American Electric Power
1 Riverside Plaza
Columbus, OH 43215 2373
614 223 1000

0002

AEP
AMERICAN® ELECTRIC POWER

Mr. Ed Hess
Public Utilities Commission of Ohio
180 East Broad Street
Columbus, Ohio 43215-3793

April 14, 2000

Dear Mr. Hess:

Enclosed are 40 copies of the combined Columbus Southern Power Company and Ohio Power Company 2000 Long-Term Forecast Report to the Public Utilities Commission of Ohio.

Very truly yours,

William R. Forrester
Director
Ohio Regulatory Affairs

tlr

Enclosures

c: Scott Potter

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COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

LONG-TERM FORECAST REPORT

TO THE

PUBLIC UTILITIES COMMISSION OF OHIO

2000

ELECTRIC

OPCo: Case No. 00-201-EL-FOR
CSP : Case No. 00-202-EL-FOR

LONG-TERM FORECAST REPORT

TO THE

PUBLIC UTILITIES COMMISSION OF OHIO

Submitted by

COLUMBUS SOUTHERN POWER COMPANY
215 North Front Street
Columbus, Ohio 43215
Telephone: (614) 464-7700

and

OHIO POWER COMPANY
301 Cleveland Avenue, S.W.
P. O. Box 24400
Canton, Ohio 44701
Telephone: (216) 456-8173

April 14, 2000

PREFACE

The load forecasts and resource plans that are presented herein do not reflect the possible impacts of the proposed merger between American Electric Power, Inc. and Central and South West Corporation. That proposed merger, which was announced in December 1997, has received the necessary approvals from state regulatory commissions, received clearance from the U.S. Department of Justice, and, more recently, received conditional approval from the Federal Energy Regulatory Commission. The next, and remaining, approval is now being sought from the Securities and Exchange Commission.

Also, these forecasts and plans are based on the assumption that the traditional regulatory paradigm and vertically integrated structure of the electric utility industry will continue throughout the forecast period. In view of the rapid and sweeping changes that are underway in the federal and state legislative and regulatory arenas with respect to the electric utility industry, the traditional concepts of utility forecasting, planning and operation, along with traditional ways of conducting business, will likely change in the future. The impacts of such changes are not known at this time.

In the case of the state of Ohio, a milestone was reached in 1999 when the Ohio Electric Restructuring Act of 1999 (the Act) became law. The Act provides, in part, for customer choice of energy supplier beginning January 1, 2001. The Act also directed the Commission to adopt rules for addressing a variety of issues pertinent to the restructuring process. In this regard, in December 1999, the Commission initiated a series of rulemaking proceedings, including one proceeding pertaining to proposed revised rules governing Long-Term Forecast Reports (LTFRs) filed annually by electric and gas utilities pursuant to Section 4935.04, Revised Code (Case No. 99-1614-EL-ORD). At this time, however, the procedural process for adopting and implementing such revised rules has not been completed. Thus, the information contained herein is being provided in accordance with the existing LTFR rules.

STATEMENT PURSUANT TO SECTION 4901:5-1-03(D),

OHIO ADMINISTRATIVE CODE

Columbus Southern Power and Ohio Power Companies' 2000 Long-Term Forecast Report is true and correct to the best of my knowledge and belief.

Coulter R. Boyle, III
Vice President - Regulatory Services
American Electric Power Service Corporation
On behalf of Columbus Southern Power Company
and Ohio Power Company

April 14, 2000
Dated this day in Columbus, Ohio

CERTIFICATE OF SERVICE

I hereby certify that:

1. Pursuant to Section 4901:5-1-03(F), Ohio Administrative Code, copies of Columbus Southern Power and Ohio Power Companies' 2000 Long-Term Forecast Report have been delivered or mailed to the Ohio Power Siting Board, the Office of Consumers' Counsel, and to each intervenor of record in Columbus Southern Power and Ohio Power Companies' last long-term forecast hearing on the day of filing;

2. Pursuant to Section 4901:5-1-03(G), Ohio Administrative Code, a copy of Columbus Southern Power and Ohio Power Companies' 2000 Long-Term Forecast Report to the Public Utilities Commission of Ohio will be sent by first class mail to the appropriate county libraries within three days of filing;

3. Pursuant to Section 4901:5-1-03(H), Ohio Administrative Code, Columbus Southern Power and Ohio Power Companies will keep at least one copy of their 2000 Long-Term Forecast Report at their principal business office for public inspection during business hours; and

4. Pursuant to Section 4901:5-1-03(I), Ohio Administrative Code, Columbus Southern Power and Ohio Power Companies will provide a copy of their 2000 Long-Term Forecast Report to any person upon request at a cost to cover the expenses incurred.

Marvin I. Resnik
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215
(614) 223-1606
Attorney for
Columbus Southern Power and
Ohio Power Companies

April 14, 2000
Dated this day in Columbus, Ohio

Main County and Depository Libraries to
Receive Copies of the 2000 Long-Term Forecast Report
to the Public Utilities Commission of Ohio

ADAMS COUNTY
Ohio Valley Local District Free Public Library
401 Pike Street
Manchester, Ohio 45144

ALLEN COUNTY
Lima Public Library
650 West Market Street
Lima, Ohio 45801

ASHLAND COUNTY
Ashland College Library
401 College Avenue
Ashland, Ohio 44805

ATHENS COUNTY
Nelsonville Public Library
95 West Washington
Nelsonville, Ohio 45764

ATHENS COUNTY
Vernon Alden Library Documents Division
Ohio University
Athens, Ohio 45701

AUGLAIZE COUNTY
Auglaize County Public District Library
203 South Perry Street
Wapakoneta, Ohio 45895

BELMONT COUNTY
Martins Ferry Public Library
20 South Fifth Street
Martins Ferry, Ohio 43935

BROWN COUNTY
Mary P. Shelton Library
200 West Grant Avenue
Georgetown, Ohio 45121

BUTLER COUNTY
Middletown Free Public Library
125 South Broad Street
Middletown, Ohio 45044-4004

BUTLER COUNTY
Lane Public Library
300 North Third Street
Hamilton, Ohio 45011

CARROLL COUNTY
Carroll County District Library
70 Second Street N.E.
Carrollton, Ohio 44615

CLARK COUNTY
Clark County Public Library
201 South Fountain Avenue, P.O. Box 1080
Springfield, Ohio 45501

CLERMONT COUNTY
Clermont County Library
180 South Third Street
Batavia, Ohio 45103

CLINTON COUNTY
Wilmington Public Library
268 North South Street
Wilmington, Ohio 45177

COLUMBIANA COUNTY
Lepper Library
303 East Lincoln Way
Lisbon, Ohio 44432

COSHOCTON COUNTY
Coshocton Public Library
655 Main Street
Coshocton, Ohio 43812

CRAWFORD COUNTY
Bucyrus Public Library
200 East Mansfield
Bucyrus, Ohio 44820

DARKE COUNTY
Greenville Public Library
520 Sycamore Street
Greenville, Ohio 45331

DEFIANCE COUNTY
Defiance Public Library
320 Fort Street
Defiance, Ohio 43512

DELAWARE COUNTY
Delaware County District Library
84 East Winter Street
Delaware, Ohio 43015

FAIRFIELD COUNTY
Fairfield County District Library
219 North Broad Street
Lancaster, Ohio 43130

FAYETTE COUNTY
Carnegie Public Library
127 South North Street
Washington CH, Ohio 43160

FRANKLIN COUNTY
Columbus Metropolitan Library
96 South Grant Avenue
Columbus, Ohio 43215

GALLIA COUNTY
Dr. Samuel L. Bossard Memorial Library
7 Spruce Street
Gallipolis, Ohio 45631

GREENE COUNTY
Hallie Q. Brown Memorial Library
Central State University
Wilberforce, Ohio 45384

GREENE COUNTY
Greene County District Library
76 East Market Street
Xenia, Ohio 45385

GUERNSEY COUNTY
Guernsey County District Public Library
800 Steubenville Avenue
Cambridge, Ohio 43725

HAMILTON COUNTY
Langsam Library ML 33
University of Cincinnati
Cincinnati, Ohio 45221

HAMILTON COUNTY
Public Library of Cincinnati & Hamilton County
800 Vine Street
Cincinnati, Ohio 45202

HANCOCK COUNTY
Findlay-Hancock County Public Library
206 Broadway
Findlay, Ohio 45840

HARDIN COUNTY
Mary Lou Johnson Hardin County District Library
325 East Columbus Street
Kenton, Ohio 43326

HARRISON COUNTY
Puskarich Public Library
200 East Market Street
Cadiz, Ohio 43907

HENRY COUNTY
Napoleon Public Library
301 West Clinton Street
Napoleon, Ohio 43545

HIGHLAND COUNTY
Highland County District Library
10 Willettsville Pike
Hillsboro, Ohio 45133

HOCKING COUNTY
Logan-Hocking County District Library
10 North Walnut Street
Logan, Ohio 43138

HOLMES COUNTY
Holmes County District Public Library
28 West Jackson Street
Millersburg, Ohio 44654

HURON COUNTY
Willard Memorial Library
6 West Emerald Street
Willard, Ohio 44890

JACKSON COUNTY
Jackson City Library
21 Broadway Street
Jackson, Ohio 45640

JACKSON COUNTY
Sylvester Memorial Wellston Public Library
135 East Second Street
Wellston, Ohio 45692

JEFFERSON COUNTY
Public Library of Steubenville & Jefferson County
407 South 4th Street
Steubenville, Ohio 43952

KNOX COUNTY
Public Library of Mt. Vernon & Knox County
201 North Mulberry Street
Mt. Vernon, Ohio 43050

LAWRENCE COUNTY
Briggs Lawrence County Public Library
321 South Fourth Street
Ironton, Ohio 45638

LICKING COUNTY
Newark Public Library
88 West Church Street
Newark, Ohio 43055

LOGAN COUNTY
Logan County District Library
220 North Main Street
Bellefontaine, Ohio 43311-2288

MADISON COUNTY
London Public Library
20 East First Street
London, Ohio 43140

MADISON COUNTY
Hurt/Battelle Memorial Library
270 Lilly Chapel Road
West Jefferson, Ohio 43162

MARION COUNTY
Marion Public Library
445 East Church Street
Marion, Ohio 43302

MEIGS COUNTY
Meigs County Public Library
216 West Main Street
Pomeroy, Ohio 45769

MERCER COUNTY
Dwyer-Mercer County District Library
303 North Main Street
Celina, Ohio 45822

MONROE COUNTY
Monroe County District Library
96 Home Avenue
Woodsfield, Ohio 43793

MORGAN COUNTY
Kate Love Simpson-Morgan County Library
358 East Main Street
McConnelsville, Ohio 43756

MORROW COUNTY
Mt. Gilead Free Public Library
35 East High Street
Mt. Gilead, Ohio 43338

MUSKINGUM COUNTY
Muskingum County Library System
220 North Fifth Street
Zanesville, Ohio 43701

NOBLE COUNTY
Caldwell Public Library
P.O. Box 230
Caldwell, Ohio 43725

PAULDING COUNTY
Paulding County Carnegie Library
205 South Main Street
Paulding, Ohio 45879

PERRY COUNTY
Perry County District Library
117 South Jackson Street
New Lexington, Ohio 43764

PICKAWAY COUNTY
Pickaway County District Public Library
165 East Main Street
Circleville, Ohio 43113

PIKE COUNTY
The Garnet A. Wilson Public Library
207 North Market Street
Waverly, Ohio 45690

PREBLE COUNTY
Preble County District Library
301 North Barron Street
Eaton, Ohio 45320

PUTNAM COUNTY
Putnam County District Library
525 North Thomas St. P.O. Box 308
Ottawa, Ohio 45875-0308

RICHLAND COUNTY
Mansfield/Richland County Public Library
43 West Third Street
Mansfield, Ohio 44902

ROSS COUNTY
Chillicothe & Ross County Public Library
P.O. Box 185, 140-46 South Paint Street
Chillicothe, Ohio 45601

SANDUSKY COUNTY
Birchard Public Library of Sandusky County
423 Croghan Street
Fremont, Ohio 43420

SCIOTO COUNTY
Portsmouth Public Library
1220 Gallia Street
Portsmouth, Ohio 45662

SENECA COUNTY
Kaubisch Memorial Library
205 Perry Street
Fostoria, Ohio 44830

SENECA COUNTY
Tiffin-Seneca Public Library
77 Jefferson Street
Tiffin, Ohio 44883

SHELBY COUNTY
Amos Memorial Public Library
230 East North Street
Sidney, Ohio 45365

STARK COUNTY
Stark County District Library
715 Market Avenue North
Canton, Ohio 44702

SUMMIT COUNTY
Akron-Summit County Public Library
55 South Main Street
Akron, Ohio 44326-0001

TUSCARAWAS COUNTY
Tuscarawas County Public Library
121 Fair Avenue NW
New Philadelphia, Ohio 44663

UNION COUNTY
Marysville Public Library
231 South Plum Street
Marysville, Ohio 43040

VAN WERT COUNTY
The Brumback Library
215 West Main Street
Van Wert, Ohio 45891

VINTON COUNTY
Herbert Wescoat Memorial Library
120 North Market Street
McArthur, Ohio 45651

WARREN COUNTY
Lebanon Public Library
101 South Broadway
Lebanon, Ohio 45036

WASHINGTON COUNTY
Washington County Public Library
615 Fifth Street
Marietta, Ohio 45750

WAYNE COUNTY
Wayne County Public Library
304 North Market Street
Wooster, Ohio 44691

WILLIAMS COUNTY
Bryan Public Library
107 East High Street
Bryan, Ohio 43506

WOOD COUNTY
Wood County District Public Library
251 North Main Street
Bowling Green, Ohio 43402

WYANDOT COUNTY
Upper Sandusky Community Library
301 North Sandusky Avenue
Upper Sandusky, Ohio 43351

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1. DEMAND FORECAST FORMS
Excluding DSM Adjustments

FORM FE1-1
Part 1

COLUMBUS SOUTHERN POWER COMPANY

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year) (a)

		(1)	(2)	(3)	(4)	(5)	(6)	Sales For Resale (7)	(8)	(9)	(10)	(11)
	Year	Residential	Commercial	Industrial	Railways and Railroads	Other End-Use Sales (b)	Total End-Use Sales (1)+(2)+(3)+(4)+(5)	Municipals	Associated Companies	All Other Categories	Total (7)+(8)+(9)	Total Sales (6)+(10)
-5	1995	5,648,385	5,791,540	2,988,811	-	404,008	14,832,744	451,232	-	-	451,232	15,283,976
-4	1996	5,625,945	5,936,125	3,068,087	-	412,049	15,044,206	451,356	-	-	451,356	15,495,562
-3	1997	5,595,414	6,078,776	3,208,205	-	411,489	15,293,884	455,100	-	-	455,100	15,748,984
-2	1998	5,675,394	6,288,853	3,191,429	-	428,491	15,584,167	465,628	-	-	465,628	16,049,795
-1	1999	6,112,875	6,683,121	3,196,470	-	440,612	16,435,078	488,011	-	-	488,011	16,923,089
0	2000	6,215,000	6,707,000	3,241,000	-	445,000	16,608,000	490,000	-	-	490,000	17,098,000
1	2001	6,351,000	6,919,000	3,357,000	-	460,000	17,087,000	500,000	-	-	500,000	17,587,000
2	2002	6,496,000	7,121,000	3,470,000	-	475,000	17,562,000	511,000	-	-	511,000	18,073,000
3	2003	6,645,000	7,322,000	3,545,000	-	490,000	18,002,000	521,000	-	-	521,000	18,523,000
4	2004	6,837,000	7,512,000	3,613,000	-	496,000	18,458,000	532,000	-	-	532,000	18,990,000
5	2005	7,029,000	7,701,000	3,682,000	-	502,000	18,914,000	542,000	-	-	542,000	19,456,000
6	2006	7,221,000	7,890,000	3,751,000	-	507,000	19,369,000	553,000	-	-	553,000	19,922,000
7	2007	7,413,000	8,080,000	3,820,000	-	513,000	19,826,000	564,000	-	-	564,000	20,390,000
8	2008	7,605,000	8,269,000	3,889,000	-	519,000	20,282,000	575,000	-	-	575,000	20,857,000
9	2009	7,797,000	8,459,000	3,957,000	-	525,000	20,738,000	586,000	-	-	586,000	21,324,000
10	2010	7,989,000	8,648,000	4,026,000	-	531,000	21,194,000	597,000	-	-	597,000	21,791,000
11	2011	8,181,000	8,838,000	4,095,000	-	537,000	21,651,000	608,000	-	-	608,000	22,259,000
12	2012	8,373,000	9,027,000	4,164,000	-	543,000	22,107,000	619,000	-	-	619,000	22,726,000
13	2013	8,565,000	9,217,000	4,233,000	-	549,000	22,564,000	629,000	-	-	629,000	23,193,000
14	2014	8,757,000	9,406,000	4,301,000	-	555,000	23,019,000	640,000	-	-	640,000	23,659,000
15	2015	8,949,000	9,595,000	4,370,000	-	561,000	23,475,000	651,000	-	-	651,000	24,126,000
16	2016	9,141,000	9,785,000	4,439,000	-	567,000	23,932,000	662,000	-	-	662,000	24,594,000
17	2017	9,333,000	9,974,000	4,508,000	-	573,000	24,388,000	673,000	-	-	673,000	25,061,000
18	2018	9,525,000	10,164,000	4,577,000	-	579,000	24,845,000	684,000	-	-	684,000	25,529,000
19	2019	9,717,000	10,353,000	4,646,000	-	585,000	25,301,000	695,000	-	-	695,000	25,996,000
20	2020	9,909,000	10,543,000	4,714,000	-	591,000	25,757,000	706,000	-	-	706,000	26,463,000

(a) Company operates solely in Ohio.

