax - Current		45,164,544	(11,602,231)	33,558,313	3.93		84.05	(80.12)	-0.21891	(7,345,062)
8	Federal Income Tax-Deferred		(6,646,437)	(5,932,359)	(12,578,796)	3.93			3.93	0.01073	(134,536)
9	State Income Tax-Current		4,764,450	(1,786,889)	2,977,631	3.93		24.26	(20.33)	-0.05555	(165,416)
10	Depreciation and Amortization	42,276,557	95,228,017	27,211,431	122,439,448	3.93			3.93	0.01073	1,313,456
12	Gain on Sale of Emission Allowance		(135,560)	-	(135,860)	3.93			3.93	0.01073	(1,456)
13						3.93			3.93		
14	Subtotal -		794,328,156	8,242,738	802,570,894						
15	Interest on Long-term Debt	A/C 8427 - 429	49,971,270	4,830,123	54,801,393	3.93		90.31	(86.38)	-0.23602	(12,934,429)
16	Preferred Stock Dividend	A/C 8437	2,466,627	(107,566)	2,359,061	3.93		46.32	(42.40)	-0.11584	(273,281)
17	Return on common equity		59,673,958	6	59,673,964	3.93		-	3.93	0.01073	640,147
18	Net operating income		112,111,855	4,722,563	116,834,417						
19	Working Capital Requirement for Cost of Service		906,440,010	12,965,301	919,405,311						(88,822,127)
20	Sales and Use Taxes	B-9 Pg 2									(1,452,362)
21	Minimum Bank Balances	A/C#1350 9000									197,030
22	Net Working Capital Requirement										(90,078,456)

83

SWEPCO
CASH WORKING CAPITAL FOR FUEL, O&M AND OTHER TAXES
FOR THE TEST YEAR ENDED DECEMBER 31, 1997

Line No	(1) Description	(2) Ref	(3) Total Company Per Books	(4) Pro Forma Adjustment	(5) Adjusted Test Year Amount	(6) Revenue Lag Days	(7) Ref.	(8) Expense Lead Days	(9) Net Lag Days	(10) CWC Factor	(11) CWC Requirement
1	GAS		85,995,697	(400,194)	85,595,503	3.93		51.78	(47.85)	-0.13105	(11,217,667)
2	COAL		218,213,811	(1,015,491)	217,198,320	3.93		21.06	(17.83)	-0.04913	(10,670,718)
3	LIGNITE		76,983,477	(358,254)	76,625,223	3.93		41.93	(38.00)	-0.10412	(7,977,842)
4	OIL		1,088,182	(5,084)	1,083,098	3.93		48.13	(44.20)	-0.12110	(131,158)
5	FUEL - CSWS		724,628	-	724,628	3.93		26.96	(23.03)	-0.06311	(45,730)
6	OTHER FUEL - OIL		-	-	-	3.93			3.93	0.01076	-
7	OTHER FUEL - DIESEL		1,857	-	1,857	3.93		65.28	(61.35)	-0.16808	(312)
8	OTHER FUEL - GAS		-	-	-	3.93		-	3.93	0.01076	-
9	TOTAL FUEL		383,007,632	(1,779,003)	381,228,629	3.93		32.77	(28.84)	-0.07901	(30,042,[illegible])
10	PURCHASED POWER - AFFILIATE		7,836,057	-	7,836,057	3.93		37.85	(33.92)	-0.09294	(728,319)
11	PURCHASED POWER - OTHER		18,091,863	-	18,091,863	3.93		38.81	(34.88)	-0.09557	(1,729,875)
12	TOTAL PURCHASED POWER		25,927,920	-	25,927,920	3.93		38.61	(34.68)	-0.09478	(2,457,294)
13	PAYROLL		55,073,443	(2,659,272)	52,414,171	3.93		26.41	(22.48)	-0.06160	(3,228,553)
14	O&M - CSWS		43,923,851	648,827	44,572,678	3.93		26.96	(23.03)	-0.06311	(2,812,890)
15	CSW CREDIT FACTORING		-	9,327,785	9,327,785	3.93		3.93	-	0.00000	-
16	OTHER O&M		92,717,973	(3,520,461)	89,197,512	3.93		59.32	(55.39)	-0.15176	(13,536,995)
17	TOTAL O&M		191,665,267	1,846,414	195,512,128	3.93		40.58	(36.65)	-0.10014	(19,578,447)
18	AD VALOREM TAX		33,204,298	(928,572)	32,275,726	3.93		191.33	(187.40)	-0.51343	(16,571,257)
19	FUTA		(38,854)		(38,854)	3.93		74.12	(70.19)	-0.19230	7,049
20	SUTA		77,345		77,345	3.93		63.11	(59.18)	-0.16215	(12,542)
21	FICA		4,297,246	(276,425)	4,020,821	3.93		18.28	(14.35)	-0.03932	(158,097)
22	PAYROLL TAXES - CSWS		1,724,550		1,724,550	3.93		26.96	(23.03)	-0.06311	(108,833)
23	PUC ASSESSMENTS		923,559	166,696	1,090,255	3.93		6.09	(2.16)	-0.00592	(6,454)
24	OCCUPATIONAL TAX		47,756		47,756	3.93		(112.73)	116.66	0.31962	15,264
25	TEXAS FRANCHISE TAX		1,800,000	810,824	2,610,824	3.93		(64.62)	68.55	0.18780	490,315
26	OTHER STATE FRANCHISE TAX		2,422,686	(499,074)	1,923,612	3.93		(118.53)	122.46	0.33550	645,437
27	CITY FRANCHISE FEES		8,435,128	135,520	8,570,648	3.93		77.14	(73.21)	-0.20058	(1,719,098)
28	TEXAS GROSS RECEIPTS TAX		3,353,282	(54,965)	3,298,317	3.93		76.92	(72.99)	-0.19998	(659,585)
	SUPERFUND TAXES (Note 1)		(267,500)	267,500	-	3.93		-	3.93	0.01076	-
29	FEDERAL HIGHWAY USE TAX		320	-	320	3.93		(115.55)	119.48	0.32733	105
30	TOTAL TAXES OTHER THAN INCOME		55,982,213	(358,497)	55,633,716	3.93		122.92	(119.00)	-0.32513	(18,078,299)
31	SALES & USE TAX - BY WIRE		21,199,353		21,199,353	3.93		27.03	(23.10)	-0.06330	(1,341,925)
32	SALES & USE TAX - BY CHECK		578,432		578,432	3.93		42.06	(38.14)	-0.10448	(60,436)
33	TOTAL SALES AND USE TAX		21,777,784	-	21,777,784	3.93		27.49	(23.57)	-0.06438	(1,402,362)

Note 1 Correction entries to reverse 1996 expenses. No cash receipts or payments

SOUTHWESTERN ELECTRIC POWER COMPANY
PREPAYMENTS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 1997

Line No	(1) Description	(2) Schedule Reference	(3) Total Company Per Books	(4) Pro Forma Adjustment	(5) Total Company Pro Forma
1	Monthly Balances				
2	December, 1996		$ 13,394,706	$ -	$ 13,394,706
3	January, 1997		14,285,043	-	14,285,043
4	February, 1997		14,851,119	-	14,851,118
5	March, 1997		15,252,890	-	15,252,890
6	April, 1997		15,401,590	-	15,401,590
7	May, 1997		13,250,326	-	13,250,326
8	June, 1997		14,304,151	-	14,304,151
9	July, 1997		15,101,264	-	15,101,264
10	August, 1997		13,939,930	-	13,939,930
11	September, 1997		15,870,908	-	15,870,908
12	October, 1997		13,528,589	-	13,528,589
13	November, 1997		13,554,370	-	13,554,370
14	December, 1997		13,677,712	-	13,677,712
15	13 Month Average		14,800,754	0	14,800,754
16	Prepaid Pension Asset - 13 Month Average		23,898,126	(23,898,126)	0
17	Total Prepayments - A/C 1650 - 13 Month Average		38,698,880	(23,898,126)	14,800,754

78

SOUTHWESTERN ELECTRIC POWER COMPANY
MATERIALS AND SUPPLIES
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 1997

Line No.	(1) Description	(2) Schedule Reference	(3) Total Company Per Books	(4) Pro Forma Adjustment	(5) Total Company Pro Forma
1	Monthly Balances.				
2	December, 1996		$ 29,265,405	$ (2,960,061)	$ 26,305,344
3	January, 1997		29,429,091	(2,952,801)	26,476,289
4	February, 1997		29,021,578	(2,911,519)	26,110,059
5	March, 1997		28,659,213	(2,904,994)	25,754,219
6	April, 1997		28,052,400	(2,975,724)	25,076,676
7	May, 1997		27,433,626	(2,941,392)	24,492,234
8	June, 1997		27,031,949	(2,957,154)	24,074,795
9	July, 1997		26,782,924	(2,936,799)	23,846,125
10	August, 1997		26,468,390	(2,895,251)	23,573,139
11	September, 1997		25,401,974	(2,863,676)	22,538,298
12	October, 1997		25,099,605	(2,955,520)	22,144,085
13	November, 1997		24,751,493	(2,886,700)	21,864,793
14	December, 1997		24,522,348	(1,779,483)	22,742,865
15	13 Month Average		$ 27,132,307	$ (2,840,083)	$ 24,292,225

Purpose of adjustment - The adjustment is to remove the portion of materials and supplies associated with AECC's ownership portion of Flint Creek Power Plant. These materials and supplies are recorded on SWEPCO's books.

SOUTHWESTERN ELECTRIC POWER COMPANY
FUEL INVENTORIES
FOR THE TEST YEAR ENDING DECEMBER 31, 1997

Description	Book Balance	Physical Inv. Adjustment	Ownership Adjustment	Optimal Level Adjustment	Pro Forma Balance
Oil					
Lieberman Power Plant	662,928	-	-	-	662,928
Knox Lee Power Plant	381,320	-	-	-	381,320
Lone Star Power Plant	33,150	-	-	-	33,150
Wilkes Power Plant	274,691	-	-	-	274,691
Welsh Power Plant	250,999	-	-	-	250,999
Flint Creek Power Plant	444,367	-	-	-	444,367
Pirkey Power Plant	-	-	-	-	-
Coal					
Welsh Power Plant	12,593,561	-	-	24,047,147	36,640,708
Flint Creek Power Plant	5,538,390	1,605,814	(6,101,085)	7,946,486	8,989,405
Lignite					
Pirkey Power Plant	2,680,873	-	(430,383)	379,304	2,629,794
Dolet Hills Power Plant	3,554,954	-	(1,652,164)	4,904,668	6,807,457
Total Fuel Inventory	26,415,233	1,605,814	(8,183,633)	37,277,605	57,114,820
	26,415,233			30,699,587	57,114,820

Purpose: The purpose of the optimal level adjustment is to increase fuel inventory for each coal power plant to 60 days of inventory and the Pirkey and Dolet Hills Lignite plants to 21 and 30 days of inventory, respectively.

INVENTORY LEVEL ADJUSTMENT

	Optimal Tons	12/31/97 Price Per Ton	Pro Forma Ending Bal		Ownership Adjustment	Pro Forma Ending Bal
Welsh Power Plant	1,460,371	$ 25.09	36,640,708			36,640,708
Flint Creek Power Plant	486,790	$ 31.00	15,090,490	(2)	(6,101,085)	8,989,405
Pirkey Power Plant	264,036	$ 11.59	3,060,177	(1)	(430,383)	2,629,794
Dolet Hills Power Plant	384,179	$ 22.02	8,459,622	(1)	(1,652,164)	6,807,457

PHYSICAL INVENTORY ADJUSTMENT

	Optimal Tons	12/31/97 Price Per Ton	Pro Forma Ending Bal
Flint Creek Power Plant	51,794	$ 31.00	1,605,814

(1) Pirkey Power Plant and Dolet Hills Power Plant are adjusted by their ownership percentages of total optimal tons.
(2) Flint Creek Power Plant is adjusted by AECC's portion of MWH's generated of the total optimal tons.

SOUTHWESTERN ELECTRIC POWER COMPANY
CUSTOMER DEPOSITS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 1997

Line No	(1) Description	(2) Schedule Reference	(3) Total Company Per Books	(4) Pro Forma Adjustment	(5) Total Company Pro Forma
1	Monthly Balances:				
2	December, 1996		$ 10,497,074	-	$ 10,497,074
3	January, 1997		10,471,689	-	10,471,689
4	February, 1997		10,424,773	-	10,424,773
5	March, 1997		10,388,557	-	10,389,557
6	April, 1997		10,372,330	-	10,372,330
7	May, 1997		10,362,815	-	10,362,815
8	June, 1997		10,381,001	-	10,381,001
9	July, 1997		10,424,381	-	10,424,381
10	August, 1997	-	10,584,757	-	10,584,757
11	September, 1997		10,735,824	-	10,736,824
12	October, 1997		10,960,745	-	10,960,745
13	November, 1997		11,058,367	-	11,056,367
14	December, 1997		11,353,235	-	11,353,235
	TRANSMISSION SERVICES DEPOSITS				
	Monthly Balances:				
	December, 1996		$ -		$ -
	January, 1997		-		-
	February, 1997		-		-
	March, 1997		-		-
	April, 1997		-		-
	May, 1997		-		-
16	June, 1997		645,419	-	645,419
17	July, 1997		1,315,314	-	1,315,314
18	August, 1997		1128219.74	-	1,316,314
19	September, 1997		1,259,137	-	1,259,137
20	October, 1997		2,103,977	-	2,103,977
21	November, 1997		3,116,023	-	3,116,023
22	December, 1997		3,003,348	-	3,003,348
23	TOTAL DECEMBER CUSTOMER DEPOSITS		14,356,583	0	14,356,583

93

Southwestern Electric Power Company
Additional Deductions to Rate Base - Deferred Credits
For the Test Year Ending December 31, 1997

Line No.	Description	Balance 31-Dec-97	Adjustments	Pro Forma Balance 31-Dec-97
1	Miscellaneous Deposits	2,000		2,000
2	Bremco Liability	1,849,639		1,849,639
3	Property Salvage Proceeds	225,000		225,000
4	Non Rate Base	1,939,285	(1,939,285)	0
		4,015,924	(1,939,285)	2,076,639

Southwestern Electric Power Company
Additional Rate Base Items
For the Twelve Months Ending December 31, 1997

Line No.	Description	Total Company Balance Dec. 31, 1997	Adjustments	Total Company Pro Forma Balance Dec. 31, 1997
1	Regulatory Assets:			
2	AMAX Coal Contract	15,709,474	(1,963,684)	13,745,790
3	Ft. Davis R&D Project	2,473,338	0	2,473,338
4	South Tie Asset Costs	0	10,226,802	10,226,802
5	Severance Costs - W/P D-1-35	0	2,558,583	2,558,583
6	Fuel Litigation & Consulting Costs	0	18,488,452	18,488,452
7	Deferred Charges:			
8	Deferred DSM Costs	0	5,097,942	5,097,942
9	Accum. Amort. of Deferred DSM Costs	0	(933,053)	(933,053)
10	Cajun Merger Costs Deferred	5,200,027	(5,200,027)	0
11	Deliberative Polling - TX	2,140,223	0	2,140,223
12	Rate Case Expenses - Estimated	0	2,950,000	2,950,000
13	Recoverable Inventory - W/P D-1-16	0	1,149,828	1,149,828
14	Total	25,523,062	32,374,843	57,897,905

SOUTHWESTERN ELECTRIC POWER COMPANY
ACCUMULATED DEFERRED INCOME TAXES
FOR THE TEST YEAR ENDED DECEMBER 31, 1997

	Total Company Per Books	Pro Forma Adjustments	Total Company Pro Forma Balance
ADIT Account			
2820.xxxx	(410,312,903)	9,516,867	(400,796,036)
2830.xxxx	(74,840,339)	2,813,490	(72,026,849)
1900.xxxx	84,649,850	(7,250,961)	77,398,889
	(400,503,392)	5,079,396	(395,423,996)
Net reg asset/liability			
2540.xxxx	(114,668,688)	-	(114,668,688)
1823.xxxx	104,596,295	-	104,596,295
	(10,072,393)	-	(10,072,393)
Total - ADIT	(410,575,785)	5,079,396	(405,496,389)
ITC Account 2550			
Pre-71	(345,089)	-	(345,089)
Post 70	(66,499,892)	-	(66,499,892)
Total	(66,844,981)	-	(66,844,981)

91

EXHIBIT C

SOUTHWESTERN ELECTRIC POWER COMPANY
COMPONENTS OF CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 1997

Line No.	(1) Description	(2) Schedule Reference	(3) Capital Per Books	(4) Pro-Forma Adjustments	(5) Adjusted Capital	(6) Capital Ratio	(7) Cost Rate	(8) Weighted Average Cost
1	Long-Term Debt	C-1	$ 639,524,230	$ -	$ 639,524,230	48.47460817%	8.09611592%	3.76263800%
2	Preferred Stock	C-2	34,312,853	(3,972,926)	30,339,927	2.20482064%	7.34828663%	0.16197200%
3	Common Equity		702,235,261	3,972,926	706,208,187	51.32057119%	7.98351560%	4.09718600%
4	Total Capital		$1,378,072,344	$ -	$ 1,378,072,344	100.00%		8.02179600%

KPSC Case No. 99-149
Order Dated June 14, 1999
Item No. 13
Page 45 of 119

SOUTHWESTERN ELECTRIC POWER COMPANY
ADJUSTMENTS TO OPERATING INCOME STATEMENT
FOR THE TEST YEAR ENDED DECEMBER 31, 1997

	Total Company Per Books	WP-D-1-1 Factoring Expense	WP D-1-2 Customer Deposit Interest	WP D-1-3 Adjust Depreciation & Amortization	WP D-1-4 Auto Purchase Assistance	WP D-1-5 OPEBS SFAS 106 Adjustment
Revenues						
Residential Sales	$ 259,723,381					
Commercial Sales	182,115,273					
Industrial Sales	263,208,856					
Pub St & Highway Lighting	15,139,937					
Other Sales to Public Authorities	12,084,316					
	$ 772,269,763	$ -	$ -	$ -	$ -	$ -
Off System Sales	146,815,557					
Forfeited Discounts & Service Rev.	3,073,881					
Rent From Electric Property	1,958,832					
Other Electric Revenue	15,850,781					
Required Adjustment for Rate Filing	0					
Total Electric Operating Revenues	$ 939,868,615	$ -	$ -	$ -	$ -	$ -
Fuel	$ 383,007,832					
Deferred Fuel	(603,883)					
Purchased Power	25,927,920					
Total Fuel and Purchased Power	$ 408,331,870	$ -	$ -	$ -	$ -	$ -
Operations Expense	$ 147,827,296	9,327,765	846,680		(804,000)	(783,931)
Maintenance Expense	44,037,971					
Depreciation Expense	91,093,261			17,179,415		
Amortization Expense	4,134,736			2,062,072		
Other Taxes	55,962,212					
Gain on Sale of Emission Allowances	(135,568)					
Operating Expenses Before Income Taxes	$ 342,719,928	$ 9,327,765	$ 846,680	$ 19,241,487	$ (804,000)	$ (783,931)
Operating Income Before Income Taxes	$ 188,817,016	$ (9,327,765)	$ (846,680)	$ (19,241,487)	$ 804,000	$ 783,931
Federal Income Taxes	$ 43,174,551					
Deferred Investment Tax Credit	(4,682,444)					
State Income Taxes	4,784,450					
Total Income Taxes	$ 43,276,557	$ -	$ -	$ -	$ -	$ -
Net Operating Income	$ 145,540,459	$ (9,327,765)	$ (846,680)	$ (19,241,487)	$ 804,000	$ 783,931

2

	WP D-1-6 Pension SFAS 87 Adjustment	WP D-1-7 DSM Amortization Adjustment	WP D-1-8 Reclass Cr. Line and Filn Fees	WP D-1-9 South Tie Costs	WP D-1-10 Recognize Central Lab Revenues	WP D-1-11 Reverse Dues Recorded Above The Line
Revenues						
Residential Sales						
Commercial Sales						
Industrial Sales						
Pub St & Highway Lighting						
Other Sales to Public Authorities						
	$ -	$ -	$ -	$ -	$ -	$ -
Off System Sales						
Forfeited Discounts & Service Rev.						
Rent From Electric Property						
Other Electric Revenue					2,842	
Required Adjustment for Rate Filing						
Total Electric Operating Revenues	$ -	$ -	$ -	$ -	$ 2,842	$ -
Fuel						
Deferred Fuel						
Purchased Power						
Total Fuel and Purchased Power	$ -	$ -	$ -	$ -	$ -	$ -
Operations Expense	2,057,720	(4,552,851)	145,693	(10,226,802)		(70,714)
Maintenance Expense						
Depreciation Expense						
Amortization Expense		832,978		2,045,360		
Other Taxes						
Gain on Sale of Emission Allowances						
Operating Expenses Before Income Taxes	$ 2,057,720	$ (3,719,873)	$ 145,693	$ (8,181,442)	$ -	$ (70,714)
Operating Income Before Income Taxes	$(2,057,720)	$ 3,719,873	$ (145,693)	$ 8,181,442	$ 2,842	$ 70,714
Federal Income Taxes						
Deferred Investment Tax Credit						
State Income Taxes						
Total Income Taxes	$ -	$ -	$ -	$ -	$ -	$ -
Net Operating Income	$(2,057,720)	$ 3,719,873	$ (145,693)	$ 8,181,442	$ 2,842	$ 70,714

3

Revenues	WP D-1-12 Fed. & State Income Tax Adjustments	WP D-1-13 Amortization of Litigation and Consulting Costs	WP D-1-14 Amortization of Rate Case Expense	WP D-1-15 Reverse Laredo Expense	WP D-1-16 Reverse Inventor Write-off & Allow Amortization	WP D-1-1: Increase Distribution C Expense
Residential Sales						
Commercial Sales						
Industrial Sales						
Pub St & Highway Lighting						
Other Sales to Public Authorities						
	$ -	$ -	$ -	$ -	$ -	$
Off System Sales						
Forfeited Discounts & Service Rev.						
Rent From Electric Property						
Other Electric Revenue	-					
Required Adjustment for Rate Filing						
Total Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$
Fuel						
Deferred Fuel						
Purchased Power						
Total Fuel and Purchased Power	$ -	$ -	$ -	$ -	$ -	$ -
Operations Expense				(1,090,376)	(1,149,828)	
Maintenance Expense						7,993,000
Depreciation Expense						
Amortization Expense		2,312,038	983,333		229,966	
Other Taxes						
Gain on Sale of Emission Allowances						
Operating Expenses Before Income Taxes	$ -	$ 2,312,038	$ 983,333	$ (1,090,376)	$ (919,862)	$ 7,993,000
Operating Income Before Income Taxes	$ -	$ (2,312,038)	$ (983,333)	$ 1,090,376	$ 919,862	$ (7,993,000
Federal Income Taxes	(18,400,860)					
Deferred Investment Tax Credit	790,877					
State Income Taxes	(1,711,507)					
Total Income Taxes	$(19,321,490)	$ -	$ -	$ -	$ -	$ -
Net Operating Income	$ 19,321,490	$ (2,312,038)	$ (983,333)	$ 1,090,376	$ 919,862	$ (7,993,000)

4

	WP D-1-24 Adjustment of CSWS Billings	WP D-1-25 Open Access Adjustment	WP D-1-26 Unbilled Revenue Adjustment	WP D-1-27 TFO Expense Reversal	WP D-1-28 Amortization of Deliberative Polling
Revenues					
Residential Sales					
Commercial Sales					
Industrial Sales					
Public St & Highway Lighting					
Other Sales to Public Authorities					
	$ -	$ -	$ -	$ -	$ -
Off System Sales					
Forfeited Discounts & Service Rev.					
Rent From Electric Property					
Other Electric Revenue			(169,000)		
Required Adjustment for Rate Filing					
Total Electric Operating Revenues	$ -	$ -	$ (169,000)	$ -	$ -
Fuel					
Deferred Fuel					
Purchased Power					
Total Fuel and Purchased Power	$ -	$ -	$ -	$ -	$ -
Operations Expense	(682,611)	6,290,574		(5,005,288)	
Maintenance Expense					
Depreciation Expense					
Amortization Expense					713,408
Other Taxes					
Gain on Sale of Emission Allowances					
Operating Expenses Before Income Taxes	$ (682,611)	$ 6,290,574	$ -	$ (5,005,288)	$ 713,408
Operating Income Before Income Taxes	$ 682,611	$ (6,290,574)	$ (169,000)	$ 5,005,288	$ (713,408)
Federal Income Taxes					
Deferred Investment Tax Credit					
State Income Taxes					
Total Income Taxes	$ -	$ -	$ -	$ -	$ -
Net Operating Income	$ 682,611	$ (6,290,574)	$ (169,000)	$ 5,005,288	$ (713,408)

Case No. 99-149
Order Dated June 14, 1999
Item No. 13
Page 53 of 119

Service List
Docket No U-23327

Commissioners
Eve Gonzalez - LPSC General Counsel
Uma Subramanian - LPSC Staff Counsel
Harold Lasserre - LPSC Utilities Division
Owen "Buddy" Stricker - LPSC Utilities Division
Farhad Niami - LPSC Economics Division
Stanley Perkins - LPSC Auditing Division
SC - Michael R Fontham, Esq., Stone, Pigman et al, 546 Carondelet St , New Orleans, LA 70130-3588
C - J. Kennedy & Associates, 35 Glenlake Parkway, Ste 475, Atlanta, GA 30328
AA - Frank P. Simoneaux , Simoneaux Ryan Carleton & Dunlap, 2431 S. Acadian Thruway, Suite 600, Baton Rouge, LA 70808 (Rep American Electric Power)
AA - Bobby Gilliam, Wilkinson, Carmody & Gilliam, Seventeenth Floor Beck Building, 400 Travis St, Shreveport, LA 71101
I - William Hodgkins, Taylor, Porter Brooks & Phillips, P. O. Box 2471, Baton Rouge, LA 70821 (Rep. Assoc. of LA Electric Cooperatives)
I - J. Wayne Anderson, Margot G Augustine, Mail Unit L-ENT-26E, 639 Loyola Ave., New Orleans, Louisiana 70130 (Rep ELI and EDGI)
I - Katherine W King, J. Randy Young, Gordon Polozola, Kean, Miller, Hawthorne, D'Armond, McCowan & Jarman, P.O. Box 3513, Baton Rouge, LA 70821 (Rep. LEUG)
I - John M. Sharp, H. Craig Davidson, Jr., 14481 Old Hammond Highway, Suite 2, Baton Rouge, LA 70816 (Rep DEMCO, Beauregard, Valley, Claiborne)
I - Margarida C Williamson, Koch Refining Company, L P , 20 Greenway Plaza, Houston, TX 77046 (Rep. Koch Refining Company)
I-Kimberly M. Hammer, Law Offices of Jim Boyle, 1005 Congress, Suite 550, Austin, TX 78701 (Rep International Brotherhood of Electrical Workers).

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the joint application of **INDIANA MICHIGAN POWER COMPANY** and the **MICHIGAN PUBLIC SERVICE COMMISSION STAFF** for ex parte approval of a rate reduction and accounting authority related to the merger of American Electric Power Company, Inc., and Central and South West Corporation.

Case No. U-12204

At the December 16, 1999 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. John G. Strand, Chairman
Hon. David A. Svanda, Commissioner
Hon. Robert B. Nelson, Commissioner

ORDER APPROVING SETTLEMENT AGREEMENT

On November 16, 1999, Indiana Michigan Power Company (I&M) and the Commission Staff (Staff) filed a joint application for ex parte approval of a settlement agreement related to the proposed merger of American Electric Power Company, Inc., (AEP), I&M's parent company, and Central and South West Corporation, which is at issue in a matter pending before the Federal Energy Regulatory Commission (FERC) in Docket No. EC98-40-000. The Commission and the State of Michigan are intervenors in the FERC merger docket. The purpose of the settlement signed by I&M, AEP, and the Staff is to ensure that I&M's Michigan retail customers are held harmless from certain potential effects of the proposed merger.

Under the settlement, the Commission agrees not to oppose the merger in the FERC proceedings nor AEP's previous submissions to the Securities and Exchange Commission (together with any nonmaterial changes and supplements) in connection with the merger. AEP and I&M agree to file tariff sheets implementing rate reductions representing the net merger savings allocable to I&M's Michigan jurisdictional customers. The settlement authorizes I&M to use deferred cost accounting to record certain costs incurred to achieve the merger. It specifies how I&M will give rate recognition to merger-related fuel savings. In addition, the settlement provides, among other things, for the maintenance and enhancement of reliable retail electric service by I&M in Michigan, AEP's participation in a regional transmission organization, and standards of conduct governing relationships between regulated AEP operating utilities and affiliates.

The settlement contains various provisions that coordinate its rate effects with another settlement agreement that imposes a conditional ceiling on I&M's rates in Cases Nos. U-11181-R, U-11531-R, and U-11792, which is being approved today in a separate order. The Commission wishes to make plain its understanding that the parties drafted both settlements to make the rate reductions in each cumulative to those in the other and that ratepayers will receive the full benefit of both sets of rate reductions. The Commission also wants to emphasize that the settlement provides that the rate reductions will be accomplished notwithstanding any future restructuring or unbundling of rates.

After reviewing the settlement agreement, the Commission finds that it is reasonable and in the public interest, and should be approved.

The Commission FINDS that:

a. Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; MSA 22.151 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; MSA 22.1 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; MSA 22.13(1) et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; MSA 3.560(101) et seq.; and the Commission's Rules of Practice and Procedure, as amended, 1992 AACS, R 460.17101 et seq.

b. The settlement agreement is reasonable and in the public interest, and should be approved.

c. Ex parte approval is appropriate.

THEREFORE, IT IS ORDERED that:

A. The settlement agreement, a copy of which is attached to this order as Exhibit A,[1] is approved.

B. Upon consummation of the merger, Indiana Michigan Power Company is authorized to implement the rate reductions required by the settlement agreement and the deferred cost accounting provisions in the settlement agreement.

C. Within 30 days of consummation of the merger, Indiana Michigan Power Company shall file tariff sheets implementing the settlement agreement.

The Commission reserves jurisdiction and may issue further orders as necessary.

[1]Attachment D to the settlement agreement, a proposed order, is not attached to copies of this order. The Commission is not adopting the proposed order as submitted.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26; MSA 22.45.

MICHIGAN PUBLIC SERVICE COMMISSION

/s/ John G. Strand
Chairman

(SEAL)

/s/ David A. Svanda
Commissioner

/s/ Robert B. Nelson
Commissioner

By its action of December 16, 1999.

/s/ Dorothy Wideman
Its Executive Secretary

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE JOINT APPLICATION OF INDIANA MICHIGAN POWER COMPANY AND THE STAFF OF THE MICHIGAN PUBLIC SERVICE COMMISSION FOR EX PARTE APPROVAL OF A RATE REDUCTION AND ACCOUNTING AUTHORITY RELATED TO THE MERGER OF AMERICAN ELECTRIC POWER, INC. AND CENTRAL AND SOUTH WEST CORPORATION.	)	Case No. U-________

SETTLEMENT AGREEMENT

On June 30, 1998, the Michigan Public Service Commission ("MPSC" or "Commission") intervened in Docket EC98-40-000, the proceeding initiated before the Federal Energy Regulatory Commission ("FERC") regarding the proposed merger of American Electric Power Company, Inc. ("AEP"), the parent company of Indiana Michigan Power Company ("I&M"), and Central and South West Corporation ("CSW") to ensure that the Michigan retail customers of I&M were protected from any potential adverse effects of the merger. During the course of the FERC proceeding, the Commission Staff, acting on behalf of the Commission, reviewed numerous filings and participated in numerous discussions regarding the proposed merger. In addition, the Commission Staff negotiated with representatives of AEP and I&M to achieve a resolution of issues of concern to Michigan customers and regulators.

Solely for the purposes of compromise and settlement, Indiana Michigan Power Company, which does business in Michigan as American Electric Power, AEP and the Commission Staff (collectively referred to as the "Parties") have met and reached a settlement agreement ("Agreement") which they hereby submit and recommend for approval to the Commission. If the Commission does not approve the settlement agreement in its entirety and incorporate it in the Final Order, the proposed Agreement shall be null and void and deemed withdrawn, unless such change is agreed to by the Parties.

SETTLEMENT AGREEMENT

WHEREAS AEP and CSW have filed various applications before federal and state agencies seeking approvals necessary to consummate a proposed merger of the two companies, and

WHEREAS AEP, I&M and the Commission Staff have met and explored over a period of months various issues related to the proposed merger and their agreements and differences regarding the effects of the proposed merger on competition between electricity providers and on the terms and conditions under which retail electric utility service is provided, and

WHEREAS AEP, I&M and the Commission Staff recognize the costs and uncertainty of litigation and the desirability of consensual voluntary resolution of their differences and the legitimate interests and good faith of each of the parties in achieving the objectives each desires to achieve.

The Parties agree as follows:

The Commission Staff will recommend to the MPSC that the following Agreement be adopted by the Commission in an order or other appropriate formal action that references this Agreement or incorporates all of the provisions thereof. Where appropriate, the Commission action may address or reserve other matters ancillary or incidental to the matters addressed in this Agreement, for immediate or future disposition, in a manner not inconsistent with the Agreement.

All appropriate terms are defined in the "Definitions" section of the Agreement.

THE MPSC:

1. Will not oppose the proposed merger pending before the Federal Energy Regulatory Commission.

2. Will not oppose AEP's filings previously made at the United States Securities and Exchange Commission ("SEC") in connection with the proposed merger, together with any non-material changes or supplements thereto.

AEP or I&M, AEP's Michigan jurisdictional AEP operating company, conditional on merger consummation will:

1. REGULATORY PLAN. The net merger savings allocable to the Michigan jurisdictional customers will be used to reduce customers' bills. I&M will implement net merger savings reduction riders that will reduce bills to customers by the annual amounts shown in Attachment A beginning with the first revenue month after the consummation of the merger. The annual customer net savings reduction amounts shown in column 3 of Attachment A ("customer net savings") will be allocated to rate classes based upon the ratio of each class's jurisdictional tariff

revenue to total jurisdictional tariff revenue, excluding fuel cost adjustment, and credited to customers' bills through the application of a per kilowatt hour factor specific to each rate class. Each individual year's customer net savings reduction will apply for a twelve month period except for an adjustment during each third quarter to reconcile actual kWh sales and projected kWh sales for the prior year. The last reduction will continue to apply in years following the end of year eight until base rates for the operating company are changed.

The merger savings and costs are based on estimated values included in AEP's filing with FERC in Docket No. EC98-40-000.

Notwithstanding any base rate proceeding during the eight year period after the consummation of the merger, the annual amounts shown in Attachment A will remain in effect.

I&M must implement the customer net savings reductions in the manner and amounts described above notwithstanding any changes to the current regulatory structure in Michigan and notwithstanding the rate filing limitations contained in paragraphs 3, 4 and 5 of the settlement agreement pending before the Commission in Case Nos. U-11181-R, U-11531-R, and U-11792 ("PSCR cases"). When retail electric deregulation is implemented in Michigan, or if there is any unbundling or restructuring of rates, I&M shall continue to apply the regulatory plan's provisions to regulated rates of its Michigan customers. The allocation to rate classes after any unbundling or restructuring will be determined as described above in the next annual customer net savings reduction submittal.

Any legislatively or administratively mandated adjustments to rates, of any kind, that are part of any retail electric deregulation legislation implemented in Michigan shall not diminish or offset, but shall be in addition to, the customer net savings reductions established in this proceeding.

Subject to this Agreement, AEP and I&M will defer and amortize their Michigan jurisdictional share of estimated merger costs-to-achieve over an 8-year recovery period. Costs to achieve the merger are those costs incurred to consummate the merger and combine the operations of AEP and CSW. These costs include, but are not limited to, investment banking fees; consulting and legal services incurred in connection with obtaining regulatory and shareholder approvals; transition planning and development costs; employee separation costs including severance costs, change-in-control payments and retraining costs; and facilities consolidation costs. Costs to achieve shall be recorded in Account 182.3. Actual amounts in excess of the estimated costs to achieve shall be expensed as incurred by AEP. The MPSC will issue accounting orders or other orders necessary to authorize the deferral and amortization of merger costs.

In any proceeding to change base rates for I&M to become effective after the consummation of the merger, the following rate treatment will be reflected:

A. Estimated non-fuel merger savings, net of costs to achieve, will be included in cost of service as an allowable expense in order to avoid duplication and to continue to provide shareholders with their share of the net savings. The amount to be included in the cost of service shall be based upon the test year period. (See Attachment B)

B. Amortization of estimated costs to achieve will be included in cost of service as an allowable expense. The amount to be included in the cost of service shall be based upon the test year period. (See Attachment B)

The parties note that the settlement agreement pending before the Commission in the PSCR cases contains a conditional moratorium on general increases in basic rates and charges. The exact language, which is found on page 6, paragraph 5 of the June 1, 1999 PSCR settlement document says, " Subject to paragraphs 6 and 8, AEP shall not file an application, which, if approved, would have the effect either directly or indirectly, of authorizing a general increase in basic rates and charges that would be effective prior to January 1, 2004." In the event the PSCR settlement is approved by the Commission without modification, the moratorium on general increases in basic rates and charges will be extended by one year to January 1, 2005, subject to the same conditions contained in the PSCR settlement agreement.

2. FUEL MERGER SAVINGS. All savings of fuel and purchased power expenses resulting from the merger shall benefit retail customers through existing fuel clause recovery mechanisms applied by State Commissions. In circumstances when one or more AEP operating companies in one AEP zone are supplying power to the other AEP zone, and as a result, the supplying zone needs to purchase replacement power to serve its native load, AEP shall hold harmless the native load customers of the supplying zone from any price differential between the replacement power and the system power supplied to the other zone. Similarly, if one or more AEP operating companies in one AEP zone are supplying power to the other AEP zone, and as a result, the supplying zone loses the opportunity to sell power at a price higher than received from the zone being supplied, AEP shall credit the supplying zone for the foregone revenues.

The parties note that paragraphs 3 and 4 of the settlement agreement pending before the Commission in the PSCR cases set forth a conditional suspension of the PSCR process. In the event that the settlement agreement in the PSCR cases is approved without modification, I&M will accrue the Michigan jurisdictional amount of merger fuel savings achieved during the fixed PSCR factor period and credit customers with those accrued savings, either through the PSCR factor in effect at that time or through base rates, as soon as possible after the end of the fixed PSCR factor period, but no later than July 1, 2004. After the fixed PSCR factor period, I&M will continue to pass through the merger fuel savings consistent with Michigan regulation.

3. STRANDED COSTS. AEP and its operating companies agree not to seek or recover any stranded costs associated with the operating companies of one AEP zone from the retail customers of the other AEP zone.

4. PROCEEDS OF FACILITY SALES. Any proceeds from the sale of facilities shall go to the AEP operating company in whose rate base the facilities are included, for further disposition in accordance with the rules and orders of the regulatory authorities whose jurisdiction encompasses the ultimate disposition of such proceeds.

5. SYSTEM INTEGRATION AGREEMENTS. To mitigate any perceived impacts of the merger on AEP's ability to exercise market power, AEP proposed in its FERC merger application a mitigation plan. To protect retail customers, AEP agrees to hold harmless the retail customers from any mitigation plan included in any FERC order approving the merger of AEP-CSW. To implement this Agreement in any general retail electric rate proceeding commenced by the filing of a petition on or after the date of this Agreement, in which an AEP operating company requests a change in its basic rates and charges, or in any other proceeding where so ordered by the Commission, AEP shall have the burden therein to prove that such requested rate relief does not reflect mitigation-related costs.

AEP commits to file any allocation of the cost of new, modified or upgraded generation or transmission facilities whose costs will be subject to the System Integration Agreement or the System Transmission Agreement with the FERC and to notify the Commission of any such filing at the time it is made. Notification to the Commission will include an estimate of the cost of construction, an explanation of the reasons for constructing the facilities, studies supporting the construction of the facilities, and a proposed allocation of the facilities' costs. If AEP plans to purchase an in-service facility or already constructed and soon-to-be-in-service facility, AEP will follow the above described procedures and will include as part of the notification to the Commission an explanation of the circumstances causing the AEP operating company to make the purchase in question.

6. REGULATORY AUTHORITY. AEP agrees not to seek to overturn, reverse, set aside, change or enjoin, whether through appeal or the initiation or maintenance of any action in any forum, a decision or order of the Commission based on the assertion that the authority of the SEC as interpreted in Ohio Power Co. v. FERC, 954 F.2d 779 (D.C. Cir. 1992) cert. denied, 506 U.S. 981 (1992) impairs the Commission's ability to examine and determine the reasonableness of non-power affiliate transaction costs to be passed to retail customers. The parties agree that the Ohio Power waiver does not include waiver of any arguments that AEP may have with respect to the reasonableness of SEC approved cost allocations. AEP will provide the Commission with notice at least 30 days prior to any filings that propose new allocation factors with the SEC. The notice need not be in the precise form of the final filing but shall include, to the extent information is available, a description of the proposed factors and the reasons supporting such factors. AEP and the Commission Staff will make a good faith attempt to resolve their differences, if any, in advance of a filing being made at the SEC.

7. REGIONAL TRANSMISSION ORGANIZATION.

A. Prior to December 31, 2000, AEP will file with the FERC an unconditional application, consistent with the RTO agreement and tariff, to transfer the operation and control of its bulk transmission facilities in Indiana, Michigan, Kentucky, Ohio, Tennessee, Virginia and West Virginia owned, controlled and/or operated by AEP to the Midwest Independent Transmission System Operator, Inc. or another FERC-approved Regional Transmission Organization directly interconnected with AEP transmission facilities. Provided that, if, by June 30, 2000, there is pending before the FERC for approval an RTO to which AEP is a signatory that includes two or more directly interconnected control areas, at least one of which is not affiliated with AEP, the December 31, 2000 date shall be extended to the date that is 75 days after the date on which the FERC issues an order either approving or disapproving the RTO.

B. AEP shall endeavor to eliminate "pancaking" of transmission rates and to incorporate equitable reciprocal pricing arrangements with contiguous RTOs in the Alliance RTO or any other filing to which AEP is a signatory seeking FERC approval of the formation of a new RTO.

C. AEP will provide generation dispatch information necessary for RTOs to monitor the effect of such dispatch on the loading of that RTO's constrained transmission facilities. This information must be provided to any RTO of which AEP is a member, and to RTOs providing service over any transmission facilities directly interconnected with the AEP east zone transmission facilities. Each of these RTOs shall determine the format, quantity, and timing of these data as necessary to perform this monitoring function. The information provided by AEP shall be equivalent to that provided by all parties who control the dispatch of generation facilities taking transmission service from these RTO(s) and shall be subject to appropriate confidentiality provisions.

D. Nothing in this Agreement precludes the Commission, or its staff from actively participating in any proceedings at the FERC arising from any RTO filings made by AEP. However the Commission and its staff commits that it will not offer such participation as a reason to delay the consummation of the merger or to advocate a position before FERC inconsistent with Paragraph A above.

8. AFFILIATE STANDARDS. The following affiliate standards shall apply from the date of closing of the merger until new affiliate standards imposed by state legislation or Commission action become effective.

A. The financial policies and guidelines for transactions between an AEP operating company and its affiliates shall reflect the following principles:

1. An AEP operating company's retail customers shall not subsidize the activities of the operating company's non-utility affiliates or its utility affiliates.

2. An AEP operating company's costs for jurisdictional rate purposes shall reflect only those costs attributable to its jurisdictional customers.

3. An objective of these principles shall be to avoid costs found to be just and reasonable for ratemaking purposes by the Commission being left unallocated or stranded between various regulatory jurisdictions, resulting in the failure of the opportunity for timely recovery of such costs by the operating company and/or its utility affiliates; provided, however, that no more than one hundred percent of such costs shall be allocated on an aggregate basis to the various regulatory jurisdictions.

4. An AEP operating company shall maintain and utilize accounting systems and records that identify and appropriately allocate costs between the operating company and its affiliates, consistent with these cross-subsidization principles and such financial policies and guidelines.

B. The Commission shall have access to the employees, officers, books and records of any affiliate of its jurisdictional AEP operating company to the same extent and in like manner that the Commission has over a public utility operating within the state if the affiliate had engaged in direct or indirect transactions with the jurisdictional AEP operating company. If such employees, officers, books and records can not be reasonably made available to the Commission, then upon request of the Commission, the AEP operating company shall, in accordance with state reimbursement rules, reimburse the Commission for appropriate out-of-state travel expenses incurred in accessing the employees, officers, books and records. Each AEP operating company shall maintain, in accordance with generally accepted accounting principles, books, records, and accounts that are separate from the books, records, and accounts of its affiliates, consistent with Part 101 – Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. Any objections to providing all books and records must be raised before the Commission and the burden of showing that the request is unreasonable or unrelated to the proceeding is on the AEP operating company. The confidentiality of competitively sensitive information shall be maintained in accordance with the Commission's rules and regulations and relevant state law.

not preclude AEP operating companies from issuing securities or assuming obligations related to their existing coal subsidiaries.

E. Any untariffed, non-utility service provided by an AEP operating company or affiliated service company to any affiliate shall be itemized in a billing statement pursuant to a written contract or written arrangement. The AEP operating company and any affiliated service company shall maintain and keep available for inspection by the Commission copies of each billing statement, contract and arrangement between the AEP operating company or affiliated service company and its affiliates that relate to the provision of such untariffed non-utility services.

F. Any good or service provided by a non-utility affiliate to an AEP operating company shall be by itemized billing statement pursuant to a written contract or written arrangement. The operating company and non-utility affiliate shall maintain and keep available for inspection by the Commission copies of each billing statement, contract and arrangement between the operating company and its non-utility affiliates that relate to the provision of such goods and services in accordance with applicable Commission retention requirements.

G. Employees responsible for the day to day operations of the AEP operating companies and those of affiliated exempt wholesale generators or affiliated power marketers shall operate independently of one another. AEP shall document all employee movement between and among all affiliates. Such information shall be made available to the Commission upon request.

H. An AEP operating company may not own property in common with an affiliated exempt wholesale generator or affiliated power marketer.

I. No market information obtained in the conduct of utility business may be shared with an affiliated exempt wholesale generator or affiliated power marketer, except where such information has been publicly disseminated or simultaneously shared with and made available to all non-affiliated entities who have requested such information. Customer specific information shall not be made available to an affiliated exempt wholesale generator or affiliated power marketer except under the same terms as such information would be made available to a non-affiliated company, and only with the written consent of the customer specifying the information to be released.

J. A non-utility affiliate may use an AEP operating company's name or logo only if, in connection with such use, the affiliate makes adequate disclosures to the effect that (i) the two entities are separate; (ii) it is not necessary to purchase the non-regulated product or service to obtain service from the operating company;

and (iii) the customer will gain no advantage from the operating company by buying from the affiliate.

K. An AEP operating company shall not condition or tie the provision of any product, service, pricing benefit, or waiver of associated terms or conditions, to the purchase of any good or service from its affiliated exempt wholesale generator or power marketer.

L. Except as provided in paragraph M, an affiliated exempt wholesale generator or affiliated power marketer shall not share office space, office equipment, computer systems or information systems with an AEP operating company.

M. Computer systems and information systems may be shared between an AEP operating company and non-utility affiliates only to the extent necessary for the provision of corporate support services; however, the operating company shall ensure that the proper security access and other safeguards are in place to ensure full compliance with these affiliate rules.

N. An AEP operating company may engage in transactions directly related to the provision of corporate support services with its affiliates in accordance with requirements relating to service agreements. As a general principle, such provision of corporate support services shall not allow or provide a means for the transfer of confidential information from the operating company to the affiliate, create the opportunity for preferential treatment or unfair competitive advantage, create opportunities for cross-subsidization of affiliates, or otherwise provide any means to circumvent these affiliate rules.

O. Except as provided in paragraph N, an AEP operating company may only make a product or service available to an affiliated exempt wholesale generator or an affiliated power marketer if the product or service is equally available to all non-affiliated exempt wholesale generators and power marketers on the same terms, conditions and prices, and at the same time. An AEP operating company shall process all requests for a product or service from affiliated and non-affiliated exempt wholesale generators and power marketers on a non-discriminatory basis.

P. An AEP operating company which provides both regulated and non-regulated services or products, or an affiliate which provides services or products to an AEP operating company, shall maintain documentation in the form of written agreements, an organization chart of AEP (depicting all affiliates and AEP operating companies), accounting bulletins, procedure and work order manuals, or other related documents, which describe how costs are allocated between regulated and non-regulated services or products. Such documentation shall be available, subject to requests for confidential treatment, for review by the Commission in accordance with Paragraph B above.

Q. AEP shall designate an employee who will act as a contact for the Commission seeking data and information regarding affiliate transactions and personnel transfers. Such employee shall be responsible for providing data and information requested by the Commission for any and all transactions between the jurisdictional operating company and its affiliates, regardless of which affiliate(s), subsidiary(ies) or associate(s) of an AEP operating company from which the information is sought.

R. AEP shall designate an employee or agent within Michigan who will act as a contact for retail consumers regarding service and reliability concerns and to allow a contact for retail consumers for information, questions and assistance. Such AEP representative shall be able to deal with billing, maintenance and service reliability issues.

S. AEP shall provide the Commission a current list of employees or agents that are designated to work with the Commission concerning state regulatory matters, including, but not limited to, rate cases, consumer complaints, billing and retail competition issues.

T. Thirty (30) days prior to filing any affiliate contract (including service agreements) with the SEC or the FERC an AEP operating company shall submit to the Commission Staff a copy of the proposed filing.

U. Any violation of the provisions of these affiliate standards is subject to the enforcement powers and penalties of the Commission.

V. AEP shall contract with an independent auditor who shall conduct biennial audits for eight years after merger consummation of affiliated transactions to determine compliance with these affiliate standards. The results of such audits shall be filed with the Commission. Prior to the initial audit, AEP will conduct an informational meeting with the Commission regarding how its affiliates and affiliate transactions will or have changed as a result of the proposed merger.

W. If the Public Utility Holding Company Act of 1935 is repealed or materially amended during the time this Agreement is in effect and equivalent jurisdiction is not given to another federal agency, AEP will work with the Commissions to ensure that AEP continues to furnish the Commission with the appropriate information to regulate its jurisdictional AEP operating company. The Commission may establish its reporting requirements regarding the nature of intercompany transactions concerning the operating company and a description of the basis upon which cost allocations and transfer pricing have been established in these transactions.

9. ADEQUACY AND RELIABILITY OF RETAIL ELECTRIC SERVICE. AEP agrees to maintain or enhance the adequacy and reliability of retail electric service provided by each of the AEP operating companies. Service reports will be submitted to the Commission in the format described in Attachment C to this Agreement. The substance or format of reporting may be changed by mutual agreement of the parties.

10. STATUTORY AND OTHER ISSUES. Provided the proposed merger is ultimately consummated, AEP commits that upon issuance of any final and non-appealable order from any state or federal commission addressing the merger that provides benefits or imposes conditions on AEP that would benefit the ratepayers of any jurisdiction, such net benefits and conditions will be extended to all other retail customers to the extent necessary to achieve equivalent net benefits and conditions to all retail customers of AEP.

11. CONTINUED PARTICIPATION. Upon execution of this Agreement, AEP may notify the FERC in FERC Docket No. EC98-40-000 that a settlement agreement has been executed by AEP, I&M and the Commission Staff and is being submitted to the Commission for its review and approval. No press releases related to this Agreement may be issued by either party until the Commission has acted on it. Upon the approval of this Agreement, the Commission will immediately notify the FERC that it is has reached a settlement agreement with AEP and will not continue to pursue its argument before the FERC.

12. ENFORCEABILITY. AEP and I&M will not assert in any action to enforce an order approving this Agreement that the Commission lacks the authority to have the provisions of this Agreement enforced under Michigan law. Disputes regarding the interpretation of this Agreement shall be brought to a state court of competent jurisdiction.

DEFINITIONS

1. "AEP zone" means either the area comprising the AEP operating companies providing service in Michigan, Michigan, Kentucky, Ohio, Tennessee, Virginia and West Virginia ("East") or the area comprising the former CSW operating companies providing service in Arkansas, Texas, Oklahoma and Louisiana ("West").

2. "AEP operating company" means an AEP affiliate that is a public utility subject to rate regulation by the FERC and/or a state utility regulatory agency.

3. "Affiliate" means an entity that is an operating company's holding company, a subsidiary of the operating company or a subsidiary of the holding company.

4. "Entity" means a corporation or a natural person.

5. "Exempt wholesale generator" means an entity which is engaged directly or indirectly through one or more affiliates exclusively in the business of owning or operating all or part of a facility for generating electric energy and selling electric energy at wholesale and who:

   a. does not own a facility for the transmission of electricity, other than an essential interconnecting transmission facility necessary to affect a sale of electric energy at wholesale; and

   b. has applied to the FERC for a determination under 15 U.S.C. Section 79z-5a.

6 "FERC" means the Federal Energy Regulatory Commission, or any successor governmental agency.

7 "Non-Utility Affiliate" means an Affiliate which is not a domestic public utility. Non-utility affiliate includes a foreign affiliate.

8 "Holding Company" means AEP, or its successor in interest, or any Entity that owns directly or indirectly 10 percent or more of the voting capital stock of a utility operating company, or its successor in interest.

9. "Power Marketer" means an entity which:

   a. becomes an owner or broker of electric energy in a state for the purpose of selling the electric energy at wholesale;

   b. does not own transmission or distribution facilities in a state;

   c. does not have a certified service area; and

   d. has been granted authority by the FERC to sell electric energy at market-based rates.

10. "Regional Transmission Organization" (RTO) means an organization that operates electric transmission equipment and facilities on a regional basis.

11. "SEC" means the United States Securities and Exchange Commission, or any successor governmental agency.

12. "Service Agreement" means the agreement entered into between American Electric Power Service Corp. and AEP's operating companies, under which services are provided by American Electric Power Service Corp. to the operating companies.

13. "Service Company" means an Affiliate whose primary business purpose is to provide, among other functions, administrative and general or operating services to AEP utility operating companies.

14. "Services" means the performance of activities having value to one party including, but not limited to, managerial, financial, accounting, legal, engineering, construction, purchasing, marketing, auditing, statistical, advertising, publicity, tax, research, and other similar services.

15. "Subsidiary" means any corporation 10 percent or more of whose voting capital stock is controlled by another Entity.

16. "Utility Affiliate" means an affiliate of a utility operating company that is also a public utility.

Presentation of Agreement to the Commission

1. I&M shall, contemporaneously with the execution of this Agreement, petition the Commission for ex parte approval of the net merger savings reductions and accounting authority set forth in the Agreement, conditioned on the Commission's approval of the Agreement without modification. As part of the proceeding on the petition for ex parte approval, the Parties will submit this Agreement to the Commission for review and approval.

2. The Parties stipulate and agree to the issuance by the Commission of the Proposed Order in the form attached hereto as Attachment D. All of the terms and agreements contained in the Proposed Order are to be interpreted consistent with the provisions of this Agreement, which is to be attached to and incorporated by reference in the Final Order issued by the Commission.

Effect and Use of Agreement

1. This Agreement shall not constitute nor be cited as precedent or deemed an admission by any Party in any other proceeding except as necessary to enforce its terms before the Commission, or any State Court of competent jurisdiction. This Agreement is solely the result of compromise in the settlement process, shall not constitute a concession of subject matter jurisdiction, and except as expressly provided herein, is without prejudice to and shall not constitute a waiver of any position that any of the Parties may take with respect to any or all of the items resolved herein in any future regulatory or other proceedings and, failing approval by this Commission, shall not be admissible or discussed in any subsequent proceedings.

2. The undersigned have represented and agreed that they are fully authorized to execute this Agreement.

3. The Parties to this Agreement shall not appeal the agreed Final Order or any other Commission order approving this Agreement to the extent such orders are specifically implementing the provisions of this Agreement and shall support this Agreement in the event of any appeal by a person not a Party. This provision shall be enforceable by any Party, in any state court of competent jurisdiction.

4. The communications and discussions during the negotiations and conferences that produced the Agreement have been conducted on the explicit understanding that they are or relate to offers of settlement and shall therefore be privileged and not admissible in any proceeding.

ACCEPTED and AGREED this 16th day of November, 1999.

Indiana Michigan Power Company

By: [signature]
Marc E. Lewis
Senior Attorney

American Electric Power

By: [signature]
Richard E. Munczinski
Senior Vice President
American Electric Power
Service Corporation

Michigan Public Service Commission Staff

By: [signature]
Steven D. Hughey (P32203)
Assistant Attorney General

AEP/CSW MERGER
EXAMPLE OF BASE RATE CASE TREATMENT
BASED ON YEAR 3 ($000)

CREDIT PER RIDER CONTINUES			(1,560)
INCLUDED IN TEST YEAR:			
GROSS MERGER SAVINGS		(3,575)	
CHANGE IN CONTROL AMORTIZATION	160		
OTHER CTA AMORTIZATION	575		
TOTAL CTA/CIC AMORTIZATION		735	
NET MERGER SAVINGS IN TEST YEAR		(2,840)	
ADD BACK TO TEST YEAR COST OF SERVICE:			
CUSTOMER SHARE	1,560		
SHAREHOLDER PORTION	1,280		
		2,840	
NET BASE RATE REDUCTION			0
MICHIGAN CUSTOMER RATE REDUCTION			(1,560)

Case No. 99-149
Order Dated June 14, 1999
Item No. 13
Page 75 of 119

AEP/CSW MERGER
BASE RATE CASE TREATMENT
FOR INCLUSION IN COST OF SERVICE ($000)

RATE YEAR	Add Back to Test Year Cost of Service: CUSTOMER NET SAVINGS	SHAREHOLDER NET SAVINGS
Year 1	685	472
Year 2	1,243	987
Year 3	1,560	1,280
Year 4	1,815	1,515
Year 5	1,982	1,670
Year 6	2,109	1,787
Year 7	2,208	1,878
Year 8	2,265	1,930
	13,867	11,519

AEP/CSW MERGER
AMORTIZATION OF ESTIMATED
COSTS TO ACHIEVE*

RATE YEAR	AMOUNT
Year 1	735,465
Year 2	735,465
Year 3	735,465
Year 4	735,465
Year 5	735,465
Year 6	735,465
Year 7	735,465
Year 8	735,465
TOTAL	5,883,722 **

* Includes change in control payments.
**May not add due to roundings.

Quality of Service Reporting

Indiana Michigan Power will maintain the overall quality and reliability of its electric service at levels no less than it has achieved in the past decade.

Indiana Michigan Power will provide service reliability reports annually indicating its calendar year Michigan Customer Average Interruption Duration Index (CAIDI) and Michigan System Average Interruption Frequency Index (SAIFI). These indices shall be determined and reported, including all storms. Definitions for these measures are included in this Attachment.

Indiana Michigan Power also will provide annual Call Center performance measures for those centers which handle Michigan customer calls. These will include the Call Center Average Speed of Answer (ASA), Abandonment Rate, and Call Blockage. Definitions for these measures are included in this Attachment.

The performance information described above shall be provided by the end of May of the year following the calendar year in question.

AEP Call Center Measures

1) Average Speed of Answer (ASA) is defined as the average time that elapses in seconds between the instant when a call is answered and the time it is connected to a Call Center representative (CSR) or an interactive voice recorder (IVR). It is calculated using the equation:

$$\underset{\text{(seconds)}}{\text{Average Speed of Answer}} = \frac{\text{time for all calls between call answer and CSR/IVR connection}}{\text{total number of calls made to the Call Center}}$$

2) Abandonment Rate is the percentage of callers who hang up before being connected to a Call Center representative (CSR) or an interactive voice recorder (IVR). It is calculated using the equation:

$$\underset{\text{(percent)}}{\text{Abandonment Rate}} = \frac{\{\text{total number of callers who hang up}\}}{\{\text{total number of calls made to the Call Center}\}} \times 100$$

3) Call Blockage is the percentage of non-outage call attempts which do not get connected to a Call Center (busy signal, etc.). It is calculated using the equation:

$$\underset{\text{(percent)}}{\text{Call Blockage}} = \frac{\{\text{total number of non-outage calls that do not get connected}\}}{\{\text{total number of non-outage calls made to the Call Center}\}} \times 100$$

HOWREY & SIMON

July 14, 1999

Stephen Angle

Mr. David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Offer of Settlement in Docket Nos. EC98-40-000, ER98-2770-000, and ER98-2786-000

Dear Mr. Boergers:

Pursuant to Rule 602 of the Federal Energy Regulatory Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602, the American Electric Power Service Company, Inc. and Central and South West Corporation hereby tender for filing an original and fourteen copies of a Settlement Agreement, along with a separate Explanatory Statement, that would resolve all issues raised by the Missouri Public Service Commission in the above-captioned dockets.

Please call if you have any questions regarding this filing.

Very truly yours,

Stephen Angle
Counsel for American Electric Power Company, Inc. and Central South West Corporation

Enclosures

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Company, Inc. and Central and South West Corporation	)))	Docket Nos. EC98-40-000, ER98-2770-000, and ER98-2786-000

EXPLANATORY STATEMENT
IN SUPPORT OF SETTLEMENT AGREEMENT

Pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602, American Electric Power Company, Inc. and Central and South West Corporation (Applicants) submit this Explanatory Statement in support of the attached Settlement Agreement. That attached Settlement Agreement, if approved by the Commission, would resolve all issues of concern to the Missouri Public Service Commission regarding the proposed merger, and particularly issues regarding any effect on retail market power in the state of Missouri, for purposes of the instant proceeding.

I. BACKGROUND

On April 30, 1998, American Electric Power Company, Inc. (AEP) and Central and South West Corporation (CSW) filed a joint application seeking authorization to consolidate their jurisdictional facilities through a merger. Applicants also filed a Joint Open Access Transmission Tariff (Docket ER98-2786) and additional agreements related to operation of the merged system (Docket ER98-2770). The Missouri Public Service Commission (Missouri Commission) intervened in the three now-consolidated dockets, and filed a Protest and Request for Hearing in the merger proceeding. One of the primary concerns raised by the Missouri Commission was the potential effect of the merger on retail competition in the state of Missouri. The Missouri Commission explicitly noted that it had no jurisdiction over the merger, and accordingly asked this Commission to analyze the merger's effects on retail competition as part of this proceeding.

On November 10, 1998, FERC issued an order setting several aspects of the proposed merger for hearing, including the merger's effect on retail competition in the state of Missouri. *See American Electric Power Co. and Central and South West Corp.*, 85 FERC ¶ 61.201 (1998) at 61,819. Since that time, Applicants have engaged in extensive settlement discussions with the Missouri Commission (along with other intervenors), and recently reached an agreement in principle with the Missouri Commission. That agreement, memorialized in the attached Settlement Agreement, is designed to resolve all issues raised by the Missouri Commission. If and when Missouri decides to implement a retail access program, the agreement provides a mechanism for the Missouri Commission to initiate a FERC inquiry into the merger's effects on retail competition in Missouri. To the extent that FERC finds adverse effects attributable to Applicants' reservation of 250 MW of capacity on the Ameren transmission system, FERC can then decide whether Applicants should be directed to mitigate the adverse effects attributable to that capacity reservation.

II. REASONABLENESS OF SETTLEMENT OFFER AND DESCRIPTION OF SETTLEMENT TERMS

In its Protest in the merger proceeding, one of the primary concerns noted by the Missouri Commission was the effect of the Applicants' reservation of 250 MW of capacity on the Ameren system. Specifically, the Missouri Commission noted that the firm capacity reservation could prevent other market participants from gaining needed access to customers in Missouri should the state decide to implement retail competition. *See Notice of Intervention, Protest, and Request for Hearing of the Missouri Public Service Commission* at 10, Docket EC98-40 (filed June 30, 1998). Accordingly, the Settlement Agreement attempts to address the potential harm to retail competition in Missouri attributable to the proposed capacity reservation, and to provide a mechanism to analyze any adverse effect once the state has decided to implement a retail access program.

The Settlement Agreement allows the Missouri Commission to seek further action from FERC subsequent to issuance of a Missouri Commission order implementing enabling legislation authorizing retail electric competition in Missouri. At that point, and no later than four years after consummation of the merger, the Missouri Commission can seek a FERC determination that Applicants' reservation of transmission capacity is having a significant adverse effect on retail competition in Missouri, and can request that FERC require the then-merged company to take steps to mitigate any adverse effect found.[1]

The Settlement Agreement includes certain procedural guidelines to allow for a thorough and fair review of the issues, including the following:

- Both parties will submit testimony and exhibits supporting their position on each of four issues: 1) whether a significant adverse effect exists, 2) whether it is attributable to the transmission capacity reservation, 3) whether a FERC order is appropriate to mitigate such effects, and 4) what an appropriate FERC remedy should be.
- FERC's determination on these issues is to be decided on the merits, rather than on the basis of burden of proof or burden of going forward.
- Unless otherwise agreed or directed by FERC, the analysis of adverse merger effects must be consistent with Appendix A of the FERC Merger Policy Statement.
- Applicants and their affiliates will provide such information as the Missouri Commission reasonably believes it requires to determine whether significant competitive concerns exist, with FERC to resolve any disputes.

[1] The option to initiate such an inquiry remains within the Missouri Commission's discretion. However, once the Missouri Commission notifies the merged company that it will exercise that option, the Missouri Commission and the merged company will submit a joint request to FERC.

uncertainties are resolved, and allows the merger to go forward while preserving adequate protection for Missouri consumers should retail access be implemented.

Respectfully submitted,

Clark Evans Downs
Jones, Day, Reavis & Pogue
311 First St., N.W.
Washington, D.C. 20001
Telephone: (202) 879-3939
Facsimile: (202) 626-1700

Attorneys for Central and South West Corporation

Stephen Angle
Howrey & Simon
1299 Pennsylvania Avenue, N.W.
Washington, D.C. 20004
Telephone: (202) 383-7261
Facsimile: (202) 383-6610

Edward J. Brady
Kevin F. Duffy
American Electric Power Company, Inc.
1 Riverside Plaza
Twenty-Ninth Floor
Columbus, OH 43215-2373
Telephone: (614) 223-1608
Facsimile: (614) 223-1687

James F. Mauzé
Ottsen, Mauzé, Leggat & Belz, LLC
112 South Hanley Road
St. Louis, Missouri 63105
Telephone: (314) 726-2800
Facsimile: (314) 863-3821

Attorneys for American Electric Power Company, Inc.

Dated: July 14, 1999

the merger proceeding. In that Protest, the Missouri Commission explicitly noted that it had no jurisdiction over the merger, and asked this Commission to analyze the merger's effects on retail competition in Missouri as part of this proceeding.

On November 10, 1998, FERC issued an order setting several aspects of the proposed merger for hearing, including the merger's effects on retail competition in Missouri. *American Electric Power Company and Central and South West Corporation*, 85 FERC ¶ 61,201 at 61,819 (1998). Since that time, Applicants have engaged in extensive settlement discussions with active intervenors, and recently reached an agreement with the Missouri Commission, as memorialized herein. This agreement is designed to resolve all issues of concern to the Missouri Commission regarding the merger, by providing a mechanism whereby the Missouri Commission can request that FERC initiate a new inquiry into the merger's adverse effects on retail competition (and order appropriate remedies) if and when Missouri decides to adopt a program of retail competition.

II. TERMS OF SETTLEMENT

A. Provisions Addressing Issues Raised by the Missouri Commission

The Applicants and the Missouri Public Service Commission (MoPSC) agree that if FERC determines that the Merged Company's use of Ameren transmission capacity (a) adversely affects competition in Missouri retail markets, and (b) such effect is significant and properly attributable to the Applicants' reservation of 250 MW of transmission capacity in order to integrate the systems of AEP and CSW, the Applicants will provide Ameren and other affected Missouri ratepayers with such appropriate relief, if any, determined by the FERC. Applicants and MoPSC agree that any relief ordered should consider all options for mitigation, and recognize any benefits to Missouri retail customers properly attributable to the Merged

Company's use of Ameren transmission capacity. The intent of the previous sentences shall be effected through the steps set forth below.

1. Subsequent to an order of the MoPSC implementing enabling legislation authorizing retail electric competition in Missouri, the MoPSC may notify the Merged Company of its intent to seek from FERC (a) a determination that the Merged Company's use of Ameren transmission capacity is creating a significant adverse effect on retail competition, and that such effect is properly attributable to the merger, and (b) an order from FERC requiring the Merged Company to take actions necessary to mitigate such effect.

2. Upon the receipt of such notification, the following procedures will apply:

a. The MoPSC and the Merged Company shall jointly request that FERC make a determination as to --

i. whether a significant adverse effect on retail competition exists in Missouri retail markets;

ii. if (i) is in the affirmative, the extent to which such effect is properly attributable to the applicants' reservation of 250 MW of capacity on the Ameren transmission system;

iii. if (ii) is in the affirmative, whether a FERC order to provide a remedy to mitigate such effect is appropriate; and

iv. If (iii) is in the affirmative, what an appropriate remedy should be.

The parties shall attach to their request such testimony and exhibits as each party deems necessary to support its respective position on questions (i) through (iv), including the appropriate remedy.

b. In the proceeding in which FERC makes such determination, FERC will make an affirmative decision on the merits, rather than based on a finding that a party has not carried its burden of going forward or borne its burden of proof.

6. This agreement settles all issues that the MoPSC has raised regarding the effects of the proposed merger on retail market power specific to Missouri.

B. General Provisions

1. Except as otherwise specifically provided in this Settlement Agreement, the filing of this Agreement, or support of the Agreement by any participant shall not be deemed in any respect to constitute an admission by any such participant that any allegation or contention made by any other party in these proceedings is true or valid. The filing or support of this Agreement establishes no principles and shall not be deemed to foreclose any participant from making any contention in any future proceeding or investigation. The acceptance of this Agreement by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any allegation or contention made by any party hereto in this proceeding.

2. This Agreement is expressly conditioned on the Commission's acceptance of all provisions hereof without material adverse modification (affecting the Applicants' or the Missouri Commission's interests, to be determined in their sole discretion). If the Commission does not so accept this Agreement, then the Agreement shall be deemed withdrawn and, upon such withdrawal, it shall not constitute any part of the record in this proceeding or be used for any other purpose.

3. The discussions among the parties which have preceded this Agreement of Settlement have been conducted on the explicit understanding, pursuant to Rule 602(e) of the Commission's Rules of Practice and Procedure, that this Agreement and all discussions of settlement and any comments on those offers are not admissible as evidence against any participant who objects to their admission and that any discussion among the parties with respect to offers of settlement is not subject to discovery or admissible as evidence.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in Docket Nos. EC98-40-000, ER98-2770-000, ER 98-2786-000, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010.