(b) Sales to street and highway lighting, and other public authorities.

Note: Forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-1
Part 1

FORM FE1-1
Part 2

COLUMBUS SOUTHERN POWER COMPANY

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year)

	Year	(11) Total Sales	(12) Losses and Unaccounted For (c)	(13) Net Energy for Load (11)+(12)	(14) Plant Auxiliary Use	(15) Total Energy (13)+(14)	(16) Net (d) Generation
-5	1995	15,283,976	1,113,578	16,397,554	435,123	16,832,677	12,824,875
-4	1996	15,495,562	1,168,986	16,664,548	534,085	17,198,633	13,679,485
-3	1997	15,748,984	1,151,419	16,900,403	508,344	17,408,747	14,162,844
-2	1998	16,049,795	1,396,572	17,446,367	560,745	18,007,112	14,866,965
-1	1999	16,923,089	1,164,726	18,087,815	476,969	18,564,784	13,718,340
0	2000	17,098,000	1,223,000	18,321,000	522,000	18,843,000	14,504,000
1	2001	17,587,000	1,250,000	18,837,000	496,000	19,333,000	13,780,000
2	2002	18,073,000	1,270,000	19,343,000	513,000	19,856,000	14,254,000
3	2003	18,523,000	1,292,000	19,815,000	524,000	20,339,000	14,567,000
4	2004	18,990,000	1,318,000	20,308,000	544,000	20,852,000	15,115,000
5	2005	19,456,000	1,345,000	20,801,000	539,000	21,340,000	14,979,000
6	2006	19,922,000	1,372,000	21,294,000	556,000	21,850,000	15,435,000
7	2007	20,390,000	1,397,000	21,787,000	579,000	22,366,000	16,094,000
8	2008	20,857,000	1,423,000	22,280,000	565,000	22,845,000	15,684,000
9	2009	21,324,000	1,448,000	22,772,000	603,000	23,375,000	17,923,000
10	2010	21,791,000	1,474,000	23,265,000	585,000	23,850,000	17,094,000
11	2011	22,259,000	1,499,000	23,758,000	584,000	24,342,000	17,456,000
12	2012	22,726,000	1,525,000	24,251,000	590,000	24,841,000	17,299,000
13	2013	23,193,000	1,551,000	24,744,000	490,000	25,234,000	15,271,000
14	2014	23,659,000	1,578,000	25,237,000	488,000	25,725,000	16,201,000
15	2015	24,126,000	1,604,000	25,730,000	484,000	26,214,000	18,229,000
16	2016	24,594,000	1,629,000	26,223,000	463,000	26,686,000	18,476,000
17	2017	25,061,000	1,655,000	26,716,000	461,000	27,177,000	18,883,000
18	2018	25,529,000	1,680,000	27,209,000	458,000	27,667,000	19,679,000
19	2019	25,996,000	1,706,000	27,702,000	457,000	28,159,000	19,950,000
20	2020	26,463,000	1,731,000	28,194,000	458,000	28,652,000	20,202,000

(c) Transmission, transformer and other losses and energy unaccounted for.

(d) The amount of net energy generated or estimated to be generated by the Company (does not include power purchased from other utilities).
The difference between Column (16) Net Generation and Column (13) Net Energy for Load is the net energy purchased from or sold to other utilities by the Company.

FORM FE1-1
Part 2

FORM FE1-1A
Part 1

OHIO POWER COMPANY
(OHIO PORTION) (a)

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year)

		(1)	(2)	(3)	(4)	(5)	(6)	Sales For Resale (7)	(8)	(9)	(10)	(11)
	Year	Residential	Commercial	Industrial	Railways and Railroads	Other End-Use Sales (b)	Total End-Use Sales (1)+(2)+(3)+(4)+(5)	Municipals (c)	Associated Companies	All Other Categories	Total (7)+(8)+(9)	Total Sales (6)+(10)
-5	1995	6,537,261	4,712,324	20,262,529	-	83,086	31,595,200	711,059	-	-	711,059	32,306,259
-4	1996	6,559,467	4,802,830	20,241,080	-	77,109	31,680,486	762,212	-	-	762,212	32,442,698
-3	1997	6,379,107	4,786,787	20,130,339	-	77,812	31,374,045	759,474	-	-	759,474	32,133,519
-2	1998	6,399,068	5,014,947	20,640,227	-	78,060	32,132,302	769,389	-	-	769,389	32,901,691
-1	1999	6,546,137	5,050,789	20,303,285	-	82,678	31,982,889	151,526	-	-	151,526	32,134,415
0	2000	6,804,000	5,160,000	16,331,000	-	80,000	28,375,000	6,000	-	-	6,000	28,381,000
1	2001	6,901,000	5,279,000	15,789,000	-	78,000	28,047,000	6,000	-	-	6,000	28,053,000
2	2002	7,008,000	5,390,000	15,791,000	-	76,000	28,265,000	6,000	-	-	6,000	28,271,000
3	2003	7,114,000	5,503,000	15,992,000	-	75,000	28,684,000	6,000	-	-	6,000	28,690,000
4	2004	7,240,000	5,581,000	16,086,000	-	75,000	28,982,000	6,000	-	-	6,000	28,988,000
5	2005	7,366,000	5,658,000	16,179,000	-	76,000	29,279,000	6,000	-	-	6,000	29,285,000
6	2006	7,492,000	5,736,000	16,273,000	-	76,000	29,577,000	6,000	-	-	6,000	29,583,000
7	2007	7,618,000	5,813,000	16,366,000	-	77,000	29,874,000	6,000	-	-	6,000	29,880,000
8	2008	7,743,000	5,891,000	16,460,000	-	78,000	30,172,000	5,000	-	-	5,000	30,177,000
9	2009	7,869,000	5,968,000	16,553,000	-	78,000	30,468,000	5,000	-	-	5,000	30,473,000
10	2010	7,995,000	6,046,000	16,647,000	-	79,000	30,767,000	5,000	-	-	5,000	30,772,000
11	2011	8,121,000	6,123,000	16,740,000	-	80,000	31,064,000	5,000	-	-	5,000	31,069,000
12	2012	8,247,000	6,200,000	16,834,000	-	80,000	31,361,000	5,000	-	-	5,000	31,366,000
13	2013	8,373,000	6,278,000	16,927,000	-	81,000	31,659,000	5,000	-	-	5,000	31,664,000
14	2014	8,499,000	6,355,000	17,021,000	-	81,000	31,956,000	5,000	-	-	5,000	31,961,000
15	2015	8,624,000	6,433,000	17,114,000	-	82,000	32,253,000	5,000	-	-	5,000	32,258,000
16	2016	8,750,000	6,510,000	17,208,000	-	83,000	32,551,000	5,000	-	-	5,000	32,556,000
17	2017	8,876,000	6,588,000	17,301,000	-	83,000	32,848,000	5,000	-	-	5,000	32,853,000
18	2018	9,002,000	6,665,000	17,395,000	-	84,000	33,146,000	5,000	-	-	5,000	33,151,000
19	2019	9,128,000	6,743,000	17,488,000	-	84,000	33,443,000	5,000	-	-	5,000	33,448,000
20	2020	9,254,000	6,820,000	17,582,000	-	85,000	33,741,000	5,000	-	-	5,000	33,746,000

(a) Excludes sales to Wheeling Power Company, an AEP affiliate.

(b) Sales to street and highway lighting, and other public authorities.

(c) Includes certain sales to Ohio Edison Company.

Note: Forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-1A
Part 1

FORM FE1-1A
Part 2

OHIO POWER COMPANY
(OHIO PORTION)

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year)

	Year	(11) Total Sales	(12) Losses and Unaccounted For (d)	(13) Net Energy for Load (11)+(12)	(14) Plant Auxiliary Use	(15) Total Energy (13)+(14)	(16) Net (e) Generation
-5	1995	32,306,259	2,097,444	34,403,703	1,738,383	36,142,086	25,219,291
-4	1996	32,442,696	2,272,440	34,715,138	1,917,069	36,632,207	28,909,737
-3	1997	32,133,519	2,277,449	34,410,968	1,747,786	36,158,754	27,853,757
-2	1998	32,901,691	2,425,289	35,326,980	1,834,485	37,161,465	28,125,941
-1	1999	32,134,415	2,587,653	34,722,068	1,621,283	36,343,351	23,957,069
0	2000	28,381,000	2,618,000	30,999,000	1,625,000	32,624,000	24,425,000
1	2001	28,053,000	2,527,000	30,580,000	1,719,000	32,299,000	25,834,000
2	2002	28,271,000	2,557,000	30,828,000	1,911,000	32,739,000	28,701,000
3	2003	28,690,000	2,588,000	31,278,000	1,997,000	33,275,000	29,988,000
4	2004	28,968,000	2,580,000	31,568,000	2,030,000	33,598,000	30,478,000
5	2005	29,285,000	2,575,000	31,860,000	2,033,000	33,893,000	30,531,000
6	2006	29,583,000	2,568,000	32,151,000	2,013,000	34,164,000	30,225,000
7	2007	29,880,000	2,563,000	32,443,000	2,010,000	34,453,000	30,177,000
8	2008	30,177,000	2,557,000	32,734,000	2,099,000	34,833,000	31,515,000
9	2009	30,473,000	2,553,000	33,026,000	1,810,000	34,836,000	27,195,000
10	2010	30,772,000	2,545,000	33,317,000	1,754,000	35,071,000	26,361,000
11	2011	31,069,000	2,540,000	33,609,000	1,738,000	35,347,000	26,126,000
12	2012	31,366,000	2,533,000	33,899,000	1,803,000	35,702,000	27,098,000
13	2013	31,664,000	2,527,000	34,191,000	1,806,000	35,997,000	27,135,000
14	2014	31,961,000	2,521,000	34,482,000	1,796,000	36,278,000	26,988,000
15	2015	32,258,000	2,516,000	34,774,000	1,789,000	36,563,000	26,884,000
16	2016	32,556,000	2,510,000	35,066,000	1,771,000	36,837,000	26,618,000
17	2017	32,853,000	2,504,000	35,357,000	1,763,000	37,120,000	26,504,000
18	2018	33,151,000	2,498,000	35,649,000	1,761,000	37,410,000	26,472,000
19	2019	33,448,000	2,492,000	35,940,000	1,762,000	37,702,000	26,483,000
20	2020	33,746,000	2,485,000	36,231,000	1,767,000	37,998,000	26,550,000

(d) Transmission, transformer and other losses and energy unaccounted for.

(e) The amount of net energy generated or estimated to be generated within Ohio by the company (does not include power purchased from other utilities). Energy from generating plants outside Ohio boundaries is shown on Form FE1-1B as part of Net Generation.

FORM FE1-1A
Part 2

FORM FE1-1B
Part 1

OHIO POWER COMPANY
(TOTAL SYSTEM) (a)

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year)

		(1)	(2)	(3)	(4)	(5)	(6)	Sales For Resale (7)	(8)	(9)	(10)	(11)
	Year	Residential	Commercial	Industrial	Railways and Railroads	Other End-Use Sales (b)	Total End-Use Sales (1)+(2)+(3)+ (4)+(5)	Municipals (c)	Associated Companies	All Other Categories	Total (7)+(8)+(9)	Total Sales (6)+(10)
-5	1995	6,537,261	4,712,324	20,262,529	-	83,086	31,595,200	711,059	1,832,412	-	2,543,471	34,138,671
-4	1996	6,559,467	4,802,830	20,241,080	-	77,109	31,680,486	762,212	1,865,916	-	2,628,128	34,308,614
-3	1997	6,379,107	4,786,787	20,130,339	-	77,812	31,374,045	759,474	1,819,036	-	2,578,510	33,952,555
-2	1998	6,399,068	5,014,947	20,640,227	-	78,060	32,132,302	769,389	1,777,751	-	2,547,140	34,679,442
-1	1999	6,546,137	5,050,789	20,303,285	-	82,678	31,982,889	151,526	1,838,299	-	1,989,825	33,972,714
0	2000	6,804,000	5,160,000	16,331,000	-	80,000	28,375,000	6,000	1,757,000	-	1,763,000	30,138,000
1	2001	6,901,000	5,279,000	15,789,000	-	78,000	28,047,000	6,000	1,695,000	-	1,701,000	29,748,000
2	2002	7,008,000	5,390,000	15,791,000	-	76,000	28,265,000	6,000	1,704,000	-	1,710,000	29,975,000
3	2003	7,114,000	5,503,000	15,992,000	-	75,000	28,684,000	6,000	1,716,000	-	1,722,000	30,406,000
4	2004	7,240,000	5,581,000	16,086,000	-	75,000	28,982,000	6,000	1,723,000	-	1,729,000	30,711,000
5	2005	7,366,000	5,658,000	16,179,000	-	76,000	29,279,000	6,000	1,729,000	-	1,735,000	31,014,000
6	2006	7,492,000	5,736,000	16,273,000	-	76,000	29,577,000	6,000	1,736,000	-	1,742,000	31,319,000
7	2007	7,618,000	5,813,000	16,366,000	-	77,000	29,874,000	6,000	1,742,000	-	1,748,000	31,622,000
8	2008	7,743,000	5,891,000	16,460,000	-	78,000	30,172,000	5,000	1,749,000	-	1,754,000	31,926,000
9	2009	7,869,000	5,968,000	16,553,000	-	78,000	30,468,000	5,000	1,755,000	-	1,760,000	32,228,000
10	2010	7,995,000	6,046,000	16,647,000	-	79,000	30,767,000	5,000	1,762,000	-	1,767,000	32,534,000
11	2011	8,121,000	6,123,000	16,740,000	-	80,000	31,064,000	5,000	1,768,000	-	1,773,000	32,837,000
12	2012	8,247,000	6,200,000	16,834,000	-	80,000	31,361,000	5,000	1,775,000	-	1,780,000	33,141,000
13	2013	8,373,000	6,278,000	16,927,000	-	81,000	31,659,000	5,000	1,781,000	-	1,786,000	33,445,000
14	2014	8,499,000	6,355,000	17,021,000	-	81,000	31,956,000	5,000	1,788,000	-	1,793,000	33,749,000
15	2015	8,624,000	6,433,000	17,114,000	-	82,000	32,253,000	5,000	1,794,000	-	1,799,000	34,052,000
16	2016	8,750,000	6,510,000	17,208,000	-	83,000	32,551,000	5,000	1,800,000	-	1,805,000	34,356,000
17	2017	8,876,000	6,588,000	17,301,000	-	83,000	32,848,000	5,000	1,807,000	-	1,812,000	34,660,000
18	2018	9,002,000	6,665,000	17,395,000	-	84,000	33,146,000	5,000	1,813,000	-	1,818,000	34,964,000
19	2019	9,128,000	6,743,000	17,488,000	-	84,000	33,443,000	5,000	1,820,000	-	1,825,000	35,268,000
20	2020	9,254,000	6,820,000	17,582,000	-	85,000	33,741,000	5,000	1,826,000	-	1,831,000	35,572,000

(a) Includes sales to Wheeling Power Company, an AEP affiliate.

(b) Sales to street and highway lighting, and other public authorities.

(c) Includes certain sales to Ohio Edison Company.