Dated at Washington, D.C. on this 14th day of July 1999.

Julie B. Greenisen

scan

PUC DOCKET NO. 19265
SOAH DOCKET NO. 473-98-0839

APPLICATION OF CENTRAL AND SOUTH WEST CORPORATION AND AMERICAN ELECTRIC POWER COMPANY, INC. REGARDING PROPOSED BUSINESS COMBINATION	§ § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order finds that the proposed business combination involving Central and South West Corporation (CSW) and American Electric Power Company, Inc. (AEP) (collectively applicants) is consistent with the public interest, pursuant to PURA[1] § 14.101, under the terms and conditions specified in this Order. This conclusion rated the comprehensive public interest standard articulated in *Application of Southwestern Public Service Company Regarding Proposed Business Combination with Public Service Company of Colorado*.[2] Furthermore, this Order and approves the requested regulatory treatments detailed in Section X of the application to the extent specified in this Order.

This Order is consistent with the non-unanimous stipulation (ISA)[3] entered into by several parties in this proceeding. Nevertheless, this Order addresses two areas, allocation of certain savings to regulated rates and reliability standards, to ensure compatability of the ISA and this Order with electric restructuring legislation passed by the 76th Legislature.[4] The State Office of Administrative Hearings' Proposal for Decision,[5] including findings of fact and conclusions of law, is adopted and incorporated by reference into this Order, except where inconsistent with this Order.

---

[1] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§11.001-64.158 (Vernon 1999) (PURA).

[2] *Application of Southwestern Public Service Company Regarding Proposed Business Combination with Public Service Company of Colorado*, Docket No. 14980 (Feb. 14, 1997).

[3] Integrated Stipulation and Agreement (May 4, 1999) (ISA).

[4] Act of May 27, 1999, 76th Leg., R.S., ch. 405 (S.B. 7), 1999 Tex. Sess. Law Serv. 2543 (Vernon) (to be codified primarily as Chapters 39, 40, and 41 of the Texas Utilities Code).

[5] Proposal for Decision (Sept. 30, 1999).

I. Discussion

Distribution rates

The ISA provides that the Texas operating companies[6] will apply the savings detailed in Attachments A and H of the ISA to the "regulated rates of their customers"[7] and that all rate reduction riders will be credited to customers in accordance with Attachment I.[8] Paragraph 9 of Attachment I provides:

> In the event of industry restructuring legislation, the base rate revenue credits will be maintained by individual rate class, to the extent possible, although it is impossible to formulate a specific plan at this time. If and when restructuring legislation is enacted, the Applicants will submit a plan for [Commission] approval to allocate the credits set forth in Attachments A and H consistent with Sections 3.C, 3.F(8) and Attachment H, Section 6.[9]

Subsequent to the filing of the ISA, electric restructuring legislation was enacted into law.[10]

The Commission concludes that customers of the Texas operating companies will not receive the full benefit of the savings specified in the ISA after January 1, 2002, unless the savings are allocated to the distribution rates of the successor transmission and distribution utilities.[11] A representative of AEP has assured the Commission that the proposed savings in the ISA can, as a practical matter, be applied against distribution rates.[12] The Commission's decision in this matter rests, in part, on this assurance.

---

[6] Central Power and Light, Southwestern Electric Power Company, and West Texas Utilities and their respective successors in interest. *See* ISA § 1.

[7] ISA § 3.C and Attachment H, ¶ 6.

[8] *Id.* Attachment H, ¶ 1.

[9] *Id.* Attachment I, ¶ 9.

[10] Act of May 27, 1999, 76th Leg., R.S., ch. 405 (S.B. 7), 1999 Tex. Sess. Law Serv. 2543 (Vernon) (to be codified primarily as Chapters 39, 40, and 41 of the Texas Utilities Code).

[11] Under PURA § 39.051, all electric utilities, including the Texas operating companies, will be required to unbundle their business activities into several entities, one of which will be a transmission and distribution utility.

[12] Open Meeting Tr. at 284-88 (Nov. 4, 1999).

Therefore, the unbundling proceedings in 2000, in which the Commission will approve the transmission and distribution tariffs[13] are the appropriate forums to reflect these post-2002 savings in distribution rates. The savings are not effective, however, until the first month after the effective date of the merger,[14] and the merger may not be effective until after the April 1, 2000 deadline for filing tariffs initiating the unbundling proceedings.[15] In that event, after the merger is effective, the Texas operating companies' filings shall be amended to reflect the regulated-rate savings in the distribution rates of their successor transmission and distribution utilities. Ordering Paragraph 9 is modified and new Ordering Paragraph 9A is added to reflect this decision.

Reliability Standards

Section 7.B of the ISA specifies reliability standards that are based upon P.U.C. SUBST. R. 25.53 and 25.81, and guarantees related to those standards. The Commission is, however, presently considering amendments to these rules[16] to conform to newly enacted statutory requirements.[17] Anticipating such changes, Section 7.D(2) of the ISA provides that:

> In the event the Commission's service reliability rule (Substantive Rule 25.52) is amended, such amendments shall automatically be incorporated in this agreement. Additionally, the signatories agree that they will revisit these standards and penalties in the future in the context of any performance-based ratemaking plans or rules for CSW and /or the electric industry.[18]

To effectuate this provision, the Commission adds new Ordering Paragraph 9B directing the Office of Regulatory Affairs, after any amendments to the Commission's service reliability rules, to establish a project to address any inconsistencies between the ISA and those amendments.

---

[13] *See* PURA § 39.201.

[14] ISA § 3A.

[15] Open Meeting Tr. at 301-02 (Nov. 4, 1999).

[16] *Electric Reliability Standards*, Project No. 21076 (pending).

[17] *See* PURA § 38.005.

[18] ISA § 7.D(2).

V. Findings of Fact and Conclusions of Law

A. Findings of Fact

Description of the Applicants

1. This case involves the potential merger of American Electric Power Company, Inc. (AEP) with Central and South West Corporation (CSW) (collectively called the Applicants).

2. AEP is a utility holding company based in Columbus, Ohio. It owns all the common shares of seven domestic electric utility operating companies: Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company. The AEP operating companies serve almost three million customers in parts of Ohio, Michigan, Indiana, Kentucky, West Virginia, Virginia, and Tennessee.

3. CSW is a utility holding company based in Dallas, Texas. It owns four domestic utility operating companies: Central Power and Light Company (CPL), Public Service Company of Oklahoma (PSO), Southwestern Electric Power Company (SWEPCO), and West Texas Utilities Company (WTU). CPL and WTU operate within Texas, SWEPCO serves customers in Texas, Arkansas and Louisiana, and PSO serves customers within Oklahoma. The CSW operating companies provide electric service to approximately 1.7 million customers in a widely diversified area covering 152,000 square miles. The three utility companies serving Texas are referred to as the "Texas operating companies."

Description of the Merger

4. Under the proposed transaction, CSW will in effect be merged into AEP, and CSW shares will be converted into AEP shares using an exchange ratio of .6 AEP shares per CSW share. Any fractional shares of AEP stock resulting from the exchange will be paid in cash. The merger will be accounted for by the "pooling of interests" method of accounting.

5. The only corporate effect of the merger on the operating companies of CSW is a change in the ownership of the holding company. AEP will be the surviving corporation, which will be headquartered in Columbus, Ohio.

6. The eleven domestic utility operating companies of CSW and AEP retain their separate corporate identities, assets and liabilities, franchises, and certificates of convenience and necessity.

7. The merger will require the approval of the Oklahoma Corporation Commission, the Arkansas Public Service Commission, and the Louisiana Public Service Commission. Each of those bodies has issued an order approving the merger with various conditions. On the federal level, approvals are being requested from the Federal Energy Regulatory Commission (FERC), the Securities and Exchange Commission under the Public Utility Holding Company Act of 1935, the Federal Trade Commission under the Hart-Scott-Rodino Antitrust Improvement Act, the Nuclear Regulatory Commission, and the Federal Communications Commission.

Procedural History

8. On April 30, 1998, the Applicants submitted an application to the Public Utility Commission of Texas (PUC or Commission) for a public interest finding. On May 1, 1998, the Commission referred this docket to the State Office of Administrative Hearings (SOAH).

9. On May 27, 1998, the Administrative Law Judge (ALJ) held a pre-hearing conference and set December 2, 1998 as the date for the hearing on the merits. On June 1, 1998, the PUC Office of Policy Development (OPD) issued an order requesting briefing on threshold issues. On June 5, 1998, OPD requested additional briefing on the issue of federal authority *vis-a-vis* the Commission's regulatory authority. After consideration of the briefs of the parties, the Commission issued its first Preliminary Order in this docket on July 1, 1998. That Preliminary Order identified statutory issues, issues arising from Commission precedent, and twelve case-specific questions. On July 14, 1998, the Commission issued its Supplemental Preliminary Order, adding a thirteenth question. On July 14, 1998, the Applicants submitted supplemental testimony that addressed each of the issues identified in the Commission's Preliminary Orders.

10. On July 24, 1998, the ALJ directed parties to engage in settlement meetings, and specified dates on which the Applicants would report to the ALJ on those settlement discussions. No comprehensive settlement was reached as a result of those discussions, but the Applicants did reach a settlement with the Office of Public Utility Counsel (OPC) and intervenor Cities.[19] That settlement was filed November 9, 1998. As a result, the Applicants filed additional testimony in support of that stipulation on November 25, 1998. On December 8, 1998, the ALJ issued an order setting a new date for the hearing on the merits of April 27, 1999. The ALJ also ordered the Applicants to file supplemental testimony on market power on January 15, 1999.

11. Several parties contended that the non-unanimous stipulation required additional notice. In Order No. 32, issued on December 14, 1998, the ALJ denied the motion. On appeal, in an order dated January 27, 1999, the Commission reversed the ALJ's ruling and ordered bill insert notices be given to affected customers and affected municipalities.

---

[19] Cities include Abilene, Corpus Christi, McAllen, Victoria, Big Lake, Vernon, and Paducah.

12. On March 23, 1999, the ALJ suspended the procedural schedule and rescheduled the hearing on the merits to May 4, 1999. On April 1, 1999, the ALJ moved the hearing on the merits to May 25, 1999. On April 23, 1999, the ALJ granted a motion to suspend the procedural schedule in light of a pending settlement. On May 4, 1998, numerous parties (the Signatories) submitted an Integrated Stipulation and Agreement (ISA). In addition to the OPC and the Cities, the Signatories included the Commission Office of Regulatory Affairs (ORA), the State of Texas, the Texas Industrial Energy Consumers, and Low Income Intervenors. On May 11, 1999, the ALJ issued Order No. 52, requiring the filing of additional testimony in support of the ISA and setting August 9, 1999 as the date for the hearing on the merits.

13. In accordance with Order No. 52, the Signatories filed supplemental testimony on May 21, 1999. Several non-signatory parties filed testimony regarding the merger on July 16, 1999. The Signatories filed rebuttal testimony on July 30, 1999.

14. The hearing on the merits commenced on August 9, 1999. At the start of the hearing, counsel for Applicants announced additional settlements had been reached with all but one of the active non-signatories. As a result, the hearing consisted exclusively of the cross-examination by Power Choice, Inc.'s (Power Choice) counsel, with limited redirect by the Signatories and inquiry by the ALJ. Upon receipt of a letter from the counsel for the Public Utility Board of Brownsville, the ALJ closed the hearing on August 11.

The ISA

15. The ISA resolves all the merger-related issues among the Signatories and also resolves some regulatory proceedings of the Texas operating companies as well. The ISA contains merger-related rate reductions, as well as rate reductions arising from the settlement of other cases. It provides for additional amortization of Excess Cost Over Market (ECOM) of CPL. It contains a market power mitigation plan and provides affiliate standards. It sets detailed customer service standards. It includes a rate moratorium for the Texas Operating companies that will last until January 1, 2003, subject to certain force majeure provisions. It contains provisions regarding jurisdictional issues between the PUC and federal agencies. It provides for Applicants to implement a Customer Education Plan and an expanded Low-Income program. It includes a sharing of off-system sales margins and other provisions relating to the operations of the merged companies.

16. The ISA represents a compromise among all the Signatories. If the PUC does not accept the ISA or issues an interim or final order that is materially inconsistent with the ISA, any Signatory adversely impacted by that material modification or inconsistency may withdraw its consent and proceed to a hearing on all issues.

Reasonable Value

17. This merger is accomplished through a stock transaction. The price of CSW's and AEP's stock is set through the daily trading activity of the New York Stock Exchange. The merger was analyzed by the Board of Directors of both CSW and AEP and included the consideration of fairness opinions produced for both Boards. The transaction was the product of a willing buyer and a willing seller establishing a reasonable value after consideration of a number of factors. The Boards of both companies utilized fairness opinions prepared by investment bankers. Those opinions considered discounted cash flows, comparable companies, selected other mergers and acquisitions, historic trading ratios, and a *pro forma* analysis of the merger.

18. AEP will convert CSW stock to AEP stock using a conversion ratio of .60 of AEP shares for each share of CSW stock.

Health and Safety

19. AEP has an excellent safety record. AEP has employee training regarding safety, programs for the health and well being of its employees, and an active safety outreach program for the general public. After the merger, the similar health and safety programs of CSW will eventually be combined into a unified health and safety program. The proposed merger will not adversely affect the health or safety of customers or employees.

Employment Impacts

20. The merger could result in some jobs being transferred out of the state of Texas. Most of the potential job losses will be in the middle and upper ranks of management in the service companies. The geographic diversity of the merger ensures that many functions remain local.

21. Paragraph 9.C. of the ISA commits the Merged Company[20] not to reduce operating company field positions and customer service jobs for eighteen months beginning April 1, 1999. "Field positions" includes all employees on the front-line of providing service to the customer. This term would include all linemen, servicemen, and meter readers. "Customer service jobs" would include all the jobs having day-to-day contact with customers, such as telephone service representatives in the companies' call centers.

22. The merger will not result in the material transfer of jobs of citizens of this state to workers domiciled outside this state.

[20] Merged company is defined in the ISA as the post-merger AEP and its successors in interest. *See* ISA § 1.

No Decline in Service

23. The ISA contains numerous standards for service quality, with monetary penalties if they are not met. The merger will not result in a decline of service quality or reliability.

Merger Does "More than Promise" Cost Savings

24. The ISA provides for the sharing of net merger savings with Texas customers through a "net merger savings rate reduction rider." A total of \$84.4 million of merger savings will be shared with customers of CPL (\$52.7 million), SWEPCO (\$16 million), and WTU (\$15.6 million). After the sixth year, the net merger savings rider will continue at the same level as the year six rider. In the first base rate proceeding for an operating company after the six-year net merger sharing savings period, all merger savings will be reflected in rates and the net merger savings rate reduction rider will be terminated. The amount of the net merger savings rate reduction rider is based on the estimates of net Texas retail merger savings. Even if net merger savings fall short of the estimates, the Applicants are guaranteeing a fixed level of benefits to customers and will bear the risk of any failure to actually achieve the full amount of net savings.

25. The ISA also contains rate reduction riders in Attachment H. In the context of the overall ISA, the total amount of the rate reductions (merger-related and Attachment H) is just and reasonable. Attachment H also provides that CPL will extend the terms of the Docket No. 12820[21] Stipulation to include a pre-tax ECOM amortization of \$20,000,000 per year in 2000 and 2001 and a pre-tax ECOM amortization of \$5,000,000 per year in the years 2002 through 2005. The provisions of the ISA dealing with rate reduction riders and reductions of ECOM are reasonable and in the public interest.

[21] *Inquiry of General Counsel for an Inquiry Into the Reasonableness of the Rates and Services of Central Power and Light Company (CPL)*, Docket No. 12820, Order on Rehearing (Oct. 11, 1995).

26. The ISA requires that all reconcilable fuel and purchased power savings be passed through to customers in accordance with PUC rules and proceedings for fuel factor adjustments and fuel reconciliation. The Applicants estimate that there will be fuel savings as a result of the merger.

27. The ISA does more than "just promise" savings to the Texas retail customers of the Texas Operating companies.

Improvement in Service

28. AEP made the commitment to meet current levels of service and strive to exceed those levels. AEP may improve CSW service through the introduction of a real-time customer service data system, developments in the AEP transmission and distribution system which may be useful to CSW in the proper circumstances, and software programs which may be useful to CSW service.

29. The ISA contains eight pages of detailed standards relating to quality of service. The ISA specifies standards for service turn on and upgrades, light replacements, telephone response, and reporting requirements. Each of the customer standards has an accompanying penalty for failure to meet the standard. The ISA similarly establishes standards for distribution feeders and system standards, with detailed monetary penalties for failure to meet each standard. The ISA authorizes an independent audit of the standards by the Office of Customer Protection twenty-four months after the standards are implemented by the Merged Company, and every twenty-four months thereafter.

30. The quality of service provisions provide additional assurances that the merger will result in improvements in service to CSW's Texas customers because of the financial incentives contained in the standards. The customer service reporting standards are new requirements that do not exist under current Commission rules. The ISA establishes numerous reporting,

surveying, and independent auditing requirements, which enhance the Commission's and customers' monitoring and evaluation of the customer service provided by the Merged Company.

31. The ISA contains an expanded Low-Income program which will improve the quality of service for the customers served by that program. The Low-Income program is reasonable and in the public interest.

32. The ISA includes a Customer Education plan in the event of retail competition. Now that Senate Bill No. 7 has been signed, this provision of the ISA will mean more information for Texas consumers. The Customer Education plan is reasonable and in the public interest.

33. The customer service standards and reliability standards contained in the ISA are appropriate. Based on Findings of Fact Nos. 28 through 32, the quality of service for Texas customers will improve as a result of the merger.

Merger Costs and Merger Benefits

34. Over a ten-year period, the Applicants estimate they would have a total savings of \$2.407 billion, less merger costs-to-achieve of \$248,080 million and pre-merger initiatives of \$193,327 billion for a net savings level of \$1.965 billion.

35. The total amount of merger savings was allocated to each company by creating a synergy savings work order based on the analysis of services provided by the functional group. They utilized appropriate allocation factors for those functions to determine savings allocated to each operating company. The merger costs and pre-merger initiatives were allocated to all companies on a pro rata basis following gross savings. The individual company estimates of costs savings and costs were divided among regulatory jurisdictions using allocation factors that were generally consistent with the practices used for cost assignments in past

CSW rate proceedings. These efforts resulted in the level of merger savings shown in the ISA.

36. The ISA authorizes a "net merger savings" expense item (as shown in ISA Attachment B) to be reflected as a reasonable and necessary operating expense, if there is a proceeding to change base rates of a Texas Operating Company to become effective prior to the end of a six-year period after the effective date of the merger.

37. The ISA authorizes the Merged Company and Texas Operating companies to defer and amortize their merger-related costs-to-achieve over a six-year period following the effective date of the merger. If there is a proceeding to change base rates of a Texas Operating Company within six years after the effective date of the merger, the ISA states that the amortization of costs to achieve the merger included in Attachment C to the ISA will be reflected as a reasonable and necessary expense included in the cost of service. The ISA also reduces the amount that will be considered reasonable and necessary as included in Attachment E if a Texas operating company requests an increase to overall base revenues to be effective prior to the end of the six-year period.

38. Both the provisions of the ISA relating to the "net merger savings" expense item and the deferral and amortization of costs to achieve the merger, including change in control payments, are reasonable and should be approved.

39. The merger will not cause Texas customers to bear merger costs unrelated to corresponding benefits to Texas customers.

Merger Facilitates Regulatory Oversight

40. This merger does not cause any change in the jurisdiction of any regulatory body.

41. The Merged Company will propose a substantially expanded set of allocation factors over those presented by CSW in the last CPL rate case. Those factors will correlate to the volume of activity that is generated in performing certain services and thereby emphasize cost causation factors.

42. The ISA contains numerous provisions that relate to the regulatory jurisdiction of the PUC. They are primarily contained within ISA Section 4, but other provisions will assist the PUC in its regulatory oversight over the Merged Company.

43. The books and records of the Texas operating companies might be kept outside the state. The Merged Company will return such records for inspection pursuant to P.U.C. Subst. R. 25.71.

44. The merger is not a means of evading regulation and will facilitate regulatory oversight of the Merged Company.

Market Power and Competition

45. Under the Applicants' market power study, there were instances in the Southwest Power Pool (SPP) and the Electric Reliability Council of Texas (ERCOT) in which the merger might cause failures of the FERC merger guidelines screen. The mitigation proposed by the ISA will address the apparent problems.

46. Under the ISA, the Merged Company agrees to divest 1604 megawatts (MW) of generation capacity in ERCOT. The ISA specifies that the divestiture shall consist of Lon Hill Units 1-4 (546 MW), Nueces Bay Plant (559 MW), Joslin Unit 1 (249 MW), and Frontera Plant (250 MW). The ISA also specifies that the Merged Company agrees to divest 300 MW in the SPP, or more if it is required to do so by FERC.

47. The ISA protects the accounting of the merger by timing the ERCOT divestiture so as to not violate the criteria of pooling of interests accounting. Paragraph 6.C of the ISA contains the procedures that the Applicants and ORA will follow in order to determine the appropriate timing for the divestiture.

48. CPL may recall up to 1354 MW of the divested capacity under certain circumstances. The ISA contains numerous details regarding when and under what circumstances CPL may recall the capacity.

49. Gains from the sale of the CPL plants will be used to reduce ECOM of the South Texas Nuclear Project (STP). Pursuant to the ISA, CPL is required to submit the terms of the divestiture of its plants to the Commission for approval.

50. The ISA also addresses a Regional Transmission Organization (RTO) in SPP. Under paragraph 6 M of the ISA, the Applicants set a date certain to place CSW's SPP transmission facilities within an RTO.

51. The market power mitigation plan contained in the ISA is consistent with the public interest.

Consistency with CPL Rate Case

52. The ISA regulatory plan does not change the accounting treatments ordered in Docket No. 14965,[22] or the rate reductions associated with the "glide path." The ISA reduces rates as reflected in the rate reduction riders contained in the ISA. The final order in Docket No. 14965 does not restrict CPL's ability to file for rate increases, but the ISA imposes a rate moratorium, with certain force majeure conditions, until January 1, 2003.

---

[22] *Application of Central Power and Light Company for Authority to Change Rates*, Docket No. 14965 (Oct. 16, 1997).

53. Under the ISA, within 30 days of the effective date of the merger, CPL will withdraw from its pending appeal of Docket No. 14965 all issues which relate to the mandated glide path rate reductions. Paragraph 4.L of the ISA also provides that the Merged Company will abide by the ultimate resolution of affiliate allocation issues in the Docket No. 14965 appeal.

54. The ISA is consistent with and furthers the final decision in Docket No. 14965.

<u>Consistency With WTU Rate Case</u>

55. Docket No. 13369[23] limited WTU-initiated rate increases, which has now been extended by the ISA to January 1, 2003. The ISA does not impact the amortization of the deferred Oklaunion costs, but does reduce rates as provided in the ISA's rate reduction riders.

56. With regard to sharing margins for off-system sales, the CPL final order requires that 100 percent of the off-system sales be passed through to CPL customers, while the WTU settlement allows 15 percent of the margins to be shared with shareholders. The ISA contains sharing mechanisms that allow for 100 percent of off-system margins to go to customers if the margins are below a certain level, 85 percent to customers if the margins exceed that level, and 50 percent of margins to customers if the margins exceed a significantly greater level.

57. There is good cause to authorize the treatment for off-system sales contained in the ISA. The current high credit percentages diminish the incentive to the Texas operating companies to commit additional resources to pursue additional sales and/or trading activities. The levels proposed in the ISA for sharing of 15 percent with shareholders is approximately 30 percent higher than the previous maximum margins in the last three years. In order to justify 50/50

[23] *Petition & Statement of Intent of West Texas Utilities for Rate Review, Request for Good Cause Exceptions for Filing & Procedural Requests*, Docket No. 13369 (Nov. 10, 1995).

sharing, the margins must increase by almost 100 percent from historical maximum levels. The ISA's provisions with regard to off-system sales are reasonable and in the public interest.

58. While the ISA contains off-system sales margins that differ from those contained in the CPL or WTU rate cases, they are "consistent with" or "further the rate treatments incorporated in" those two cases, and should, therefore, be adopted as part of the overall ISA. Similar treatment should be given to SWEPCO.

59. The ISA's provisions as a whole are consistent with or further the rate treatments incorporated in the WTU rate case.

<u>Consistency with IRP</u>

60. While the merger with AEP will potentially result in an additional source of firm capacity for the CSW Texas Companies after closing the merger, because planning for the sources of supply in the current IRP must occur today and given the limited amount of available firm transmission capacity, the CSW Texas Companies will continue the resource solicitation approved in Docket No. 16995.[24]

61. The ISA contains an agreement by the Applicants not to seek any new resource surcharge or Power Cost Recovery Factor or increase in any existing resource surcharge or PCRF, subject to certain conditions. Those conditions include if the requested surcharge or PCRF (1) was authorized in Docket Nos. 18041 or 18845,[25] or (2) is to provide for recovery of fuel and

[24] *Joint Application of Central Power and Light Company, West Texas Utilities Company and Southwestern Electric Power Company for Approval of Preliminary Integrated Resource Plans (IRP) and Related Good Cause Exceptions*, Docket No. 16995 (July 30, 1997 and April 13, 1998)(Interim Order on Preliminary Plan and Interim Order on Interruptible Phase, respectively).

[25] *Petition of Central Power and Light Company, West Texas Utilities Company, and Southwestern Electric Power Company for Approval of Contracts for Low-Income DSM Programs and for Authority to Implement a Power Cost Recovery Factor Associated Therewith*, Docket No. 18041, Final Order (May 11, 1998) or *Petition of Central*

purchased power energy savings resulting from demand-side management (DSM) as required by the preliminary integrated resource plan in Docket No. 16995. Docket Nos. 18041 and 18845 provide for certification of contracts and recovery of costs associated with low-income DSM programs and renewable-energy resources, which were acquired in compliance with the Commission's interim order in Docket No. 16995.

62. Neither the merger nor the provisions of the ISA affect the decisions in the interim orders issued in Docket No. 16995.

<u>Transmission Rights</u>

63. The rights of Texas transmission users (and all other parties) are potentially affected by the merger only to the extent that available transmission capacity through Ameren and into PSO and SWEPCO is reduced by the reservation of 250 MW of transmission capacity. AEP will continue to offer open-access transmission service between its East region (the current AEP) and the West region (the current CSW). The Applicants have filed a tariff at FERC that follows FERC Order No. 888 and ERCOT rules.

64. The Applicants have agreed to waive certain transmission priorities at FERC. They will agree to waive the SPP operating companies' priority to the use of their interfaces with other transmission systems to import centrally dispatched energy from the existing AEP East Zone in excess of 250 MW. The Merged Company will also waive PSO's and SWEPCO's priority to the use of those interfaces to import non-firm energy from non-affiliates. Finally, the Merged Company will schedule its use of the HVDC ties between SPP and ERCOT on a first-in-time basis for certain transactions.

Power and Light Company, West Texas Utilities Company and Southwestern Electric Power Company for Approval of Photovoltaic Contract and Renewable Energy Technologies Trailer Program and Associated Cost Recovery Mechanisms, PUC Docket No. 18845, Final Order (Nov. 24, 1998).

65. The acquisition and use of transmission rights by AEP for the merger will not impair the access, rights or priorities of other transmission owners or customers in Texas.

Tangible Benefits on a Timely Basis

66. Based on Findings of Fact Nos. 19 through 65, the ISA contains tangible benefits for Texas customers.

67. The ISA will produce timely benefits for Texas customers in the areas of rate reductions, ECOM amortization, market power mitigation, affiliate standards, customer service standards, rate moratorium, jurisdictional issues, customer education, low-income programs, off-system sales margins, and other ISA provisions.

68. Based on Findings of Fact Nos. 66 and 67, the merger will result in tangible benefits to Texas customers on a timely basis.

Impact of Retail Competition

69. The net merger savings rate reduction rider will continue to apply to regulated rates in the event of legislatively-mandated unbundling. The rate reductions apply even if there is a legislatively-mandated rate freeze. The net merger savings rate reduction rider will continue if there are legislatively-mandated rate reductions, and the net merger savings rate reduction rider will not be considered an offset to the legislative reduction.

Form of Merger Savings Sharing

70. The nature of the merger savings sharing plan has changed since the Commission issued its Preliminary Order. The Applicants' current regulatory plan is contained in the ISA, and is an appropriate means to implement sharing with customers. Preliminary Order question No. 6, as posed, is moot or should be modified to ask if the ISA's provisions are reasonable.

Service Quality Guarantees

71. The ISA contains several guarantees for service quality, including penalties if the standards are not met. The ISA also requires several reports (including statistically valid customer service surveys) and bi-annual audits by the Office of Customer Protection. The ISA contains appropriate guarantees to ensure that service quality in Texas does not suffer after the merger.

Guaranteed Minimum Amount

72. The ISA's net merger savings rate reduction rider is based on the estimated net Texas retail merger savings. Use of a fixed amount of savings allows for guaranteed benefits for customers while providing flexibility to accommodate a transition to competition. The Applicants bear the risk of any failure to actually achieve the full amount of net savings.

73. Using a fixed value for merger costs is reasonable. The ISA provides for a guaranteed minimum amount for the customers' share of merger savings. No true-up mechanism should be adopted.

Affiliate Standards

74. The ISA contains affiliate standards that will apply in the absence of PUC rules or legislation. The PUC is also devising rules for affiliate relations, including unbundling rules and code of conduct rules. Senate Bill No. 7 also contains several provisions concerning the ability of electric utilities to engage in cost shifting, cross subsidies, and/or discriminatory behavior. The Applicants have provided sufficient guarantees that will prevent unjustified cost shifting, cross subsidies, or discriminatory behavior.

Contested Issue

75. Section 4.E. of the ISA states that stranded costs will be recovered on a stand-alone basis among the Texas operating companies. This section of the ISA is intended to ensure a clear

separation between the three Texas companies and the AEP companies or PSO in Oklahoma in the allocation and recovery of stranded costs. It guarantees that customers of the CSW operating companies will not be at risk for stranded costs incurred by AEP.

76. Central Power & Light Company is likely to have stranded costs related to its ownership interest in the STP. WTU and SWEPCO do not currently have stranded costs related to generation plant. The language of § 4.E. does not address whether CPL stranded costs should be netted against the value of WTU and SWEPCO plants among the CSW operating companies. Furthermore, treatment of CSW stranded costs through netting among its Texas operating companies is not relevant to issues in this merger case.

77. The ISA does provide for ECOM mitigation in two instances: Attachment H, paragraph 3.d. of the ISA pledges a $60 million stranded cost reduction for CPL customers as an extension of the Docket No. 12820 Stipulation, and § 6.J. provides that the gains on the sale of CPL's power plants will be applied to reduce the company's stranded costs. The ISA does not bind the Commission to any particular treatment of stranded costs or ECOM in future proceedings.

<u>General Evaluation</u>

78. The ISA, taken as a whole, is a reasonable resolution of contested issues in this docket, is supported by the record, and is in the public interest. Therefore, the ISA should be adopted as the basis for the Commission's decision in this case.

79. The Applicants have presented substantial evidence that demonstrates that this merger meets each of the statutory standards, the Docket No. 14860[26] (SPS/PSCo) standards and the questions posed by the PUC in the Preliminary Orders. This evidence supports an independent finding that the ISA is just and reasonable.

[26] *Application of Southwestern Public Service Company Regarding Proposed Business Combination With Public Service Company of Colorado*, Docket No. 14980, Final Order (Feb. 14, 1997).

80. Under the provisions and conditions of the ISA, the merger of AEP with CSW is consistent with the public interest.

B. Conclusions of Law

81. CPL, SWEPCO and WTU are electric utilities as defined by Section 31.002 of the Public Utility Regulatory Act (PURA), TEX. UTIL. CODE ANN. (Vernon 1999). The Commission has jurisdiction over those utilities under PURA §14.001, *et seq.;*§31.001 *et seq.;*§33.001, *et seq.;* §36.001, *et seq.*; and §38.001 *et seq.*

82. The Applicants seek a public interest determination pursuant to PURA §14.101.

83. SOAH has jurisdiction over all matters relating to the conduct of a hearing of this proceeding including the preparation of a proposal for decision with findings of fact and conclusions of law pursuant to PURA §14.053 and TEX. GOV. CODE ANN. §2003.049 (Vernon 1999).

84. The Applicants have complied with the notice requirements as set by the PUC.

85. Because the Applicants, along with numerous other parties, presented a non-unanimous stipulation for approval, the procedure for considering such stipulations is proscribed by PURA §14.054 and PUC Procedural Rule §22.206. The hearing on the merits to consider the ISA was conducted in accordance with these provisions.

86. *Cities of Abilene, et al. v. Public Utility Comm'n,* 854 S.W.2d 932, 937-38 (Tex. App. - - Austin 1993), *aff'd in part and rev'd in part,* 909 S.W. 2d 493 (Tex. 1995) determined that a non-unanimous stipulation could be considered as a basis for a final order so long as "nonstipulating parties had an opportunity to be heard on the merits of the stipulation and the Commission made an independent finding on the merits, supported by substantial evidence

in the record, that the stipulation set just and reasonable rates." The procedure followed in this case conforms with the *Cities of Abilene* procedural requirements.

87. The ISA is a reasonable resolution of the contested issues in this docket, is consistent with PURA, is supported by the record, and is in the public interest.

88. The Applicants will comply with P.U.C. Subst. R. 25.71 by returning records to the PUC for inspection.

89. The Applicants have demonstrated good cause for the ISA's provisions regarding sharing of the margin for off-system sales in a manner different than that contained within P.U.C. Subst. R. 25.236(a)(8).

90. The Applicants have met their burden of proof with regard to the statutory standards; the SPS/PSCo standards found in Docket No. 14980, which specified other issues that need to be examined prior to the determination of the public interest; and the questions posed by the PUC in its Preliminary Orders in this case.

91. The rates resulting from the net merger savings rate reduction rider and the rate reduction riders in ISA Attachment H are just, reasonable, in the public interest and are not unreasonably preferential, prejudicial, or discriminatory pursuant to PURA §36.003.

92. Under the provisions and conditions of the ISA, the merger of AEP with CSW is consistent with the public interest under PURA §14.101.

VI. Ordering Language

In accordance with the foregoing findings of fact and conclusions of law, the Commission issues the following orders:

1. The application of CSW and AEP to combine their two businesses, as amended by the Integrated Stipulation and Agreement, is approved.

2. CPL, SWEPCO and WTU shall implement the net merger savings rate reductions riders and the ISA Attachment H rate reductions riders through filings with appropriate regulatory authorities to be effective for bills rendered in the first revenue month after the closing of the merger as specified in this Order.

3. CPL shall reduce stranded costs related to its generating plants consistent with the agreements contained in ISA.

4. The Merged Company shall comply with the jurisdictional resolutions contained in § 4 of the ISA.

5. The Merged Company shall adopt the Low-Income program, customer service, and reliability standards established in the ISA and shall implement the customer education program to provide information concerning electric industry restructuring and retail competition.

6. The Applicants shall provide for the sharing of off-system sales margins as specified in the ISA and for the treatment of fuel savings arising from the integrated operations of the Merged Company.

7. Applicants shall defer and amortize over a six-year period the estimated costs to achieve the merger, including change in control payments as specified in the ISA.

8. If the Merged Company maintains CSW's Texas operating companies' business records outside the State of Texas, it shall do so in accordance with the requirements of P.U.C. Subst. R. 25.71(c).

9. The Merged Company or the Texas operating companies shall file tariff sheets consistent with this Order upon closing of the merger. Only savings applied to regulated rates that will be recognized prior to January 1, 2002 shall be included in this filing; additional tariffs to recognize post-2002 savings to regulated rates shall be filed pursuant to Paragraph 9A. This tariff, and all filings related to it, shall be filed in Tariff Control Number 21429, and shall be styled: *COMPLIANCE TARIFF Pursuant to Final Order in PUC Docket No. 19265, SOAH Docket No. 473-98–0839, Application of Central and South West Corporation and American Electric Power Company, Inc. Regarding Proposed Business Combination*. The filing shall include a transmittal letter stating that the tariffs attached are in compliance with the order, giving the docket number, date of the order, a list of tariff sheets filed, and any other necessary information. The timetable for review of the compliance tariff shall be established by the PUC ALJ assigned to the tariff. In the event any sheets are modified or rejected, the Applicants shall file proposed revisions to those sheets in accordance with the PUC ALJ's notice. The effective date of the tariff shall be as determined in the written notice of approval by the PUC ALJ. All subsequent filings in connection with the compliance tariff (i.e., requests for extensions, textual corrections, revisions) shall be filed in the same Tariff Control No. provided above, and styled as set forth above. After issuance of the final order in this docket, no further filings other than those pertaining to a Motion for Rehearing shall be made in this docket.

9A. The Merged Company or Texas operating companies shall file, or shall amend the filings made prior to the merger by the Texas operating companies relating to, tariffs and supporting information to reflect the savings provided in the ISA in the distribution rates of the Texas operating companies' successor transmission and distribution utilities. The filings or amendments shall be made in the unbundling proceedings established by the Commission to approve proposed transmission and distribution tariffs under PURA § 39.201 and shall comply with any applicable Commission rules related to that proceeding.

9B. The Office of Regulatory Affairs shall, after adoption of any amendments to the Commission's service reliability rules, establish a project to address any inconsistencies between the ISA and those amendments.

10. Entry of the Order does not indicate the Commission's endorsement or approval of any principle or methodology that may underlie the ISA. Neither shall entry of the Order be regarded as binding precedent as to the appropriateness of any principle underlying the ISA.

11. All motions, applications, requests for entry of specific findings of fact and conclusions of law, and other requests for relief, general or specific not expressly granted herein, are denied for want of merit.

SIGNED AT AUSTIN, TEXAS the 18th day of November, 1999.

PUBLIC UTILITY COMMISSION OF TEXAS

Pat Wood III

PAT WOOD, III, CHAIRMAN

Judy Walsh

JUDY WALSH, COMMISSIONER

Brett A. Perlman

BRETT A. PERLMAN, COMMISSIONER

q:\opd\orders\final\19000\19265fo.doc

14

Kentucky Power Company
d/b/a
American Electric Power

REQUEST:

The Joint Applicants should submit copies of final approval received from the FERC, SEC, FTC, DOJ, and all state regulatory commissions to the extent that these documents have not been provided. With each submittal, the Joint Applicants shall further state whether Paragraph 10 of the Settlement Agreement requires changes to the regulatory plan approved herein.

RESPONSE:

A copy of the FERC and the SEC's final approval is attached.

There was no FTC review of this transaction under the anti-trust laws.

The review under the anti-trust law was conducted by the DOJ. Attached is a letter closing it's investigation into the proposed merger.

WITNESS: Errol K. Wagner

5TH ITEM of Level 1 printed in FULL format.

American Electric Power Company, Central and Southwest Corporation

Docket Nos. EC98-40-005, ER98-2770-005, ER98-2786-006

FEDERAL ENERGY REGULATORY COMMISSION - COMMISSION

91 F.E.R.C. P61,129; 2000 FERC LEXIS 969

OPINION NO. 442-A OPINION AND ORDER DISMISSING IN PART, DENYING IN PART, AND GRANTING IN PART REHEARING

May 15, 2000

CORE TERMS: merger, proposed merger, transmission, generation, mitigation, pricing, formula, interim, adversely affect, consummation, divestiture, combining, long-term, energy, Federal Power Act, ownership interest, conditions imposed, public interest, delivered price, modification, manipulation, ineffective, conditioned, decremental, methodology, generating, intervenor, aggrieved, reiterate, strategic

PANEL:
[*1] Before Commissioners: James J. Hoecker, Chairman; William L. Massey, Linda Breathitt, and Curt Hebert, Jr.

OPINION:
This Opinion dismisses in part, denies in part, and grants in part rehearing of Opinion No. 442, n1 in which the Commission conditionally approved the proposed merger of American Electric Power Company (AEP) and Central and South West Corporation (CSW) (jointly, Applicants). Applicants request rehearing of two determinations in Opinion No. 442. In addition, Wabash Valley Power Association, Inc. (Wabash) and Lafayette Utilities System (Lafayette) filed a joint request for rehearing of other determinations in Opinion No. 442. n2

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n1 *American Electric Power Co. and Central and South West Corp., Opinion No. 442, 90 FERC P61,242 (2000).*

n2 Dayton Power & Light Company (Dayton) withdrew its request for rehearing.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

BACKGROUND

In Opinion No. 442, the Commission concluded that the Applicants had not carried their burden of establishing that the proposed merger will not adversely affect competition. [*2] The Commission therefore conditioned its approval of the merger upon the adoption of certain long-term and interim remedies and mitigation measures. For example, the Commission accepted Applicants' proposal to divest 550 MW of generating capacity, but modified it to require divestiture of Applicants' entire ownership interest in the generating facilities to be divested, explaining that "divestiture of Applicants' entire ownership interest provides the maximum assurance that control has been transferred to a third party." n3 As another example, the Commission also accepted Applicants' proposal to join a Commission-approved Regional Transmission Organization (RTO) and transfer operational control of their transmission facilities to the RTO, but required that the RTO be fully functional and required Applicants to transfer control by December 15, 2001, n4 the date specified in the RTO Final Rule for RTO formation n5

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n3 Opinion No. 442 at 61,792. Another merger approval condition was that Applicants complete the divestiture within a certain time frame.

n4 Id. at 20.

n5 Regional Transmission Organizations, Order No. 2000, FERC Stats. & Regs. P31,089 (2000), order on reh'g, Order No. 2000-A, FERC Stats. & Regs. P31,092 (2000) appeal pending.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

[*3]

Pending the implementation of these long-term remedies, the Commission also required certain interim mitigation measures, n6 and directed Applicants to notify the Commission within 15 days of the issuance of Opinion No. 442 whether they accept the merger approval conditions. On March 27, 2000, Applicants notified the Commission that they accept the conditions, and on March 31, 2000, Applicants submitted two compliance filings to implement the interim mitigation measures.

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n6 Opinion No. 442 at 61,788-794 and Ordering Paragraph (B) at 61,799-80.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

REHEARING REQUESTS

Applicants state in their rehearing request that they "support the Commission's determination that, subject to certain mitigation measures, the merger will be consistent with the public interest." n7 They also state that they have accepted the merger approval conditions of Opinion No. 442 and are "committed to comply with them. Applicants will abide by their commitments regardless of the disposition of this request for rehearing." n8 In addition, Applicants [*4] state that they do not "expect the Commission to rule on the issues raised in the request for rehearing before consummation" n9 of the merger. Applicants then go on, however, to request rehearing of the Commission's finding that Applicants' "analysis provides an incomplete and inadequate evaluation of the potential vertical effect of the proposed merger . . . . Consequently we conclude that Applicants failed to show that the proposed merger will not adversely affect competition as a result of combining their generation and transmission." n10 Applicants claim that concerns about vertical market power were raised by their competitors to delay the merger and pursue their own economic agenda. They also request rehearing of the modification that the Commission required to the pricing methodology for system energy exchanges between the AEP and CSW zones after the merger is consummated.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n7 Applicants' Rehearing Request at 1.

n8 Id. at 6.

n9 Id. at 2.

n10 Id. at 22 quoting from Opinion No. 442 at 61,786.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

Wabash [*5] and Lafayette request rehearing of the Commission's determination that the proposed merger, as conditioned in Opinion No. 442, is in the public interest. They argue that the Commission should have rejected the merger, and that the conditions imposed are ineffective to resolve market power concerns. Wabash and Lafayette reiterate arguments previously made (in Briefs On Exceptions to the Initial Decision) that Applicants should have been required to join the Midwest ISO before consummating the merger. In addition, they reiterate the arguments that the ratepayer protection measures are "worthless," n11 and that Wabash should be given the opportunity to terminate its contract without being exposed to stranded costs.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n11 Wabash and Lafayette's Rehearing Request at 21.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

DISCUSSION

1. Applicants' Rehearing Request

Applicants' rehearing request contains the unequivocal statement that they will comply with the merger approval conditions regardless of the disposition of their rehearing request. n12 Applicants in effect support [*6] our determination to impose certain conditions on the merger. n13 Moreover, Applicants state that they do not expect the Commission to rule on the rehearing request prior to consummation of the merger. n14 The Commission also observes that Applicants' notice accepting the merger approval conditions is unconditional. It does not even mention that Applicants will seek rehearing of the findings on which the conditions are predicated.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n12 Applicants' Rehearing Request at 6.

n13 Id. at 1.

n14 Id. at 2.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

The result of these statements and actions is that Applicants seek no relief from the Commission as a result of the finding in Opinion No. 442 that "in order to find that the proposed merger will not adversely affect competition as a result of combining transmission and generation, we find it necessary to impose certain remedies and conditions . . . ." n15 The Commission therefore concludes that Applicants are not aggrieved by the Commission's determination on this issue. n16 Any further analysis of this determination [*7] would be pointless, since Applicants are not challenging the conditions we imposed on the basis of this determination. Accordingly, we will not address the merits of Applicants' request for rehearing as to our finding on this issue, and hereby dismiss it as moot.

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n15 Opinion No. 442 at 61,786.

n16 Section 313(a) of the Federal Power Act, *16 U.S.C. § 8251*, permits only those persons that are aggrieved by a Commission order to request rehearing of that order. See, e.g., *City of Summersville, 84 FERC P61,073 (1998)* and *Arizona Public Service Co., 26 FERC P61,357 (1984).*

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

We shall grant rehearing with respect to our rejection of Applicants' original pricing proposal, because as Applicants have explained on rehearing, the formula will always operate so as not to result in an above-market price for the buying company. Applicants correctly point out that their formula defines the buyer's decremental cost as the lower of its decremental [*8] generation or its zonal purchase opportunity. Therefore, as noted by Applicants, the buyer can never pay more than the market price available in its own zonal market which was the Commission's main concern in modifying the pricing formula. Based upon our further review, we conclude that Applicants' original pricing formula produces a reasonable result and an equitable sharing of the benefits of the economic energy transfers between merged companies. Accordingly, we will grant rehearing, reverse our modification to Applicants' proposed pricing formula, and accept Applicants' proposal.

2. Wabash and Lafayette's Joint Request For Rehearing

Wabash and Lafayette raise four issues in their joint rehearing request: (1) the Commission failed to assess the impact of the defective HHI analysis and the inadequacy of the Competitive Analysis Screening Model (CASm) associated with CASm's failure to include the AEP/Ameren transmission path as a component of the analysis and Applicants' failure to test CASm against a benchmark; n17 (2) the conditions imposed by the Commission were limited, ineffective, and failed to address intervenor arguments (e.g., strategic manipulation of generation); n18 (3) [*9] the Commission failed to insist upon implementation of RTO commitments before consummation; n19 and (4) the Commission failed to address how the proposed merger would adversely affect transmission availability. n20 We do not find Wabash and Lafayette's arguments compelling, as discussed below.

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n17 Wabash and Lafayette's Rehearing Request at 6, 8.
n18 Id. at 5.

n19 Id. at 14.

n20 Id. at 17.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

In regard to concerns about CASm and benchmarking, we stated in the Merger Policy Statement that:

It would be expected that there be some correlation between the suppliers included in the market by the delivered price test and those actually trading in the market. As a check, actual trade data should be used to compare actual trade patterns with the delivered price test. n21

In fact, Applicants provided such checks in their Application and in testimony filed during the hearing. n22 We also note that Wabash and Lafayette's argument regarding the failure of CASm to include the AEP/Ameren transmission path is unsupported. [*10] The data on the AEP/Ameren link is included in CASm. However, because CASm accounts for simultaneous transfer capability constraints, the AEP/Ameren link may not be used in all time periods. Thus we disagree that the AEP/Ameren link is not included in CASm.

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n21 See Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, FERC Stats. & Regs. 68,595 at 30,133 (1996), order on reconsideration, *Order No. 592-A, 79 FERC P61,321 (1997)* (Merger Policy Statement).

n22 Direct Testimony of William H. Hieronymus, Exhibit No. AC-500 at 42:9-12.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

Wabash and Lafayette argue that the Commission failed to implement a remedy to resolve the harm of strategic manipulation of generation, loop flows, and transmission availability. We disagree. We note that Wabash and Lafayette do not explain how the Commission's remedies fail to address these problems. In fact, the Commission considered the arguments made by intervenors regarding the adverse competitive [*11] effects of the proposed merger and fashioned remedies accordingly.

Wabash and Lafayette argue that the Commission erred by failing to require Applicants to implement their RTO commitments before merger consummation. As explained in Opinion No. 442, in cases where it will take time to implement a long-term remedy, such as here, interim mitigation is warranted. As we stated in Opinion No. 442, the interim mitigation will be fully effective in remedying the identified market power problems. n23

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n23 Opinion No. 442 at 61,789 and 61,794.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

All the other arguments raised by Wabash and Lafayette are arguments that we have considered and either addressed or rejected as not material to our determination of the issues in this case. n24

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n24 See, e.g., Opinion No. 442 at 61,794-97 for a discussion of arguments raised by Wabash and Lafayette on ratepayer protection and contract termination.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

[*12]
The Commission orders:

(A) The Applicants' rehearing request on the finding on the effect of combining transmission and generation is hereby dismissed as moot, as discussed in the body of this Opinion. Applicants' rehearing request on the energy exchange pricing methodology is hereby granted as discussed in the body of this Opinion.

(B) The joint rehearing request of Wabash and Lafayette is hereby denied as discussed in the body of this Opinion.

By the Commission.

4TH ITEM of Level 1 printed in FULL format.

American Electric Power Company, Central and South West Corporation

Docket Nos. EC98-40-003, EC98-40-004, ER98-2770-003, ER98-2770-004, ER98-2786-004, ER98-2786-005

FEDERAL ENERGY REGULATORY COMMISSION - COMMISSION

91 F.E.R.C. P61,208; 2000 FERC LEXIS 1096

Order Accepting Compliance Filings, As Modified

May 31, 2000

CORE TERMS: monitor, transmission, monitoring, merger, interim, energy, screen, revise, protest, calculation, indices, output, consummation, mitigation, posting, generation, load, anticompetitive, collected, purchaser, wholesale, merged, plant, sheet, modifications, calculate, reporting, monitored, customers, hourly

PANEL:
[*1] Before Commissioners: James J. Hoecker, Chairman; William L. Massey, Linda Breathitt, and Curt Hebert, Jr.

OPINION:
In this order, we accept, as modified, the compliance filings made by American Electric Power Company (AEP or AEP East) and Central and South West Corporation (CSW or AEP West) (jointly, Applicants) in response to Opinion No. 442. n1

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n1 *American Electric Power Company and Central and South West Corporation, Opinion No. 442, 90 FERC P61,242 (2000)*, order on reh'g, *91 FERC P61,129 (2000)*.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

I. Background

In Opinion No. 442, the Commission conditionally authorized the proposed merger between Applicants. The merger approval conditions consist of long-term remedies to address the market power concerns arising from the proposed merger, as well as certain interim mitigation measures to be implemented prior to merger consummation. n2 With regard to the interim mitigation measures, Opinion No. 442 requires Applicants to: (1) implement independent calculation and posting [*2] of Available Transmission Capability (ATC) for the AEP East service territory; (2) implement independent market monitoring for the AEP East service territory; and (3) file with the Commission the proposed terms and conditions of the interim sales contracts that would effectively eliminate the merged company's ability to withhold output. Opinion No. 442 directed Applicants, if they accepted the merger approval conditions, n3 to make a compliance filing prior to merger consummation describing their plan to implement the interim mitigation measures.

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n2 Opinion No. 442 requires the interim mitigation measures to remain in place until Applicants transfer operational control of their transmission facilities to a fully-functioning, Commission-approved RTO and divest certain generating facilities.

n3 On March 27, 2000, Applicants notified the Commission that they accept the conditions imposed in Opinion No. 442.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

-On March 31, 2000, Applicants submitted two compliance filings in response to Opinion No. 442. In one compliance [*3] filing, n4 Applicants state that they have: (1) entered into an agreement under which the Southwest Power Pool, Inc. (SPP) will independently calculate and post ATC and perform the OASIS function of processing transmission service requests for customers seeking service over the AEP East zone; and (2) entered into an agreement with Dr. Douglas R. Bohi, who will head a team responsible for implementing a market monitoring plan (Monitoring Plan). In the other compliance filing, n5 Applicants submitted the terms and conditions of the interim sales contracts.

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n4 Docket Nos. EC98-40-003, ER98-2770-003, and ER98-2786-004.

n5 Docket Nos. EC98-40-004, ER98-2770-004, and ER98-2786-005.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

On March 31, 2000, Applicants also filed a motion requesting that Ordering Paragraph (B) of Opinion No. 442 be modified so as to permit Applicants to close the merger on May 15, 2000. Ordering Paragraph (B) requires Applicants to make their compliance filings at least 60 days before consummation of the merger. Applicants filed two compliance [*4] filings on March 31, 2000. Therefore, under Ordering Paragraph (B), Applicants could not consummate the merger until May 31, 2000.

II. Notice of Filings and Interventions

Notices of Applicants' compliance filings were published in the Federal Register, *65 Fed. Reg. 20,152 (2000)* with comments, protests, and interventions due on or before April 21, 2000. The National Rural Electric Cooperative Association (NRECA) and the American Public Power Association (APPA) filed a joint protest to the proposed market monitoring plan. Enron Power Marketing, Inc. (EPMI) filed a protest to SPP's calculation and posting of ATC and the terms and conditions of the interim sales. n6

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n6 On May 8, 2000, Industrial Energy Users - Ohio withdrew its protest.

- - - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

NRECA/APPA's Protest and Applicants' and Dr. Bohi's Response

NRECA/APPA protest Applicants' proposed Monitoring Plan, claiming that it is vague, lacks detail and includes many elements that have yet to be determined. They argue, for example, that the screens, [*5] indices, and procedures must be in place and filed with the Commission before Dr. Bohi begins to perform his responsibilities. n7 Dr. Bohi responds that the Monitoring Plan was "intended to provide an outline of the activities to be monitored and the data needed to carry out the [Monitoring Plan]" and that "sufficient information is provided in the Monitoring Plan to ascertain whether it is consistent with the Commission's Order." n8 He notes that details regarding screening criteria and indices and the specific data to be collected are currently under development and that he expects to collect daily price data from public sources for various hubs around the AEP East system.

- -Footnotes- - - - - - - - - - - - - - - - - - -

n7 NRECA/APPA Protest at 3-4.

n8 Letter from Douglas R. Bohi to Federal Energy Regulatory Commission, May 1, 2000, at 1-2 (Bohi Letter).

- - - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

NRECA/APPA assert that the terms of the arrangement between AEP and Charles River Associates (CRA) (Dr. Bohi's employer) are not provided in the compliance filing. Specifically, they argue that the Monitoring [*6] Plan does not detail the circumstances under which AEP can dismiss the monitor, the length of the monitor's engagement, confidentiality requirements, the monitor's authority to contact the Commission without prior AEP approval, promises made to AEP in return for the engagement, and whether the compensation is sufficient to provide an incentive for the monitor to fully perform his function. n9 NRECA/APPA also point out that the Monitoring Plan's budget does not provide for additional reports or investigations. They object to the provision that if the monitor requires additional funds for such purposes, the monitor must work through AEP to acquire such funds. They suggest that the Commission require AEP to deposit monitoring funds in advance into an account controlled by the Commission and that the Commission disburse the funds directly to the monitor. n10 Dr. Bohi responds that he is confident that the budget limit (which he determined) is sufficient to cover all foreseeable costs involved in data collection, analysis and reporting and that unforeseen costs are difficult to anticipate for budget purposes. n11

- -Footnotes- - - - - - - - - - - - - - - - - - -

n9 NRECA/APPA Protest at 5. [*7]

n10 Id. at 5.

n11 Bohi Letter at 4-5.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - -

NRECA/APPA believe that Applicants have not justified keeping the data associated with the implementation of the Monitoring Plan confidential. They argue that the data and analyses underlying the monitor's reports should be made public so that the Commission Staff, transmission customers and other interested parties can assess whether or not the monitor has correctly analyzed the data and identified all instances of potential anticompetitive conduct. n12 Applicants oppose the suggestion that the reports be made public, since they may contain confidential proprietary information.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n12 Id. at 8-9.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

NRECA/APPA argue that it is not clear that Dr. Bohi's past experience makes his team capable of identifying specific types of anticompetitive conduct with which the Commission is concerned. In response, Dr. Bohi points out that CRA has a strong incentive to perform the monitoring function well, since [*8] "our individual and collective professional reputations are at stake . . . ." n13

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n13 Id. at 5.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

Finally, NRECA/APPA object to the Monitoring Plan's provision that the monitor conduct investigations into alleged misconduct only upon notification. Rather they contend that the monitor should investigate any concerns raised about the merged company's behavior regardless of whether the monitor has been officially notified or not. NRECA/APPA also point out that the "exercise of market power in wholesale electric markets is often both subtle and transitory" n14 and that if monitoring is conducted on a monthly basis and reported every six months, as proposed in the Monitoring Plan, "it is virtually guaranteed that events will have been missed that cost ultimate customers real money . . . ." n15 They argue that the monitor should be required to carry out his functions daily, report activities and findings on a monthly basis, and report promptly to the Commission Staff any alleged misconduct by AEP that it is investigating. [*9] In response, Applicants argue that the Monitoring Plan's provision is consistent with prior Commission rulings in various ISO proceedings. n16 Dr. Bohi notes that semi-annual reporting does not restrict the frequency with which competitive concerns may be brought to the Commission. n17

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n14 NRECA/APPA Protest at 7.

n15 Id.

n16 Applicants' Answer at 12-13.

n17 Bohi Letter at 6.

- - - - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

EPMI's Protest and Applicants' and SPP's Response

EPMI asserts that SPP does not meet Opinion No. 442's requirement of independence, because it is "dominated by integrated transmission owners generally, and by CSW in particular, which gives the SPP a strong incentive to discriminate in favor of the Applicants." n18 A truly independent entity, such as PJM Interconnection or a consultant, should be chosen to calculate and post ATC. EPMI also argues that the proposed terms and conditions of the interim sales do not eliminate the merged company's incentive and ability to withhold output, because: (1) the sales in the SPP are recallable; [*10] (2) the sales are from facilities the Applicants control; (3) the penalty for failure to deliver has no relevance to the market price of the power withheld; and (4) the penalty should be set at a punitive level. There is no need to rely on Applicants' proposal to use day-ahead prices for the penalty, according to EPMI, since the penalty will be calculated long after the failure to deliver, and actual prices in the affected market should be used to make the buyer whole and remove the merged company's incentive to withhold power.

- -Footnotes- - - - - - - - - - - - - - - - - - - -

n18 EPMI's Protest at 2.

- - - - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

On April 27, 2000, SPP filed a response to EPMI's protest, claiming that EPMI's protest contains incorrect assertions regarding SPP that must be set straight for the record, because they relate to SPP's pending application to be recognized as an RTO/ISO in Docket No. EL00-39-000. n19 Under SPP's newly structured Board of 21 members, transmission owners (three of which are not investor owned) have only seven members. SPP asserts that even if all transmission owners agree, [*11] they cannot block Board action or require the Board to take a particular action. Thus, according to SPP, the Board is not controlled by integrated transmission owners. SPP also disputes the assertion that SPP staff would show favoritism towards CSW or any other member, since SPP staff acts at the direction of its Board, which is not controlled by any one member or group of members.

- -Footnotes- - - - - - - - - - - - - - - - - - - -

n19 *Southwest Power Pool, Inc., 91 FERC P61,137 (2000).*

- - - - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

On May 1, 2000, Applicants filed a response to the EPMI's protest. Applicants argue that CSW has no ability to control SPP or influence SPP employees under the current governance structure. There is also no control exerted through threats to withdraw from SPP, since Applicants have committed that they will not terminate their SPP membership without prior approval from the Texas and Arkansas Commissions. Furthermore, Applicants contacted several entities to perform the ATC functions, including PJM Interconnection, as suggested by EPMI, but none could undertake [*12] to do so within Applicants' time frame for closing the merger. Applicants are, however, willing to contract with another entity, as long as the merger closing is not delayed for this reason.

Applicants object to EPMI's claims that the terms and conditions of the SPP interim sales are untimely and illogical. Punitive liquidated damages are also unnecessary. In addition, the day-ahead price for the "Into Entergy" market is an adequate replacement price, given that the "Into Entergy" market is adjacent to the Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SWEPCO) control area, Entergy frequently has limited inbound ATC, and the day-ahead "Into Entergy" price is higher than market prices paid by PSO and SWEPCO. In any event, Applicants have received 21 bids for the SPP interim energy primarily from large, sophisticated power marketers, some of whom want to negotiate the liquidated damages provision and some other terms. Applicants intend to use model agreements developed by national trade organizations and the Commission need not "intrude into the operation of the marketplace to protect these experienced traders." n20

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n20 Applicants' Response to Protests at 10.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

[*13]

III. Procedural Issues

Responses to protests are not generally permitted under Rule 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213 (1999). In this case, however, we will accept the pleadings filed by SPP, the Applicants, and Dr. Bohi, because they have assisted us in achieving a better understanding of the positions of the parties and the disputed facts.

IV. Discussion

A. Market Monitoring Plan

Applicants state that in order to meet the requirements of the Opinion No. 442 regarding market monitoring, Dr. Bohi "will develop a plan to monitor to protect against anticompetitive effects in electricity markets until a fully functional RTO is available and will submit to the Commission reports of its findings, accompanied by supporting data." n21 Information regarding Applicants' proposed market monitoring plan is provided in three different locations, i.e., in the compliance filing's transmittal letter, the affidavit of Dr. Bohi, and the "Market Monitoring Plan: American Electric Power Company." The Monitoring Plan provides for: (1) the purpose and objectives; (2) access to data and information; (3) performance indices and screens; (4) a process for addressing [*14] complaints and requests for investigations; and (5) reports and budget.

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n21 Transmittal Letter at 5.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

We believe that Applicants' proposed market Monitoring Plan represents a good start in specifying objectives, data, analysis and reporting. However, we find that, as pointed out by NRECA/APPA, the proposed Monitoring Plan is not a fully effective remedy, as described in the following sections. As a result, we will modify and accept Applicants' proposed Monitoring Plan. We note that these modifications do not expand the scope of the market monitoring requirement set forth in the Opinion No. 442, but will ensure that the Monitoring Plan is fully effective mitigation. These modifications are specified in the following sections, so as to facilitate Applicants' compliance with Opinion No. 442 and to allow AEP and CSW to consummate their merger as expeditiously as possible. As discussed below, we require that the Monitoring Plan be fully developed and functioning at the time of merger consummation.

Purpose and Objectives of [*15] the Market Monitoring Plan

We believe that the Monitoring Plan relies unnecessarily on the exercise of a significant degree of judgment by the monitor in order to fulfill its stated purpose. For example, before the monitor can investigate a market event that results in a significant increase in wholesale prices or foreclosure, the proposed Monitoring Plan states that the monitor must first identify conduct that departs substantially from rational behavior (i.e., strategic, unjustifiable actions the company may take to cause transmission constraints to bind) in a workably competitive market. n22 This articulation of the Monitoring Plan's purpose could have the effect of "setting the bar" too high in what the monitor concludes is conduct worthy of investigation. While we realize that the need to exercise some degree of judgment is unavoidable, the Commission must be confident that all market events that may have been driven by misconduct on the part of the merged company are identified and investigated. Put in a different way, the Commission believes that, in this particular case, the purpose of the Monitoring Plan is for the monitor to first identify and investigate market events, [*16] and then to attempt to explain the underlying cause of the event (i.e., misconduct). As proposed, the Monitoring Plan would not do this.

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n22 Monitoring Plan at 1.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

At the same time, we believe it is reasonable for the monitor to use a "significant increase in wholesale prices" as a screen for identifying market events requiring investigation. As explained by Dr. Bohi, the term "significant" price increase has meaning, first, ". . . in a statistical sense to refer to events that can be distinguished from noise in the data" and second, as it relates to market definition under the DOJ/FTC Horizontal Merger Guidelines whereby ". . . the price effect must be large enough and last long enough to be detectable in the data, and to be worth pursuing as an indicator of market abuse." n23 In light of the above, we direct Applicants to revise the first paragraph of Section 1.1 of the proposed Monitoring Plan to state:

The purpose of the market monitoring plan is to identify, through the use of screens and indices, market events [*17] that result in a significant increase in wholesale prices, as measured by an increase from previous day peak prices, or the foreclosure of competition by rival suppliers, and to investigate any anticompetitive conduct by the merged company that may have caused such events.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n23 Bohi Letter at 6. We do not believe it is necessary to establish a tolerance level (i.e., a specific percentage) for what is a "significant" increase in wholesale prices, since it would prevent Dr. Bohi from exercising judgement regarding which of the two criteria (or combination of criteria) he should rely on in specific situations.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

Similarly, we direct Applicants to revise the first paragraph of Section 1.2 of the proposed Monitoring Plan to state:

The anticompetitive conduct described in Section 1.1 that the Market Monitor will investigate refers to actions the company may take to cause transmission constraints to bind. Such actions may relate to the operation of transmission and/or generation facilities and could be identified through the [*18] use of screens and indices.

Section 1.1 of the Monitoring Plan states that, among other things, the monitor will provide independent and impartial monitoring and reporting on "other information required to determine the effects of generation dispatch on transmission constraints and associated effects on market prices." n24 This does not explicitly include Opinion No. 442's requirement that AEP East provide to the monitor the volume and pricing of energy before and after redispatch. n25 However, since Dr. Bohi's affidavit states that his monitoring team will review, among other things, "information concerning the level of transactions and prices charged by AEP (and its affiliates) and in the marketplace as a whole before and after AEP implements TLRs or other congestion management actions," n26 we direct Applicants to revise item (4) in the second paragraph of Section 1.1 to state:

(4) Information concerning the volume of transactions and prices charged by AEP (and its affiliates) and in the electricity markets affected by the merged company before and after AEP implements redispatch, TLRs or other congestion management actions.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n24 Monitoring Plan at 1. [*19]

n25 Opinion No. 442 at 61,789.

n26 Bohi Affidavit at 4.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

Section 1.3 states that the market monitor shall obtain AEP's comments regarding his findings or analysis before reaching final conclusions. n27 To ensure the independence of the market monitoring process, it is important for the monitor to conduct his prescribed activities at "arm's length" from AEP. As proposed, the Monitoring Plan does not accomplish this. Therefore, we direct

Applicants to revise the first paragraph of Section 1.3 to state:

The market monitoring plan will be implemented by an independent expert who shall report its findings to the FERC. The Market Monitor shall not review its findings with AEP prior to submission to FERC.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n27 Monitoring Plan at 2.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

In addition, the second paragraph of Section 1.3 of the Monitoring Plan states that the market Monitoring Plan will continue until the Commission-approved RTO is established. However, in Opinion No. 442, the [*20] Commission conditioned its approval on AEP East (and AEP West) transferring operational control of their transmission facilities to a fully-functioning, Commission-approved RTO by December 15, 2001, and on certain interim mitigation measures. n28 Therefore, we direct Applicants to revise the second paragraph of Section 1.3 to state:

The market monitoring plan will be implemented when the merger between AEP and CSW is consummated, and will continue until operational control of Applicants' transmission assets has been transferred to a fully-functioning, FERC-approved RTO.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n28 Opinion No. 442 at 61,788.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

Data and Information Collected Under the Market Monitoring Plan

Section 2.1 of the Monitoring Plan states that the monitor shall routinely receive data and information generated by AEP in the course of its operations, and including, among other things: (1) the hourly output of each of AEP's generating units; (2) transmission limits (including temporary deratings) and hourly flow on each of the monitored flowgates or other [*21] transmission facilities that have been limiting over the previous two years; and (3) generation and transmission facility outage data. n29 While we recognize that this section of the Monitoring Plan lists the data to be collected by the monitor from AEP, it is necessary for the section to list information to be collected from non-AEP sources as well. Without an exhaustive list of data and information to be collected, the Monitoring Plan is incomplete.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n29 Monitoring Plan at 2.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

We note that hourly generating unit output data alone are not particularly useful unless changes in unit output can be explained. For example, if a market event was identified by the monitor and it was accompanied by a change in AEP East's generating unit output, it would be necessary to know to what extent load conditions on AEP East's system could explain the change in output. Without such information, it would be difficult to determine if a market event was driven by anticompetitive conduct on the part of the merged company or, for example, [*22] by changes in demand. Therefore, we direct Applicants to add to the data and information to be collected in Section 2.1 the item: "Hourly load in AEP East's control area."

We note that the markets affected by the AEP transmission and generation system have been dynamic over the past several years, and certain facilities may become limiting between the dates of merger consummation and when AEP East transfers operational control of their transmission facilities to a fully-functioning, Commission-approved RTO. Therefore, we direct Applicants to revise the data items in Section 2.1 pertaining to transmission limits and hourly flows to state:

Transmission limits (including temporary deratings) on each of the monitored flowgates or other transmission facilities that have been limiting over the previous three years, or become limiting after merger consummation.

and

Hourly flow over each of the monitored flowgates or other transmission facilities that have been limiting over the previous three years or become limiting after merger consummation.

We also direct Applicants to revise the item in Section 2.1 regarding generation and transmission facility outage data to state:

Generation [*23] and transmission facility outage data, including the type of outage incurred, the length of the outage, and actions taken to alleviate the effects of the outage.

Although Section 2.1 of the Monitoring Plan does not specify that data on energy prices and volumes will be routinely collected by the monitor, Dr. Bohi states that he expects to collect daily price data at various hubs around the AEP East system from public sources (e.g., CINergy, Entergy, PJM, SPP, and TVA). Given that price and quantity information are a critical component of the data necessary to perform effective monitoring, we direct Applicants to revise Section 2.1 to include two additional data items:

Hourly megawatt-hour wholesale sales by AEP and its affiliates, including the identity of the purchaser, price, firmness, and duration of the sale.

and

Daily peak and off-peak energy prices at CINergy, Entergy, PJM, SPP, and TVA.