Note: Forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-1B
Part 1

FORM FE1-1B
Part 2

OHIO POWER COMPANY
(TOTAL SYSTEM)

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year)

	Year	(11) Total Sales	(12) Losses and Unaccounted For (d)	(13) Net Energy for Load (11)+(12)	(14) Plant Auxiliary Use	(15) Total Energy (13)+(14)	(16) Net (e) Generation
-5	1995	34,138,671	2,097,444	36,236,115	2,827,123	39,063,238	44,319,590
-4	1996	34,306,614	2,272,440	36,581,054	3,162,915	39,743,969	50,292,040
-3	1997	33,952,555	2,277,449	36,230,004	3,059,758	39,289,762	50,436,915
-2	1998	34,679,442	2,425,289	37,104,731	3,117,751	40,222,482	50,587,029
-1	1999	33,972,714	2,587,653	36,560,367	2,944,091	39,504,458	46,933,555
0	2000	30,138,000	2,618,000	32,756,000	3,069,000	35,825,000	48,883,000
1	2001	29,748,000	2,527,000	32,275,000	3,077,000	35,352,000	49,014,000
2	2002	29,975,000	2,557,000	32,532,000	3,154,000	35,686,000	50,252,000
3	2003	30,406,000	2,588,000	32,994,000	3,300,000	36,294,000	52,568,000
4	2004	30,711,000	2,580,000	33,291,000	3,276,000	36,567,000	52,183,000
5	2005	31,014,000	2,575,000	33,589,000	3,354,000	36,943,000	53,428,000
6	2006	31,319,000	2,568,000	33,887,000	3,425,000	37,312,000	54,544,000
7	2007	31,622,000	2,563,000	34,185,000	3,425,000	37,610,000	54,550,000
8	2008	31,926,000	2,557,000	34,483,000	3,506,000	37,989,000	55,840,000
9	2009	32,228,000	2,553,000	34,781,000	3,087,000	37,868,000	49,186,000
10	2010	32,534,000	2,545,000	35,079,000	2,991,000	38,070,000	47,665,000
11	2011	32,837,000	2,540,000	35,377,000	2,827,000	38,204,000	45,064,000
12	2012	33,141,000	2,533,000	35,674,000	2,881,000	38,555,000	45,922,000
13	2013	33,445,000	2,527,000	35,972,000	2,966,000	38,938,000	47,258,000
14	2014	33,749,000	2,521,000	36,270,000	2,968,000	39,238,000	47,297,000
15	2015	34,052,000	2,516,000	36,568,000	2,900,000	39,468,000	46,214,000
16	2016	34,356,000	2,510,000	36,866,000	2,840,000	39,706,000	45,260,000
17	2017	34,660,000	2,504,000	37,164,000	2,828,000	39,992,000	45,073,000
18	2018	34,964,000	2,498,000	37,462,000	2,809,000	40,271,000	44,773,000
19	2019	35,268,000	2,492,000	37,760,000	2,811,000	40,571,000	44,796,000
20	2020	35,572,000	2,485,000	38,057,000	2,817,000	40,874,000	44,899,000

(d) Transmission, transformer and other losses and energy unaccounted for.

(e) The amount of net energy generated or estimated to be generated within the total system. The difference between Column (16) Net Generation and Column (13) Net Energy for Load is the net energy purchased from or sold to other utilities by the Company.

FORM FE1-1B
Part 2

FORM FE1-1C
Part 1

AMERICAN ELECTRIC POWER SYSTEM (a)

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year)

		(1)	(2)	(3)	(4)	(5)	(6)	Sales For Resale (7)	(8)	(9)	(10)	(11)
	Year	Residential	Commercial	Industrial	Railways and Railroads	Other End-Use Sales (b)	Total End-Use Sales (1)+(2)+(3)+(4)+(5)	Municipals (c)	Associated Companies	All Other Categories (d)	Total (7)+(8)+(9)	Total Sales (6)+(10)
-5	1995	30,620,022	22,189,776	44,607,162	-	1,225,602	98,642,562	5,461,016	-	1,161,622	6,622,638	105,265,200
-4	1996	30,853,637	22,556,289	45,676,288	-	1,257,678	100,345,892	4,927,167	-	1,782,513	6,709,680	107,055,572
-3	1997	30,283,477	22,720,127	46,584,371	-	1,258,479	100,846,454	4,978,126	-	1,789,736	6,767,862	107,614,316
-2	1998	30,414,110	23,596,849	47,297,678	-	1,329,669	102,640,306	4,116,510	-	1,220,226	5,336,736	107,977,042
-1	1999	31,606,847	24,454,512	47,351,567	-	1,371,976	104,784,902	2,754,737	-	844,603	3,599,340	108,384,242
0	2000	32,746,000	24,831,000	43,701,000	-	1,375,000	102,653,000	2,522,000	-	860,000	3,382,000	106,035,000
1	2001	33,402,000	25,468,000	43,536,000	-	1,404,000	103,810,000	2,586,000	-	876,000	3,462,000	107,272,000
2	2002	34,050,000	26,074,000	44,010,000	-	1,434,000	105,568,000	2,651,000	-	893,000	3,544,000	109,112,000
3	2003	34,693,000	26,680,000	44,691,000	-	1,464,000	107,528,000	2,716,000	-	910,000	3,626,000	111,154,000
4	2004	35,338,000	27,184,000	45,157,000	-	1,485,000	109,164,000	2,794,000	-	934,000	3,728,000	112,892,000
5	2005	35,982,000	27,687,000	45,623,000	-	1,506,000	110,798,000	2,873,000	-	958,000	3,831,000	114,629,000
6	2006	36,627,000	28,190,000	46,089,000	-	1,527,000	112,433,000	2,952,000	-	981,000	3,933,000	116,366,000
7	2007	37,271,000	28,694,000	46,554,000	-	1,548,000	114,067,000	3,030,000	-	1,005,000	4,035,000	118,102,000
8	2008	37,916,000	29,197,000	47,020,000	-	1,568,000	115,701,000	3,109,000	-	1,029,000	4,138,000	119,839,000
9	2009	38,560,000	29,701,000	47,486,000	-	1,589,000	117,336,000	3,187,000	-	1,052,000	4,239,000	121,575,000
10	2010	39,205,000	30,204,000	47,952,000	-	1,610,000	118,971,000	3,266,000	-	1,076,000	4,342,000	123,313,000
11	2011	39,849,000	30,707,000	48,418,000	-	1,631,000	120,605,000	3,344,000	-	1,100,000	4,444,000	125,049,000
12	2012	40,493,000	31,211,000	48,884,000	-	1,651,000	122,239,000	3,423,000	-	1,123,000	4,546,000	126,785,000
13	2013	41,138,000	31,714,000	49,350,000	-	1,672,000	123,874,000	3,501,000	-	1,147,000	4,648,000	128,522,000
14	2014	41,782,000	32,218,000	49,816,000	-	1,693,000	125,509,000	3,580,000	-	1,171,000	4,751,000	130,260,000
15	2015	42,427,000	32,721,000	50,282,000	-	1,714,000	127,144,000	3,658,000	-	1,195,000	4,853,000	131,997,000
16	2016	43,071,000	33,224,000	50,748,000	-	1,734,000	128,777,000	3,737,000	-	1,218,000	4,955,000	133,732,000
17	2017	43,716,000	33,728,000	51,214,000	-	1,755,000	130,413,000	3,816,000	-	1,242,000	5,058,000	135,471,000
18	2018	44,360,000	34,231,000	51,679,000	-	1,776,000	132,046,000	3,894,000	-	1,266,000	5,160,000	137,206,000
19	2019	45,004,000	34,735,000	52,145,000	-	1,797,000	133,681,000	3,973,000	-	1,288,000	5,261,000	138,942,000
20	2020	45,649,000	35,238,000	52,611,000	-	1,818,000	135,316,000	4,051,000	-	1,313,000	5,364,000	140,680,000

(a) Represents multi-state integrated power system, of which the Company is a member.

(b) Sales to street and highway lighting, and other public authorities.

(c) Includes certain sales to Ohio Edison Company.

(d) Sales to cooperatives, private systems, and state agencies.

Note: Forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-1C
Part 1

FORM FE1-1C
Part 2

AMERICAN ELECTRIC POWER SYSTEM

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year)

	Year	(11) Total Sales	(12) Losses and Unaccounted For (e)	(13) Net Energy for Load (11)+(12)	(14) Plant Auxiliary Use	(15) Total Energy (13)+(14)	(16) Net (f) Generation
-5	1995	105,265,200	8,116,663	113,381,863	6,671,395	120,053,258	124,688,886
-4	1996	107,055,572	8,892,539	115,948,111	7,437,075	123,385,186	137,183,012
-3	1997	107,614,316	8,521,493	116,135,809	7,311,626	123,447,435	136,553,143
-2	1998	107,977,042	9,093,377	117,070,419	7,004,154	124,074,573	126,940,407
-1	1999	108,384,242	8,863,769	117,248,011	6,771,346	124,019,357	122,917,726
0	2000	106,035,000	9,141,000	115,176,000	7,604,000	122,780,000	139,282,000
1	2001	107,272,000	9,099,000	116,371,000	7,890,000	124,261,000	144,729,000
2	2002	109,112,000	9,151,000	118,263,000	7,972,000	126,235,000	146,256,000
3	2003	111,154,000	9,246,000	120,400,000	8,105,000	128,505,000	148,639,000
4	2004	112,892,000	9,324,000	122,216,000	8,225,000	130,441,000	150,779,000
5	2005	114,629,000	9,404,000	124,033,000	8,284,000	132,317,000	152,977,000
6	2006	116,366,000	9,483,000	125,849,000	8,372,000	134,221,000	155,649,000
7	2007	118,102,000	9,563,000	127,665,000	8,498,000	136,163,000	158,306,000
8	2008	119,839,000	9,643,000	129,482,000	8,604,000	138,086,000	160,752,000
9	2009	121,575,000	9,723,000	131,298,000	8,255,000	139,553,000	163,029,000
10	2010	123,313,000	9,801,000	133,114,000	8,224,000	141,338,000	160,517,000
11	2011	125,049,000	9,881,000	134,930,000	7,954,000	142,884,000	156,715,000
12	2012	126,785,000	9,962,000	136,747,000	8,010,000	144,757,000	156,282,000
13	2013	128,522,000	10,041,000	138,563,000	7,867,000	146,430,000	155,845,000
14	2014	130,260,000	10,119,000	140,379,000	7,675,000	148,054,000	155,934,000
15	2015	131,997,000	10,199,000	142,196,000	7,313,000	149,509,000	156,196,000
16	2016	133,732,000	10,280,000	144,012,000	7,211,000	151,223,000	156,617,000
17	2017	135,471,000	10,357,000	145,828,000	7,182,000	153,010,000	157,166,000
18	2018	137,206,000	10,439,000	147,645,000	7,093,000	154,738,000	157,849,000
19	2019	138,942,000	10,519,000	149,461,000	7,094,000	156,555,000	158,644,000
20	2020	140,680,000	10,597,000	151,277,000	7,111,000	158,388,000	159,544,000

(e) Transmission, transformer and other losses and energy unaccounted for.

(f) The amount of energy generated or estimated to be generated within the pool.
The difference between Column (16) Net Generation and Column (13) Net Energy for Load is the energy purchases or sales of the pool. If (16-13) is positive, the difference represents sales; if (16-13) is negative, the difference represents purchases.

FORM FE1-1C
Part 2

FORM FE1-2

Part 1

COLUMBUS SOUTHERN POWER COMPANY

FORECAST OF ENERGY DEMAND BY INDUSTRIAL SECTORS

(Megawatt Hours/Year)

		(1)	(2)	(3)	(4)	(5)	(6)
SIC Code		11-12	20	22	26	27	28
	Year	Coal Mining	Food and Kindred Products	Textile Mill Products	Paper and Allied Products	Printing and Publishing	Chemicals and Allied Products
-5	1995	0	321,598	32,340	230,903	100,802	423,320
-4	1996	0	347,165	33,453	240,345	103,800	445,406
-3	1997	0	352,739	32,388	243,355	104,255	472,105
-2	1998	0	375,547	30,661	233,421	105,769	461,015
-1	1999	0	364,615	31,018	229,298	104,584	448,083
0	2000	0	367,044	30,859	228,486	105,425	449,570
1	2001	0	379,058	31,497	234,852	108,197	462,414
2	2002	0	392,340	32,242	240,650	111,158	475,114
3	2003	0	402,416	32,667	244,103	113,099	482,198
4	2004	0	411,827	33,065	247,027	115,161	487,661
5	2005	0	421,072	33,446	249,875	117,334	493,171
6	2006	0	430,550	33,770	252,935	119,427	499,005
7	2007	0	440,185	34,103	255,961	121,272	504,871
8	2008	0	449,708	34,476	258,980	123,104	510,725
9	2009	0	458,988	34,813	261,914	124,933	517,036
10	2010	0	468,259	35,156	264,893	126,729	523,250
11	2011	0	477,509	35,517	267,989	128,416	529,252
12	2012	0	486,306	35,850	271,094	130,043	535,096
13	2013	0	494,800	36,170	273,991	131,568	540,877
14	2014	0	503,032	36,483	276,807	132,992	546,324
15	2015	0	511,391	36,799	279,557	134,357	551,981
16	2016	0	519,262	37,131	282,347	135,812	557,375
17	2017	0	527,219	37,445	285,080	137,071	562,492
18	2018	0	534,685	37,730	287,667	138,325	567,891
19	2019	0	541,772	38,002	290,324	139,427	573,105
20	2020	0	549,035	38,210	292,744	140,580	578,168

FORM FE1-2
Part 2

COLUMBUS SOUTHERN POWER COMPANY

FORECAST OF ENERGY DEMAND BY INDUSTRIAL SECTORS
(Megawatt Hours/Year)

		(7)	(8)	(9)	(10)	(11)	(12)
	SIC Code	29	30	32	33	34	35
	Year	Petroleum and Coal Products	Rubber and Misc. Plastics	Stone, Clay and Glass Products	Primary Metals	Fabricated Metal Products	Non-Electrical Machinery
-5	1995	22,197	194,323	205,591	415,328	207,149	124,079
-4	1996	21,545	199,457	199,466	415,557	212,304	126,092
-3	1997	23,398	198,974	192,661	430,955	236,847	131,105
-2	1998	26,451	210,995	191,739	451,917	252,293	144,662
-1	1999	30,222	222,294	199,217	390,568	242,756	151,656
0	2000	30,384	223,742	198,845	397,733	243,920	158,842
1	2001	31,484	229,433	204,315	412,533	251,402	169,686
2	2002	32,444	235,653	209,720	425,271	257,914	180,005
3	2003	33,014	239,565	212,780	433,159	260,856	188,379
4	2004	33,553	242,670	215,095	440,832	263,592	196,121
5	2005	34,117	245,974	217,464	448,547	266,400	204,156
6	2006	34,673	249,480	219,892	456,083	269,238	212,632
7	2007	35,197	252,707	222,458	463,308	271,937	221,397
8	2008	35,718	255,884	225,019	470,556	274,510	230,430
9	2009	36,231	258,973	227,508	477,537	277,006	239,684
10	2010	36,748	262,103	230,003	484,713	279,563	249,302
11	2011	37,249	265,272	232,228	491,701	282,171	259,215
12	2012	37,743	268,445	234,580	498,709	284,568	269,466
13	2013	38,247	271,723	236,923	505,804	286,928	279,919
14	2014	38,747	274,762	239,172	513,014	289,194	290,583
15	2015	39,265	277,801	241,456	520,312	291,508	301,274
16	2016	39,789	280,807	243,769	527,555	293,882	311,745
17	2017	40,289	284,006	245,964	534,693	296,121	322,532
18	2018	40,766	286,967	247,966	542,102	298,139	333,544
19	2019	41,261	290,103	250,134	549,669	300,329	345,018
20	2020	41,748	293,393	252,504	557,005	302,367	356,663

FORM FE1-2
Part 3

COLUMBUS SOUTHERN POWER COMPANY

FORECAST OF ENERGY DEMAND BY INDUSTRIAL SECTORS
(Megawatt Hours/Year)

		(13)	(14)	(15)	(16)
SIC Code		36	37		
	Year	Electrical Machinery	Transportation Equipment	All Other Industrials	Total (a) Industrial
-5	1995	295,624	127,720	287,837	2,988,811
-4	1996	290,195	126,560	306,742	3,068,087
-3	1997	303,858	135,202	350,363	3,208,205
-2	1998	295,634	139,035	272,290	3,191,429
-1	1999	308,048	145,991	330,120	3,198,470
0	2000	326,236	147,695	332,218	3,241,000
1	2001	349,824	152,324	339,981	3,357,000
2	2002	373,369	156,716	347,403	3,470,000
3	2003	392,332	159,144	351,288	3,545,000
4	2004	410,531	161,207	354,658	3,613,000
5	2005	429,095	163,339	358,009	3,682,000
6	2006	446,573	165,458	361,285	3,751,000
7	2007	464,447	167,605	364,553	3,820,000
8	2008	482,375	169,744	367,772	3,889,000
9	2009	499,831	171,713	370,834	3,957,000
10	2010	517,924	173,537	373,820	4,026,000
11	2011	536,417	175,289	376,776	4,095,000
12	2012	555,405	177,014	379,680	4,164,000
13	2013	574,850	178,624	382,577	4,233,000
14	2014	594,463	180,187	385,240	4,301,000
15	2015	614,592	181,686	388,020	4,370,000
16	2016	635,410	183,155	390,961	4,439,000
17	2017	656,828	184,420	393,841	4,508,000
18	2018	678,565	186,227	396,428	4,577,000
19	2019	701,078	186,532	399,246	4,646,000
20	2020	722,749	187,835	400,999	4,714,000

(a) The Total Industrial column is equal to the sum of all previous columns (1) through (15). Total Industrial for a given year is also equal to Column (3) Industrial on Form FE1-1.