In regard to the disclosure of confidential information obtained in conjunction with the implementation of the Monitoring Plan, NRECA/APPA do not make a compelling argument as to why sensitive confidential and/or proprietary data and information pertaining to AEP East should routinely [*24] be made available to AEP's competitors and customers. The purpose of market monitoring is to identify and investigate instances when the monitored firm has acted anticompetitively, not to make public information that may, through widespread disclosure to the firms' competitors, hamper the firm's ability to function effectively. Thus, we will not require confidential information collected in conjunction with the Monitoring Plan to be made public. However, the provision of such information to the Commission Staff is necessary for the Commission Staff to evaluate the monitor's analysis and findings. Consequently, we direct Applicants to revise Section 2.3 of the Monitoring Plan to add that:

Confidential information obtained in connection with the implementation of the market monitoring plan will be provided to FERC. When filing this information, the Market Monitor may claim confidentiality under 18 C.F.R. § 388.112 (1999), and others may challenge such a claim.

Performance Indices and Screens Under the Market Monitoring Plan

Section 3 of the Monitoring Plan discusses the development and use of indices and screens for reviewing the data and other information collected in connection with [*25] the implementation of the Monitoring Plan. We note that the indices and screens have yet to be developed, but the Monitoring Plan indicates that they will be developed in consultation with market participants. Dr. Bohi states that "the plan also requires that the screens and indices be filed as an attachment to the plan." n30 We agree with Dr. Bohi that "this process should be completed prior to the effective date of the plan. . . . ." n31 Without developed indices and screens, the Monitoring Plan is not fully effective mitigation, which must be in place prior to the consummation of the merger. Therefore, we will require that such screens and indices be developed and included in the modified plan to be filed with the Commission, and be in place at the time the market monitoring plan is effective (i.e., merger consummation).

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n30 Bohi Letter at 2.

n31 Id. at 2.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

As noted above, the Monitoring Plan indicates that the indices and screens will be developed in consultation with market participants, including AEP. However, [*26] we direct Applicants to revise Section 3.2 of the Monitoring Plan to state:

AEP, its customers, its competitors, or other interested parties may submit comments or alternative proposed indices or screens for review of the data or other information collected in connection with the implementation of this market monitoring plan. The Market Monitor shall disclose such comments and proposed alternatives, without attribution, to the FERC and, on an as-requested basis, to other parties.

Complaints and Requests for Investigations

We direct Applicants to revise Section 4 of the Monitoring Plan to add:

TThe Market Monitor shall notify FERC within one week of all requests for investigation and if the Market Monitor denies any request, the reason(s) for doing so.

Reports

Section 5.1 of the Monitoring Plan states that the "monitor will prepare and submit to FERC a semi-annual report summarizing its analysis and evaluation of the operation of AEP's transmission system, and the competitive performance of the wholesale power market within AEP's control area." We note three important items in regard to the reporting requirements of the Monitoring Plan.

First, our timely awareness of, and [*27] response to, any merger-related anticompetitive effects resulting from the operation of AEP's generation and transmission system would be greatly limited by the filing of semi-annual reports. Nor are we persuaded by Applicants' argument that the Monitoring Plan's provision for reporting twice annually is consistent with prior Commission rulings. Those rulings were in various ISO proceedings, which pose different competitive and timeliness issues compared to monitoring the effects of a merger. n32 Therefore, we agree with NRECA/APPA that the monitor should be required to report activities and findings more frequently than semi-annually. Second, we note that the Commission stated in Opinion No. 442 that market monitoring by an independent party is needed to protect against anticompetitive effects in electricity markets. n33 Therefore, we clarify that markets inside AEP's control area as well as other markets likely to be affected by AEP's actions should be monitored. As noted earlier, Dr. Bohi expects to collect daily prices at various regional hubs and it is expected that markets to be monitored will correspond to such hubs. Third, it is important that the Commission receive all reports [*28] of investigations conducted by the market monitor in a timely manner. As a result, we will require that such reports (other than the quarterly reports described in Section 5.1) be provided promptly to the Commission upon completion.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n32 Applicants' Answer at 12-13.

n33 Opinion No. 442 at 61,789.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

To address the foregoing concerns, we direct Applicants to revise Section 5.1 to state:

The Market Monitor shall prepare and submit to FERC a quarterly report within 10 days of the end of each quarter summarizing the Market Monitor's analysis and evaluation of market events that result in a significant increase in wholesale prices or the foreclosure of competition by rival suppliers and any anticompetitive conduct by the merged company that may have caused such events.

We direct Applicants to make conforming changes regarding the quarterly reporting requirement in Sections 1.1, 4 and 6. We also direct Applicants to revise Section 5.2 to state:

The Market Monitor shall submit to FERC such other reports as may be requested [*29] by the FERC or other parties or that, based on an investigation conducted by the Market Monitor, raise competitive issues. Such reports will be provided to FERC promptly upon completion, and not as part of the periodic quarterly report.

Any report containing analysis and findings submitted to the Commission by the monitor will be publicly available. All concerned parties including AEP may review and comment on, the monitor's findings or analysis, and may file such comments directly with the Commission. We expect that the monitor will use his discretion in filing a redacted version of any report. Any party desiring access to redacted portions of reports filed by the monitor can follow the Commission's usual procedures under 18 C.F.R. § 388.112 (1999).

Budget

Section 6 of the Monitoring Plan proposes, among other things, that if the monitor requires additional funds to conduct investigations or produce additional reports, the monitor will notify AEP of the requirement and allow AEP the opportunity to request that FERC determine that the additional costs are reasonably necessary to accomplish the objectives of the Monitoring Plan. To preserve the independence of the market monitor, we [*30] direct Applicants to add the following to Section 6 of the Monitoring Plan:

AEP will pay the additional funds until FERC reaches a determination as to whether or not the additional costs are reasonably necessary.

We expect to reach such a determination within 45 days after AEP makes its request. We do not see the need, as NRECA/APPA suggest, for the Commission to administer the funds allocated for implementing the Monitoring Plan. Given the modifications specified herein regarding the frequency of monitoring and reporting activities, however, we would expect the monitor to redetermine with AEP the Monitoring Plan budget.

Other Matters

NRECA/APPA raise concerns regarding Dr. Bohi's qualifications and terms of engagement. However, NRECA/APPA do not make a compelling argument as to why Dr. Bohi and his team, given the experience he describes in his affidavit, are not qualified to competently carry out the functions required of the monitor. We do not see the need to review the terms of the monitor's contract, in light of several of the modifications to the Monitoring Plan described above. However, Applicants are directed to seek the Commission's approval for any change in the monitor [*31] or the Monitoring Plan.

Conclusion

Once the modifications discussed above have been filed with the Commission, we believe that the proposed Monitoring Plan will be a fully effective interim mitigation measure, as required in Opinion No. 442. We will also require that the market Monitoring Plan be fully developed and functioning at the time of merger consummation, as discussed above. Furthermore, Applicants should notify the Commission within 5 days of the date of this order as to whether they accept these modifications to their proposed Monitoring Plan.

B. Independent ATC Calculation and Posting

Applicants state that American Electric Power Service Corporation (AEPSC) has entered into an agreement (Agreement) with SPP to implement the calculation and posting of ATC. Under the Agreement, SPP will perform the following functions for the AEP East Zone based on data provided by AEPSC: (1) long-term ATC calculation and posting on the AEP OASIS; (2) short-term ATC calculation and posting on the AEP OASIS; and (3) acceptance and denial of transmission service requests for customers seeking service over the AEP East zone. Applicants represent that SPP will perform these functions until AEPSC [*32] transfers operational control of the AEP transmission facilities to a fully-functioning, Commission-approved RTO. n34

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n34 Applicants note that the initial term of this agreement shall be from March 31, 2000 to May 31, 2001. Applicants state that after the initial term, the Agreement shall continue in effect month-to-month until terminated by AEPSC by giving at least three months' written notice.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

In support of this proposal, Applicants state that: (1) SPP is a regional reliability council, security coordinator, and tariff administrator for certain transmission facilities in the Southwest region; (2) SPP is responsible for calculating Total Transfer Capability (TTC) and ATC, posting TTC and ATC on the SPP OASIS and processing transmission service requests in the region; (3) SPP staff possess relevant experience and training to perform the above functions; (4) SPP is independent from AEP and CSW because SPP employees have no financial interests in AEP or CSW; n35 (5) AEP's merger partner, CSW, has one member on the 21-member [*33] board, but board action requires a two-thirds majority; and (6) SPP employees that perform independent calculation and posting of ATC will abide by the Standards of Conduct requirement of Order No. 889 n36 and thus, will be restricted from relating transmission information to merchant employees of AEPSC.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n35 Applicants note that two of the operating utilities of CSW, SWEPCO and PSO, operate within the SPP region.

n36 Open Access Same-Time Information System and Standards of Conduct, Order No. 889, FERC Stats. & Regs. P31,035 at 31,588-91 (1996), order on reh'g, Order No. 889-A, FERC Stats. & Regs. P31,049 at 30,549 (1997), order on reh'g, *Order No. 889-B, 81 FERC P61,253 (1997).*

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

Discussion

We will accept Applicants' proposal to implement independent calculation and posting of ATC by entering into an Agreement with SPP. However, we note that

Opinion No. 442 requires that Applicants implement independent calculation and posting of ATC as outlined in the RTO Final Rule, n37 which, in turn, [*34] requires that an RTO calculate both TTC and ATC. Therefore, we direct Applicants to modify their Agreement to reflect that SPP will also calculate TTC.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n37 Regional Transmission Organizations, Order No. 2000, FERC Stats. & Regs. P31,089 (2000), order on reh'g, Order No. 2000-A, FERC Stats & Regs. P31,092 (2000), appeal pending.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

Applicants represent that SPP will calculate ATC values based on raw data supplied by AEP. We note that this corresponds to performing ATC calculation at level 2, as explained in the RTO Final Rule. n38 While we note that the RTO Final Rule requires that the RTO perform this function at level 3, we find ATC calculation at level 2 to be acceptable in this case because this function is being implemented on an interim basis just for AEP and not for an RTO. In addition, Applicants represent that AEP will telemeter raw data from generator buses and substations to the AEP control center, which will then be directly telemetered to SPP. In this regard, if AEP makes any adjustments to the data before [*35] transmitting it to SPP, we direct AEP to post promptly on its OASIS a notice describing the adjustments made and the reasons therefor. n39

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n38 At level 1, an RTO would post ATC values received from transmission owners. At level 2, an RTO would receive raw data from transmission owners and itself calculate ATC values. At level 3, an RTO would itself calculate ATC values based on data developed partially or totally by the RTO.

n39 AEP must fully comply with the requirements of Order Nos. 889 and 638. Open Access Same-time Information System and Standards of Conduct, Order No. 638, FERC Stats. & Regs. P31,092 (2000), order denying reh'g, *91 FERC P61,081 (2000)*.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

We do not agree with EPMI's assertion that SPP will favor AEP East because of CSW's pre-existing ties with SPP. We find that SPP is independent from Applicants because CSW has only one member on the SPP's 21-member board. Therefore, SPP meets our requirement for independent calculation and posting of ATC imposed in Opinion No. 442. [*36] However, concerned parties may notify the Commission promptly of any perceived favoritism to AEP by SPP post-merger in performing this function.

C. Energy Sales Contracts

1. SPP Interim Sales

Applicants have submitted a term sheet providing terms and conditions for the sale of 300 MW of capacity and associated energy in SPP from system resources. n40 Potential buyers will bid "capacity prices" in units of $ /kW-month for the right to take energy at the rate of $ 14MWh for all hours. The initial sales will begin on the day the merger is consummated and will continue for a term of 24 months. The term sheet provides that Applicants must accept proposals for the purchase of the entire 300 MW of capacity and associated energy.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n40 While the purchasers will be charged for capacity, a contractual restriction will prevent them from relying on this capacity to meet their planning reserve requirements because Applicants intend to rely on this capacity to meet their own planning reserve requirements.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

The term sheet provides that [*37] all or a portion of the energy may be recalled. Any such recall will be made only if necessary to maintain adequate power supply for the AEP West retail native load and firm power wholesale customers and only after all other alternatives have failed (e.g., curtailment of interruptible load and purchases from third parties). If the energy is recalled, the term sheet provides that Applicants will compensate purchasers by repaying the actual purchase price of the energy when purchasers are able to secure replacement energy. When purchasers are unable to replace the energy, Applicants will refund an amount calculated using the published day-ahead price for the "Into Entergy" market. n41

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n41 The term sheet also provides that a different replacement price may be negotiated by the parties to this sale.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

Discussion

We find that Applicants' proposed SPP interim sale adequately addresses the market power concerns identified by Applicants' Appendix A analysis for the SPP market. We find that, in the context of Applicants' continuing [*38] near-term requirement to reliably serve native load, Applicants have effectively relinquished control of 300 MW of output in the SPP market. This is true for three reasons: (1) Applicants have committed to the Commission to sell all of this power (except in extraordinary circumstances where native load service is jeopardized); (2) the proposed sale is priced such that there is likely to be demand for this energy well in excess of the amount of energy offered for sale; and (3) the contractual limitations on the recall provision will prevent Applicants from withholding this output from the SPP market. As a result of these strict limitations, this output will remain in the market either by going to the purchasers or to Applicants' native load when all other means of serving that load have failed. n42 We reject EPMI's argument that a severely punitive refund is required to eliminate Applicants' incentive to withhold output because, as we have just explained, the contractual limitations negate Applicants' ability to withhold output.

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - -

n42 The term sheet also specifies that such recall will take place when necessitated by the declaration of a generation emergency pursuant to either SPP operating guidelines or Applicants' own operating agreements. We expect that the circumstances surrounding a declaration of generation emergency will always be consistent with SPP guidelines.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -
[*39]

This leaves only the question of the appropriateness of Applicants' proposed refund mechanism from a rate-making standpoint. We agree with EPMI that payment for non-delivery will likely be calculated long after the non-delivery occurs, at a time when actual prices from the relevant time period are known. n43 Accordingly, we find that Applicants have failed to support the use of a day-ahead index. We will require Applicants to revise their proposal for refunds to purchasers of recalled energy. The default calculation n44 should be based on the "Absolute High" price recorded in Megawatt Daily's Market Report for the "Into Entergy" market for the day that the recall event took place. n45 We direct Applicants to reflect this change, where appropriate, in the actual rate schedules negotiated with purchasers pursuant to the SPP term sheet. We also direct Applicants to file, within one week of each recall event, a notification of the recall event with the Director of Energy Markets, Office of Markets Tariffs and Rates. This filing should detail the amount, timing, and duration of the event and demonstrate why Applicants could not serve their native load through any other means during this [*40] period.

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n43 For example, Megawatt Daily's Market Report contains transaction records showing, among other things, actual low and high prices for the "Into Entergy" market.

n44 We call this a default calculation because of the provision, noted above, which allows bidders to negotiate some other refund mechanism with Applicants. The reasonableness of any such negotiated refund mechanism will be addressed at the time that the proposed power sale is filed with the Commission.

n45 The "Absolute High" is appropriate since it should generally capture the highest price paid during periods when high demand outstrips supply, the very situation that will trigger Applicants' need to recall this power to meet their native load.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

2. ERCOT Interim Sales

In ERCOT, Applicants have revised their interim mitigation proposal such that they will now sell 290 MW (up from 250 MW originally) of the output of their 470 MW Frontera merchant plant under rates, terms, and conditions that will mitigate the generation market power identified [*41] by Applicants' screen analysis. n46 Of the 290 MW, Applicants have contracted to sell 100 MW to the Lower Colorado River Authority (LCRA) from March 16, 2000, to February 15, 2001 (LCRA

Contract). Applicants will offer the remaining 190 MW, through competitive bid, from May 15, 2000, to December 31, 2000, under proposed terms and conditions that are included in the instant filing (Frontera Term Sheet). n47 If, by December 31, 2000, Applicants have not yet divested the Frontera plant to meet the long-term mitigation requirement of Opinion No. 442, Applicants will extend the 190 MW sale until the plant is sold. n48

- -Footnotes- - - - - - - - - - - - - - - - - - - -

n46 The remaining 180 MW is under contract to Tenaska Power Services Co. through December 31, 2000, but Applicants do not rely on this sale to meet the interim mitigation requirement and do not make any representation with respect to its ability to mitigate market power concerns.

n47 All sales by the Frontera Plant are made to entities exclusively within ERCOT.

n48 Therefore, until February 15, 2001, Applicants would still be selling 290 MW on terms, included in the Frontera Term Sheet, meant to mitigate potential market power.

- - - - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - - - -

[*42]

The Frontera Term Sheet provides for the sale of 190 MW of capacity and associated energy to the highest bidder. n49 This term sheet does not provide for recall, since Applicants do not rely on this plant to meet planning reserve requirements. Buyers may not, however, resell such capacity and energy outside of ERCOT. Potential buyers will bid capacity prices in units of $ /kW-month for the right to take energy at the variable cost (the sum of the fuel cost and the operation and maintenance cost) of the Frontera plant. n50 As was the case in SPP, the Frontera Term Sheet provides that Applicants must accept proposals for the purchase of the entire 190 MW of capacity and associated energy.

- -Footnotes- - - - - - - - - - - - - - - - - - - -

n49 Bidding criteria include that the winning bidder must not cause Appendix A Screen violations and must meet certain credit requirements.

n50 There is no rate designed to recover the fixed costs of the plant.

- - - - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - - - -

Applicants indicate that the LCRA Contract contains rates, terms, and conditions that are similar to those contained in [*43] the proposed Frontera Term Sheet. They state that LCRA will pay a price for energy that reflects the marginal operating cost of the Frontera plant and a negotiated capacity charge. n51

- -Footnotes- - - - - - - - - - - - - - - - - - - -

n51 Application at 3.

- - - - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - - - -

Discussion

We find that Applicants' proposed Frontera Term Sheet addresses the market power concerns identified by Applicants' Appendix A analysis for the ERCOT market. The proposal to recover only the variable costs of the Frontera plant should ensure that the interim sale will be economic in all time periods. This, in combination with the facts that there is no recall provision and that Applicants have committed to the Commission to sell all of this power, should ensure that the power will be sold to third parties over the entire interim period. n52 Accepting the representation that the LCRA Contract is similar to the Frontera Term Sheet, we find that Applicants have proposed mitigation measures that will alleviate horizontal concerns in the interim period in ERCOT. n53

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n52 The limitation that purchasers may not resell this capacity outside of ERCOT is consistent with the fact that Applicants have proposed this interim sale in order to alleviate horizontal concerns identified by their Appendix A screen in the ERCOT market. [*44]

n53 Our finding that the LCRA Contract is an acceptable component of a remedy for identified market power concerns is based on two assumptions. One assumption is that since the sale to LCRA is also from the Frontera plant, it will not have a recall provision. The second assumption is that LCRA has negotiated this agreement because it fully intends to make use of the entire 100 MW. Based on these assumptions, we believe that this 100 MW will be removed from Applicants' control during the interim period.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

D. Applicants' Motion To Amend Ordering Paragraph (B)

We will dismiss as moot Applicants' motion to amend Ordering Paragraph (B) of Opinion No. 442.

The Commission orders:

(A) Applicants' compliance filings are accepted as modified and discussed in the body of this order. Applicants shall submit an additional compliance filing, consistent with the body of this order, prior to consummation of the merger.

(B) Applicants are hereby directed to notify the Commission within five days if they accept the modifications to their compliance filings, as discussed in the body of the order.

(C) Applicants' [*45] motion to amend Ordering Paragraph (B) of Opinion No. 442 is dismissed as moot.

(D) Applicants shall promptly notify the Commission when the proposed merger is consummated.

By the Commission.

SECURITIES AND EXCHANGE COMMISSION

(Release No. 35-27186; 70-9381)

American Electric Power Company, Inc. and Central and South West Corporation

Order Authorizing Acquisition of Registered Holding Company and Related Transactions; Approving Amended Service Agreements; and Denying Requests for Hearing

June 14, 2000

American Electric Power Company, Inc. ("AEP"), Columbus, Ohio, and Central and South West Corporation ("CSW") (together, the "Applicants"), Dallas, Texas, each a registered public-utility holding company, have filed a joint application-declaration, as amended (the "Application"), under sections 6(a), 7, 9(a), 10, 11, 12(b), 12(c), 12(d), 12(f), 13(b), 32 and 33 of the Public Utility Holding Company Act of 1935 ("Act") and rules 43, 45, 46, 53, 54, 83, 87, 88, 90 and 91.[1]

The Commission issued a notice of the Application on March 12, 1999 (Holding Co. Act Release No. 26989). We received eight sets of comments or requests for hearing, of which six have been withdrawn.

---

[1] Applicants filed five amendments to the Application, the last on May 24, 2000.

TABLE OF CONTENTS

I. Background

A. Summary of Proposals

As discussed in more detail below, Applicants propose that AEP: (1) acquire, by means of a merger described below (the "Merger"), all of the issued and outstanding common stock of CSW ("CSW Common Stock"); (2) form a special purpose subsidiary (the "Merger Sub"); (3) issue shares of common stock ("AEP Common Stock") to effect the proposed transactions; (4) provide financing for CSW's subsidiaries; (5) merge CSW's service company subsidiary, Central and South West Services, Inc. ("CSW Service"), into AEP's service company subsidiary, American Electric Power Service Corporation ("AEP Service"), with AEP Service to render services to AEP and its subsidiaries (including CSW and its subsidiaries) under amended service agreements following consummation of the Merger; (6) retain CSW as a registered public-utility holding company subsidiary for a period of no more than eight years following the proposed Merger; and (7) retain ownership of CSW's nonutility businesses.

B. Parties

1. AEP

AEP is primarily engaged, through subsidiaries, in the generation, transmission and distribution of electricity. The AEP electric system (the "AEP System") covers more than 45,500 square miles in portions of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia and serves approximately three million customers.[2] As of October 31,

---

[2] The electric operations of AEP are an electric integrated public-utility system within the meaning of section 2(a)(29)(A) of the Act. *See American Electric Power Co., Inc.*, 46 S.E.C. 1299 (1978) ("*1978 AEP Order*").

1999, 194,103,349 shares of AEP Common Stock were outstanding. AEP's consolidated operating revenues for the twelve months ended December 31, 1999, after eliminating intercompany transactions, were $6.9 billion, and its consolidated operating income for that same period was $1.3 billion. Consolidated assets of AEP and its subsidiaries as of December 31, 1999 were approximately $21.5 billion, consisting of $13.1 billion in net electric utility property, plant and equipment and $8.4 billion in other corporate assets. AEP currently ranges from the fifth to the eighth largest public utility system in the United States, depending upon the criterion of measurement.

AEP has seven wholly owned electric operating company subsidiaries (together, the "AEP Operating Companies"): Wheeling Power Company ("Wheeling Power"), serving northern West Virginia; Appalachian Power Company ("Appalachian Power"), serving the southwestern portion of Virginia and southern West Virginia; Kentucky Power Company ("Kentucky Power"), serving eastern Kentucky; Kingsport Power Company ("Kingsport Power"), serving Kingsport, Virginia, and eight neighboring communities in northeastern Tennessee; Columbus Southern Power Company ("Columbus Southern Power"), serving central and southern Ohio; Ohio Power Company ("Ohio Power"), serving the northwestern, central, eastern and southern sections of Ohio; and Indiana Michigan Power Company ("Indiana Michigan Power"), serving northern and eastern Indiana and southwestern Michigan.[3] AEP also wholly owns an electric generating company subsidiary, AEP

[3] In addition, AEP owns interests in various nonutility businesses, including 50% of Yorkshire Electricity Group plc, a United Kingdom foreign utility company ("FUCO") as defined in section 33 of the Act. AEP's nonutility subsidiaries are used to conduct businesses that are permitted by the Act under sections 32, 33 or 34, by Commission order under section 11(b)(1), or by rule 58.

Generating Company, that sells power at wholesale to Indiana Michigan Power and Kentucky Power and to a nonaffiliate utility.

Appalachian Power, Kentucky Power, Columbus Southern Power, Ohio Power, Indiana Michigan Power and AEP Generating Company are subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the Federal Power Act (the "FPA") with respect to rates for interstate transmission and wholesale sales of electric power, accounting and other matters. Appalachian Power and Wheeling Power are subject to regulation by the West Virginia Public Service Commission ("West Virginia Commission"). Appalachian Power is also subject to regulation by the State Corporation Commission of Virginia. Columbus Southern Power and Ohio Power are subject to regulation by the Public Utilities Commission of Ohio ("Ohio Commission"). Kentucky Power is subject to regulation by the Kentucky Public Service Commission ("Kentucky Commission"). Kingsport Power is subject to regulation by the Tennessee Regulatory Authority. Indiana Michigan Power is subject to regulation by the Indiana Utility Regulatory Commission ("Indiana Commission") and the Michigan Public Service Commission ("Michigan Commission"). In addition, Indiana Michigan Power is subject to regulation by the Nuclear Regulatory Commission ("NRC") under the Atomic Energy Act of 1954 with respect to the operation of its nuclear generation plant.

The AEP Operating Companies own 23,759 megawatts ("MW") of generating capacity. The AEP System includes approximately 129,000 miles of transmission and distribution lines.[4] At December 31, 1999, the AEP System was interconnected through 121 high-voltage transmission interconnections with 25 neighboring electric utility systems. AEP is a member of, and is directly interconnected with utilities in, the East Central Area Reliability Council ("ECAR"), a regional power pool.[5] ECAR members interchange power and energy with one another on a firm, economy and emergency basis. AEP is also directly interconnected with utilities in the Southern Electric Reliability Council and the Mid-America Interconnected Network.

2. CSW

CSW is primarily engaged, through subsidiaries, in the generation, transmission and distribution of electricity. The CSW electric system (the "CSW System") covers more than 152,000 square miles in portions of Texas, Oklahoma, Arkansas and Louisiana and serves approximately 1.7 million customers. As of December 31, 1999, 212,648,293 shares of CSW Common Stock were outstanding. CSW's consolidated operating revenues for the twelve months ended December 31, 1999, after eliminating intercompany transactions, were approximately $5.5 billion, and its consolidated operating income for that same period was $866 million. Consolidated assets of CSW and its subsidiaries as of December 31, 1999 were approximately $14.2 billion, consisting of $8.7 billion in net electric utility property,

---

[4] The lines include 2,022 circuit miles of 765 kilovolt ("KV") lines wholly owned by AEP's subsidiaries and 766 miles of 345 KV lines owned jointly with nonaffiliates.

[5] ECAR's membership includes 29 major electricity suppliers located in nine states serving more than 36 million people. The current full members are those utilities whose generation and transmission have an impact on the reliability of the interconnected electric systems in the region.

plant equipment and $5.5 billion in other corporate assets. In terms of total assets, CSW is the sixteenth largest investor-owned electric utility in the United States.

CSW has four wholly owned operating subsidiaries (together, the "CSW Operating Companies"): Central Power and Light Company ("CP&L"), serving portions of southern Texas; Public Service Company of Oklahoma ("PSO"), serving portions of eastern and southwestern Oklahoma; Southwestern Electric Power Company ("SWEPCO"), serving portions of North Texas, western Arkansas and northwestern Louisiana, and West Texas Utilities Company ("WTU"), serving portions of west-central Texas.[6]

Each of the CSW Operating Companies is subject to regulation by the FERC under the FPA with respect to rates for interstate sale at wholesale and transmission of electric power, accounting and other matters. CP&L is also subject to regulation by the NRC.[7]

The Public Utility Commission of Texas ("Texas Commission") has original jurisdiction over retail rates in the unincorporated areas of Texas and appellate jurisdiction over retail rates in the incorporated areas served by CP&L, SWEPCO and WTU. In addition, SWEPCO is subject to the jurisdiction of the Arkansas Public Service Commission ("Arkansas Commission") and the Louisiana Public Service Commission ("Louisiana Commission"). PSO is subject to the jurisdiction of the Corporation Commission of the State of Oklahoma ("Oklahoma Commission").

[6] CSW owns interests in various nonutility subsidiaries, including SEEBOARD plc, a United Kingdom FUCO. CSW's nonutility subsidiaries are used to conduct businesses that are permitted by the Act under sections 32, 33 or 34, or by order under sections 9(a)(1) and 10, or rule 58.

[7] CP&L owns a 25.2% interest in the South Texas Project, a nuclear electricity generating station.

CSW owns 14,205 MW of generating capacity. The CSW System has more than 16,000 circuit miles of transmission and over 66,000 circuit miles of distribution lines.

The CSW System is a unique registered system in both shape and operation. Geographically, the CSW Operating Companies lie in roughly three-quarters of a circle, with the center of the circle in north-central Texas. The utilities are interconnected end-to-end around this arc, extending from CP&L in southern Texas through WTU's service territory, a relatively narrow corridor in western Texas, to interconnect with PSO. In turn, PSO interconnects in eastern Oklahoma with SWEPCO.

The CSW Operating Companies do not all belong to the same power pool or operate in the same interconnect.[8] PSO and SWEPCO are members of the Southwest Power Pool (the "SPP"), a regional reliability council in the Eastern Interconnect. CP&L and WTU are members of the Electric Reliability Council of Texas ("ERCOT"). The CSW System thus conducts utility operations in two different control areas, or zones: ERCOT and non-ERCOT (the SPP).

ERCOT utilities engage primarily in intrastate operations. The Texas Commission has jurisdiction over wholesale sales and transmission service in ERCOT -- matters which FERC would normally regulate.

[8] There are three U.S. interconnects: the Eastern Interconnect, which encompasses utilities in the eastern U.S. and Canada from the Atlantic Ocean to the High Plains; the Western Interconnect, which encompasses utilities from the High Plains/Rocky Mountain region to the Pacific Ocean; and the Electric Reliability Council of Texas ("ERCOT"), which has only Texas utilities as members.

We considered the CSW System's unique characteristics in *Central and South West Corp.* ("*Central and South West Corp.*"), an order reaffirming that the CSW System is an integrated electric system.[9] In that order, we noted that:

> All the members of ERCOT are electrically isolated from PSO, SWEPCO and other utilities operating in whole or in part in states other than Texas. The ERCOT interchange agreements in effect preclude direct or indirect exchange of electric energy with utilities receiving or transmitting electric energy in interstate commerce. When CP&L and WTU joined ERCOT, they ceased to exchange electric energy with PSO and SWEPCO, except for a special arrangement under which the northern division of WTU, adjacent to the Oklahoma border, could operate alternately either with PSO or with ERCOT as long as simultaneous interconnection was avoided. [footnote omitted]

The order approved a FERC-approved settlement agreement under which two asynchronous high-voltage direct current ("HDVC") ties were installed between SPP and ERCOT, specifically, a 220-MW tie owned by CSW and a 600-MW tie on which CSW owns half of the capacity. Through the ties, CSW coordinates the operation of its ERCOT and non-ERCOT Operating Companies.

C. Intervenors

As noted above, we received submissions from eight parties or groups of related parties (the "Intervenors").[10]

---

[9] 47 S.E.C. 754 (Apr. 1, 1982) (order terminating a proceeding examining CSW's compliance with the integration standards of section 11(b)(1) of the Act and upholding a 1945 determination that CSW owns a single integrated public-utility system).

[10] In addition, the Arkansas Commission, the Louisiana Commission and the Indiana Commission filed motions to intervene but did not raise any issues or concerns. The Ohio Commission filed a request for an extension to review the Application in order to determine whether to comment; it subsequently withdrew its request and advised us that it would not submit comments. These commissions have jurisdiction over AEP and CSW Operating Companies that serve retail customers in their respective states. Each has approved the proposed Merger and/or related matters. *See* section I.E.2., *infra*.

Four Intervenors subsequently withdrew their submissions.[11]

The following four Intervenors remain. The American Public Power Association (the "APPA") and the National Rural Electric Cooperative Association (the "NRECA") (together, "APPA/NRECA") filed a joint motion to intervene and comments objecting to the Merger and requested a hearing.[12] Consumers for Fair Competition ("Consumers"), a coalition of utility stakeholders, filed comments in opposition to the Merger and requested a hearing.[13] Mr. Paul S. Davis, a shareholder of AEP, filed a comment letter and request for hearing on March 21, 2000. A group of consumer counselors and others includes: the Indiana Office of Utility Consumer Advocate; the Missouri Office of the Public Counsel;[14] the Electricity

---

[11] These Intervenors consisted of three groups of cooperatives and one utility. Arkansas Electric Cooperative Corporation, Mid-Tex Generation and Transmission Electric Cooperative, Inc., and its members, Rayburn Country Electric Cooperative, Inc., the Oklahoma Association of Electric Cooperatives and its members, and Magic Valley Electric Cooperative, Inc. filed, and subsequently withdrew, a joint motion to intervene, comments and request for hearing. East Texas Electric Cooperative, Inc., Northeast Texas Electric Cooperative, Inc. and Tex-La Electric Cooperative of Texas, Inc. filed, and subsequently withdrew, a joint petition for leave to intervene, protest, comments and request for hearing. South Texas Electric Cooperative, Inc., Medina Electric Cooperative, Inc. and the City of Robstown, Texas filed, and subsequently withdrew, a joint intervention and protest. Dayton Power & Light Company, an electric utility operating in west-central Ohio, filed, and subsequently withdrew, a protest and comments in opposition to the Merger and a request for hearing.

[12] APPA is an organization of approximately 2,000 municipal and other state and local government-owned utilities. NRECA is an association of approximately 1,000 rural electric cooperatives. APPA and NRECA members are located in areas served by the Applicants.

[13] Consumers' members include public power suppliers, power marketers, investor-owned utilities, industrial and small business energy customers, consumer advocates and state regulators.

[14] These four Intervenors are the statutory representatives of their respective states' residential utility consumers before state and federal regulators, legislatures and courts.

Consumers Resource Council;[15] Industrial Energy Users - Ohio;[16] Public Citizen;[17] Ohio Partners for Affordable Energy;[18] Citizens Action Coalition of Indiana;[19] and the Environmental Law and Policy Center[20] (collectively, the "Advocates Group"), filed a joint submission opposing the Merger.[21] They did not request a hearing.

On July 23, 1999, Applicants filed a response to the various submissions ("Response"). APPA/NRECA replied to the Response on July 30, 1999.[22]

---

[15] The Electricity Consumers Resource Council is an association of large industrial consumers of electricity.

[16] Industry Energy Users - Ohio has 36 members with manufacturing facilities located throughout Ohio, including the areas served by Ohio Power and Columbus Southern Power.

[17] Public Citizen is a non-profit research, lobbying, and litigation organization that advocates consumer protection and government and corporate accountability. Its members are located throughout the United States, including states served by the AEP and CSW Operating Companies.

[18] Ohio Partners for Affordable Energy is an organization formed to advocate affordable energy policies on behalf of low- and moderate-income consumers.

[19] The Citizens Action Coalition of Indiana is a non-profit corporation with approximately 300,000 members and contributors, comprised primarily of residential utility consumers of Indiana utilities, including customers of Indiana Michigan Power.

[20] The Environmental Law and Policy Center, a Chicago-based regional environmental organization, provides technical and legal services to citizen groups throughout the Midwest, including areas served by AEP Operating Companies.

[21] The Attorney General of Oklahoma, the Ohio Consumers' Counsel, and the West Virginia Consumer Advocate Division were originally a members of the Advocates Group, but subsequently withdrew.

[22] Response to Applicants' Opposition to Motions to Intervene.

D. Proposed Merger and Post-Merger Corporate Structure

AEP will acquire CSW in accordance with an Agreement and Plan of Merger, dated as of December 21, 1997 (as subsequently amended, "Merger Agreement"), among AEP, CSW and Merger Sub. Merger Sub will be merged with and into CSW. CSW will be the surviving corporation and a wholly owned subsidiary of AEP.