FORM FE1-2
Part 1

OHIO POWER COMPANY

FORECAST OF ENERGY DEMAND BY INDUSTRIAL SECTORS
(Megawatt Hours/Year)

		(1)	(2)	(3)	(4)	(5)	(6)
SIC Code		11-12	20	24	26	27	28
	Year	Coal Mining	Food and Kindred Products	Lumber and Wood Products	Paper and Allied Products	Printing and Publishing	Chemicals and Allied Products
-5	1995	353,302	435,702	107,550	317,876	177,450	742,734
-4	1996	396,952	450,488	118,168	319,278	176,712	698,547
-3	1997	434,022	443,024	124,614	314,965	178,517	764,320
-2	1998	423,617	453,565	127,820	319,093	176,550	824,463
-1	1999	418,923	468,125	133,194	322,401	177,950	818,151
0	2000	384,000	482,568	136,129	328,980	183,693	840,594
1	2001	364,000	488,870	137,180	331,704	184,931	848,138
2	2002	162,000	498,111	137,882	334,594	187,029	857,845
3	2003	162,000	508,687	138,380	337,923	189,470	866,860
4	2004	162,000	515,219	137,939	338,446	190,936	867,646
5	2005	162,000	521,332	137,487	338,806	192,526	868,367
6	2006	162,000	527,744	137,034	339,529	194,002	869,865
7	2007	161,000	534,406	136,566	340,313	195,119	871,693
8	2008	161,000	540,906	136,075	341,135	196,231	873,627
9	2009	161,000	547,271	135,563	342,001	197,416	876,737
10	2010	160,000	553,438	134,901	342,865	198,501	879,508
11	2011	160,000	559,614	134,339	343,948	199,449	882,099
12	2012	160,000	565,251	133,855	345,080	200,319	884,527
13	2013	160,000	570,458	133,364	345,938	201,024	886,830
14	2014	160,000	575,407	132,786	346,757	201,609	888,747
15	2015	160,000	580,323	132,116	347,421	202,061	890,817
16	2016	160,000	584,708	131,524	348,181	202,672	892,579
17	2017	160,000	589,254	130,926	348,937	203,031	894,080
18	2018	160,000	593,183	130,252	349,501	203,374	895,990
19	2019	159,000	596,664	129,683	350,158	203,500	897,625
20	2020	159,000	600,436	129,085	350,610	203,749	899,224

FORM FE1-2
Part 2

OHIO POWER COMPANY

FORECAST OF ENERGY DEMAND BY INDUSTRIAL SECTORS
(Megawatt Hours/Year)

		(7)	(8)	(9)	(10)	(11)	(12)
	SIC Code	29	30	32	33	34	35
	Year	Petroleum and Coal Products	Rubber and Misc. Plastics	Stone,Clay and Glass Products	Primary Metals	Fabricated Metal Products	Non-Electric Machinery
-5	1995	1,133,120	1,026,835	998,463	12,237,187	530,636	263,366
-4	1996	1,135,441	1,047,743	1,030,386	12,148,018	549,920	270,015
-3	1997	1,089,764	1,050,560	1,029,367	11,871,660	586,035	271,583
-2	1998	1,044,108	1,065,645	1,023,101	12,571,000	597,150	296,797
-1	1999	1,065,861	1,074,604	1,041,319	11,810,990	629,608	298,684
0	2000	1,097,324	1,107,597	1,064,352	7,595,726	647,829	320,355
1	2001	1,115,386	1,114,132	1,072,797	6,957,544	654,982	335,705
2	2002	1,131,493	1,126,497	1,084,008	7,028,297	661,471	350,569
3	2003	1,146,355	1,140,231	1,095,058	7,095,867	666,117	365,287
4	2004	1,153,081	1,143,104	1,095,562	7,130,899	666,166	376,380
5	2005	1,160,313	1,146,676	1,096,165	7,164,942	666,293	387,745
6	2006	1,167,447	1,151,406	1,097,335	7,197,625	666,667	399,809
7	2007	1,173,792	1,155,172	1,099,547	7,228,065	666,926	412,319
8	2008	1,180,121	1,158,853	1,101,895	7,259,097	666,994	425,162
9	2009	1,186,664	1,162,651	1,104,401	7,289,247	667,210	438,394
10	2010	1,193,059	1,166,405	1,106,742	7,319,230	667,477	451,996
11	2011	1,199,144	1,170,557	1,108,029	7,348,986	668,024	466,006
12	2012	1,205,082	1,174,845	1,110,077	7,379,283	668,175	480,464
13	2013	1,211,265	1,179,544	1,112,065	7,410,073	668,251	495,052
14	2014	1,217,494	1,183,394	1,113,835	7,442,682	668,256	509,889
15	2015	1,223,979	1,186,983	1,115,537	7,474,744	668,251	524,449
16	2016	1,230,727	1,190,564	1,117,536	7,506,618	668,494	538,488
17	2017	1,236,949	1,195,178	1,119,214	7,538,168	668,582	552,981
18	2018	1,242,332	1,198,714	1,119,984	7,571,838	668,162	567,633
19	2019	1,248,268	1,202,983	1,121,545	7,606,821	668,165	582,881
20	2020	1,254,147	1,208,119	1,124,256	7,640,390	667,996	598,342

FORM FE1-2
Part 3

OHIO POWER COMPANY

FORECAST OF ENERGY DEMAND BY INDUSTRIAL SECTORS
(Megawatt Hours/Year)

		(13)	(14)	(15)	(16)
	SIC Code	36	37		
	Year	Electrical Machinery	Transportation Equipment	All Other Industrials	Total (a) Industrial
-5	1995	611,849	624,394	702,065	20,262,529
-4	1996	622,993	618,372	658,047	20,241,080
-3	1997	610,378	662,147	699,383	20,130,339
-2	1998	601,225	637,849	478,244	20,640,227
-1	1999	591,983	663,902	787,590	20,303,285
0	2000	642,002	687,794	812,055	16,331,000
1	2001	675,305	695,835	812,490	15,789,000
2	2002	709,521	704,736	816,946	15,791,000
3	2003	742,323	712,552	824,887	15,992,000
4	2004	768,751	714,349	825,522	16,086,000
5	2005	795,198	716,308	824,842	16,179,000
6	2006	819,323	718,351	824,864	16,273,000
7	2007	843,986	720,730	826,365	16,366,000
8	2008	868,440	723,161	827,303	16,460,000
9	2009	892,046	725,195	827,205	16,553,000
10	2010	916,247	726,484	830,145	16,647,000
11	2011	940,963	727,632	831,210	16,740,000
12	2012	966,284	728,769	831,990	16,834,000
13	2013	992,000	729,433	831,703	16,927,000
14	2014	1,017,814	730,053	832,276	17,021,000
15	2015	1,043,919	730,279	833,122	17,114,000
16	2016	1,070,951	730,503	834,455	17,208,000
17	2017	1,098,823	730,079	834,797	17,301,000
18	2018	1,126,796	731,783	835,457	17,395,000
19	2019	1,155,696	727,643	837,369	17,488,000
20	2020	1,183,089	727,601	835,956	17,582,000

(a) The Total Industrial column is equal to the sum of all previous columns (1) through (15). Total Industrial for a given year is also equal to Column (3) Industrial on Form FE1-1A or FE1-1B.

FORM FE1-3
Part 1

COLUMBUS SOUTHERN POWER COMPANY

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts) (a)

NATIVE LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	3,378	215	6.8	2,720	124	4.8
-4	1996	3,335	-43	-1.3	2,898	178	6.5
-3	1997	3,354	19	0.6	2,529	-369	-12.7
-2	1998	3,551	197	5.9	2,916	387	15.3
-1	1999	3,804	253	7.1	3,030	114	3.9
0	2000	3,758	-46	-1.2	3,051	21	0.7
1	2001	3,848	90	2.4	3,128	77	2.5
2	2002	3,937	89	2.3	3,197	69	2.2
3	2003	4,028	91	2.3	3,272	75	2.3
4	2004	4,123	95	2.4	3,347	75	2.3
5	2005	4,218	95	2.3	3,422	75	2.2
6	2006	4,313	95	2.3	3,496	74	2.2
7	2007	4,407	94	2.2	3,571	75	2.1
8	2008	4,502	95	2.2	3,646	75	2.1
9	2009	4,597	95	2.1	3,721	75	2.1
10	2010	4,692	95	2.1	3,795	74	2.0
11	2011	4,787	95	2.0	3,870	75	2.0
12	2012	4,881	94	2.0	3,945	75	1.9
13	2013	4,976	95	1.9	4,020	75	1.9
14	2014	5,071	95	1.9	4,095	75	1.9
15	2015	5,166	95	1.9	4,169	74	1.8
16	2016	5,260	94	1.8	4,244	75	1.8
17	2017	5,355	95	1.8	4,319	75	1.8
18	2018	5,450	95	1.8	4,394	75	1.7
19	2019	5,545	95	1.7	4,468	74	1.7
20	2020	5,640	95	1.7	4,547	79	1.8

(a) Company's service area is located solely in Ohio.
(b) Excludes interruptible load.
(c) Winter load reference is to peak loads which occur in the following winter.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.

Note: Forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-3
Part 2

COLUMBUS SOUTHERN POWER COMPANY

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts) (a)

INTERNAL LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	3,378	199	6.3	2,729	118	4.5
-4	1996	3,335	-43	-1.3	2,917	188	6.9
-3	1997	3,354	19	0.6	2,547	-370	-12.7
-2	1998	3,551	197	5.9	2,931	384	15.1
-1	1999	3,804	253	7.1	3,036	105	3.6
0	2000	3,782	-22	-0.6	3,078	42	1.4
1	2001	3,872	90	2.4	3,155	77	2.5
2	2002	3,961	89	2.3	3,224	69	2.2
3	2003	4,052	91	2.3	3,299	75	2.3
4	2004	4,147	95	2.3	3,374	75	2.3
5	2005	4,242	95	2.3	3,449	75	2.2
6	2006	4,337	95	2.2	3,523	74	2.1
7	2007	4,431	94	2.2	3,598	75	2.1
8	2008	4,526	95	2.1	3,673	75	2.1
9	2009	4,621	95	2.1	3,748	75	2.0
10	2010	4,716	95	2.1	3,822	74	2.0
11	2011	4,811	95	2.0	3,897	75	2.0
12	2012	4,905	94	2.0	3,972	75	1.9
13	2013	5,000	95	1.9	4,047	75	1.9
14	2014	5,095	95	1.9	4,122	75	1.9
15	2015	5,190	95	1.9	4,196	74	1.8
16	2016	5,284	94	1.8	4,271	75	1.8
17	2017	5,379	95	1.8	4,346	75	1.8
18	2018	5,474	95	1.8	4,421	75	1.7
19	2019	5,569	95	1.7	4,495	74	1.7
20	2020	5,664	95	1.7	4,574	79	1.8

(a) Company's service area is located solely in Ohio.
(b) Includes interruptible load.
(c) Winter load reference is to peak loads which occur in the following winter.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.

Note: Forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-3A
Part 1

OHIO POWER COMPANY
(OHIO PORTION) (a)

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts)

NATIVE LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	5,264	134	2.6	4,978	56	1.1
-4	1996	5,202	-62	-1.2	4,867	-111	-2.2
-3	1997	5,140	-62	-1.2	4,683	-184	-3.8
-2	1998	5,329	189	3.7	4,982	299	6.4
-1	1999	5,237	-92	-1.7	4,812	-170	-3.4
0	2000	4,458	-779	-14.9	3,979	-833	-17.3
1	2001	4,519	61	1.4	4,045	66	1.7
2	2002	4,579	60	1.3	4,104	59	1.5
3	2003	4,653	74	1.6	4,148	44	1.1
4	2004	4,709	56	1.2	4,190	42	1.0
5	2005	4,764	55	1.2	4,233	43	1.0
6	2006	4,821	57	1.2	4,275	42	1.0
7	2007	4,876	55	1.1	4,317	42	1.0
8	2008	4,932	56	1.1	4,359	42	1.0
9	2009	4,987	55	1.1	4,402	43	1.0
10	2010	5,044	57	1.1	4,444	42	1.0
11	2011	5,101	57	1.1	4,486	42	0.9
12	2012	5,156	55	1.1	4,528	42	0.9
13	2013	5,212	56	1.1	4,572	44	1.0
14	2014	5,267	55	1.1	4,615	43	0.9
15	2015	5,324	57	1.1	4,657	42	0.9
16	2016	5,379	55	1.0	4,699	42	0.9
17	2017	5,435	56	1.0	4,741	42	0.9
18	2018	5,490	55	1.0	4,784	43	0.9
19	2019	5,547	57	1.0	4,826	42	0.9
20	2020	5,603	56	1.0	4,869	43	0.9

(a) Excludes Sales to Wheeling Power Company, an AEP affiliate.
(b) Excludes interruptible load.
(c) Winter load reference is to peak loads which occur in the following winter.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.

Note: Forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-3A
Part 2

OHIO POWER COMPANY
(OHIO PORTION) (a)

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts)

INTERNAL LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	5,378	215	4.2	5,122	141	2.8
-4	1996	5,291	-87	-1.6	4,980	-142	-2.8
-3	1997	5,289	-2	0.0	4,938	-42	-0.8
-2	1998	5,363	74	1.4	5,211	273	5.5
-1	1999	5,423	60	1.1	4,952	-259	-5.0
0	2000	4,986	-437	-8.1	4,515	-437	-8.8
1	2001	4,963	-23	-0.5	4,526	11	0.2
2	2002	5,023	60	1.2	4,585	59	1.3
3	2003	5,097	74	1.5	4,629	44	1.0
4	2004	5,153	56	1.1	4,671	42	0.9
5	2005	5,208	55	1.1	4,714	43	0.9
6	2006	5,265	57	1.1	4,756	42	0.9
7	2007	5,320	55	1.0	4,798	42	0.9
8	2008	5,376	56	1.1	4,840	42	0.9
9	2009	5,431	55	1.0	4,883	43	0.9
10	2010	5,488	57	1.0	4,925	42	0.9
11	2011	5,545	57	1.0	4,967	42	0.9
12	2012	5,600	55	1.0	5,009	42	0.8
13	2013	5,656	56	1.0	5,053	44	0.9
14	2014	5,711	55	1.0	5,096	43	0.9
15	2015	5,768	57	1.0	5,138	42	0.8
16	2016	5,823	55	1.0	5,180	42	0.8
17	2017	5,879	56	1.0	5,222	42	0.8
18	2018	5,934	55	0.9	5,265	43	0.8
19	2019	5,991	57	1.0	5,307	42	0.8
20	2020	6,047	56	0.9	5,350	43	0.8

(a) Excludes Sales to Wheeling Power Company, an AEP affiliate.
(b) Includes interruptible load.
(c) Winter load reference is to peak loads which occur in the following winter.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.

Note: Forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-3B
Part 1

OHIO POWER COMPANY
(TOTAL SYSTEM) (a)

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts)

NATIVE LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	5,527	150	2.8	5,229	48	0.9
-4	1996	5,445	-82	-1.5	5,128	-101	-1.9
-3	1997	5,357	-88	-1.6	4,902	-226	-4.4
-2	1998	5,547	190	3.5	5,216	314	6.4
-1	1999	5,498	-49	-0.9	5,051	-165	-3.2
0	2000	4,703	-795	-14.5	4,228	-823	-16.3
1	2001	4,760	57	1.2	4,297	69	1.6
2	2002	4,824	64	1.3	4,360	63	1.5
3	2003	4,901	77	1.6	4,406	46	1.1
4	2004	4,960	59	1.2	4,451	45	1.0
5	2005	5,018	58	1.2	4,496	45	1.0
6	2006	5,077	59	1.2	4,541	45	1.0
7	2007	5,135	58	1.1	4,586	45	1.0
8	2008	5,194	59	1.1	4,631	45	1.0
9	2009	5,252	58	1.1	4,676	45	1.0
10	2010	5,311	59	1.1	4,721	45	1.0
11	2011	5,370	59	1.1	4,766	45	1.0
12	2012	5,428	58	1.1	4,811	45	0.9
13	2013	5,487	59	1.1	4,857	46	1.0
14	2014	5,545	58	1.1	4,902	45	0.9
15	2015	5,604	59	1.1	4,947	45	0.9
16	2016	5,662	58	1.0	4,992	45	0.9
17	2017	5,721	59	1.0	5,037	45	0.9
18	2018	5,779	58	1.0	5,082	45	0.9
19	2019	5,838	59	1.0	5,127	45	0.9
20	2020	5,897	59	1.0	5,173	46	0.9

(a) Includes sales to Wheeling Power Company, an AEP affiliate.
(b) Excludes interruptible load.
(c) Winter load reference is to peak loads which occur in the following winter.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.

Note: Forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-3B
Part 2

OHIO POWER COMPANY
(TOTAL SYSTEM) (a)

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts)

INTERNAL LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	5,641	231	4.3	5,373	133	2.5
-4	1996	5,547	-94	-1.7	5,254	-119	-2.2
-3	1997	5,519	-28	-0.5	5,177	-77	-1.5
-2	1998	5,588	69	1.3	5,465	288	5.6
-1	1999	5,705	117	2.1	5,212	-253	-4.6
0	2000	5,245	-460	-8.1	4,778	-434	-8.3
1	2001	5,218	-27	-0.5	4,792	14	0.3
2	2002	5,282	64	1.2	4,855	63	1.3
3	2003	5,359	77	1.5	4,901	46	0.9
4	2004	5,418	59	1.1	4,946	45	0.9
5	2005	5,476	58	1.1	4,991	45	0.9
6	2006	5,535	59	1.1	5,036	45	0.9
7	2007	5,593	58	1.0	5,081	45	0.9
8	2008	5,652	59	1.1	5,126	45	0.9
9	2009	5,710	58	1.0	5,171	45	0.9
10	2010	5,769	59	1.0	5,216	45	0.9
11	2011	5,828	59	1.0	5,261	45	0.9
12	2012	5,886	58	1.0	5,306	45	0.9
13	2013	5,945	59	1.0	5,352	46	0.9
14	2014	6,003	58	1.0	5,397	45	0.8
15	2015	6,062	59	1.0	5,442	45	0.8
16	2016	6,120	58	1.0	5,487	45	0.8
17	2017	6,179	59	1.0	5,532	45	0.8
18	2018	6,237	58	0.9	5,577	45	0.8
19	2019	6,296	59	0.9	5,622	45	0.8
20	2020	6,355	59	0.9	5,668	46	0.8

(a) Includes sales to Wheeling Power Company, an AEP affiliate.
(b) Includes interruptible load.
(c) Winter load reference is to peak loads which occur in the following winter.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.

Note: Forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-3C

Part 1

AMERICAN ELECTRIC POWER SYSTEM (a)

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts)

NATIVE LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	19,431	1,579	8.8	19,314	854	4.6
-4	1996	18,721	-710	-3.7	19,101	-213	-1.1
-3	1997	18,792	71	0.4	17,362	-1,739	-9.1
-2	1998	19,365	573	3.0	18,386	1,024	5.9
-1	1999	19,847	482	2.5	18,918	532	2.9
0	2000	18,922	-925	-4.7	18,419	-499	-2.6
1	2001	19,261	339	1.8	18,788	369	2.0
2	2002	19,601	340	1.8	19,115	327	1.7
3	2003	19,969	368	1.9	19,417	302	1.6
4	2004	20,293	324	1.6	19,719	302	1.6
5	2005	20,617	324	1.6	20,021	302	1.5
6	2006	20,941	324	1.6	20,322	301	1.5
7	2007	21,265	324	1.5	20,624	302	1.5
8	2008	21,589	324	1.5	20,926	302	1.5
9	2009	21,913	324	1.5	21,228	302	1.4
10	2010	22,237	324	1.5	21,530	302	1.4
11	2011	22,561	324	1.5	21,831	301	1.4
12	2012	22,885	324	1.4	22,133	302	1.4
13	2013	23,209	324	1.4	22,435	302	1.4
14	2014	23,533	324	1.4	22,737	302	1.3
15	2015	23,856	323	1.4	23,039	302	1.3
16	2016	24,180	324	1.4	23,340	301	1.3
17	2017	24,504	324	1.3	23,642	302	1.3
18	2018	24,828	324	1.3	23,944	302	1.3
19	2019	25,152	324	1.3	24,246	302	1.3
20	2020	25,476	324	1.3	24,559	313	1.3

(a) Represents multi-state integrated power system, of which the Company is a member.

(b) Excludes interruptible load.

(c) Winter load reference is to peak loads which occur in the following winter.

(d) Difference between reporting year and previous year.

(e) Difference expressed as a percent of previous year.

Note: Forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-3C
Part 2

AMERICAN ELECTRIC POWER SYSTEM (a)

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts)

INTERNAL LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	19,516	1,446	8.0	19,557	924	5.0
-4	1996	18,864	-652	-3.3	19,381	-176	-0.9
-3	1997	19,119	255	1.4	17,841	-1,540	-7.9
-2	1998	19,414	295	1.5	18,546	705	4.0
-1	1999	19,952	538	2.8	19,167	621	3.3
0	2000	19,586	-366	-1.8	19,090	-77	-0.4
1	2001	19,841	255	1.3	19,378	288	1.5
2	2002	20,181	340	1.7	19,705	327	1.7
3	2003	20,549	368	1.8	20,007	302	1.5
4	2004	20,873	324	1.6	20,309	302	1.5
5	2005	21,197	324	1.6	20,611	302	1.5
6	2006	21,521	324	1.5	20,912	301	1.5
7	2007	21,845	324	1.5	21,214	302	1.4
8	2008	22,169	324	1.5	21,516	302	1.4
9	2009	22,493	324	1.5	21,818	302	1.4
10	2010	22,817	324	1.4	22,120	302	1.4
11	2011	23,141	324	1.4	22,421	301	1.4
12	2012	23,465	324	1.4	22,723	302	1.3
13	2013	23,789	324	1.4	23,025	302	1.3
14	2014	24,113	324	1.4	23,327	302	1.3
15	2015	24,436	323	1.3	23,629	302	1.3
16	2016	24,760	324	1.3	23,930	301	1.3
17	2017	25,084	324	1.3	24,232	302	1.3
18	2018	25,408	324	1.3	24,534	302	1.2
19	2019	25,732	324	1.3	24,836	302	1.2
20	2020	26,056	324	1.3	25,149	313	1.3

(a) Represents multi-state integrated power system, of which the Company is a member.
(b) Includes interruptible load.
(c) Winter load reference is to peak loads which occur in the following winter.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.

Note: Forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-4

COLUMBUS SOUTHERN POWER COMPANY

RANGE OF FORECASTS (a)

		Energy Forecast (MWH/yr) (Net Energy for Load)			Peak Load Forecast (MW) (Summer)		
	Year	Lowest	Most Likely(b)	Highest	Lowest	Most Likely(c)	Highest
0	2000	18,088,000	18,321,000	18,476,000	3,734	3,782	3,812
1	2001	18,546,000	18,837,000	18,999,000	3,812	3,872	3,905
2	2002	19,008,000	19,343,000	19,667,000	3,892	3,961	4,027
3	2003	19,448,000	19,815,000	20,251,000	3,977	4,052	4,141
4	2004	19,877,000	20,308,000	20,857,000	4,059	4,147	4,259
5	2005	20,313,000	20,801,000	21,506,000	4,143	4,242	4,386
6	2006	20,728,000	21,294,000	22,084,000	4,222	4,337	4,498
7	2007	21,146,000	21,787,000	22,657,000	4,301	4,431	4,608
8	2008	21,557,000	22,280,000	23,226,000	4,379	4,526	4,718
9	2009	21,950,000	22,772,000	23,803,000	4,454	4,621	4,830
10	2010	22,328,000	23,265,000	24,369,000	4,526	4,716	4,940
11	2011	22,711,000	23,758,000	24,935,000	4,599	4,811	5,049
12	2012	23,096,000	24,251,000	25,491,000	4,671	4,905	5,156
13	2013	23,476,000	24,744,000	26,048,000	4,744	5,000	5,263
14	2014	23,840,000	25,237,000	26,604,000	4,813	5,095	5,371
15	2015	24,153,000	25,730,000	27,208,000	4,872	5,190	5,488
16	2016	24,477,000	26,223,000	27,817,000	4,932	5,284	5,605
17	2017	24,833,000	26,716,000	28,440,000	5,000	5,379	5,726
18	2018	25,179,000	27,209,000	29,095,000	5,066	5,474	5,853
19	2019	25,517,000	27,702,000	29,740,000	5,130	5,569	5,979
20	2020	25,829,000	28,194,000	30,410,000	5,189	5,664	6,109

(a) Company's service area is located solely in Ohio.

(b) Same as Column 13 on Form FE1-1.

(c) Same as highest of Summer or Winter Internal Load on Form FE1-3.

Note: Forecasts are initial estimates and do not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-4A

OHIO POWER COMPANY
(OHIO PORTION) (a)

RANGE OF FORECASTS

		Energy Forecast (MWH/yr) (Net Energy for Load)			Peak Load Forecast (MW) (Summer)		
	Year	Lowest	Most Likely(b)	Highest	Lowest	Most Likely(c)	Highest
0	2000	30,604,000	30,999,000	31,337,000	4,900	4,986	5,003
1	2001	30,108,000	30,580,000	30,843,000	4,864	4,963	4,984
2	2002	30,294,000	30,828,000	31,344,000	4,915	5,023	5,084
3	2003	30,699,000	31,278,000	31,965,000	4,980	5,097	5,186
4	2004	30,898,000	31,568,000	32,421,000	5,021	5,153	5,269
5	2005	31,114,000	31,860,000	32,939,000	5,064	5,208	5,361
6	2006	31,296,000	32,151,000	33,344,000	5,102	5,265	5,435
7	2007	31,488,000	32,443,000	33,738,000	5,140	5,320	5,507
8	2008	31,673,000	32,734,000	34,124,000	5,179	5,376	5,579
9	2009	31,833,000	33,026,000	34,521,000	5,212	5,431	5,651
10	2010	31,975,000	33,317,000	34,898,000	5,244	5,488	5,724
11	2011	32,128,000	33,609,000	35,273,000	5,277	5,545	5,794
12	2012	32,284,000	33,899,000	35,631,000	5,310	5,600	5,860
13	2013	32,439,000	34,191,000	35,992,000	5,342	5,656	5,927
14	2014	32,574,000	34,482,000	36,350,000	5,372	5,711	5,994
15	2015	32,643,000	34,774,000	36,772,000	5,390	5,768	6,072
16	2016	32,731,000	35,066,000	37,199,000	5,411	5,823	6,149
17	2017	32,864,000	35,357,000	37,638,000	5,440	5,879	6,231
18	2018	32,990,000	35,649,000	38,120,000	5,468	5,934	6,317
19	2019	33,105,000	35,940,000	38,584,000	5,493	5,991	6,403
20	2020	33,191,000	36,231,000	39,078,000	5,515	6,047	6,494

(a) Excludes Sales to Wheeling Power Company, an AEP affiliate.

(b) Same as Column 13 on Form FE1-1A.

(c) Same as highest of Summer or Winter Internal Load on Form FE1-3A.

(d) Winter load reference is to peak loads which occur in the following Winter.

Note: Forecasts are initial estimates and do not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-4B

OHIO POWER COMPANY
(TOTAL SYSTEM) (a)

RANGE OF FORECASTS

		Energy Forecast (MWH/yr) (Net Energy for Load)			Peak Load Forecast (MW) (Summer)		
	Year	Lowest	Most Likely(b)	Highest	Lowest	Most Likely(c)	Highest
0	2000	32,339,000	32,756,000	33,108,000	5,178	5,245	5,287
1	2001	31,777,000	32,275,000	32,553,000	5,137	5,218	5,263
2	2002	31,969,000	32,532,000	33,077,000	5,191	5,282	5,370
3	2003	32,383,000	32,994,000	33,719,000	5,260	5,359	5,477
4	2004	32,584,000	33,291,000	34,191,000	5,303	5,418	5,565
5	2005	32,802,000	33,589,000	34,727,000	5,348	5,476	5,662
6	2006	32,986,000	33,887,000	35,144,000	5,388	5,535	5,740
7	2007	33,179,000	34,185,000	35,550,000	5,428	5,593	5,816
8	2008	33,365,000	34,483,000	35,947,000	5,469	5,652	5,892
9	2009	33,525,000	34,781,000	36,355,000	5,504	5,710	5,968
10	2010	33,666,000	35,079,000	36,744,000	5,537	5,769	6,043
11	2011	33,818,000	35,377,000	37,129,000	5,571	5,828	6,117
12	2012	33,974,000	35,674,000	37,497,000	5,606	5,886	6,187
13	2013	34,129,000	35,972,000	37,867,000	5,640	5,945	6,258
14	2014	34,263,000	36,270,000	38,235,000	5,671	6,003	6,328
15	2015	34,327,000	36,568,000	38,669,000	5,690	6,062	6,410
16	2016	34,411,000	36,866,000	39,108,000	5,712	6,120	6,492
17	2017	34,544,000	37,164,000	39,562,000	5,743	6,179	6,578
18	2018	34,668,000	37,462,000	40,059,000	5,772	6,237	6,669
19	2019	34,781,000	37,760,000	40,538,000	5,799	6,296	6,759
20	2020	34,864,000	38,057,000	41,048,000	5,822	6,355	6,855

(a) Includes sales to Wheeling Power Company, an AEP affiliate.

(b) Same as Column 13 on Form FE1-1B.

(c) Same as highest of Summer or Winter Internal Load on Form FE1-3B.

(d) Winter load reference is to peak loads which occur in the following Winter.

Note: Forecasts are initial estimates and do not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-4C

AMERICAN ELECTRIC POWER SYSTEM (a)

RANGE OF FORECASTS

		Energy Forecast (MWH/yr) (Net Energy for Load)			Peak Load Forecast (MW) (Summer)		
	Year	Lowest	Most Likely (b)	Highest	Lowest	Most Likely(c)	Highest
0	2000	113,710,000	115,176,000	116,097,000	19,337	19,586	19,743
1	2001	114,575,000	116,371,000	117,374,000	19,535	19,841	20,012
2	2002	116,216,000	118,263,000	120,243,000	19,832	20,181	20,519
3	2003	118,710,000	120,400,000	123,047,000	20,168	20,549	21,001
4	2004	119,619,000	122,216,000	125,521,000	20,430	20,873	21,437
5	2005	121,126,000	124,033,000	128,235,000	20,700	21,197	21,915
6	2006	122,501,000	125,849,000	130,518,000	20,949	21,521	22,319
7	2007	123,907,000	127,665,000	132,762,000	21,202	21,845	22,717
8	2008	125,282,000	129,482,000	134,980,000	21,450	22,169	23,110
9	2009	126,558,000	131,298,000	137,240,000	21,681	22,493	23,511
10	2010	127,751,000	133,114,000	139,433,000	21,898	22,817	23,900
11	2011	128,983,000	134,930,000	141,614,000	22,121	23,141	24,287
12	2012	130,232,000	136,747,000	143,737,000	22,347	23,465	24,664
13	2013	131,463,000	138,563,000	145,864,000	22,570	23,789	25,042
14	2014	132,611,000	140,379,000	147,983,000	22,779	24,113	25,419
15	2015	133,480,000	142,196,000	150,365,000	22,938	24,436	25,840
16	2016	134,422,000	144,012,000	152,768,000	23,111	24,760	26,265
17	2017	135,549,000	145,828,000	155,238,000	23,316	25,084	26,703
18	2018	136,632,000	147,645,000	157,880,000	23,513	25,408	27,169
19	2019	137,671,000	149,461,000	160,456,000	23,702	25,732	27,625
20	2020	138,585,000	151,277,000	163,168,000	23,870	26,056	28,140

(a) Represents multi-state integrated power system, of which the Company is a member.