Each share of CSW Common Stock (with certain exceptions) issued and outstanding immediately prior to the Merger will be converted into the right to receive, and will become exchangeable for, 0.60 shares of AEP Common Stock.[23] The former holders of CSW Common Stock will own approximately 40% of the outstanding shares of AEP Common Stock after the Merger. Applicants state that the Merger is expected to have no effect on the outstanding public debt and other equity securities of CSW, AEP or their respective subsidiaries.

All of CSW's utility and nonutility subsidiaries will become indirect subsidiaries of AEP except CSW Service, which will be merged into AEP Service, and CSW Credit, Inc., a wholly owned nonutility subsidiary of CSW that engages in the factoring of utility accounts receivable, which AEP will hold directly. Applicants propose that CSW remain a registered holding company subsidiary of AEP for up to eight years following the Merger. AEP's utility and nonutility subsidiaries will remain its subsidiaries. AEP, CSW and their subsidiaries after the Merger are referred to collectively below as "New AEP." New AEP's Operating Companies are referred to below as the "New AEP System."

[23] Shares of CSW Common Stock owned by AEP, CSW or any of their direct or indirect subsidiaries, including Merger Sub, if not held on behalf of third parties, will not be converted into AEP Common Stock.

The table below contains financial and related data for the AEP System and the CSW System for the twelve months ended December 31, 1999, as well as *pro forma* data for the New AEP System at that date.

	For the Twelve Months Ended December 31, 1999 (In Millions)		At December 31, 1999 (In Millions)	
	Operating Revenues	Net Income	Number of Customers	Total Assets
AEP System	$6,916	$520	3.0	$21,500
CSW System	5,500	455	1.8	14,200
New AEP System	$12,416	$975	4.8	$35,700

E. Other Approvals

The holders of AEP Common Stock and CSW Common Stock approved the Merger at their respective annual meetings held in May 1998. In addition, the Merger was reviewed by several federal and state regulatory agencies.

1. Federal Approvals

Both AEP and CSW filed notification and report forms under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (the "HSR Act") with the Federal Trade Commission (the "FTC") and the Department of Justice (the "DOJ"). On February 2, 2000, the DOJ notified Applicants that it had completed its review of the Merger and that no further action was warranted.

On March 15, 2000, the FERC issued an order (the "FERC Order") conditionally approving the Merger.[24] The order primarily addresses market power and competitive concerns raised by the Merger. The FERC Order, among other things, holds that, subject to the conditions of the order, including certain commitments of Applicants, the Merger is consistent with the public interest as required by the FPA.[25] The FERC also conditioned its approval on the transfer of operational control of the New AEP System transmission facilities to a fully-functioning, FERC-approved regional transmission operator(s) ("RTO(s)") by December 15, 2001.[26]

---

[24] *See American Electric Power Company and Central and South West Corporation*, Dkt. Nos. EC98-40-000, ER98-2770-000 and ER98-2786-000, 90 FERC ¶ 61,242 (Mar. 15, 2000), reh'g request dismissed in part, denied in part and granted in part, Opinion No. 442-A (May 15, 2000). The disposition of the request is discussed in note 26, *infra*.

[25] Applicants committed: (1) to divest 550 MW of generation capacity (250 MW of CSW's generation capacity in ERCOT immediately upon consummation of the Merger and 300 MW of CSW's generation capacity in the SPP by July 1, 2002); (2) to limit their ability to contract for firm transmission capacity from the AEP system to the CSW system to 250 MW, unless authorized by the FERC to contract for more capacity; (3) to schedule available capacity between ERCOT and the SPP on the HVDC ties on a first-in-time basis; (4) to waive their native load priority into the CSW-SPP control area for nonfirm imports; (5) to waive their native load priority for transfers of energy from the CSW System to the AEP System for a four-year period following the Merger; and (6) to adopt certain ratepayer protection measures. The effect of commitment (4) upon the New AEP System is discussed in section II.B.1.a., *infra*. As discussed in section II.B.1.b.(2), *infra*, the FERC Order also approved proposed New AEP System agreements and tariffs.

[26] To "determine whether operations or wholesale transactions involving Applicants are unduly discriminatory or preferential or show evidence of the exercise of market power," the FERC also requires that Applicants provide for interim mitigation measures. Applicants committed to provide generation dispatch information necessary for the Midwest Independent System Operator (the "MISO") to monitor the effects of the dispatch on the loading of the MISO's constrained transmission facilities. The FERC Order requires AEP to provide similar generation dispatch information and other additional data to an independent party in order to monitor the effects of this dispatch on the loading of AEP's constrained transmission facilities. The FERC Order requires that the independent party analyze the data and submit the analysis and data to the FERC for review.

The NRC approved the transfer of control of CP&L's NRC licenses with a condition that the Merger be completed by December 31, 1999.[27] The NRC subsequently extended the deadline to June 30, 2000. The Federal Communications Commission approved the transfer of certain microwave licenses held by CSW.

2. State Approvals

The interested state regulatory authorities have approved the proposed Merger and/or related matters. The state commissions of Arkansas, Indiana, Kentucky, Louisiana, Oklahoma and Texas conditionally approved the Merger, pending the FERC order and final action by other relevant authorities.[28]

Because the proposed divestitures could not be completed by the consummation of the Merger, Applicants proposed to make interim sales equivalent to the capacity to be divested until the completion of each divestiture. The FERC Order requires the Applicants to file, prior to the consummation of the Merger, the proposed terms and conditions of the interim sales contracts. Applicants made the required compliance filings with the FERC on March 31, 2000.

Applicants sought a rehearing of two aspects of the FERC Order: first, the finding that their analysis did not adequately evaluate the potential vertical effect of the Merger; and second, the FERC's modification to the pricing methodology proposed for system energy exchanges between the East and West Zones (discussed in section II.B.1.b.(2).(B), *infra*). The FERC dismissed the first request as moot, in view of Applicants' commitment to comply with the conditions of the FERC Order regardless of the disposition of their rehearing request. The FERC granted the second request because Applicants explained that their proposed pricing formula would always operate so as not to result in an above-market price for a New AEP System Operating Company purchaser.

[27] CP&L will continue to hold the interests in the South Texas Project and STP Nuclear Operating Company following the Merger.

[28] In an order, a copy of which is attached to the Application as Exhibit D-2.2, the Arkansas Commission approved a settlement among its staff, AEP, CSW and SWEPCO. Among other things, the Arkansas Commission imposed certain conditions concerning quality and reliability of service and cost of capital protection, and adopted a regulatory plan governing the treatment of the costs and benefits of the Merger and the manner in which they would be reflected in SWEPCO's Arkansas retail rates. The Arkansas Commission also

required Applicants to hold Arkansas ratepayers harmless for any adverse impact on rates resulting from any Merger mitigation plan entered into with other state or federal regulators.

In an order, a copy of which is attached to the Application as Exhibit D-8.1 ("Indiana Order"), the Indiana Commission conditionally approved a settlement agreement among its staff, AEP and Indiana Michigan Power. Among other things, the settlement agreement addresses: (1) net non-fuel Merger savings; (2) fuel and purchase power Merger savings; (3) limitation on requests for stranded cost recovery; (4) allocation of the proceeds from the sale of facilities; (5) system integration agreements; (6) standards for affiliate transactions; and (7) adequacy and reliability of electric service.

In an order, a copy of which is attached to the Application as Exhibit D-7.1 ("Kentucky Order"), the Kentucky Commission approved a settlement agreement among AEP, CSW, the Kentucky Attorney General, and intervenors in the state proceeding. The agreement, among other things, provides for: (1) the pass-through of Merger savings to customers; (2) a rate moratorium; (3) quality of service and reliability standards; (4) reporting requirements; and (5) standards for affiliate transactions.

In an order, a copy of which is attached to the Application as Exhibit D-3.2 ("Louisiana Order"), the Louisiana Commission approved conditions in a settlement agreement designed to (1) capture for Louisiana ratepayers the actual (rather than projected) savings resulting from the Merger; (2) protect ratepayers from any adverse effect on rates or quality and reliability of service; and (3) ensure that transactions among New AEP System affiliate companies do not result in cost increases to Louisiana customers.

The Missouri Public Service Commission also entered into a settlement agreement with Applicants in the FERC proceeding. The FERC set for hearing the effect of the Merger on wholesale rates and on retail competition in Missouri. In the proceeding, the Missouri Commission raised concerns regarding competitive impacts that may occur as a result of Applicants' use of the Contract Path, discussed in section II.B.1.a., *infra*. Under the settlement, the Missouri Commission may, within four years after the Merger, initiate a review by the FERC of the Merger's effects on retail competition, assuming retail competition has been implemented in Missouri. The FERC approved the settlement. *See* 90 FERC ¶ 61,094 (2000).

In an order, a copy of which is attached to the Application as Exhibit D-10.1 ("Michigan Order"), the Michigan Commission approved a settlement agreement similar to those described above, between its staff and AEP.

A settlement agreement was approved in an order by the Texas Commission, a copy of which is attached to the Application as Exhibit D-5.4. This agreement, which addressed issues related to competition and reliability, is discussed *infra*.

Certain of the state commissions addressed concerns relating to the potential effects of the Merger on competition as a result of the amount of generating capacity that New AEP would control. The Texas Commission approved a settlement agreement with its staff under which Applicants agreed to divest 1,604 MW of generation capacity in ERCOT and an additional 300 MW in SPP.[29] In addition, the Oklahoma Commission directed AEP and CSW to request that the SPP evaluate, and AEP and CSW help remedy, any adverse competitive effect that may result from power transfers from AEP to CSW over a Contract Path, discussed further below, that will afford a 250 MW firm east-to-west point-to-point transmission service over the service territory of Ameren Corporation ("Ameren") to certain transmission assets in the SPP.

F. <u>Expected Benefits of the Merger</u>

Applicants state that the Merger will benefit the public, investors and consumers. Specifically, Applicants anticipate that:

- ♦ New AEP will operate more efficiently and be better able to keep rates low in an increasingly competitive electric utility industry;
- ♦ New AEP will achieve savings through the elimination of duplication in corporate and administrative programs, greater efficiencies in operations and business processes, improved purchasing power, and the combination of two work forces;

Other state commissions, such as Ohio, Virginia and West Virginia, were apprised of the Merger but concluded that they did not have to take formal action. The Ohio commission, in particular, opened a formal docket on the Merger and appeared in the FERC proceeding.

[29] The 1,604 MW of generation capacity includes 250 MW of generating capacity to be divested under a settlement agreement with the FERC.

♦ New AEP will have a stronger financial base, improved position in the credit markets, and greater market diversity than either AEP or CSW standing alone would have;

♦ The Merger will diversify the service territory of the New AEP System, reducing exposure to local changes in economic and competitive conditions; and

♦ The Merger will enhance the profitability of New AEP.

Applicants estimate that net non-fuel savings from the Merger will be approximately $2 billion and net fuel-related savings will be approximately $98 million over the first ten years after the Merger. The expected benefits of the Merger are discussed in greater detail in section II.B.2 below.

Fees and expenses in the estimated amount of $72.7 million are anticipated in connection with the proposed transactions.

II. Discussion of the Merger and Intervenors' Objections

The proposed Merger requires our prior approval under sections 9(a) and 10 of the Act. We have reviewed the proposed transaction and find that the requirements of the Act are satisfied. Our application of the integration standards of the Act and our consideration of the potential anticompetitive effects of the Merger are central to our approval of the Merger. Accordingly, these matters are discussed below.

A. Applicable Standards for Approving the Merger: Section 10(b)

Section 10(b) requires us to approve the Merger unless we make adverse findings under three specific standards.

1. Section 10(b)(1): Concentration of Control

Section 10(b)(1) requires that we not approve the proposed acquisition if we find that it will "tend towards interlocking relations or the concentration of control of public-utility companies, of a kind or to an extent detrimental to the public interest or the interest of investors or consumers." Although we are primarily concerned under the Act with the structure of public-utility holding company systems, our analysis under section 10(b)(1) includes consideration of federal antitrust policies.[30] Anticompetitive ramifications of an acquisition are considered in light of the fact that utilities are regulated monopolies subject to the ratemaking authority of federal and state administrative bodies.[31]

In considering whether an acquisition satisfies the standards of section 10(b)(1) in previous applications, we have exercised "watchful deference" to the analysis of other federal and state regulators that considered antitrust policies in connection with the merger.[32] We have done so here. As noted above, Applicants made HSR filings with the FTC and the DOJ and the applicable waiting period has expired. In addition, the FERC fully considered the competitive impact of the Merger under section 203 of the FPA. The FERC Order approved the Merger after a hearing on its potential effect on wholesale competition. The FERC Order incorporates a number of conditions designed to address competition issues. The Texas, Oklahoma and Missouri Commissions also considered competition issues.

---

[30] *See, e.g., Sempra Energy*, Holding Co. Act Release No. 26890 (June 26, 1998) at text accompanying n.24 ("*Sempra Energy I*").

[31] *Id.* at text accompanying n.25 (citations omitted).

[32] *See, e.g., id.* The United States Court of Appeals for the District of Columbia Circuit has upheld this approach. *See Madison Gas and Electric Co. v. SEC*, 168 F.3d 1337, 1341-42 (D.C. Cir. 1999) (citations omitted) ("*Madison Gas*"), *aff'g WPL Holdings, Inc.*, Holding Co. Act Release No. 26856 (Apr. 14, 1998) ("*WPL Holdings I*").

APPA/NRECA asserts that the Merger would have "profound anti-competitive effects," detrimental to the public interest and the interest of consumers.[33] APPA/NRECA acknowledges that it is the Commission's practice to exercise "watchful deference," but urges us to "ensure that the FERC's ultimate resolution addresses the market-power concerns relevant under the Act."[34]

APPA/NRECA filed with their Motion to Intervene a copy of their protest of the Merger filed at the FERC. Their concerns, as outlined in their FERC protest, involve the elimination of a competitor from both the AEP and CSW service territories and from the wholesale market in general, and perceived inadequacies in the Applicants' competition analysis.[35] These concerns were fully considered at the FERC. The FERC recognized that the proposed Merger raised competitive concerns, but determined that, with the conditions and remedies imposed in the FERC Order, the Merger is consistent with the public interest under section 203 of the FPA.

Three state agencies and the FERC considered the potential competitive effects of the Merger. The FERC, in particular, recognized that the transaction raised competitive concerns involving operational matters and sought to address and remedy potential

---

[33] APPA/NRECA at 6.

[34] *Id.* at 22.

[35] In particular, APPA/NRECA asserts that (1), the proposed Contract Path "appears to be a wholly arbitrary choice and subject to change," (2) the proposal to divest generation capacity (300 MW in the SPP and 250 MW in ERCOT), as a mitigation measure, depends on the inability of CSW to exercise the market power sought to be remedied; and (3) Applicants' reliance on market entry by new competitors to cure the Merger's competitive problems is misplaced. *Id.* at 23-24.

anticompetitive effects by required divestiture of capacity and other remedial measures. These matters are entrusted to the expertise of the FERC.[36]

We have reviewed the entire record in this proceeding and have considered in particular the remedial measures that the FERC and the Texas Commission require to address potential anticompetitive effects of the proposed Merger. We believe that we may appropriately rely upon the findings and requirements of these agencies in concluding that no adverse finding under section 10(b)(1) of the Act is required in this matter.[37]

2. Section 10(b)(2): Fairness of Consideration

Section 10(b)(2) requires us not to approve an acquisition if we find that the consideration is "not reasonable or does not bear a fair relation to the sums invested in or the earning capacity of the utility assets to be acquired. . . ." As noted above, CSW shareholders will receive 0.60 shares of AEP Common Stock for each share of CSW Common Stock that they currently own.

Based upon our review, we are satisfied that the purchase price is not unfair or unreasonable within the meaning of section 10(b)(2). The price is the result of arm's-length negotiations between AEP and CSW. The Applicants state that these negotiations were preceded by months of due diligence, analysis and evaluation of the assets, liabilities and business prospects of the respective companies, which were described in detail in the Applicants' joint proxy statement seeking shareholder approval of the Merger.

---

[36] *See Sempra Energy I, supra* note 30.

[37] *See id.* (relying upon combined findings and requirements of the DOJ, the FERC and the California Public Utilities Commission).

The record does not offer any basis to conclude that the consideration to be paid in the Merger is unfair or unreasonable. There also is no basis to conclude that the consideration does not bear a fair relation to the earning capacity of the utility assets to be acquired within the meaning of section 10(b)(2).

Mr. Davis urges us to consider that the market price of AEP and CSW Common Stock has declined.[38] To the extent that Mr. Davis suggests that the Merger may not satisfy section 10(b)(2) of the Act because of this decline, we reject the suggestion.

The consideration offered by AEP will be AEP Common Stock. On December 19, 1997, the last trading day before the Merger was announced, the closing prices of AEP Common Stock and CSW Common Stock were $52 and $26, respectively. The Exchange Ratio in the Merger Agreement provided, in effect, that CSW shareholders would receive

---

[38] Mr. Davis acknowledges that his comments were filed almost a year after the notice period closed, but he states that "substantial changes in circumstances," specifically problems in a nuclear plant of AEP, litigation brought against AEP by the Environmental Protection Agency ("EPA"), and a decline in the market price of AEP and CSW Common Stock, make it appropriate for us to consider his submission. We note that any problems in the operation of the nuclear plant are the immediate concern of another federal agency, the NRC, and have no relevance to the findings that we are required to make under the Act. Similarly, litigation brought by the EPA has no bearing upon our consideration of the Merger.

In addition, Mr. Davis asks us to consolidate the Application with a request by AEP and its subsidiaries for financing authorizations in File No. 70-8779, a proceeding in which he has also filed comments. He suggests that consolidation is appropriate because the requested financing authorizations contemplate "very large security issues" and the Application proposes to combine two large holding company systems. He adds that, "[t]he uncertainties in integrating the companies and achieving cost savings were recognized by the two managements in the Statement to Stockholders dated April 17, 1998." We do not perceive any relationship between the Application and the requested authorizations. Specifically, the findings upon which we base our approval of the Merger in no way depend upon whether we approve AEP's financing request in File No. 70-8779. Accordingly, we deny the requested consolidation. We will address Mr. Davis' comments on File No. 70-8779 when we consider that matter.

approximately \$31.20 per share of CSW Common Stock (in AEP Common Stock). This represents a premium of approximately 20% over the closing price of CSW Common Stock on December 19, 1997.

To support their assertion that section 10(b)(2) is satisfied in this matter, Applicants describe:

- ♦ arm's length negotiations between AEP and CSW, conducted in a competitive context, resulting in the proposed Exchange Ratio;

- ♦ fairness opinions from the Applicants' financial advisers, Salomon Smith Barney Inc., which provided an opinion to AEP, and Morgan Stanley & Co. Incorporated, which provided an opinion to CSW;

- ♦ a valuation analysis demonstrating the fairness of consideration, as evidenced by the comparative market prices of, and dividends paid on, AEP Common Stock and CSW Common Stock;

- ♦ necessary shareholder approvals; and

- ♦ the inclusion of required closing conditions in the Merger Agreement intended to assure that the Merger will be consummated on terms that are fair to Applicants and their shareholders.

Mr. Davis does not explain how the price of AEP's Common Stock raises a material question of fact or law that requires examination at a hearing.[39] He does not explain whether the Merger consideration is unfair to either AEP or CSW shareholders. We are satisfied that no adverse finding under section 10(b)(2) is required in this matter.[40]

---

[39] We note that on May 16, 2000, the closing prices of AEP's and CSW's Common Stock were \$36 1/4 and \$21 3/16, respectively. These prices closely approximate the Exchange Ratio agreed to in the Merger Agreement.

[40] The Application states that the estimated fees, commissions and expenses will total approximately \$72.7 million, representing approximately 1.1% of the value of the consideration to be paid by AEP. We have found that fees within this range are permissible under section 10(b)(2). *See, e.g., Entergy Corp.*, Holding Co. Act Release No. 25952 (Dec.

3. Section 10(b)(3): Capital Structure and Public Interest

a. Effect upon Capital Structure

Section 10(b)(3) of the Act requires us to approve a proposed acquisition unless we find that it would "unduly complicate the capital structure of the holding-company system of the applicant" or would "be detrimental to the public interest or the interest of investors or consumers [the "protected interests" under the Act] or the proper functioning of such holding-company system." We have considered the anticipated capital structure of the New AEP System following the Merger and have concluded that a negative finding under section 10(b)(3) is not warranted.

Set forth below is a table showing the consolidated capital structure of each of AEP and CSW and the *pro forma* consolidated capital structure of New AEP after the Merger.

17, 1993) (fees and expenses of approximately $38 million, representing approximately 2% of the value of the consideration to be paid to shareholders of Gulf States Utilities) ("*Entergy Corp.*"); *Northeast Utilities*, Holding Co. Act Release No. 25548 (June 3, 1992) (fees and expenses of approximately $46.5 million, representing approximately 2% of the value of the assets to be acquired). On our review of the record in this matter, we are satisfied that the fees and commissions are not unreasonable.

	At December 31, 1999					
	AEP		CSW		Pro Forma New AEP	
	Amount (In $ millions)	Percent of Total	Amount (In $ millions)	Percent of Total	Amount (In $ millions)	Percent of Total
Common stock equity	$ 5,006	37.1%	$ 3,683	36.0%	$ 8,689	36.6%
Preferred stock	164	1.2	18	0.2	182	0.8%
Long-term debt	7,447	55.1	4,077	39.8	11,524	48.5
Short-term debt	888	6.6	2,124	20.7	3,012	12.7
Trust preferred securities	--	--	335	3.3	335	1.4
Total capitalization	$ 13,505	100.0%	$ 10,237	100.0%	$ 23,742	100.0%

The proposed Merger will not significantly change AEP's existing capital structure. Equity would be reduced from 38.3% to 37.4% of total capitalization, and debt increased from 61.7% to 62.6%.[41] These figures are well within the 60%/30% debt/common equity

[41] Equity includes a common stock equity component of 36.6%. The *pro forma* consolidated capitalization of AEP includes substantial levels of short-term debt (more than $3 billion), most of which is attributable to the acquired CSW System. The rating agencies have taken these levels of short-term debt into consideration. Ratings of the senior securities of the Operating Companies of both Systems have not changed since the announcement of the Merger in December, 1997. As of March 31, 2000, the overall levels of short-term debt of both AEP and CSW have declined.

ratio that we have generally viewed as adequate for registered holding companies.[42] We therefore do not find that the Merger would unduly complicate the capital structure of the New AEP System.

b. Effect Upon the Protected Interests and System Functioning

As discussed below, Applicants anticipate that the proposed Merger will benefit consumers. The FERC, the NRC, and various state commissions have granted necessary approvals after extensive reviews, as discussed below. Finally, the Merger is expected to have no adverse effect on the rights of holders of the outstanding preferred stock and debt securities of New AEP. In view of these considerations, we do not find that the Merger would be detrimental to the protected interests or the proper functioning of the New AEP System.

B. Applicable Standards for Approving the Merger: Section 10(c)

Section 10(c)(1) of the Act requires us not to approve an acquisition that would be "detrimental to the carrying out of the provisions of section 11."[43] Section 10(c)(2) further requires us to find that the acquisition "will serve the public interest by tending towards the economical and efficient development of an integrated public-utility system." As discussed below, the Merger will satisfy these standards.

---

[42] *See, e.g., Entergy Corp., supra* note 40, citing *Northeast Utilities*, Holding Co. Act Release No. 25221 (Dec. 21, 1990), n.47 ("*Northeast Utilities*"), *supplemented*, Holding Co. Act Release No. 25273 (Mar. 15, 1991), *aff'd sub nom. City of Holyoke v. SEC*, 972 F.2d 358 (D.C. Cir. 1992).

[43] Section 10(c)(1) further prohibits approval of an acquisition that is unlawful under the provisions of section 8. Section 8, which is not applicable to the Merger, addresses an acquisition by a registered holding company of an interest in an electric utility and gas utility that serve substantially the same territory.

1. <u>Sections 10(c)(1), 11(b)(1) and 2(a)(29)(A): Integrated Electric System</u>

Section 10(c)(1) of the Act makes reference to section 11(b)(1), which generally confines the utility properties of a registered holding company to a "single integrated public-utility system." Section 2(a)(29)(A) defines an "integrated public-utility system," as applied to electric utility properties, to mean:

> . . . a system consisting of one or more units of generating plants and/or transmission lines and/or distributing facilities, whose utility assets, whether owned by one or more electric utility companies, are physically interconnected or capable of physical interconnection and which under normal conditions may be economically operated as a single interconnected and coordinated system confined in its operations to a single area or region, in one or more States, not so large as to impair (considering the state of the art and the area or region affected) the advantages of localized management, efficient operation, and the effectiveness of regulation [...].

Following the statutory definition, we have recognized four standards that must be met before we will find that a proposed combination of utility properties will result in an integrated system:

- the combined utility assets must be physically interconnected or capable of physical interconnection (the "interconnection requirement");
- the combined utility assets, under normal conditions, must be economically operated as a single interconnected and coordinated system (the "economic and coordinated operation requirement");
- the system must be confined in its operations to a single area or region (the "single area or region requirement"); and
- the system must not be so large as to impair (considering the state of the art and the area or region affected) the advantages of localized management, efficient operation, and the effectiveness of regulation (the "no impairment requirement").[44]

---

[44] *See, e.g.*, *Environmental Action, Inc. v. SEC*, 895 F.2d 1255, 1263 (9th Cir. 1990), citing *Electric Energy Inc.*, 38 SEC 658, 668 (1958) ("*Electric Energy*").

We have read each standard of section 2(a)(29)(A) in connection with the other provisions of the section, and in light of the facts under consideration and the other objectives of the Act.[45]

The U.S. Supreme Court has recognized that the Act is an "intricate statutory scheme" which must be given "practical sense and application."[46] We have noted in the context of the statutory integration requirements that the Act "creates a system of pervasive and continuing economic regulation that must in some measure at least be refashioned from time to time to keep pace with changing economic and regulatory climates."[47] We have previously taken notice of developments that have occurred in the gas and electric industries in recent years, and have interpreted the Act and analyzed proposed transactions in light of these changed and changing circumstances.[48] This approach is consistent with the language

---

[45] *See generally 1978 AEP Order*, *supra* note 2. *See also Sempra Energy*, Holding Co. Act Release No. 26971 (Feb. 1, 1999) ("*Sempra Energy II*"), citing *North American Co.*, 18 S.E.C. 459, 463 (1945) (in applying the integration standards for gas utility systems, the Commission has "read each standard of section 2(a)(29)(B) in connection with the other provisions of the section").

[46] *SEC v. New England Electric System*, 384 U.S. 176 (1966), *rev'g and remanding* 346 F.2d 399 (1st Cir. 1966), *rev'g*, *New England Electric System*, 41 SEC 888 (1964), *on remand*, 376 F.2d 107 (1st Cir. 1967), *rev'd*, 390 U.S. 207 (1968).

[47] *Union Electric Co.*, 45 S.E.C. 489, 503 n.52 ("*Union Electric*"), *aff'd sub nom. City of Cape Girardeau v. SEC*, 521 F.2d 324 (D.C. Cir. 1975) (the issue of retainability of both gas and electric properties must be resolved "in a way that makes economic and social sense in the light of contemporary realities").

[48] *New Century Energies, Inc.*, Holding Co. Act Release No. 26748 (Aug. 1, 1997) ("*New Century Energies*") (reassessing the requirements of section 11(b)(1)(A) with respect to an additional integrated system). We have taken industry conditions into consideration when appropriate. *Id.*, *citing Union Electric*, *supra* note 47, at 509-10 and *Municipal Electric Assn. of Massachusetts v. SEC*, 413 F.2d 1052, 1059 (D.C. Cir. 1969), reversing and quoting a dissenting opinion from *Vermont Yankee Nuclear Power Corp.*, 43 S.E.C. 693 (1968) ("That [a] . . . development of . . . importance and probable impact . . . was not

of section 2(a)(29)(A) itself, which directs us to consider the "state of the art" -- that is, the contemporary realities of the industry.[49] Our precedents under sections 2(a)(29)(A), 10(b)(1) and 10(c)(2) of the Act reflect this approach.[50] The ultimate determination has always been whether, on the facts of a given matter, the proposed transaction "will lead to a recurrence of the evils the Act was intended to address," *i.e.*, the abuses identified in section 1 of the Act.[51] On the facts of this matter, we find that the New AEP System will constitute an electric integrated system.

---

foreseen when the Act was written should not justify a static historical reading of its provisions.").

[49] We have stated that "[w]e think it is clear from the language of Section 2(a)(29)(A), which defines an integrated public utility system, that Congress did not intend to imposed [sic] rigid concepts with respect thereto". *Yankee Atomic Electric Co.*, Holding Co. Act Release No. 13048 (Nov. 25, 1955). *Accord: UNITIL Corp.*, Holding Co. Act Release No. 25524 (Apr. 24, 1992) ("*UNITIL*") (the integration requirement creates a "flexible" standard designed "to accommodate changes in the electric utility industry"). In *UNITIL*, we effectively determined that a tight power pool was the functional equivalent of a traditional integrated system.

[50] *See, e.g., UNITIL, supra* note 49 (participation in a tight power pool was sufficient to meet the standard of economic and coordinated operation even though the "definition [of section 2(a)(29)(A)] reflects an assumption that the holding company would coordinate the operations of the integrated system"); *1978 AEP Order, supra* note 2, at 1309-10 (technological advances in generation and transmission, unavailable thirty years previously, served to distinguish a prior case and justified "large systems spanning several states"). *See also New Century Energies, supra* note 48.

[51] *Southern Co.*, Holding Co. Act Release No. 25639 (Sept. 23, 1992) (quotation omitted). Section 1(c) of the Act directs us to interpret all the provisions of the Act to "meet the problems and eliminate the evils" identified in section 1 of the Act. In particular, section 1(b)(4) identifies as an abuse "the growth and extension of holding companies [that] bears no relation to economy of management and operation or the integration and coordination of related operating properties."

a. Interconnection

Applicants have obtained a 250 MW firm Contract Path providing east-to-west firm point-to-point transmission service from AEP's Breed-Casey interconnection with Ameren, along the Indiana/Illinois border, to Ameren's interconnection in Missouri with the MOKANOK line, which runs to an interconnection with CSW in Oklahoma. The term of the Contract Path is from June 1, 1999 to May 31, 2003.[52] Applicants have the ability through the Ameren open access tariff to renew the Contract Path. We have previously found the interconnection requirement to be satisfied on the basis of the merging companies' contractual rights to use a third party's transmission lines.[53]

Applicants note that the Contract Path provides a means to meet the statutory interconnection standard and, at the same time, preserves flexibility to enter into other more favorable arrangements should they become available during the four-year term of the Contract Path. Applicants commit to either extend their right to use the Contract Path prior

---

[52] The MOKANOK line is owned by several utilities, including subsidiaries of Ameren, CSW and Western Resources, Inc. ("Western Resources"). CSW owns only the segment of the line located in Oklahoma, but it has a contractual right, as one of owners of the line, to a share of the transmission capacity over the full length of the line. To obtain 250 MW of transmission capacity over the MOKANOK line, the New AEP System will use CSW's existing share of capacity and will purchase 38 MW of additional capacity from Western Resources.

[53] *See, e.g., Madison Gas, supra* note 32, at 1340 (physical interconnection through a three-year firm contract to use a 200 MW transmission line owned by two nonaffiliates). *See also Northeast Utilities, supra* note 42 (interconnection standard met where combining entities reached an agreement to obtain service by nonaffiliates having a transmission line connecting the two systems); *Centerior Energy Corp.*, Holding Co. Act Release No. 24073 (Apr. 29, 1986) ("*Centerior*") (interconnection standard met where merging systems could be connected through a power transmission line, owned by a nonaffiliate, that each had the right to use).

to May 31, 2003, or to file a post-effective amendment explaining how the New AEP System will continue to satisfy the interconnection requirement if its rights with respect to the Contract Path are not extended.

The Advocates Group challenges the adequacy of the term of the Contract Path and states that we "must find that arrangements will be in place throughout the life of the post-acquisition entity."[54] The Advocates Group refers to prior orders where "the utilities had the right to use the third party's lines for ten years and indefinitely."[55]

The Advocates Group asserts that, where third party transmission rights are not in place for an indefinite period after a merger, we have consistently "found that alternative or subsequent interconnection arrangements were certain" and have not relied on a temporary contract only.[56] The Advocates Group notes that Applicants have no plan comparable to that of the applicants in the recent *Madison Gas* decision.[57] In *Madison Gas*, the Court of Appeals relied upon the applicant's "showing of a current transmission line contract and of a plan to build two tie-lines of its own across the Mississippi before the end of the contract term." APPA/NRECA also emphasizes that the merging companies have no plans to build an interconnection.[58]

---

[54] Advocates Group at 7.

[55] *Id.* at 8 citing *Northeast Utilities*, *supra* note 42, at n.74; *Centerior*, *supra* note 53.

[56] Advocates Group at 7-8.

[57] *Id.* *See supra* note 32.

[58] APPA/NRECA at 9-10.

We disagree with the Advocates Group's assertion that the Applicants have not made sufficient commitments upon which we may conclude that the New AEP System will satisfy the interconnection requirement. Applicants have committed to renew the Contract Path or to inform us of the means by which the interconnection requirement will be satisfied if it is not renewed. The Act imposes a continuing requirement upon registered systems to satisfy the statutory integration requirements. We do not believe that *Madison Gas* stands for the proposition that plans must be in place to build transmission lines; an existing contract path, coupled with a commitment to find alternatives should the contract path not be renewed, should be sufficient to satisfy the statutory requirement.[59] Moreover, the Advocates Group

---

[59] As noted above, the holding company in *Madison Gas* had a current transmission line contract and planned to build two tie-lines across the Mississippi before the end of the contract term. The applicants in that matter committed to take measures to ensure that the interconnection requirements of section 2(a)(29)(A) would be satisfied if the tie-lines were not constructed and a connection agreement was not in place at that time. 168 F.3d at 1340-41.

In this context, we note the efforts of the FERC to restructure the way in which transmission is provided and obtained in the U.S., first, by requiring that utilities provide open access to transmission service to all market participants on comparable terms; and second, by requiring utilities to participate in RTOs. *See* Order No. 888: *Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, FERC Stats. & Regs., Regulations Preambles, ¶ 31,036 (1996) ("Order 888"), *order on reh'g*, FERC Stats. & Regs., Regulations Preambles, ¶ 31,048 (1997) ("Order 888-A"), *order on reh'g*, 81 FERC ¶ 61,248 (1997) ("Order 888-B"), *order on reh'g*, 82 FERC ¶ 61,046 (1998) ("Order 888-C"); Order No. 2000: *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285 (1999), *reprinted at* 65 Fed. Reg. 810 (Jan. 6, 2000).

Order 888's key provision was the requirement that utilities file open access tariffs under which a transmission provider must offer service. The tariffs provided utilities and power marketers for the first time with a generally available right to use the transmission systems of others to move power at tariffed rates.

and APPA/NRECA err to the extent that they suggest that Applicants must have concrete plans now to construct an interconnection.[60]

APPA/NRECA asserts that "the Commission has never held that the interconnection requirement may be satisfied by the use of third-party transmission service in lieu of actual physical interties, when utilities are as widely separated as AEP and CSW and lie in different power pools."[61] There is *dicta* in a series of our decisions stating that contract rights cannot be relied on to "integrate" "distant" utility properties.[62] We do not believe that these

---

Order No. 2000 requires all public utilities that own, operate or control interstate transmission facilities subject to FERC jurisdiction to file, by October 15, 2000, a proposal for an RTO with the minimum characteristics and functions identified in Order No. 2000, or, alternatively, a description of any efforts made by the utility to participate in an RTO, any obstacles to participation, and any plans and timetable for further work toward RTO participation. FERC defines an RTO as an entity that satisfies the minimum characteristics (independence, scope and regional configuration, operational authority and short-term reliability) and minimum functions (tariff administration and design, congestion management, parallel path flow, ancillary services, OASIS information, market monitoring, planning and expansion and interregional coordination). 18 CFR § 35.34. Public utilities that are members of an existing FERC-approved regional entity must file by January 15, 2001 an explanation of the extent to which the regional entities in which they participate meet the minimum characteristics and functions of an RTO.

We have yet to address whether physical interconnection can be demonstrated through membership in an RTO. The Applicants have not sought to rely upon AEP's participation in a RTO for a showing of interconnection. The question of AEP's ability to do so, if the Contract Path is terminated, thus remains open. The ongoing industry restructuring will require our continuing consideration of the interconnection requirement.

[60] The Court of Appeals stated in *Madison Gas*, "The SEC has reasonably construed this requirement [that assets be 'capable of physical interconnection'] to be satisfied in cases past 'on the basis of contractual rights to use a third-party's transmission lines' *or* 'if physical interconnection is 'contemplated or . . . possible within the reasonably near future.'" *Id.* at 1340 (emphasis added).

[61] APPA/NRECA at 10.

[62] *See WPL Holdings I*, *supra* note 32, at n.39 citing *UNITIL*, *supra* note 49; *Northeast Utilities*, *supra* note 42; *Centerior*, *supra* note 53.

statements mean that a contract path might not meet the interconnection requirement because of its length. These earlier cases suggest that the reason a contract path might not "integrate" two distant utilities was due to the "single area or region" requirement of section 2(a)(29)(A).[63] We did not hold in any of these prior cases that the length of a contract path was relevant in determining whether the interconnection requirement of section 2(a)(29)(A) was met. Such an approach would be inappropriate in view of the express language of section 2(a)(29)(A) as well as technological and commercial developments that have made feasible the transmission of power over longer distances.

The Advocates Group suggests, without discussion, that a one-way transmission contract is inadequate.[64] We do not agree. As explained in section II.B.2. below, Applicants anticipate net-fuel related savings of approximately $98 million over the ten-year period following the Merger. Applicants contemplate that fuel-related savings will result from the economic transfer of energy from one zone of the New AEP System, the "East Zone," to another, the "West Zone." (These zones correspond to the pre-merger AEP System and CSW System, respectively.) The Contract Path will also afford the New AEP System additional opportunities for cost-effective energy transfers. Applicants do not anticipate sufficient levels of west-to-east energy transfers to warrant a firm two-way contract path. In view of these consideration, the Contract Path is adequate to support these transactions and satisfy the interconnection requirement.

[63] *UNITIL*, *supra* note 49, at n.30; *Northeast Utilities*, *supra* note 42, at n.75.

[64] Advocates Group at 6.

The Advocates Group further claims that, by ceding use of the HVDC ties, the CSW Operating Companies will no longer constitute an integrated system and that CSW's Texas assets will be "fatally separated from the remainder of the post-merger system."[65] The Advocates Group notes that the HVDC ties, which link the CSW SPP assets with the CSW ERCOT assets, were constructed specifically to connect the CSW Operating Companies.[66]

Applicants state, however, that they have committed only to waive priority with respect to use of the HVDC ties for unplanned (*i.e.*, non-firm) transactions in ERCOT and the SPP. The waiver would not apply to planned (*i.e.*, firm) transactions submitted to ERCOT or other transfers of firm capacity between the SPP and ERCOT control areas. Applicants state that New AEP will continue to use the HVDC ties to connect the New AEP ERCOT and non-ERCOT (SPP) Operating Companies in the manner described in *Central and South West Corporation*.[67]

The Advocates Group also asserts that Applicants' intention to join an independent system operator ("ISO") in the future is not a substitute for real integration.[68] The APPA/NRECA agrees.[69] Applicants, however, do not rely on participation in an ISO or

---

[65] *Id.* at 5. *See* note 25 *supra*, discussing the conditions of the FERC Order.

[66] *Id.* at 13-14, citing *Central and South West Corp.*, *supra* note 9.

[67] Applicants state that CSW's firm transmission capacity has always been adequate to coordinate its operations and there has never been a need to assert a priority for unplanned transactions over the HVDC ties. As a result, Applicants do not expect their waiver of priority for non-firm use of the HVDC ties to affect the coordination of the New AEP System in any way.

[68] Advocates Group at 9.

[69] "The Applicants' reliance on their generalized ISO plans must . . . be rejected as a means of satisfying the statute's requirement." APPA/NRECA at 12.

RTO to satisfy the interconnection requirement specifically or the statutory integration requirements generally. Applicants note merely that this participation will likely result in increased reliability for the New AEP System.

We are satisfied that the utility properties of the New AEP System will be interconnected.

b. Economic and Coordinated Operation

(1) Introduction

In applying section 2(a)(29)(A), we have noted that, "[c]learly, Congress intended that more than interconnection is needed . . . ."[70] The Court of Appeals for the District of Columbia Circuit has affirmed our view that the words "economically operated" in section 2(a)(29)(A) impose a requirement "that facilities, in addition to their physical interconnection, be consolidated so as to take advantage of efficiencies."[71]

(2) Proposed Operation of the New AEP System

The proposed operation of the New AEP System will differ in some respects from the traditional vertically-integrated monopoly utility model.[72] Power supply will not be pooled

[70] *Cities Service Co.*, 14 S.E.C. 28, 59 (1943) ("*Cities Service*").

[71] *City of New Orleans v. SEC.*, 969 F.2d 1163, 1168 (D.C. Cir. 1992) ("*City of New Orleans*") (citations omitted). The Court of Appeals rejected intervenors' argument that a system would no longer be "economically operated" within the meaning of section 2(a)(29)(A) as a result of the transfer of certain system generating facilities to an unregulated affiliate. The problem identified by intervenors was that power from these facilities would no longer be offered first for in-system use. The Court of Appeals concluded that we could find economic coordination bases on a "less stringent requirement." *Id.*

[72] The traditional model is characterized by pooling of system energy resources and the exchange of energy and operating reserves through central load dispatch. As the demand on system utilities rises, a system operator draws upon the least expensive available resource, whether system-owned generation or purchased power, without regard to which utility owns

and dispatched in the manner characteristic of that model, but will instead be coordinated through FERC-approved agreements that will be set over existing operating and transmission agreements, which will remain in place. Applicants state that the continuation of the existing agreements is necessary to assure the affected state regulators that the Merger will not result in cost or benefit transfers within or among the New AEP System Operating Companies as a result of the proposed Merger to the detriment of ratepayers.[73] In addition, the New AEP System will coordinate its operations by various measures, including joint marketing and trading of electricity in the wholesale bulk power market, a comparatively new way in which utilities coordinate their operations today.

(A) Existing Agreements

(i) AEP Operating Companies

Appalachian Power, Columbus Southern Power, Indiana Michigan Power, Kentucky Power and Ohio Power are parties to an Interconnection Agreement, dated July 6, 1951, as amended, defining how these AEP Operating Companies share the costs and benefits

---

that resource. Generators are started, loaded and taken off-line at the operator's direction. This process optimizes the interchange of energy among system operating companies. Power flows over interconnecting transmission ties are determined by economic dispatch programs.

[73] *See, e.g.*, page 3-4 of Louisiana Order, conditionally approving the Merger (expressing concern "that the proposed system agreements not result in cost shifting from AEP to SWEPCO or be otherwise unjust or unreasonable"); Michigan Order, Exhibit A (Settlement Agreement), Section 5 (citing AEP's commitment to file any allocation of the cost of new, modified or upgraded generation or transmission facilities whose costs will be subject to the System Integration Agreement or System Transmission Integration Agreement with the FERC, described in section II.B.1.b.(2).(B). below, and to notify the Michigan Commission of the filing); p. 9 of Indiana Order, approving the Merger under the terms of a Stipulation and Settlement Agreement (noting that the approved agreement includes provisions designed to prevent cost shifting or cross subsidization).

associated with their generating plants (the "AEP Interconnection Agreement").[74] The same AEP Operating Companies are also parties to a Transmission Equalization Agreement, dated April 1, 1984, which defines the method under which they share the costs associated with their relative ownership of transmission facilities (the "AEP Transmission Agreement" and, together with the AEP Interconnection Agreement, the "Existing AEP Agreements").[75]

(ii) CSW Operating Companies

The CSW Operating Companies and CSW Service are parties to the Restated and Amended Operating Agreement, dated as of January 1, 1997 ("CSW Operating Agreement"). The agreement requires the CSW Operating Companies to maintain specified annual planning reserve margins and requires those utilities that have capacity in excess of the required margins to make that capacity available for sale to associate utilities as capacity commitments. The CSW Operating Agreement also provides for the coordination of construction and operation of jointly-owned facilities; unit sales to assist associate utilities to meet capacity reserve levels; emergency energy; economy energy; off-system sales and purchases; and central load dispatching. Under the agreement, CSW Service has authority to coordinate the acquisition, disposition, planning, design and construction of system generating units and to supervise the operation and maintenance of a central control center.

---

[74] Sharing is based upon each Operating Company's "member-load-ratio," which is calculated monthly on the basis of each utility's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months.

[75] The facilities at issue are the extra-high-voltage transmission system (which includes facilities rated 345 KV and above) and certain facilities operated at lower voltages (which include facilities rated 138 KV and above). Sharing of costs and benefits under this agreement is also based upon each AEP Operating Company's member-load-ratio.

CSW Service schedules the energy output of the system capability to obtain the lowest cost of energy for serving aggregate system demand and coordinates off-system purchases and sales. The CSW Operating Agreement has been accepted for filing and allowed to become effective by the FERC.

The CSW Operating Companies and CSW Service are also parties to a transmission coordination agreement ("CSW Transmission Coordination Agreement" and, together with the CSW Operating Agreement, the "Existing CSW Agreements"). This agreement establishes a coordinating committee that has responsibility to oversee the coordinated planning of system transmission facilities.[76] Under the CSW Transmission Coordination Agreement, CSW Service has the responsibility to monitoring the reliability of transmission systems and to administer the CSW open access transmission tariff filed with the FERC.[77] The CSW Transmission Coordination Agreement has been accepted for filing by the FERC effective as of January 1, 1997, and is the subject of proceedings commenced to consider the reasonableness of its terms and conditions.

Together, the Existing AEP Agreements and the Existing CSW Agreements are sometimes referred to below as the "Existing Agreements."

---

[76] The committee's responsibilities include the performance of transmission planning studies and the interaction of the CSW Operating Companies with ISOs and other regional bodies interested in transmission planning.

[77] The CSW Transmission Coordination Agreement also provides for the allocation among the CSW Operating Companies of revenues collected for transmission and ancillary services provided under the open access tariff.

(B) Proposed Umbrella Agreements

Upon consummation of the Merger, the power supply and transmission of the New AEP System will be coordinated under two FERC-approved agreements, a System Integration Agreement and a System Transmission Integration Agreement (together, the "Umbrella Agreements"). As noted above, the Existing Agreements will continue in effect and will thus continue to control the distribution of power supply costs and benefits, and the allocation of costs and benefits associated with ownership of transmission assets, among the East Zone Operating Companies and the West Zone Operating Companies, respectively, of the New AEP System.

(i) System Integration Agreement

The System Integration Agreement applies to the coordination of the power supply resources of the New AEP System and the distribution of costs and benefits between the New AEP Operating Companies in the East and West Zones.[78]

Under the agreement, each Zone is required to have enough generating capacity to meet its firm load obligations. When one Zone has surplus capacity available for sale and the other has insufficient capacity, the surplus Zone will make its surplus capacity available.[79] If neither Zone has surplus capacity after meeting its firm load obligations, or if third party capacity is cheaper than that available from the surplus Zone, capacity will be purchased from third parties for the Zone(s) with insufficient capacity.

---

[78] The existing AEP Interconnection Agreement and the CSW Operating Agreement will continue to govern the distribution of costs and benefits within the East and West Zones.

[79] Applicants generally expect that the East Zone will have surplus capacity.

Economic energy will also be transferred from one Zone to the other to minimize the total production cost of the New AEP System. The East Zone and the West Zone will be centrally dispatched on a least-cost basis for the New AEP System, as discussed further below. AEP Service will perform these functions.

The System Integration Agreement contains four FERC-approved service schedules governing: (1) the allocation of capacity costs and purchased power costs; (2) pricing for capacity exchanges between the Zones; (3) pricing for energy exchanges between the Zones; and (4) the allocation of "Trading and Marketing Realizations," which are the net gains or losses from the New AEP System's off-system transactions.

(ii) System Transmission Integration Agreement

The System Transmission Integration Agreement applies to the transmission facilities owned or operated by the New AEP System. The agreement contains two FERC-approved service schedules governing: (1) the allocation of transmission costs and revenues between the East Zone and the West Zone; and (2) the allocation of control and dispatch costs associated with the integration of the Zones, the cost of the transmission capacity reserved on other systems to link the Zones, and any revenues from the resale of those capacity rights. AEP Service will coordinate the planning, operation and maintenance of transmission facilities and capacity of the New AEP System.

(C) Central Dispatch

Power supply and transmission of the New AEP System will not be pooled and dispatched in the manner characteristic of the traditional vertically integrated monopoly utility model. Rather, Applicants intend, when and as practicable, to combine the control area functions of the East Zone and the West Zone. Except as provided in the System Integration Agreement, while operating as separate control areas (AEP, CSW-SPP and CSW-ERCOT), the pre-Merger generation dispatch priorities and methodologies applicable within each control area will continue to apply to that control area. Dispatch of the combined properties will be conducted on a least-cost basis, subject to availability of transmission entitlements linking the control areas. In determining the New AEP System's generation dispatch priorities, each Zone's most economic generation will be used to serve its native load customers and previously committed firm load contracts.

The control areas will be centrally dispatched in real time to minimize total generation costs for the New AEP System, subject to any transmission constraints. A single control center will schedule the generating resources of the New AEP System on a day-ahead and an hour-ahead basis. The center will control the joint dispatch of all of the power supply resources of the New AEP System.

Dispatch of the New AEP System will be performed in two steps. The first step will be unit commitment. In this step, the system operator projects the system peak load requirements for a period, and, to meet that requirement, schedules available generating units to be on-line in economic order, subject to any operational or other constraints, including transfer limitations within the New AEP System. The operator will not load the less economic units unless the load requires them. The system operator will also examine the energy market to determine if lower cost reliable energy can be purchased in order to avoid loading higher cost generating sources.

The second step will be the incremental loading of the on-line generation sources and purchases. This step will be performed continuously and each unit's available generation dispatched above its minimum load level in order to match the generation to the load. Generation of the New AEP System's various units will be dispatched from lowest cost to highest cost. Dispatch will be subject to available transmission, including the HVDC ties connecting the ERCOT and non-ERCOT areas of the West Zone and the 250 MW Contract Path between the East Zone and the West Zone.

(D) <u>The Contract Path</u>

The New AEP System will transmit power from the East Zone to the West Zone over the Contract Path. As noted previously, Applicants have agreed to limit their reservation of firm transmission service from east to west over the Contract Path to 250 MW, unless the FERC authorizes them to exceed this limit. This commitment is intended to mitigate anticompetitive effects that may be attributable to the Merger.[80]

In addition to the use of the Contract Path, quantities in excess of 250 MW may be moved within the New AEP System in any given hour by using non-firm transmission rights. These additional transfers will be made when they would be economical for New AEP System operations, after taking opportunity costs into consideration.

Applicants also expect that, from time to time, there will be opportunity to transfer energy economically from the West Zone to the East Zone. In these circumstances,

[80] *See supra* note 25 and accompanying text.

Applicants will make use of their rights to nominate secondary points of receipt and delivery under their transmission service agreements with Western Resources and Ameren.[81]

(E) Other Forms of Coordination

Applicants note that industry restructuring has expanded the means by which a company can coordinate merged utility operations. Applicants intend, subject to applicable regulatory restraints, to implement measures in addition to the Umbrella Agreements and transactions described above that will permit the operation of the New AEP System in an economic and coordinated manner. These measures are described briefly below.

(i) Joint Marketing and Trading

Following the Merger, AEP intends to coordinate the activities of the New AEP System through various business units of AEP Service. AEP Service's wholesale business unit will be responsible for evaluating marketing and trading efforts, design and purchase of new generating facilities, operation and maintenance of generating capacity resources, centralization of trading and marketing activities, acquisition and maintenance of transmission services needed for intrasystem power transfers, provision of billing and administration, and other administrative services.

The wholesale business unit will coordinate the New AEP System's joint marketing and trading efforts, both as a buyer and as a seller. The Applicants emphasize the importance of coordinated trading operations in the contemporary electric industry.[82]

---

[81] PSO has the right to transfer approximately 113 MW of energy on a non-firm basis across the MOKANOK line.

[82] The Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (1992), among other things, created the exemption for exempt wholesale generators ("EWGs"). The EWG

Currently, trading operations are coordinated with the operation of generating assets as part of AEP's regulated operations. Applicants state that this measure has enabled AEP to coordinate the operation of its generation assets with the broader power market. Upon consummation of the Merger, New AEP will combine AEP's and CSW's trading operations with the operation of their generating assets to achieve similar benefits.

Applicants note that the ability to diversify supply over a broader region with diverse weather and time zones is another way in which the New AEP System can achieve the benefits of economic integration with a market-based commodity like electricity. The wholesale business unit will take advantage of the New AEP's System's generation capacity, wholesale customer base, diversity of weather, time and fuel supply to allocate resources more efficiently and thereby decrease the overall production costs of the New AEP System.

(ii) Administrative Coordination

The New AEP System will achieve administrative coordination by various measures. The North American energy delivery unit of AEP Service will centralize asset-management policy decisions, provide an integrated approach to financial decisions, develop an appropriate allocation of resources between new capital investment and routine operation and maintenance expenses, and implement the use of best practices throughout the New AEP System. The North American energy delivery unit will consist of a transmission

---

exemption insures that the integration requirements of the Act are not a barrier to the participation of independent power producers in the wholesale electric market -- an implicit acknowledgement that the economic operations of a utility depend on contractual relationships as well as ownership of generating facilities. Since the Energy Policy Act, a competitive electric supply wholesale market has rapidly developed, facilitated by FERC's willingness to permit the sale of electric capacity and energy at market-based rates. Utilities have increasingly focused on their own wholesale marketing efforts.

organization, a distribution organization, a customer interface and services organization, a regulatory, planning and budgeting services organization, and a customer and community services organization.

The corporate development unit will provide direction to the New AEP System in areas such as integration, best practices and business re-engineering. The corporate development unit will provide communications and energy information services that complement New AEP's affiliated businesses and invest in new ventures that will support New AEP's strategic plan.

Finally, the coordination of the New AEP System will be furthered by the coordination of information system networks and other support services. AEP Service will perform many administrative and support services for the New AEP System.

(3) Contentions of the Intervenors

The Advocates Group argues that the Application does not support a finding that the New AEP System will be operated in an economic and coordinated manner.[83] The Advocates Group states that the level of coordination is limited to the capacity of the Contract Path, which is inadequate.[84]

---

[83] APPA/NRECA also asserts that the Applicants fail to satisfy this standard of section 2(a)(29)(A). APPA/NRECA at 12.. APPA/NRECA states, however, that we need not reach that issue because the Applicants also have not met their burden to satisfy "the stricter economic integration requirement" of section 10(c)(2) of the Act. APPA/NRECA at 8, n.7. The APPA/NRECA's arguments concerning section 10(c)(2) are discussed in section II.B.2., *infra*.

[84] "Integration means joint operations, not a token wire path. In none of the integration cases decided under the Act has the actual integration been so insignificant relative to the size of the merged company." Advocates Group at 6.

The Advocates Group asserts that:

> The merged company cannot be a "coordinated system." There are two systems. The components within each system are tied together through coordination agreements and some central dispatch. But there is no plan to coordinate the two previously separate systems through coordination and dispatch, except for insignificant amounts limited by the 250 MW connection. . . . The Applicants make no pretense to being a single coordinated system after the merger. All that is "coordinated" is the transfer of a token amount of power between two huge systems.[85]

Contrary to the suggestion of the Advocates Group, the Contract Path is only one of several measures proposed to coordinate the New AEP System.[86] Moreover, the Advocates Group's argument seems to rest on the assumption that power supply must be pooled and dispatched in the manner characteristic of the traditional vertically-integrated monopoly utility model if we are to make a finding of economic and coordinated operation. This is not the case, however. Pooling and central dispatch are merely one way in which coordination is achieved in the traditional model. They are not required by the Act or our precedent.

Moreover, as indicated above, the recent development of a competitive wholesale bulk power market is changing the way in which utilities coordinate the operation of their generating facilities and their marketing and trading operations. For example, a utility's trading strategy necessarily affects its use of its generation facilities. If the price of electricity is such that the utility can sell electricity profitably, the trading group will direct

---

[85] *Id.*

[86] As discussed above, although the New AEP System will continue to operate under the Existing Agreements concerning shared power supply and transmission, the Umbrella Agreements will permit control and coordination of the New AEP System. Our finding of economic and coordinated operation is also supported by other proposed measures: potential intrasystem transfers of capacity and energy; joint trading and marketing; and corporate and administrative coordination.

the utility's generating units to generate electricity to capacity.[87] In contrast, if the price of electricity is so low that it is cheaper to purchase electricity instead of incurring production costs, the trading group will direct its generating units to curtail operations. The coordination of generating assets and marketing/trading activities represents a form of operational coordination that characterizes the emerging utility market model in the electric industry today.

The Advocates Group also asserts that, "The Applicants [c]annot [s]atisfy the "[e]conomical and [e]fficient [test] of Section 10(c)(2) by [s]elling [o]ff [g]eneration [p]resently [u]sed to [i]ntegrate the [s]ystem." The Advocates Group refers to the CSW System's commitment to divest generation capacity in ERCOT and the SPP to mitigate potential anticompetitive effects of the Merger.[88]

We address the Advocates Group's contentions concerning section 10(c)(2) in section II.B.2. of this Order. To the extent that the Advocates Group suggests that the proposed divestiture will impair economic and coordinated operation, Applicants respond that it will not. The New AEP System will coordinate the dispatch of generating units under its control, make economic purchases of power, and supply power to its customers. The divestiture of portions of certain existing generating units that are currently part of Applicants' supply

---

[87] A traditional utility's customers were generally limited to end-users in its service territory. A utility created the most value for its shareholders by incurring the least possible costs to generate just enough electricity to serve its native load. In contrast, today a utility sells electricity not only to the customers located in its service area but also to wholesale customers. A utility creates value by selling as much electricity as it can profitably sell, after meeting the requirements of native load.

[88] Advocates Group at 27-28.

options will not affect the Applicants' ability to coordinate the operations of the New AEP System.[89]

(4) Conclusion

We find that the proposed forms of central control and coordination of the New AEP System satisfy the "economic and coordinated operation" requirement of section 2(a)(29)(A). The fact that power supply and transmission of the New AEP System will not be pooled and dispatched in the manner characteristic of the traditional utility model does not preclude this finding. As noted above, the Act does not, by its terms, specify the measures that are required for a finding of economic and coordinated operations. The Applicants' approach to coordination reflects the extent to which actions of Congress, the FERC and the states are shaping the contemporary electric industry. The unbundling of generation and transmission and the new forms of central control and coordination that are developing are the direct result of federal and state efforts to promote a competitive energy market -- a goal consistent with the purpose of the Act to promote "economy of management and operation" of public-utility companies.[90]

c. "Single Area or Region"

The "single area or region" standard, like the "no impairment" standard discussed below and the provisions of sections 10(b)(1) and 10(c)(2) of the Act, implicitly requires us to consider the size of the system that would result from the proposed Merger. The Act was

[89] Response at 39. Applicants also note that, under the Texas settlement, most of the generating capacity being divested will be subject to recall by the New AEP System during peak months to ensure that adequate capacity is available to serve native load. *Id.* at n.48.

[90] Section 1(b)(4) of the Act.

not intended to preclude a holding company from expanding its utility system by acquisition or otherwise. Indeed, the Act expressly permits a holding company that meets the standards of the Act to function and develop as a regional system.[91]

The leading case interpreting the size standards of sections 2(a)(29)(A), 10(b)(1), and 10(c)(2) of the Act is our 1978 decision in *American Electric Power Co.*, 46 S.E.C. 1299 ("*1978 AEP Order*") approving AEP's proposed acquisition of Columbus and Southern Ohio Electric Company. In 1946, we had declined to approve the acquisition because we could not find that the combined system was "not so large as to impair . . . the advantages of localized management and the effectiveness of regulation."[92] Our 1946 decision did not identify any abuses that might ensue from the affiliation. Rather, it emphasized that an essential part of the spirit of the Act was the desire to avert the process of concentration of power which had characterized the growth of holding companies.[93]

---

[91] *The Regulation of Public-Utility Holding Companies*, Division of Investment Management, SEC (June 1995) ("*1995 Report*") at 56, citing S. Rep. 621, 74th Cong., 1st Sess. (1935) (Report of Senator Wheeler from the Committee on Interstate Commerce at 30; H.R. Rep. No. 1318, 74th Cong., 1st Sess. (1935) at 15. We find no support for APPA/NRECA's general assertion that "the statutory presumption is against large mergers." APPA/NRECA at 5-6.

[92] *American Gas and Electric Co.*, 22 S.E.C. 808, 816-817 (1946) ("*American Gas and Electric*"). In a 1945 decision, we had identified the size and extensive area of the utility operations of the central system of AEP's predecessor (essentially identical to the current AEP system) as a potential problem under section 11(b)(1) of the Act. At the same time, we had noted that the system had a long history of having been planned, developed and operated as a highly coordinated system. *American Gas and Electric Co.*, 21 S.E.C. 575, 595 (1945).

[93] *1978 AEP Order*, *supra* note 2 at 1308, discussing *American Gas and Electric*, *supra* note 92.

In 1978, we revisited and approved the acquisition. In discussing the "no impairment standard," we noted the relevance of section 10(b)(1).[94] We observed:

> The standards in these sections were relatively easy to apply to the huge, complex, and irrational holding company systems at which the Act was primarily aimed; such systems clearly contravened these standards as well as the physical ones. But those standards were, and are now, difficult to apply to a system like AEP, which is large but efficient, with, or without, [the acquisition].[95]

We further noted that section 10(c)(2) requires us to consider the size of the resulting system before approving an acquisition, but, like section 10(b)(1), imposes no precise limits on holding company growth.[96] Rather, these sections "are couched in discretionary terms and require the Commission to exercise its best judgment as to the maximum size of a holding company in a particular area, considering the state of the art and the area or region affected." "[T]he determination of whether to permit enlargement of a system by acquisition is to be made on the basis of all the circumstances, not on the basis of preconceived notions of size."[97] We concluded:

---

[94] *Id.* at 1307. Section 10(b)(1), discussed in section II.A.1. *supra*, requires us to disapprove an acquisition that, among other things, will tend towards "the concentration of control of public-utilities companies, of a kind or to an extent detrimental to the public interest or the interest of investors or consumers."

[95] *Id.*

[96] Section 10(c)(2) of the Act requires us to find that a proposed acquisition will "serve the public interest by tending towards the economical and efficient development of an integrated public-utility system."

[97] In *Commonwealth & Southern Corp.*, Holding Co. Act Release No. 7615 (Aug. 1, 1947), we stated:

> We do not, in applying particular size standards, lose sight of the objectives of other criteria. There must be a reconciliation of all objectives to the end of accomplishing a satisfactory administration of the Act. Thus we do not disregard operating efficiency in our determination of whether size is excessive

> In sum, the framers of the Act were clearly concerned about the evils of bigness, and they pointed to certain problems which large holding company systems may create. On the other hand, they were also aware that the combination of isolated local utilities into an integrated system afforded opportunities for economies of scale, the elimination of duplicate facilities and activities, the sharing of production capacity and reserves and generally more efficient operations. They wished to preserve these opportunities while avoiding an excess of concentration and bigness.[98]

Although the *1978 AEP Order* focuses upon section 2(a)(29)(A) in the context of the "no impairment requirement" rather than the "single area or region requirement," the decision considers the issue of size in a broad statutory context and articulates general principles which we reaffirm.[99]

The Act does not define the terms "area" and "region." The terms, by their nature, are susceptible of flexible interpretation, which permits us to respond to the current state of the industry and to give the terms practical meaning and effect.

We have found that the single area or region test should be applied flexibly when doing so does not undercut the policies of the Act "against scatteration -- the ownership of widely dispersed utility properties which do not lend themselves to efficient operation and

---

from the viewpoint of localized management or effectiveness of regulation.

[98] *1978 AEP Order*, *supra* note 2, at 1309. In an earlier decision, we had stated that, "The legislative history of Section 2(a)(29)(A) of the Act indicates that its overall purpose is the encouragement of operating advantages stemming from unified operations to the extent that such advantages are not outweighed by disadvantages resulting from an undue concentration of economic power." *North American Co.*, Holding Co. Act Release No. 10320 (Dec. 28, 1950).

[99] The utility to be acquired was a "hole in the doughnut," surrounded by AEP's service territory. *1978 AEP Order*, *supra* note 2, at 1307. The size of the acquisition raised no issue and the "single area or region" of AEP was unchanged.

effective state regulation."[100] We have not required that combining systems be contiguous for the requirement to be met.[101]

Distance raised many more barriers to integration when the Act was passed in 1935 than is the case today. The *1995 Report* recognized that "recent institutional, legal and technological changes . . . have reduced the relative importance of . . . geographical limitations by permitting greater control, coordination and efficiencies" and "have expanded the means for achieving the interconnection and economic operation and coordination of utilities with non-contiguous service territories."[102] These advances and developments are breaking down traditional boundaries and concepts of regions.

We have followed the recommendations of the *1995 Report*, citing, in particular, its recommendation that we "continue to interpret the 'single area or region' requirement to take into account technological advances."[103] The *1995 Report* also recommended, in

---

[100] *NIPSCO Industries, Inc.*, Holding Co. Act Release No. 26975 (Feb. 10, 1999) ("*NIPSCO*") (applying single area or region requirement to gas utility system).

[101] *See, e.g.*, *Conectiv, Inc.*, Holding Co. Act Release No. 26832 (Feb. 25, 1998) ("*Conectiv*"); *cf. New Century Energies*, *supra* note 48 (finding that electric utilities located in two different power pools, in two different reliability councils, in both the Eastern and Western Interconnects, and with a physical separation of 300 miles were in the same area or region); *Electric Energy*, *supra* note 44 (utility assets were within the same area or region as the acquirer's service area despite a distance of 100 miles crossing two states); *Mississippi Valley Generating Co.*, Holding Co. Act Release No. 12794 (Feb. 9, 1955) (single area or region test met where generating station was located 150 air miles from the territory served by the acquiring company).

[102] *1995 Report*, *supra* note 91, at 69-70. The *1995 Report* noted that the concept of "geographic integration" has been affected by "technological advances on the ability to transmit electric energy economically over longer distances, and other developments in the industry, such as brokers and marketers." *Id.* at 69.

[103] *NIPSCO*, *supra* note 100, at n.30 citing the *1995 Report*, *supra* note 91, at 69. *Accord: Sempra Energy II*, *supra* note 45, at n.27.

recognition of the changing environment in the utility industry, that we adopt "a more flexible interpretation of the geographic and physical integration standards, with more emphasis on whether an acquisition will be economical and subject to effective regulation."[104] We believe that this approach is consistent with the Act's goal of preventing "the growth and extension of holding companies [that] bears no relation to economy of management and operation."[105] We also believe that this approach is consistent with our precedent, which evaluates the "single area or region" requirement not only in terms of size and distance, but also in light of "the existing state of the arts of generating and transmission and the demonstrated economic advantages of the proposed arrangement[],"[106] the importance of effective regulation and the absence of anticompetitive concerns under section 10(b)(1).

As described above, the New AEP System will be interconnected and susceptible of economic and coordinated operation and no adverse finding is required on anticompetitive grounds under section 10(b)(1). We find below that the size of the New AEP System will not impair efficient operation, localized management or effective regulation and that the Merger will result in economies and efficiencies under section 10(c)(2).[107] In view of these considerations, we find that the New AEP System will operate in a "single area or region."

---

[104] *1995 Report*, *supra* note 91, at 66.

[105] Section 1(b)(4) of the Act.

[106] *Connecticut Yankee Atomic Power Co.*, 41 S.E.C. 705, 710 (1963) ("*Connecticut Yankee*").

[107] The Merger is expected to result in nearly $2 billion in net non-production savings and $98 million in net fuel related savings over a ten-year period.

The Advocates Group and APPA/NRECA challenge the Merger on the ground that the New AEP System does not satisfy the single area or region requirement. The Advocates Group asserts that, "[t]he size alone of the territory that is proposed to constitute an integrated system may be determinative of whether the 'single area or region' standard is met."[108] According to the Advocates Group, the Applicants "do not provide any specific information relating to how the proposed territory would constitute one region in terms of generation, fuel sources, marketing, transportation, community size, or any other factor the Commission has considered in the past."[109]

We considered these factors in our early precedent, in keeping with our application of section 2(a)(29)(A) in terms of practical considerations.[110] In view of the changes in the

---

[108] Advocates Group at 15. For this proposition, the OCC Group cites *Middle West Corp.*, 15 S.E.C. 309, 336, n.81 (Jan. 25, 1944) ("*Middle West Corp.*") ("[W]hen extremely large sections are considered . . . distance alone may be definitive.") and *Cities Service*, *supra* note 70, at 59 ("[T]erritory as vast as that covered by the States of Wyoming, Colorado, New Mexico and Arizona," spanning 900 miles from north to south, is not a single area or region under section 2(a)(29)(A)).

[109] Advocates Group at 21.

[110] For example, in one decision cited by the Advocates Group, we determined that combined electric properties constituted an electric integrated system on the following grounds:

> The companies operate in a relatively compact geographical area. Their assets are physically interconnected, and they can be, and are, operated as a unit with respect to economical power interchange. They are amenable to regulation within a single State.

Cities Service, *supra* note 70, at 36. In the *Cities Service* decision, we declined to find that electric operations in Wyoming, Colorado, New Mexico and Arizona constituted an electric integrated system. With respect to the single area or region requirement, we noted that: "The statute and its legislative history make it clear that, consistently with geographic conditions (in the broad sense of the term) as much compactness should be achieved in outlining the spheres of holding company influence as physical facts permit." *Id.* at 59.

electric industry, many of these factors have far less relevance than they did sixty-five years ago. Moreover, our application of section 2(a)(29)(A) has evolved with the changes in the industry. As discussed previously, we rejected a *per se* size standard in the *1978 AEP Order*, in favor of an approach that considers each standard of section 2(a)(29)(A) in light of the other standards and the other objectives of the Act.

The Advocates Group also suggests that the single area or region requirement is not met because the proposed Merger reflects merely the Applicants' desire for growth.[111] In this regard, the Advocates Group contrasts the Application with the *1978 AEP Order*, in which the purpose and result of the acquisition was to include the acquired utility within a systemwide practice of joint planning and dispatch.[112]

Again, this contention seems to rest on the assumption that pooling and dispatch of power supply in the manner characteristic of a vertically integrated monopoly utility are required to satisfy section 2(a)(29)(A) of the Act. We have explained that this is not the

---

Further, we stated that: "The standard of localized management cannot be met by any combination of properties (as one or more systems) spread over a territory as vast as that covered by the States of Wyoming, Colorado, New Mexico and Arizona." *Id.* We rejected this *per se* size approach in the *1978 AEP Order*.