(b) Same as Column 13 on Form FE1-1C.

(c) Same as highest of Summer or Winter Internal Load on Form FE1-3C.

(d) Winter load reference is to peak loads which occur in the following Winter.

Note: Forecasts are initial estimates and do not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-5
Part 1

COLUMBUS SOUTHERN POWER AND AMERICAN ELECTRIC POWER SYSTEM

NET MONTHLY ENERGY FORECAST (Thousands of Megawatt-Hours)

Year 0 (2000)	OHIO (a)	SYSTEM (a)	POOL (b) AEP System
January (c)	1,652		10,708
February (c)	1,449		9,424
March	1,498		9,857
April	1,345	Same as	8,736
May	1,384	"Ohio"	8,831
June	1,582	column	9,406
July	1,741		10,090
August	1,716		10,144
September	1,490		9,174
October	1,403		8,989
November	1,431		9,225
December	1,607		10,339
Year 1 (2001)			
January	1,680		10,778
February	1,533		9,810
March	1,544		9,954
April	1,377	Same as	8,815
May	1,420	"Ohio"	8,888
June	1,625	column	9,532
July	1,789		10,217
August	1,759		10,242
September	1,542		9,296
October	1,441		9,073
November	1,472		9,308
December	1,656		10,458

(a) Company's service area is located solely in Ohio.

(b) Represents multi-state integrated power system, of which the Company is a member.

(c) Actual

Note: Forecasts are initial estimates and do not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-5
Part 2

COLUMBUS SOUTHERN POWER AND AMERICAN ELECTRIC POWER SYSTEM

NET MONTHLY INTERNAL PEAK LOAD FORECAST (Megawatts)

Year 0 (2000)	OHIO (a)	SYSTEM (a)	POOL (b) AEP System
January (c)	3,036		19,167
February (c)	2,671		17,052
March	2,648		17,082
April	2,276	Same as	15,277
May	2,909	"Ohio"	16,058
June	3,488	column	18,592
July	3,687		19,186
August	3,782		19,586
September	3,265		17,939
October	2,225		14,790
November	2,576		16,436
December	2,877		17,917
Year 1 (2001)			
January	3,078		19,090
February	2,918		18,293
March	2,720		17,264
April	2,320	Same as	15,419
May	2,990	"Ohio"	16,234
June	3,577	column	18,691
July	3,786		19,473
August	3,872		19,841
September	3,364		18,036
October	2,277		14,918
November	2,637		16,580
December	2,952		18,125

(a) Company's service area is located solely in Ohio.

(b) Represents multi-state integrated power system, of which the Company is a member.

(c) Actual

Note: Forecasts are initial estimates and do not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-5

Part 1

OHIO POWER AND AMERICAN ELECTRIC POWER SYSTEM

NET MONTHLY ENERGY FORECAST (Thousands of Megawatt-Hours)

Year 0 (2000)	OHIO (a)	SYSTEM (b)	POOL (c) AEP System
January (d)	2,700	2,868	10,708
February (d)	2,472	2,632	9,424
March	2,695	2,850	9,857
April	2,431	2,574	8,736
May	2,471	2,614	8,831
June	2,514	2,655	9,406
July	2,638	2,791	10,090
August	2,694	2,845	10,144
September	2,478	2,614	9,174
October	2,457	2,596	8,989
November	2,493	2,633	9,225
December	2,712	2,866	10,339
Year 1 (2001)			
January	2,778	2,932	10,778
February	2,547	2,685	9,810
March	2,643	2,792	9,954
April	2,392	2,532	8,815
May	2,404	2,541	8,888
June	2,501	2,640	9,532
July	2,629	2,777	10,217
August	2,658	2,803	10,242
September	2,457	2,588	9,296
October	2,425	2,557	9,073
November	2,456	2,590	9,308
December	2,691	2,839	10,458

(a) Excludes sales to Wheeling Power Company, an AEP affiliate.

(b) Includes sales to Wheeling Power Company, an AEP affiliate.

(c) Represents multi-state integrated power system, of which the Company is a member.

(d) Actual

Note: Forecasts are initial estimates and do not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-5
Part 2

OHIO POWER AND AMERICAN ELECTRIC POWER SYSTEM

NET MONTHLY INTERNAL PEAK LOAD FORECAST (Megawatts)

Year 0 (2000)	OHIO (a)	SYSTEM (b)	POOL (c) AEP System
January (d)	4,491	4,756	19,167
February (d)	4,318	4,587	17,052
March	4,525	4,779	17,082
April	4,174	4,421	15,277
May	4,262	4,504	16,058
June	4,792	5,039	18,592
July	4,838	5,095	19,186
August	4,986	5,245	19,586
September	4,661	4,899	17,939
October	4,050	4,280	14,790
November	4,333	4,573	16,436
December	4,524	4,778	17,917
Year 1 (2001)			
January	4,490	4,753	19,090
February	4,503	4,755	18,293
March	4,461	4,708	17,264
April	4,126	4,371	15,419
May	4,187	4,423	16,234
June	4,770	5,017	18,691
July	4,847	5,102	19,473
August	4,963	5,218	19,841
September	4,606	4,841	18,036
October	4,007	4,230	14,918
November	4,297	4,530	16,580
December	4,501	4,750	18,125

(a) Excludes sales to Wheeling Power Company, an AEP affiliate.

(b) Includes sales to Wheeling Power Company, an AEP affiliate.

(c) Represents multi-state integrated power system, of which the Company is a member.

(d) Actual

Note: Forecasts are initial estimates and do not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

COLUMBUS SOUTHERN POWER COMPANY (A)
FORM FE1-5 PART 3
MONTHLY FORECAST OF PEAK LOAD AND RESOURCES, 2000 - 2001
(MW)

Current Calendar Year (2000)

	Jan.(B)	Feb.(B)	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Net Demonstrated Capability	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595
Net Seasonal Capability	2,595	2,595	2,595	2,595	2,565	2,564	2,564	2,564	2,564	2,594	2,595	2,595
Purchases	50	47	32	32	50	56	56	56	47	0	0	0
Sales	44	45	37	37	37	37	37	36	36	36	36	36
Available Capability	2,601	2,597	2,590	2,590	2,578	2,583	2,583	2,584	2,575	2,558	2,559	2,559
Native Load	3,030	2,656	2,621	2,249	2,885	3,464	3,663	3,758	3,241	2,198	2,549	2,850
Available Reserve	(429)	(59)	(31)	341	(307)	(881)	(1,080)	(1,174)	(666)	360	10	(291)
Internal Load (C)	3,036	2,671	2,648	2,276	2,909	3,488	3,687	3,782	3,265	2,225	2,576	2,877
Reserve	(435)	(74)	(58)	314	(331)	(905)	(1,104)	(1,198)	(690)	333	(17)	(318)

Next Calendar Year (2001)

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Net Demonstrated Capability	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595
Net Seasonal Capability	2,595	2,595	2,595	2,595	2,565	2,564	2,564	2,564	2,564	2,594	2,595	2,595
Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Sales	37	37	37	37	37	37	37	36	36	36	36	36
Available Capability	2,558	2,558	2,558	2,558	2,528	2,527	2,527	2,528	2,528	2,558	2,559	2,559
Native Load	3,051	2,891	2,693	2,293	2,966	3,553	3,762	3,848	3,340	2,250	2,610	2,925
Available Reserve	(493)	(333)	(135)	265	(438)	(1,026)	(1,235)	(1,320)	(812)	308	(51)	(366)
Internal Load (C)	3,078	2,918	2,720	2,320	2,990	3,577	3,786	3,872	3,364	2,277	2,637	2,952
Reserve	(520)	(360)	(162)	238	(462)	(1,050)	(1,259)	(1,344)	(836)	281	(78)	(393)

Notes: (A) Inasmuch as Columbus Southern Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

(B) Actual data.

(C) Equals Native Load plus Interruptible Load. Load forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

OHIO POWER COMPANY (A)
FORM FE1-5 PART 3
MONTHLY FORECAST OF PEAK LOAD AND RESOURCES, 2000 - 2001
(MW)

Current Calendar Year (2000)

	Jan.(B)	Feb.(B)	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Net Demonstrated Capability	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520
Net Seasonal Capability	8,520	8,520	8,520	8,520	8,470	8,445	8,395	8,395	8,445	8,490	8,520	8,520
Purchases	212	164	113	113	173	195	195	195	165	0	0	0
Sales	67	77	273	273	273	273	273	271	271	271	271	271
Available Capability	8,665	8,607	8,360	8,360	8,370	8,367	8,317	8,319	8,339	8,219	8,249	8,249
Native Load	4,565	4,411	4,154	3,796	3,890	4,471	4,553	4,703	4,285	3,655	3,948	4,202
Available Reserve	4,100	4,196	4,206	4,564	4,480	3,896	3,764	3,616	4,054	4,564	4,301	4,047
Internal Load (C)	4,756	4,587	4,779	4,421	4,504	5,039	5,095	5,245	4,899	4,280	4,573	4,778
Reserve	3,909	4,020	3,581	3,939	3,866	3,328	3,222	3,074	3,440	3,939	3,676	3,471

Next Calendar Year (2001)

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Net Demonstrated Capability	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520
Net Seasonal Capability	8,520	8,520	8,520	8,520	8,470	8,445	8,395	8,395	8,445	8,490	8,520	8,520
Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Sales	320	320	320	320	320	320	320	320	320	320	320	320
Available Capability	8,200	8,200	8,200	8,200	8,150	8,125	8,075	8,075	8,125	8,170	8,200	8,200
Native Load	4,284	4,260	4,164	3,827	3,893	4,559	4,644	4,760	4,357	3,686	3,986	4,255
Available Reserve	3,916	3,940	4,036	4,373	4,257	3,566	3,431	3,315	3,768	4,484	4,214	3,945
Internal Load (C)	4,753	4,755	4,708	4,371	4,423	5,017	5,102	5,218	4,841	4,230	4,530	4,750
Reserve	3,447	3,445	3,492	3,829	3,727	3,108	2,973	2,857	3,284	3,940	3,670	3,450

Notes: (A) Inasmuch as Ohio Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

(B) Actual data.

(C) Equals Native Load plus Interruptible Load. Load forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

AMERICAN ELECTRIC POWER SYSTEM
FORM FE1-5 PART 3
MONTHLY FORECAST OF PEAK LOAD AND RESOURCES, 2000 - 2001
(MW)

Current Calendar Year (2000)

	Jan.(A)	Feb.(A)	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Net Demonstrated Capability	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509
Net Seasonal Capability	23,509	23,509	23,509	23,514	23,372	23,278	23,203	23,203	23,237	23,399	23,497	23,509
Purchases	516	468	316	316	487	547	547	547	463	0	0	0
Sales	257	257	436	436	436	436	436	436	436	436	436	436
Available Capability	23,768	23,720	23,389	23,394	23,423	23,389	23,314	23,314	23,264	22,963	23,061	23,073
Native Load	18,918	16,574	16,072	14,267	15,027	17,737	18,522	18,922	16,908	13,780	15,426	17,055
Available Reserve	4,850	7,146	7,317	9,127	8,396	5,652	4,792	4,392	6,356	9,183	7,635	6,018
Internal Load (B)	19,167	17,052	17,082	15,277	16,058	18,592	19,186	19,586	17,939	14,790	16,436	17,917
Reserve	4,601	6,668	6,307	8,117	7,365	4,797	4,128	3,728	5,325	8,173	6,625	5,156

Next Calendar Year (2001)

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Net Demonstrated Capability	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509
Net Seasonal Capability	23,509	23,509	23,509	23,514	23,372	23,278	23,203	23,203	23,237	23,399	23,497	23,509
Purchases	24	27	28	15	30	20	15	16	21	30	33	27
Sales	491	491	491	491	491	491	491	491	491	491	491	491
Available Capability	23,042	23,045	23,046	23,038	22,911	22,807	22,727	22,728	22,767	22,938	23,039	23,045
Native Load	18,500	17,512	16,335	14,490	15,287	18,111	18,893	19,261	17,265	13,989	15,651	17,344
Available Reserve	4,542	5,533	6,711	8,548	7,624	4,696	3,834	3,467	5,502	8,949	7,388	5,701
Internal Load (B)	19,090	18,293	17,264	15,419	16,234	18,691	19,473	19,841	18,036	14,918	16,580	18,125
Reserve	3,952	4,752	5,782	7,619	6,677	4,116	3,254	2,887	4,731	8,020	6,459	4,920

Notes: (A) Actual data.

(B) Equals Native Load plus Interruptible Load. Load forecast is an initial estimate and does not reflect the impact of any future additional utility-directed demand-side programs or customer generation.

FORM FE1-5
Part 3

CSP/OPCo 2000

2. DEMAND FORECAST FORMS
Reflecting DSM Adjustments

Table 1

COLUMBUS SOUTHERN POWER COMPANY
ESTIMATED DEMAND-SIDE MANAGEMENT IMPACTS
ON FORECASTED ENERGY REQUIREMENTS AND PEAK DEMANDS

	Energy Requirements Impacts GWH					Peak Demand Impacts MW	
Year	Residential	Commercial	Industrial	Losses	Total	Summer	Winter Following
2000	0	0	0	0	0	0	0
2001	-1	0	0	0	-1	0	-1
2002	-2	0	0	0	-2	0	-1
2003	-3	0	0	0	-3	0	-2
2004	-4	0	0	0	-4	-1	-2
2005	-4	0	0	-1	-5	-1	-2
2006	-5	0	0	-1	-6	-1	-2
2007	-5	0	0	-1	-6	-1	-2
2008	-5	0	0	-1	-6	-1	-2
2009	-5	0	0	-1	-6	-1	-2
2010	-4	0	0	-1	-5	-1	-2
2011	-4	0	0	-1	-5	-1	-2
2012	-4	0	0	-1	-5	-1	-2
2013	-4	0	0	-1	-5	-1	-2
2014	-4	0	0	-1	-5	-1	-2
2015	-4	0	0	0	-4	0	-2
2016	-4	0	0	0	-4	0	-1
2017	-3	0	0	0	-3	0	-1
2018	-2	0	0	0	-2	0	-1
2019	-1	0	0	0	-1	0	-1
2020	-1	0	0	0	-1	0	-1

Table 2

OHIO POWER COMPANY
(OHIO PORTION) (a)
ESTIMATED DEMAND-SIDE MANAGEMENT IMPACTS
ON FORECASTED ENERGY REQUIREMENTS AND PEAK DEMANDS

	Energy Requirements Impacts GWH					Peak Demand Impacts MW	
Year	Residential	Commercial	Industrial	Losses	Total	Summer	Winter Following
2000	-1	0	0	0	-1	0	-2
2001	-4	0	0	-1	-5	-1	-3
2002	-5	0	0	-1	-6	-1	-4
2003	-7	0	0	-1	-8	-1	-5
2004	-9	0	0	-1	-10	-2	-6
2005	-10	0	0	-1	-11	-2	-6
2006	-10	0	0	-1	-11	-2	-6
2007	-10	0	0	-1	-11	-2	-6
2008	-10	0	0	-1	-11	-2	-6
2009	-10	0	0	-1	-11	-2	-5
2010	-9	0	0	-1	-10	-2	-5
2011	-9	0	0	-1	-10	-1	-5
2012	-9	0	0	-1	-10	-1	-5
2013	-9	0	0	-1	-10	-1	-5
2014	-8	0	0	-1	-9	-1	-5
2015	-7	0	0	-1	-8	-1	-4
2016	-5	0	0	-1	-6	-1	-3
2017	-4	0	0	0	-4	-1	-2
2018	-3	0	0	0	-3	0	-1
2019	-1	0	0	0	-1	0	-1
2020	-1	0	0	0	-1	0	-1

Note: (a) Excluding Wheeling Power Company

Table 2 a

OHIO POWER COMPANY
(TOTAL SYSTEM) (a)
ESTIMATED DEMAND-SIDE MANAGEMENT IMPACTS
ON FORECASTED ENERGY REQUIREMENTS AND PEAK DEMANDS