[111] The Advocates Group asserts that, "Acceptance of this Application will leave the public unprotected from holding company acquisitions that sacrifice operational efficiency for expansionism." Advocates Group at 3.

[112] The Advocates Group states that, "In contrast, the new proposed 'region' covered by the merged company is not the product of past efforts to plan generation and transmission for the combined load, and there certainly is no plan to do so in the future . . . . The new proposed 'region' is a product only of a desire of the two systems' corporate managers to increase the size and geographical scope of the enterprise." *Id.* at 19.

case. Accordingly, we reject the Advocates Group's argument that the single area or region requirement is not satisfied.

The Advocates Group also suggests that the New AEP System does not meet the single area or region requirement because of ERCOT's separation from the rest of the nation's electric grid.[113] We have previously concluded, however, that the location of CSW Operating Companies inside and outside of ERCOT, connected by HVDC ties, does not preclude a finding that the CSW System is an integrated electric system.[114] Similarly, the features of the CSW System do not compel a finding that the New AEP System does not satisfy the single area or region requirement. Rather, the features of the CSW System, with its two control areas or zones, suggest that the integration characteristics of the New AEP System are less than novel.

APPA/NRECA contends that the New AEP System's operations will not be confined to a single area or region because they will span 11 states and cover an area of 197,400 square miles.[115] APPA/NRECA notes that AEP already has electric utility assets in more states, covering a larger area, than any other registered holding company. APPA/NRECA describes other multistate registered systems as "decidedly more compact" (*e.g.*, Entergy Corporation, The Southern Company and New Century Energies, Inc.) and adds that except

---

[113] *Id.* at 17-18, 21.

[114] *Central and South West Corp.*, *supra* note 9. As noted previously, Applicants state that the New AEP System will continue to use the HVDC ties in the manner described in that order. *See* the discussion in section II.B.1.a., *supra*.

[115] "Deeming these operations to be in a single area or region would effectively read the requirement out of the Act." APPA/NRECA at 12.

for New Century Energies, Inc. (for which physical interconnection is planned), these systems are characterized by multiple interconnections and close system proximity.[116]

APPA/NRECA asserts that the relevant facts in this matter are that the AEP and CSW headquarters are approximately 1,000 miles apart and the boundaries of the service territories are even more distant. Further, APPA/NRECA notes that the New AEP System's power pools and reliability councils are not contiguous.[117]

APPA/NRECA does not identify any factor other than distance that precludes a finding that the New AEP System is in a single area or region. APPA/NRECA does not identify any abuses identified by the Act that would recur if the New AEP System were found to be in a single area or region, except to the extent that the APPA challenges the anticompetitive effects of the Merger, a contention that we have addressed in section II.A.1. above.

Taken overall, APPA/NRECA's argument appears to be that the New AEP System, by any measure, is simply too large to be within a single area or region. We reject this argument. To do otherwise would effectively return us to the *per se* size requirement that we rejected in the *1978 AEP Order*. In that regard, we note that the APPA/NRECA's emphasis on geographical distances ignores the technological and regulatory changes in the

---

[116] *Id.* at 12-13. APPA/NRECA cites *Entergy Corp.*, *supra* note 40 (four states over a 73,000 square-mile area) and *Southern Co.*, Holding Co. Act Release No. 24579 (Feb. 12, 1988) (four states, geographically contiguous service territories, covering a 122,000 square-mile area, interconnected at three points, with a fourth to be built the year the merger was completed). *Id.* at 13, n.20. We note that the CSW integrated system is "decidedly less compact" than these systems and lacks multiple interconnections.

[117] *Id.* at 14.

industry that have made economic and coordinated operation possible over great distances.[118] We also reaffirm our view that the various requirements of section 2(a)(29)(A) cannot be considered independently of one another and the other objectives of the Act.[119] Accordingly, we reject the contention that the New AEP System is too large to satisfy the single area or region requirement.

d. No Impairment to Efficient Operation, Localized Management or Effective Regulation by Reason of System Size

The record in this matter supports a finding that the Merger will not impair localized management, efficient operation or effective regulation due to the size of the New AEP System. Both we and the FERC will continue to regulate the New AEP System as before. The FERC did not set the issue of effective regulation for hearing.[120]

Various state regulators have also demonstrated that they can effectively regulate the New AEP System. The orders of the Arkansas, Indiana, Kentucky, Louisiana, Michigan, Oklahoma and Texas Commissions impose an extensive list of service quality standards on the New AEP System Operating Companies that operate within their states.[121] The order

---

[118] In light of recent technological advances in the electric industry, for example, "a geographic radius of 1,000 miles or more is currently considered reasonable for choosing among supply options." Rodney E. Stevenson & David W. Penn, "Discretionary Evolution: Restructuring the Electric Utility Industry," *Land Economics*, Vol. 71, No. 3 (Aug. 1, 1995).

[119] *See 1978 AEP Order*, *supra* note 2.

[120] The FERC concluded that Applicants had adequately addressed its concerns about its own jurisdiction and that state commissions could "impose in their own proceedings appropriate conditions to ensure that there is no impairment of effective regulation at the state level." *American Electric Power Co.*, 85 FERC ¶ 61,201 at 61,821-22 (1998). Thus, the FERC concluded that the Merger would not impair the effectiveness of regulation and that the issue did not merit further investigation.

[121] *See* Application at 91.

of the Texas Commission approves several provisions designed to ensure the effectiveness of its regulatory authority over the New AEP System's operations in Texas, as well as provisions to ensure the continuity of CSW's local management and organizational structure following the Merger.[122] The Indiana and Kentucky orders contain detailed guidelines relating to affiliate transactions.[123] The Oklahoma order grants the Oklahoma Commission and the State Attorney General access to the books and records of AEP and its affiliates and subsidiaries, including their participation in joint ventures, with respect to matters and activities that relate to Oklahoma retail rates.[124] Under the proposed Louisiana settlement, the Louisiana Commission will have an opportunity to conduct several reviews of Merger savings over an eight-year period following the Merger.[125] We have found that effectiveness of state regulation is not impaired where state regulators have the same jurisdiction before and after a merger.[126]

---

[122] Among other things, these provisions include (1) a requirement that the New AEP System continue to comply with the Texas Commission's transmission pricing rules in ERCOT; (2) a commitment by the New AEP System not to withdraw from either ERCOT or the SPP without the Texas Commission's prior approval; (3) a commitment by the New AEP System to comply with a detailed code of conduct governing activities among AEP's subsidiaries, and (4) a commitment that the New AEP System will not contend in any forum that the jurisdiction of the Texas Commission over any of CSW's Operating Companies located in Texas changed as a result of the Merger.

[123] Indiana Order, Stipulation at Section 8 and Kentucky Order, Stipulation at Section 8.

[124] Oklahoma Commission Order (attached to the Application as Exhibit D-4.2), Stipulation at Section 5.

[125] Louisiana Order, Appendix A at Section III.

[126] *See, e.g., Conectiv, supra* note 101.

APPA/NRECA acknowledges that the regulators will have the same jurisdiction before and after the Merger. But APPA/NRECA states that "that argument, however, misses the point," because "having operations in eleven states would give the merged company many additional ways to 'hide the pea' from its various state regulators, who would have difficulty coordinating their regulatory efforts due to the sheer numbers of commissions and staffs involved."[127]

These assertions lack support. None of the state commissions that regulates the New AEP System Operating Companies has raised as an objection to the Merger the impairment of its ability to regulate, or any other objection, in submissions to us. There is also no empirical basis for the suggestion that New AEP would seek to obstruct regulation by its state regulators.[128]

APPA/NRECA also suggests that "all indications in the application are that localized management will be substantially curtailed."[129] In particular, APPA/NRECA cites the proposed centralization of management of power generation, transmission, distribution and customer services; the elimination of duplicative positions at the corporate management level; and the relocation of CSW's headquarters in Ohio. APPA/NRECA further asserts that the Applicants have provided "meager and contradictory information" on the impact of the

[127] APPA/NRECA at 18.

[128] Citing section 1 of the Act, APPA/NRECA suggests that consumers may be injured by service transactions and allocations of costs that present problems that the states cannot deal with effectively. APPA/NRECA at n.30. The proposed intrasystem transactions and cost allocation measures of the New AEP System are subject to the requirements of section 13 of the Act and related rules. These requirements are designed, precisely, to obviate the abuses identified in section 1 of the Act.

[129] APPA/NRECA at 16.

Merger on localized management, and contends that we do not have an adequate record on which to determine whether New AEP will impair localized management. APPA/NRECA does not explain how the alleged impairment is related to the size of the New AEP System.

APPA/NRECA's unsupported assertions concerning the curtailment of localized management are unpersuasive.[130] Applicants anticipate that the impact of the Merger will be predominantly confined to the combination of AEP's and CSW's service companies and the establishment of a business unit and management structure which will resemble the existing structures of CSW and AEP. Applicants state that the New AEP Operating Companies will continue to operate through the regional offices with local service personnel and line crews available to respond to customers' needs. AEP will preserve well-established delegations of authority, currently in place at AEP and CSW, which permit the local, district and regional management teams to budget for, operate and maintain the electric distribution system, to procure materials and supplies and to schedule work forces in order to continue to provide the same quality of service as before the Merger.[131]

We note our previous determination that the Merger will meet the section 2(a)(29)(A) standard of "economic and coordinated operation" and our finding below under section 10(c)(2) that the Merger will result in economies and efficiencies. To the extent that APPA

---

[130] *Id.* at 17. With respect to the movement of CSW's headquarters to Columbus, Ohio, we have previously concluded that the distance of corporate headquarters from local management is less important than in 1935, in view of the contemporary ease of communication and transportation. *1978 AEP Order*, *supra* note 2, at 1312 (AEP had headquarters in New York City and operations in Michigan and Virginia).

[131] Applicants observe that New AEP's responsiveness to local customers and concerns should be the criteria for evaluating the effectiveness of its management. Response at 51.

argues that the size of the New AEP System will impair efficient operation, APPA does not explain how this impairment will occur, although it does object that the Application does not satisfy section 10(c)(2) of the Act.[132] As we discuss below, we find that section 10(c)(2) is satisfied in this matter.

e. Conclusion

For the reasons discussed above, we find that the New AEP System will be an integrated system within the meaning of section 2(a)(29)(A) of the Act. Accordingly, the proposed Merger will not be detrimental to the carrying out of section 11 of the Act, which, as noted previously, generally limits a registered holding company to a single integrated system. Section 10(c)(1) of the Act is therefore satisfied. For the reasons discussed immediately below, we also find that the Merger will "tend[] towards the economical and efficient development of an integrated public-utility system," as required by section 10(c)(2).

2. Section 10(c)(2): Economies and Efficiencies

Section 10(c)(2) of the Act requires us to find that a proposed acquisition will "serve the public interest by tending towards the economical and efficient development of an integrated public-utility system."

As noted previously, Applicants project almost $2 billion of net non-fuel cost savings over the ten-year period immediately following consummation of the Merger. Applicants also anticipate net fuel-related savings of approximately $98 million over this same period.

---

[132] *Id.* at 18. *See Connecticut Yankee*, *supra* note 106, at 710 (finding that the "single area or region" standard must be considered in light of "the existing state of the art of generation and transmission and the demonstrated economic advantages of the proposed arrangement").

Applicants contemplate that fuel-related savings will result from the economic transfer of energy between the East Zone and the West Zone in order to displace relatively higher cost generation in the latter with relatively lower cost generation from the former. As explained previously, the Merger will afford the New AEP System additional opportunities for cost-effective energy transfers.[133] These efficiencies will benefit consumers as well as investors. Based upon the resolution of issues related to the allocation of Merger-related savings between customers and shareholders of New AEP in the states which have approved the Merger, Applicants have guaranteed that approximately 55% of the projected savings from the Merger will be passed through to the respective customers of each New AEP System Operating Company.

We have reviewed the assumptions and methodologies that underlie Applicants' projections, and we find that they are reasonable and consistent with our precedent. The projected savings were the subject of testimony and related workpapers filed by Applicants' expert witness in the Texas and Louisiana proceedings. Applicants filed these documents as Exhibit D-2.1 (vol. 2) (testimony) and Exhibits D-3.1 (vol. 4 of 5) and D-4.1 (vol. 4 of 6) (workpapers) to the Application.

In addition to these benefits, Applicants anticipate non-quantifiable and organizational economies and efficiencies from the Merger. We have recognized that it is appropriate to

---

[133] *See* the discussion in section II.B.1.b., *supra*.

consider "not only benefits resulting from the combination of utility assets, but also financial and organizational economies and efficiencies" under section 10(c)(2).[134]

Applicants state that generation mix and system reliability are two of the principal additional benefits contemplated from the Merger. Applicants explain that the New AEP System will have a more balanced generation mix that is less susceptible to fuel price volatility and supply interruptions than either the AEP System or the CSW System.

In addition, Applicants state that the New AEP System will be better situated to provide more reliable electric service than is possible for either the AEP System or the CSW System by itself. For example, the New AEP System will have a larger generating base after the Merger, and thus more generating resources to draw upon when units are down for maintenance or there is an unscheduled outage. As another example, Applicants state that the New AEP System should have a lower risk of unserved load than either the AEP System or the CSW System has, since each System has access to fewer interconnections to neighboring systems for emergency support than the New AEP System will have.

The record indicates that the proposed Merger will result in the economies and efficiencies required under section 10(c)(2) of the Act. Accordingly, we find that the requirements of section 10(c)(2) are satisfied.

---

[134] *WPL Holdings, Inc.*, Holding Co. Act Release No. 25377 (Sept. 18, 1991) ("*WPL Holdings II*"). *See, e.g.*, *New Century Energies*, *supra* note 48 (approving combination that "will result in a larger, financially stronger company, that, through the pooling of resources and expertise, will be able to achieve increased financial stability and strength, greater opportunities for earnings and dividend growth, reduction of operating costs, deferral of certain capital expenditures, efficiencies of operations, better use of facilities for the benefit of customers, seasonal diversity of demand, improved ability to use new technologies, greater retail and industrial sales diversity and improved capability to make wholesale power purchases and sales.").

APPA/NRECA disputes Applicants' showing under section 10(c)(2). APPA/NRECA states that "[c]laims of merger savings are inherently suspect;" "[e]stimates of merger benefits are subject to great uncertainties, particularly non-production savings that form the bulk of the savings claimed here."[135] We note, however, that in addition to our review, various other regulators have considered the anticipated savings. Applicants note that they provided their estimates of Merger savings to the staffs of all eleven state commissions that will have retail rate jurisdiction over the New AEP System Operating Companies. The savings, as well as Applicants' plans for allocation of the savings, were approved by the Arkansas, Indiana, Kentucky and Oklahoma Commissions. In each of those states, the Applicants responded to discovery requests from participants, including many of the Intervenors, and defended the savings as being achievable. In each state, the Applicants either received a state commission order and/or entered into stipulations with state commission staff (and other parties) which establish the level of savings that will be shared with customers and which guarantee the savings to customers, regardless of whether savings are achieved.

APPA/NRECA observes generally that "savings often can be achieved without a merger."[136] Even if this were the case, the Act requires us to apply the standards of

---

[135] APPA/NRECA at 19.

[136] *Id.*

section 10, including section 10(c)(2), to the proposed Merger. We are not required to, nor do we, substitute our business judgment for that of the Applicants.[137]

APPA/NRECA contends that "some of the claimed savings, such as 'purchasing economies' are not true economies and efficiencies as intended by the Act's requirements, but rather are pecuniary savings enjoyed by a larger enterprise that is able to obtain lower prices from its suppliers."[138] We do not perceive, and APPA/NRECA does not elucidate, the distinction between "true economies" and "pecuniary savings," for purposes of section 10(c)(2).[139] Section 10(c)(2) of the Act does not identify the types of economies and efficiencies that must be demonstrated. Accordingly, we reject APPA/NRECA's argument concerning purchasing economies.

APPA/NRECA argues, finally, that the anticipated Merger savings are "well below the average level" as compared to other utility mergers.[140] Applicants respond that the expected savings are more than sufficient to support a finding, without a hearing, that the Merger will satisfy section 10(c)(2) of the Act.[141] As stated previously, we are satisfied on the basis of the record that Applicants have made the affirmative showing required by section

---

[137] *See, e.g., WPL Holdings II, supra* note 134 (rejecting intervenor's argument that, instead of creating a new holding company, applicant should have adopted other available ways to maintain a balanced capital structure).

[138] APPA/NRECA at 19.

[139] *Id.* at 20.

[140] *Id.*

[141] Response at 42.

10(c)(2). That section does not require a comparative analysis of the savings of the Merger and those of other utility mergers.

With respect to the proposed divestiture of 250 MW of generating capacity in ERCOT and the SPP., the Advocates Group asserts that, "Even if the divestiture of the generation plants could somehow avoid violating the integration requirement on a physical basis, it will leave customers worse off on an economic basis."[142] This concern is misplaced. As part of the respective settlements which they approved, the Oklahoma Commission and the Texas Commission considered the potential impact of the divestiture upon consumers. In the Oklahoma stipulation, Applicants committed to hold Oklahoma retail consumers harmless from any such adverse effects.[143] The Texas settlement includes (1) a requirement that proceeds from the divestiture be used to reduce stranded costs of the New AEP System; (2) a provision that limits any adverse impact on consumers related to the divestiture; and, most significant, (3) a provision for rate reductions totalling $221 million for the New AEP System's customers in Texas over the six years following the Merger. In view of these measures, it appears unlikely that the divestiture will adversely affect consumers.

It is well settled that evidentiary hearings are required only when there exists a genuine issue of material fact.[144] The proponent of the hearing must make a minimal

---

[142] Advocates Group at 28-29.

[143] *See* Oklahoma Order, Stipulation at Section 7. Applicants agreed to make an "after the fact" calculation of margins both before and after the divestiture. If negative margins result, Oklahoma consumers will be held harmless from the additional costs associated with the divestiture. *Id.*

[144] *City of New Orleans*, *supra* note 71, at 1167 n.6, quoting *Wisconsin's Environmental Decade, Inc. v. SEC*, 882 F.2d 523, 526 (D.C. Cir. 1989).

showing that material facts are in dispute; the intervenor cannot rely on bald or conclusory allegations that a dispute exists.[145] On the basis of our review, we are satisfied that no hearing is needed in this matter.

III. Related Proposals

In order to effect the Merger, Applicants request authorization, variously, for issuances and sales of securities and/or acquisitions in transactions by which (1) AEP will acquire Merger Sub, Merger Sub will merge with and into CSW and, through the merger, AEP will indirectly acquire the CSW Common Stock; (2) AEP will issue AEP Common Stock in exchange for CSW Common Stock; (3) AEP will acquire, directly or indirectly, CSW Credit, Inc. (CSW will factor accounts receivable of all the New AEP System Operating Companies, consistent with previous authorizations); (4) AEP will reorganize, consolidate and, where necessary, restate certain of the existing intrasystem short-term financing and other authorizations of AEP, CSW and their respective subsidiaries, as described in Appendix 1; (5) CSW and its nonutility subsidiaries will borrow or obtain guarantees from AEP under the same terms and conditions as currently authorized for CSW and its nonutility subsidiaries, as described in Appendix 2; (6) as management may deem appropriate, AEP will acquire, directly or indirectly, CSW's nonutility businesses through the merger of one or more CSW nonutility businesses with one or more wholly owned nonutility subsidiaries (either presently existing and performing substantially equivalent activities or to be formed, if appropriate) of AEP; and, similarly, CSW will acquire and

[145] *City of New Orleans* at 1167 n.6 (D.C. Cir. 1992), citing *Connecticut Bankers Ass'n v. Board of Governors of Fed. Reserve Sys.*, 627 F.2d 245, 251 (D.C. Cir. 1980).

consolidate one or more of AEP's nonutility businesses; upon consolidation each nonutility business would succeed to the authority of the consolidated nonutility business;[146] (7) CSW Service will merge with and into AEP Service, with AEP Service as the surviving company; and (8) CSW will distribute or pay as a dividend to AEP the common stock of one or more CSW nonutility businesses.

Applicants also request that AEP Service succeed to certain of the authority of CSW Service set forth in certain orders and that these authorized activities extend, where applicable, to the New AEP System Operating Companies.[147] Applicants further propose that New AEP Service enter into an amended service agreement with all of AEP's subsidiaries, under which New AEP Service will provide the services previously provided by CSW Service, consistent with the requirements of section 13(b) of the Act and previously approved allocation methods, as well as several new allocation methods proposed in the Application.

Previous orders have authorized both AEP and CSW to use the proceeds of certain financings to invest up to 100% of consolidated retained earnings in EWGs and FUCOs.[148]

---

[146] Applicants undertake to file with the Commission a rule 24 report on January 1 and July 1 of each year following the Merger. The report will include: (1) a written description of any changes in the nonutility organizational structure relating to the merger or reorganization of nonutility businesses of AEP; and (2) an organizational chart for New AEP that highlights any changes in its nonutility organizational structure during that reporting period.

[147] *Central Power and Light Co.*, Holding Co. Act Release Nos. 26771 (Oct. 31, 1997) and 26931 (Oct. 21, 1998); *Central and South West Services, Inc.*, Holding Co. Act Release Nos. 26795 (December 11, 1997) and 26898 (July 21, 1998).

[148] *See American Electric Power Co.*, Inc., Holding Co. Act Release Nos. 26864 (Apr. 27, 1998); *Central and South West Corp.*, Holding Co. Act Release No. 26653 (Jan. 24, 1997).

As of December 31, 1999, AEP and CSW had consolidated retained earnings of approximately $1,725 million and $1,906 million respectively. Applicants propose that these orders terminate upon consummation of the Merger and that AEP be authorized to issue and sell securities in an amount of up to 100% of its consolidated retained earnings for investment in EWGs and FUCOs, with consolidated retained earnings to be calculated on the basis of the combined consolidated retained earnings of the New AEP. As of December 31, 1999, the *pro forma* aggregate investment in EWGs and FUCOs would have been approximately $1,853 million or about 51% of consolidated retained earnings of New AEP.

Finally, Applicants propose that certain stock-based benefit plans currently maintained by AEP and CSW be continued, modified or cancelled in connection with the Merger, as described in Appendix 3.

The proposals summarized above and in the appendices to this Order are variously subject to sections 6(a), 7, 9(a), 10, 11, 12(b), 12(c), 13(b), 32 and 33 of the Act and rules 43, 45, 46, 53, 54, 83, 87, 88, 90 and 91 of the Act. We have reviewed the proposed transactions and find that the requirements of the Act are satisfied.

IV. Conclusion

We have carefully examined the Application under the applicable standards of the Act, and have concluded that the proposed transactions are consistent with those standards. We have reached these conclusions on the basis of the complete record before us.

No federal or state commission other than this Commission has jurisdiction over the proposed transactions, other than as discussed above. As noted above, Applicants state that fees and expenses in connection with the Merger will be approximately $72.7 million.

Due notice of the filing of the Application has been given in the manner prescribed in rule 23 under the Act, and no hearing has been ordered by the Commission. Upon the basis of the facts in the record, it is hereby found that the applicable standards of the Act and rules thereunder are satisfied, and that no adverse findings are necessary:

IT IS ORDERED, under the applicable provisions of the Act and rules under the Act, that the Application, as amended, be, and it hereby is, granted, subject to the terms and conditions prescribed in rule 24 under the Act.

IT IS FURTHER ORDERED, that the requests for hearing be, and are, denied.

IT IS FURTHER ORDERED, that the request for a consolidation of this Application with the application in File No. 70-8779 be, and is, denied.

By the Commission.

Jonathan G. Katz
Secretary

Margaret H. McFarland

By: Margaret H. McFarland
Deputy Secretary

Appendix 1
Current AEP and CSW Short-Term Borrowing Authority and
Applicants' Related Request for Authority

Current CSW Short-Term Borrowing Authority

Currently, the CSW system uses short-term debt, primarily commercial paper, to meet working capital requirements and other interim capital needs. In addition, to improve efficiency, CSW has established a system money pool ("CSW Money Pool") to coordinate short-term borrowings for CSW, its electric utility subsidiary companies and CSW Service, as set forth in *Central and South West Corp.*, Holding Co. Act Release No. 26697 (Mar. 28, 1997) and *Central and South West Corp.*, Holding Co. Act Release No. 26854 (Apr. 3, 1998) (together, the "CSW Money Pool Orders"). AEP has no equivalent to the CSW Money Pool.

The CSW Money Pool Orders authorize for CSW, CP&L, PSO, SWEPCO, WTU and CSW Service ("CSW Money Pool Participants") a short-term borrowing program through March 31, 2002, which includes the sale of commercial paper by CSW to commercial paper dealers and financial institutions, and the sale of short-term notes to banks and their trust departments, by the Money Pool Participants. The CSW Money Pool Orders authorize short-term borrowing limits for CSW and the CSW Money Pool Participants as follows:

CSW Money Pool Participant	Short-Term Borrowing Limit
CSW	$2,500,000,000
CP&L	600,000,000
PSO	300,000,000
SWEPCO	250,000,000
WTU	165,000,000
CSW Service	210,000,000

Current AEP Short-Term Borrowing Authority

Under *American Electric Power Co., Inc.*, Holding Co. Act Release No. 27049 (Jul. 14, 1999) ("AEP Short-Term Financing Order"), the Commission authorized the following short-term borrowing limits for AEP and certain of its subsidiaries identified below:

Company	Short-Term Borrowing Limit
AEP	$ 500,000,000
AEP Generating	125,000,000
Appalachian Power	325,000,000
Columbus Southern Power	350,000,000
Indiana Michigan Power	500,000,000
Kentucky Power	150,000,000
Kingsport Power	30,000,000
Ohio Power	450,000,000
Wheeling Power	30,000,000
Total	$2,460,000,000

Request of Applicants

Applicants request authority, effective upon consummation of the Merger, for AEP to continue the CSW Money Pool and to manage and to fund it consistent with all the terms and conditions of the CSW Money Pool Orders and all previous orders relating to the CSW Money Pool, subject to the following:

(1) CSW's $2,500,000,000 short-term borrowing authorization will transfer to AEP and AEP's short-term borrowing limit will be increased from $500,000,000 to $5,000,000,000. The new limit will consist of (a) $2,500,000,000 authorized for CSW; (b) $2,460,000,000 authorized for AEP, AEP Generating and the AEP Operating Companies, and (c) $40,000,000 for New AEP Service;

(2) AEP, AEP Generating and the AEP Operating Companies will be added as participants to the CSW Money Pool and permitted to issue short-term debt up to the amounts specified in the AEP Short-Term Financing Order; and

(3) New AEP Service and certain other subsidiaries of AEP will be added as participants to the CSW Money Pool, although their borrowings would be exempt under rule 52(b).[1]

Accordingly, Applicants propose that the CSW Money Pool Orders be revised to authorize the following short-term borrowing limits for the companies indicated (other than New AEP Service and certain subsidiaries of AEP noted above):

---

[1] The additional subsidiaries are Cedar Coal Co., Central Appalachian Coal Co., Central Coal Co., Central Ohio Coal Co., Colomet, Inc., Simco Inc., Southern Appalachian Coal Co., Southern Ohio Coal Co., Windsor Coal Co., Blackhawk Coal Co., Conesville Coal Preparation Company, Franklin Real Estate Company, Indiana Franklin Realty Company and West Virginia Power Co.

Money Pool Participant	Short-Term Borrowing Limit
AEP[2]	$5,000,000,000
AEP Generating	125,000,000
Appalachian Power	325,000,000
Columbus Southern Power	350,000,000
Indiana Michigan Power	500,000,000
Kentucky Power	150,000,000
Kingsport Power	30,000,000
Ohio Power	450,000,000
Wheeling Power	30,000,000
New AEP Service[3]	40,000,000
CP&L	600,000,000
PSO	300,000,000
SWEPCO	250,000,000
WTU	165,000,000
CSW Service[3]	210,000,000
Total	$8,525,000,000

[2] Applicants request that, following the Merger, AEP and CSW (for a transitional period not to exceed eight years) together have the authority that CSW has under the Money Pool Orders.

[3] Applicants have requested authority to complete the merger of CSW Service with and into AEP Service not later than December 31, 2000. Accordingly, during this transitional period, each of CSW Service and AEP Service will retain its current short-term borrowing authority. Applicants state that the borrowings of AEP Service and CSW Service will be exempt under rule 52(b).

Appendix 2
Current CSW Financing and Guarantee Authority and
Applicants' Related Request for Authority

Current CSW Financing Authority

CSW has supported the financing and other activities of its subsidiaries through Commission orders authorizing it to issue and guarantee certain indebtedness. This authority ("CSW Guarantee Authority") is described below:

Under *Central and South West Corp.*, Holding Co. Act Release No. 26910 (Aug. 24, 1998), CSW is authorized, through December 31, 2003, to fund the management, operations and administrative costs of the electric vehicle business of CSW Energy Services, Inc. ("CSW Energy Services") by making loans to CSW Energy Services and providing guarantees and other credit support on behalf of CSW Energy Services, up to an aggregate amount outstanding at any time of $25,000,000.

Central and South West Corp., Holding Co. Act Release No. 26811 (Dec. 30, 1997) ("*CSW Guarantee Order*"), effective through December 31, 2002, authorized the following activities: (1) external financing by CSW; (2) the acquisition by CSW of the common stock of its subsidiaries; (3) the repurchase by CSW's subsidiaries of their common stock from CSW; (4) credit enhancement for the CSW subsidiaries' securities, including guarantees by CSW; (5) the repurchase by CSW of its securities by means of tender offers; and (6) the issuance by CSW of other types of securities not exempt under rules 45 and 52 under the Act.

Central and South West Corp., Holding Co. Act Release No. 26767 (October 21, 1997) confirmed certain previous authority and granted additional authority such that CSW was authorized, through December 31, 2002, to: (1) organize and invest in EWGs and FUCOs, either directly or indirectly; (2) provide certain operational and management services to EWGs and FUCOs; (3) provide guarantees or other forms of credit support for the securities or contractual obligations in connection with permitted activities; and (4) fund these investments and obligations under the guarantees and other forms of credit support through issuances by CSW.

Under *Central and South West Corp.*, Holding Co. Act Release No. 26766 (Oct. 21, 1997), CSW is authorized, through December 31, 2002, to issue guarantees in an aggregate amount up to $250,000,000 to support the debt and other obligations of affiliated power marketers and "energy-related companies" (as that term is defined in rule 58 under the Act).

Under *Central and South West Corp.*, Holding Co. Act Release No. 26762 (Sept. 30, 1997), CSW is authorized to participate in the organization and operation of STP Nuclear Operating Company.

Under *Central and South West Corp.*, Holding Co. Act Release No. 26522 (May 29, 1996), CSW is authorized to provide up to $250,000,000 in equity support to the Sweeny Project in the form of an equity support agreement, guarantee or letter of credit to the project lender.

Request of Applicants

Applicants state that it may be more efficient or commercially necessary after the Merger for AEP to support certain of the financing arrangements and business activities that CSW previously supported. Applicants request approval for AEP, upon consummation of the Merger, to support the CSW Guarantee Authority. Applicants request that the CSW Guarantee Authority be vested in both CSW and AEP; provided that, the guarantee authority of CSW, set forth in the CSW Guarantee Order, will be vested in both CSW and AEP and all other authority of CSW set forth in the *CSW Guarantee Order* will be vested in AEP. Accordingly, the Applicants do not seek to increase the CSW Financing Authority or the authority in the *CSW Guarantee Order*.

Appendix 3
Effect of Merger on Certain Stock-Based Benefit Plans

By order dated November 27, 1996 (Holding Co. Act Release No. 26616), the Commission confirmed previous authority and authorized CSW to offer, through December 31, 2001, 10,000,000 shares of CSW Common Stock under its Dividend Reinvestment and Stock Purchase Plan ("CSW Dividend Plan"). By order dated August 13, 1996 (Holding Co. Act Release No. 26553) ("AEP Dividend Plan Order") the Commission confirmed previous authority and authorized AEP to offer, through December 31, 2000, 54,000,000 shares of AEP Common Stock under its Dividend Reinvestment and Direct Stock Purchase Plan ("AEP Dividend Plan"). Applicants request that, as soon as practicable upon consummation of the Merger, (1) the authority of the CSW Dividend Plan be terminated, and (2) AEP be authorized to issue 55,200,000 shares of AEP Common Stock through December 31, 2000 under the AEP Dividend Plan consistent otherwise with all the terms and conditions set forth in the AEP Dividend Plan Order.

By order dated November 21, 1995 (Holding Co. Act Release No. 26413) ("CSW Thrift Plan Order"), the Commission confirmed previous authority and authorized CSW to issue and sell a total of 5,000,000 shares of CSW Common Stock to the trustee of the Central and South West Thrift Plan ("CSW Thrift Plan"). By order dated December 1, 1997 (Holding Co. Act Release No. 26786) ("AEP Savings Plan Order"), the Commission confirmed previous authority and authorized AEP to sell, through December 31, 2001, 8,800,000 shares of AEP Common Stock to the trustee of the American Electric Power System Employees Savings Plan ("AEP Savings Plan"). Applicants request that, upon consummation of the Merger, (1) the authority of CSW to issue shares of CSW Common Stock to the CSW Thrift Plan be terminated, and (2) AEP be authorized to issue 11,440,000 shares of AEP Common Stock through December 31, 2001 in connection with the AEP Savings Plan and the CSW Thrift Plan, for a transitional period, consistent otherwise with all the terms and conditions of the AEP Savings Plan Order and the CSW Thrift Plan Order, respectively.

By order dated April 7, 1992 (Holding Co. Act Release No. 25511) ("CSW Incentive Plan Order"), the Commission authorized CSW to adopt the Central and South West Corporation 1992 Long Term Incentive Plan ("CSW Incentive Plan") under which certain key employees would be eligible, through December 31, 2001, to receive certain performance and equity-based awards including (a) stock options, (b) stock appreciation rights, (c) performance units, (d) phantom stock, and (e) restricted shares of common stock. Applicants request that, upon consummation of the Merger, AEP succeed to the authority of CSW to permit AEP (1) to honor the awards granted by CSW prior to the consummation of the Merger, (2) to administer the plan (subject to any necessary shareholder or regulatory approval) on a combined company basis and to grant any remaining awards, and (3) to reserve and issue sufficient shares of AEP Common Stock under (1) and (2) above in connection with the CSW Incentive Plan consistent otherwise with all the terms and conditions set forth in the CSW Incentive Plan Order.

U. S. Department of Justice

Antitrust Division

325 7th Street, NW, Suite 500
Washington, DC 20530

February 2, 2000

Kathryn M. Fenton, Esq.
Jones, Day, Reavis & Pogue
51 Louisiana Avenue, N.W.
Washington, D.C. 20001

Dear Ms. Fenton:

I am writing to advise that the Department has closed its investigation into the proposed merger of your client Central and South West Corporation with American Electric Power. Accordingly, we have no further need for the documents that CSW submitted to us during the course of this investigation. Please, let us know whether you want us to burn the documents, or prefer to pick them up.

Sincerely,

Jade Alice Eaton
Attorney