	Energy Requirements Impacts GWH						Peak Demand Impacts MW	
Year	Residential	Commercial	Industrial	Sales to Associated Cos.	Losses	Total	Summer	Winter Following
2000	-1	0	0	0	0	-1	0	-2
2001	-4	0	0	0	-1	-5	-1	-3
2002	-5	0	0	0	-1	-6	-1	-4
2003	-7	0	0	0	-1	-8	-1	-5
2004	-9	0	0	0	-1	-10	-2	-6
2005	-10	0	0	0	-1	-11	-2	-6
2006	-10	0	0	0	-1	-11	-2	-6
2007	-10	0	0	0	-1	-11	-2	-6
2008	-10	0	0	0	-1	-11	-2	-6
2009	-10	0	0	0	-1	-11	-2	-5
2010	-9	0	0	0	-1	-10	-2	-5
2011	-9	0	0	0	-1	-10	-1	-5
2012	-9	0	0	0	-1	-10	-1	-5
2013	-9	0	0	0	-1	-10	-1	-5
2014	-8	0	0	0	-1	-9	-1	-5
2015	-7	0	0	0	-1	-8	-1	-4
2016	-5	0	0	0	-1	-6	-1	-3
2017	-4	0	0	0	0	-4	-1	-2
2018	-3	0	0	0	0	-3	0	-1
2019	-1	0	0	0	0	-1	0	-1
2020	-1	0	0	0	0	-1	0	-1

Note: (a) Including Wheeling Power Company

Table 3

AMERICAN ELECTRIC POWER SYSTEM
ESTIMATED DEMAND-SIDE MANAGEMENT IMPACTS
ON FORECASTED ENERGY REQUIREMENTS AND PEAK DEMANDS

	Energy Requirements Impacts GWH					Peak Demand Impacts MW	
Year	Residential	Commercial	Industrial	Losses	Total	Summer	Winter Following
2000	-3	-1	0	0	-4	-1	-6
2001	-9	-1	0	-1	-11	-2	-11
2002	-14	-1	0	-2	-17	-3	-16
2003	-18	-2	0	-2	-22	-4	-19
2004	-20	-2	0	-2	-24	-5	-22
2005	-21	-2	0	-3	-26	-5	-22
2006	-22	-2	0	-3	-27	-5	-22
2007	-22	-2	0	-3	-27	-5	-22
2008	-22	-2	0	-3	-27	-5	-22
2009	-22	-2	0	-3	-27	-5	-22
2010	-21	-2	0	-3	-26	-5	-22
2011	-20	-2	0	-3	-25	-5	-22
2012	-20	-2	0	-3	-25	-5	-21
2013	-20	-2	0	-3	-25	-5	-21
2014	-20	-2	0	-2	-24	-5	-21
2015	-18	-2	0	-2	-22	-4	-16
2016	-13	-1	0	-2	-16	-3	-11
2017	-9	0	0	-1	-10	-2	-6
2018	-4	0	0	-1	-5	-1	-3
2019	-3	0	0	0	-3	0	-3
2020	-3	0	0	0	-3	0	-3

FORM FE1-1
Part 1

COLUMBUS SOUTHERN POWER COMPANY

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year) (a)
REFLECTING DSM ADJUSTMENTS

			(1)	(2)	(3)	(4)	(5)	(6)	Sales For Resale (7)	(8)	(9)	(10)	(11)
	Year		Residential	Commercial	Industrial	Railways and Railroads	Other End-Use Sales (b)	Total End-Use Sales (1)+(2)+(3)+(4)+(5)	Municipals	Associated Companies	All Other Categories	Total (7)+(8)+(9)	Total Sales (6)+(10)
-5	1995		5,648,385	5,791,540	2,988,811	-	404,008	14,832,744	451,232	-	-	451,232	15,283,976
-4	1996		5,625,945	5,938,125	3,068,087	-	412,049	15,044,206	451,356	-	-	451,356	15,495,562
-3	1997		5,595,414	6,078,776	3,208,205	-	411,489	15,293,884	455,100	-	-	455,100	15,748,984
-2	1998		5,675,394	6,288,853	3,191,429	-	428,491	15,584,167	465,628	-	-	465,628	16,049,795
-1	1999		6,112,875	6,683,121	3,196,470	-	440,612	16,435,078	488,011	-	-	488,011	16,923,089
0	2000		6,215,000	6,707,000	3,241,000	-	445,000	16,608,000	490,000	-	-	490,000	17,098,000
1	2001		6,350,000	6,919,000	3,357,000	-	460,000	17,086,000	500,000	-	-	500,000	17,586,000
2	2002		6,494,000	7,121,000	3,470,000	-	475,000	17,560,000	511,000	-	-	511,000	18,071,000
3	2003		6,642,000	7,322,000	3,545,000	-	490,000	17,999,000	521,000	-	-	521,000	18,520,000
4	2004		6,833,000	7,512,000	3,613,000	-	496,000	18,454,000	532,000	-	-	532,000	18,986,000
5	2005		7,025,000	7,701,000	3,682,000	-	502,000	18,910,000	542,000	-	-	542,000	19,452,000
6	2006		7,216,000	7,890,000	3,751,000	-	507,000	19,364,000	553,000	-	-	553,000	19,917,000
7	2007		7,408,000	8,080,000	3,820,000	-	513,000	19,821,000	564,000	-	-	564,000	20,385,000
8	2008		7,600,000	8,269,000	3,889,000	-	519,000	20,277,000	575,000	-	-	575,000	20,852,000
9	2009		7,792,000	8,459,000	3,957,000	-	525,000	20,733,000	586,000	-	-	586,000	21,319,000
10	2010		7,985,000	8,648,000	4,026,000	-	531,000	21,190,000	597,000	-	-	597,000	21,787,000
11	2011		8,177,000	8,838,000	4,095,000	-	537,000	21,647,000	608,000	-	-	608,000	22,255,000
12	2012		8,369,000	9,027,000	4,164,000	-	543,000	22,103,000	619,000	-	-	619,000	22,722,000
13	2013		8,561,000	9,217,000	4,233,000	-	549,000	22,560,000	629,000	-	-	629,000	23,189,000
14	2014		8,753,000	9,406,000	4,301,000	-	555,000	23,015,000	640,000	-	-	640,000	23,655,000
15	2015		8,945,000	9,595,000	4,370,000	-	561,000	23,471,000	651,000	-	-	651,000	24,122,000
16	2016		9,137,000	9,785,000	4,439,000	-	567,000	23,928,000	662,000	-	-	662,000	24,590,000
17	2017		9,330,000	9,974,000	4,508,000	-	573,000	24,385,000	673,000	-	-	673,000	25,058,000
18	2018		9,523,000	10,164,000	4,577,000	-	579,000	24,843,000	684,000	-	-	684,000	25,527,000
19	2019		9,716,000	10,353,000	4,646,000	-	585,000	25,300,000	695,000	-	-	695,000	25,995,000
20	2020		9,908,000	10,543,000	4,714,000	-	591,000	25,756,000	706,000	-	-	706,000	26,462,000

(a) Company operates solely in Ohio.

(b) Sales to street and highway lighting, and other public authorities.

FORM FE1-1
Part 1

FORM FE1-1
Part 2

COLUMBUS SOUTHERN POWER COMPANY

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year)
REFLECTING DSM ADJUSTMENTS

	Year	(11) Total Sales	(12) Losses and Unaccounted For (c)	(13) Net Energy for Load (11)+(12)	(14) Plant Auxiliary Use	(15) Total Energy (13)+(14)	(16) Net (d) Generation
-5	1995	15,283,976	1,113,578	16,397,554	435,123	16,832,677	12,824,875
-4	1996	15,495,562	1,168,986	16,664,548	534,085	17,198,633	13,679,485
-3	1997	15,748,984	1,151,419	16,900,403	508,344	17,408,747	14,162,844
-2	1998	16,049,795	1,396,572	17,446,367	560,745	18,007,112	14,866,965
-1	1999	16,923,089	1,164,726	18,087,815	476,969	18,564,784	13,718,340
0	2000	17,098,000	1,223,000	18,321,000	522,000	18,843,000	14,501,000
1	2001	17,586,000	1,250,000	18,836,000	496,000	19,332,000	13,774,000
2	2002	18,071,000	1,270,000	19,341,000	513,000	19,854,000	14,250,000
3	2003	18,520,000	1,292,000	19,812,000	524,000	20,336,000	14,562,000
4	2004	18,986,000	1,318,000	20,304,000	544,000	20,848,000	15,108,000
5	2005	19,452,000	1,344,000	20,796,000	539,000	21,335,000	14,980,000
6	2006	19,917,000	1,371,000	21,288,000	555,000	21,843,000	15,430,000
7	2007	20,385,000	1,396,000	21,781,000	579,000	22,360,000	16,090,000
8	2008	20,852,000	1,422,000	22,274,000	565,000	22,839,000	15,707,000
9	2009	21,319,000	1,447,000	22,766,000	604,000	23,370,000	17,929,000
10	2010	21,787,000	1,473,000	23,260,000	585,000	23,845,000	17,086,000
11	2011	22,255,000	1,498,000	23,753,000	584,000	24,337,000	17,432,000
12	2012	22,722,000	1,524,000	24,246,000	590,000	24,836,000	17,284,000
13	2013	23,189,000	1,550,000	24,739,000	489,000	25,228,000	15,252,000
14	2014	23,655,000	1,577,000	25,232,000	489,000	25,721,000	16,219,000
15	2015	24,122,000	1,604,000	25,726,000	486,000	26,212,000	18,224,000
16	2016	24,590,000	1,629,000	26,219,000	463,000	26,682,000	18,467,000
17	2017	25,058,000	1,655,000	26,713,000	461,000	27,174,000	18,877,000
18	2018	25,527,000	1,680,000	27,207,000	459,000	27,666,000	19,679,000
19	2019	25,995,000	1,706,000	27,701,000	457,000	28,158,000	19,949,000
20	2020	26,462,000	1,731,000	28,193,000	458,000	28,651,000	20,190,000

(c) Transmission, transformer and other losses and energy unaccounted for.

(d) The amount of net energy generated or estimated to be generated by the Company (does not include power purchased from other utilities).
The difference between Column (16) Net Generation and Column (13) Net Energy for Load is the net energy purchased from or sold to other utilities by the Company.

FORM FE1-1
Part 2

FORM FE1-1A
Part 1

OHIO POWER COMPANY
(OHIO PORTION) (a)

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year)
REFLECTING DSM ADJUSTMENTS

		(1)	(2)	(3)	(4)	(5)	(6)	Sales For Resale (7)	(8)	(9)	(10)	(11)
	Year	Residential	Commercial	Industrial	Railways and Railroads	Other End-Use Sales (b)	Total End-Use Sales (1)+(2)+(3)+(4)+(5)	Municipals (c)	Associated Companies	All Other Categories	Total (7)+(8)+(9)	Total Sales (6)+(10)
-5	1995	6,537,261	4,712,324	20,262,529	-	83,086	31,595,200	711,059	-	-	711,059	32,306,259
-4	1996	6,559,467	4,802,830	20,241,060	-	77,109	31,680,486	762,212	-	-	762,212	32,442,698
-3	1997	6,379,107	4,786,787	20,130,339	-	77,812	31,374,045	759,474	-	-	759,474	32,133,519
-2	1998	6,399,068	5,014,947	20,640,227	-	78,060	32,132,302	769,389	-	-	769,389	32,901,691
-1	1999	6,546,137	5,050,789	20,303,285	-	82,678	31,982,889	151,526	-	-	151,526	32,134,415
0	2000	6,803,000	5,160,000	16,331,000	-	80,000	28,374,000	6,000	-	-	6,000	28,380,000
1	2001	6,897,000	5,279,000	15,789,000	-	78,000	28,043,000	6,000	-	-	6,000	28,049,000
2	2002	7,003,000	5,390,000	15,791,000	-	76,000	28,260,000	6,000	-	-	6,000	28,266,000
3	2003	7,107,000	5,503,000	15,992,000	-	75,000	28,677,000	6,000	-	-	6,000	28,683,000
4	2004	7,231,000	5,581,000	16,086,000	-	75,000	28,973,000	6,000	-	-	6,000	28,979,000
5	2005	7,356,000	5,658,000	16,179,000	-	76,000	29,269,000	6,000	-	-	6,000	29,275,000
6	2006	7,482,000	5,736,000	16,273,000	-	76,000	29,567,000	6,000	-	-	6,000	29,573,000
7	2007	7,608,000	5,813,000	16,366,000	-	77,000	29,864,000	6,000	-	-	6,000	29,870,000
8	2008	7,733,000	5,891,000	16,460,000	-	78,000	30,162,000	5,000	-	-	5,000	30,167,000
9	2009	7,859,000	5,968,000	16,553,000	-	78,000	30,458,000	5,000	-	-	5,000	30,463,000
10	2010	7,986,000	6,046,000	16,647,000	-	79,000	30,758,000	5,000	-	-	5,000	30,763,000
11	2011	8,112,000	6,123,000	16,740,000	-	80,000	31,055,000	5,000	-	-	5,000	31,060,000
12	2012	8,238,000	6,200,000	16,834,000	-	80,000	31,352,000	5,000	-	-	5,000	31,357,000
13	2013	8,364,000	6,278,000	16,927,000	-	81,000	31,650,000	5,000	-	-	5,000	31,655,000
14	2014	8,491,000	6,355,000	17,021,000	-	81,000	31,948,000	5,000	-	-	5,000	31,953,000
15	2015	8,617,000	6,433,000	17,114,000	-	82,000	32,246,000	5,000	-	-	5,000	32,251,000
16	2016	8,745,000	6,510,000	17,208,000	-	83,000	32,546,000	5,000	-	-	5,000	32,551,000
17	2017	8,872,000	6,588,000	17,301,000	-	83,000	32,844,000	5,000	-	-	5,000	32,849,000
18	2018	8,999,000	6,665,000	17,395,000	-	84,000	33,143,000	5,000	-	-	5,000	33,148,000
19	2019	9,127,000	6,743,000	17,488,000	-	84,000	33,442,000	5,000	-	-	5,000	33,447,000
20	2020	9,253,000	6,820,000	17,582,000	-	85,000	33,740,000	5,000	-	-	5,000	33,745,000

(a) Excludes sales to Wheeling Power Company, an AEP affiliate.

(b) Sales to street and highway lighting, and other public authorities.

(c) Includes certain sales to Ohio Edison Company.

FORM FE1-1A
Part 1

FORM FE1-1A
Part 2

OHIO POWER COMPANY
(OHIO PORTION)

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year)
REFLECTING DSM ADJUSTMENTS

	Year	(11) Total Sales	(12) Losses and Unaccounted For (d)	(13) Net Energy for Load (11)+(12)	(14) Plant Auxiliary Use	(15) Total Energy (13)+(14)	(16) Net (e) Generation
-5	1995	32,306,259	2,097,444	34,403,703	1,738,383	36,142,086	25,219,291
-4	1996	32,442,698	2,272,440	34,715,138	1,917,069	36,632,207	28,909,737
-3	1997	32,133,519	2,277,449	34,410,968	1,747,786	36,158,754	27,853,757
-2	1998	32,901,691	2,425,289	35,326,980	1,834,485	37,161,465	28,125,941
-1	1999	32,134,415	2,587,653	34,722,068	1,621,283	36,343,351	23,957,069
0	2000	28,380,000	2,618,000	30,998,000	1,624,000	32,622,000	24,418,000
1	2001	28,049,000	2,526,000	30,575,000	1,719,000	32,294,000	25,824,000
2	2002	28,266,000	2,556,000	30,822,000	1,910,000	32,732,000	28,696,000
3	2003	28,683,000	2,587,000	31,270,000	1,996,000	33,266,000	29,982,000
4	2004	28,979,000	2,579,000	31,558,000	2,029,000	33,587,000	30,470,000
5	2005	29,275,000	2,574,000	31,849,000	2,034,000	33,883,000	30,536,000
6	2006	29,573,000	2,567,000	32,140,000	2,012,000	34,152,000	30,215,000
7	2007	29,870,000	2,562,000	32,432,000	2,009,000	34,441,000	30,170,000
8	2008	30,167,000	2,556,000	32,723,000	2,102,000	34,825,000	31,551,000
9	2009	30,463,000	2,552,000	33,015,000	1,811,000	34,826,000	27,211,000
10	2010	30,763,000	2,544,000	33,307,000	1,753,000	35,060,000	26,354,000
11	2011	31,060,000	2,539,000	33,599,000	1,741,000	35,340,000	26,164,000
12	2012	31,357,000	2,532,000	33,889,000	1,802,000	35,691,000	27,082,000
13	2013	31,655,000	2,526,000	34,181,000	1,804,000	35,985,000	27,103,000
14	2014	31,953,000	2,520,000	34,473,000	1,796,000	36,269,000	26,986,000
15	2015	32,251,000	2,515,000	34,766,000	1,791,000	36,557,000	26,919,000
16	2016	32,551,000	2,509,000	35,060,000	1,771,000	36,831,000	26,618,000
17	2017	32,849,000	2,504,000	35,353,000	1,764,000	37,117,000	26,505,000
18	2018	33,148,000	2,498,000	35,646,000	1,762,000	37,408,000	26,475,000
19	2019	33,447,000	2,492,000	35,939,000	1,762,000	37,701,000	26,483,000
20	2020	33,745,000	2,485,000	36,230,000	1,767,000	37,997,000	26,550,000

(d) Transmission, transformer and other losses and energy unaccounted for.

(e) The amount of net energy generated or estimated to be generated within Ohio by the company (does not include power purchased from other utilities). Energy from generating plants outside Ohio boundaries is shown on Form FE1-1B as part of Net Generation.

FORM FE1-1A
Part 2

FORM FE1-1B
Part 1

OHIO POWER COMPANY
(TOTAL SYSTEM) (a)

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year)
REFLECTING DSM ADJUSTMENTS

		(1)	(2)	(3)	(4)	(5)	(6)	Sales For Resale (7)	(8)	(9)	(10)	(11)
	Year	Residential	Commercial	Industrial	Railways and Railroads	Other End-Use Sales (b)	Total End-Use Sales (1)+(2)+(3)+(4)+(5)	Municipals (c)	Associated Companies	All Other Categories	Total (7)+(8)+(9)	Total Sales (6)+(10)
-5	1995	6,537,261	4,712,324	20,262,529	-	83,086	31,595,200	711,059	1,832,412	-	2,543,471	34,138,671
-4	1996	6,559,467	4,802,830	20,241,060	-	77,109	31,680,486	762,212	1,865,916	-	2,628,128	34,308,614
-3	1997	6,379,107	4,786,787	20,130,339	-	77,812	31,374,045	759,474	1,819,036	-	2,578,510	33,952,555
-2	1998	6,399,068	5,014,947	20,640,227	-	78,060	32,132,302	769,389	1,777,751	-	2,547,140	34,679,442
-1	1999	6,546,137	5,050,789	20,303,285	-	82,678	31,982,889	151,526	1,838,299	-	1,989,825	33,972,714
0	2000	6,803,000	5,160,000	16,331,000	-	80,000	28,374,000	6,000	1,757,000	-	1,763,000	30,137,000
1	2001	6,897,000	5,279,000	15,789,000	-	78,000	28,043,000	6,000	1,695,000	-	1,701,000	29,744,000
2	2002	7,003,000	5,390,000	15,791,000	-	76,000	28,260,000	6,000	1,704,000	-	1,710,000	29,970,000
3	2003	7,107,000	5,503,000	15,992,000	-	75,000	28,677,000	6,000	1,716,000	-	1,722,000	30,399,000
4	2004	7,231,000	5,581,000	16,086,000	-	75,000	28,973,000	6,000	1,723,000	-	1,729,000	30,702,000
5	2005	7,356,000	5,658,000	16,179,000	-	76,000	29,269,000	6,000	1,729,000	-	1,735,000	31,004,000
6	2006	7,482,000	5,736,000	16,273,000	-	76,000	29,567,000	6,000	1,736,000	-	1,742,000	31,309,000
7	2007	7,608,000	5,813,000	16,366,000	-	77,000	29,864,000	6,000	1,742,000	-	1,748,000	31,612,000
8	2008	7,733,000	5,891,000	16,460,000	-	78,000	30,162,000	5,000	1,749,000	-	1,754,000	31,916,000
9	2009	7,859,000	5,968,000	16,553,000	-	78,000	30,458,000	5,000	1,755,000	-	1,760,000	32,218,000
10	2010	7,986,000	6,046,000	16,647,000	-	79,000	30,758,000	5,000	1,762,000	-	1,767,000	32,525,000
11	2011	8,112,000	6,123,000	16,740,000	-	80,000	31,055,000	5,000	1,768,000	-	1,773,000	32,828,000
12	2012	8,238,000	6,200,000	16,834,000	-	80,000	31,352,000	5,000	1,775,000	-	1,780,000	33,132,000
13	2013	8,364,000	6,278,000	16,927,000	-	81,000	31,650,000	5,000	1,781,000	-	1,786,000	33,436,000
14	2014	8,491,000	6,355,000	17,021,000	-	81,000	31,948,000	5,000	1,788,000	-	1,793,000	33,741,000
15	2015	8,617,000	6,433,000	17,114,000	-	82,000	32,246,000	5,000	1,794,000	-	1,799,000	34,045,000
16	2016	8,745,000	6,510,000	17,208,000	-	83,000	32,546,000	5,000	1,800,000	-	1,805,000	34,351,000
17	2017	8,872,000	6,588,000	17,301,000	-	83,000	32,844,000	5,000	1,807,000	-	1,812,000	34,656,000
18	2018	8,999,000	6,665,000	17,395,000	-	84,000	33,143,000	5,000	1,813,000	-	1,818,000	34,961,000
19	2019	9,127,000	6,743,000	17,488,000	-	84,000	33,442,000	5,000	1,820,000	-	1,825,000	35,267,000
20	2020	9,253,000	6,820,000	17,582,000	-	85,000	33,740,000	5,000	1,826,000	-	1,831,000	35,571,000

(a) Includes sales to Wheeling Power Company, an AEP affiliate.

(b) Sales to street and highway lighting, and other public authorities.

(c) Includes certain sales to Ohio Edison Company.

FORM FE1-1B
Part 1

FORM FE1-1B
Part 2

OHIO POWER COMPANY
(TOTAL SYSTEM)

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year)
REFLECTING DSM ADJUSTMENTS

	Year	(11) Total Sales	(12) Losses and Unaccounted For (d)	(13) Net Energy for Load (11)+(12)	(14) Plant Auxiliary Use	(15) Total Energy (13)+(14)	(16) Net (e) Generation
-5	1995	34,138,671	2,097,444	36,236,115	2,827,123	39,063,238	44,319,590
-4	1996	34,308,614	2,272,440	36,581,054	3,162,915	39,743,969	50,292,040
-3	1997	33,952,555	2,277,449	36,230,004	3,059,758	39,289,762	50,436,915
-2	1998	34,679,442	2,425,289	37,104,731	3,117,751	40,222,482	50,587,029
-1	1999	33,972,714	2,587,653	36,560,367	2,944,091	39,504,458	46,933,555
0	2000	30,137,000	2,618,000	32,755,000	3,068,000	35,823,000	48,874,000
1	2001	29,744,000	2,526,000	32,270,000	3,076,000	35,346,000	49,000,000
2	2002	29,970,000	2,556,000	32,526,000	3,154,000	35,680,000	50,243,000
3	2003	30,399,000	2,587,000	32,986,000	3,300,000	36,286,000	52,557,000
4	2004	30,702,000	2,579,000	33,281,000	3,275,000	36,556,000	52,171,000
5	2005	31,004,000	2,574,000	33,578,000	3,355,000	36,933,000	53,436,000
6	2006	31,309,000	2,567,000	33,876,000	3,425,000	37,301,000	54,541,000
7	2007	31,612,000	2,562,000	34,174,000	3,424,000	37,598,000	54,540,000
8	2008	31,916,000	2,556,000	34,472,000	3,509,000	37,981,000	55,875,000
9	2009	32,218,000	2,552,000	34,770,000	3,089,000	37,859,000	49,209,000
10	2010	32,525,000	2,544,000	35,069,000	2,991,000	38,060,000	47,655,000
11	2011	32,828,000	2,539,000	35,367,000	2,832,000	38,199,000	45,129,000
12	2012	33,132,000	2,532,000	35,664,000	2,880,000	38,544,000	45,902,000
13	2013	33,436,000	2,526,000	35,962,000	2,964,000	38,926,000	47,227,000
14	2014	33,741,000	2,520,000	36,261,000	2,968,000	39,229,000	47,299,000
15	2015	34,045,000	2,515,000	36,560,000	2,905,000	39,465,000	46,296,000
16	2016	34,351,000	2,509,000	36,860,000	2,840,000	39,700,000	45,261,000
17	2017	34,656,000	2,504,000	37,160,000	2,828,000	39,988,000	45,074,000
18	2018	34,961,000	2,498,000	37,459,000	2,809,000	40,268,000	44,778,000
19	2019	35,267,000	2,492,000	37,759,000	2,811,000	40,570,000	44,796,000
20	2020	35,571,000	2,485,000	38,056,000	2,817,000	40,873,000	44,900,000

(d) Transmission, transformer and other losses and energy unaccounted for.

(e) The amount of net energy generated or estimated to be generated within the total system. The difference between Column (16) Net Generation and Column (13) Net Energy for Load is the net energy purchased from or sold to other utilities by the Company.

FORM FE1-1B
Part 2

FORM FE1-1C
Part 1

AMERICAN ELECTRIC POWER SYSTEM (a)

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year)
REFLECTING DSM ADJUSTMENTS

		(1)	(2)	(3)	(4)	(5)	(6)	Sales For Resale (7)	(8)	(9)	(10)	(11)
	Year	Residential	Commercial	Industrial	Railways and Railroads	Other End-Use Sales (b)	Total End-Use Sales (1)+(2)+(3)+(4)+(5)	Municipals (c)	Associated Companies	All Other Categories (d)	Total (7)+(8)+(9)	Total Sales (6)+(10)
-5	1995	30,620,022	22,189,776	44,607,162	-	1,225,602	98,642,562	5,461,016	-	1,161,622	6,622,638	105,265,200
-4	1996	30,853,637	22,558,289	45,676,288	-	1,257,678	100,345,892	4,927,167	-	1,782,513	6,709,680	107,055,572
-3	1997	30,283,477	22,720,127	46,584,371	-	1,258,479	100,846,454	4,978,126	-	1,789,736	6,767,862	107,614,316
-2	1998	30,414,110	23,598,849	47,297,678	-	1,329,669	102,640,306	4,116,510	-	1,220,226	5,336,736	107,977,042
-1	1999	31,606,847	24,454,512	47,351,567	-	1,371,976	104,784,902	2,754,737	-	844,603	3,599,340	108,384,242
0	2000	32,743,000	24,830,000	43,701,000	-	1,375,000	102,649,000	2,522,000	-	860,000	3,382,000	106,031,000
1	2001	33,393,000	25,467,000	43,536,000	-	1,404,000	103,800,000	2,586,000	-	876,000	3,462,000	107,262,000
2	2002	34,036,000	26,073,000	44,010,000	-	1,434,000	105,553,000	2,651,000	-	893,000	3,544,000	109,097,000
3	2003	34,675,000	26,678,000	44,691,000	-	1,464,000	107,508,000	2,716,000	-	910,000	3,626,000	111,134,000
4	2004	35,318,000	27,182,000	45,157,000	-	1,485,000	109,142,000	2,794,000	-	934,000	3,728,000	112,870,000
5	2005	35,961,000	27,685,000	45,623,000	-	1,506,000	110,775,000	2,873,000	-	958,000	3,831,000	114,606,000
6	2006	36,605,000	28,188,000	46,089,000	-	1,527,000	112,409,000	2,952,000	-	981,000	3,933,000	116,342,000
7	2007	37,249,000	28,692,000	46,554,000	-	1,548,000	114,043,000	3,030,000	-	1,005,000	4,035,000	118,078,000
8	2008	37,894,000	29,195,000	47,020,000	-	1,568,000	115,677,000	3,109,000	-	1,029,000	4,138,000	119,815,000
9	2009	38,538,000	29,699,000	47,486,000	-	1,589,000	117,312,000	3,187,000	-	1,052,000	4,239,000	121,551,000
10	2010	39,184,000	30,202,000	47,952,000	-	1,610,000	118,948,000	3,266,000	-	1,076,000	4,342,000	123,290,000
11	2011	39,829,000	30,705,000	48,418,000	-	1,631,000	120,583,000	3,344,000	-	1,100,000	4,444,000	125,027,000
12	2012	40,473,000	31,209,000	48,884,000	-	1,651,000	122,217,000	3,423,000	-	1,123,000	4,546,000	126,763,000
13	2013	41,118,000	31,712,000	49,350,000	-	1,672,000	123,852,000	3,501,000	-	1,147,000	4,648,000	128,500,000
14	2014	41,762,000	32,216,000	49,816,000	-	1,693,000	125,487,000	3,580,000	-	1,171,000	4,751,000	130,238,000
15	2015	42,409,000	32,719,000	50,282,000	-	1,714,000	127,124,000	3,658,000	-	1,195,000	4,853,000	131,977,000
16	2016	43,058,000	33,223,000	50,748,000	-	1,734,000	128,763,000	3,737,000	-	1,218,000	4,955,000	133,718,000
17	2017	43,707,000	33,728,000	51,214,000	-	1,755,000	130,404,000	3,816,000	-	1,242,000	5,058,000	135,462,000
18	2018	44,356,000	34,231,000	51,679,000	-	1,776,000	132,042,000	3,894,000	-	1,266,000	5,160,000	137,202,000
19	2019	45,001,000	34,735,000	52,145,000	-	1,797,000	133,678,000	3,973,000	-	1,288,000	5,261,000	138,939,000
20	2020	45,646,000	35,238,000	52,611,000	-	1,818,000	135,313,000	4,051,000	-	1,313,000	5,364,000	140,677,000

(a) Represents multi-state integrated power system, of which the Company is a member.

(b) Sales to street and highway lighting, and other public authorities.

(c) Includes certain sales to Ohio Edison Company.

(d) Sales to cooperatives, private systems, and state agencies.

FORM FE1-1C
Part 1

FORM FE1-1C
Part 2

AMERICAN ELECTRIC POWER SYSTEM

SERVICE AREA ENERGY FORECAST (Megawatt Hours/Year)
REFLECTING DSM ADJUSTMENTS

	Year	(11) Total Sales	(12) Losses and Unaccounted For (e)	(13) Net Energy for Load (11)+(12)	(14) Plant Auxiliary Use	(15) Total Energy (13)+(14)	(16) Net (f) Generation
-5	1995	105,265,200	8,116,663	113,381,863	6,671,395	120,053,258	124,688,886
-4	1996	107,055,572	8,892,539	115,948,111	7,437,075	123,385,186	137,183,012
-3	1997	107,614,316	8,521,493	116,135,809	7,311,626	123,447,435	136,553,143
-2	1998	107,977,042	9,093,377	117,070,419	7,004,154	124,074,573	126,940,407
-1	1999	108,384,242	8,863,769	117,248,011	6,771,346	124,019,357	122,917,726
0	2000	106,031,000	9,141,000	115,172,000	7,603,000	122,775,000	139,267,000
1	2001	107,262,000	9,098,000	116,360,000	7,889,000	124,249,000	144,702,000
2	2002	109,097,000	9,149,000	118,246,000	7,971,000	126,217,000	146,240,000
3	2003	111,134,000	9,244,000	120,378,000	8,104,000	128,482,000	148,619,000
4	2004	112,870,000	9,322,000	122,192,000	8,223,000	130,415,000	150,758,000
5	2005	114,606,000	9,401,000	124,007,000	8,284,000	132,291,000	152,954,000
6	2006	116,342,000	9,480,000	125,822,000	8,371,000	134,193,000	155,625,000
7	2007	118,078,000	9,560,000	127,638,000	8,497,000	136,135,000	158,283,000
8	2008	119,815,000	9,640,000	129,455,000	8,606,000	138,063,000	160,727,000
9	2009	121,551,000	9,720,000	131,271,000	8,257,000	139,528,000	163,005,000
10	2010	123,290,000	9,798,000	133,088,000	8,224,000	141,312,000	160,492,000
11	2011	125,027,000	9,878,000	134,905,000	7,961,000	142,866,000	156,690,000
12	2012	126,763,000	9,959,000	136,722,000	8,008,000	144,730,000	156,257,000
13	2013	128,500,000	10,038,000	138,538,000	7,860,000	146,398,000	155,821,000
14	2014	130,238,000	10,117,000	140,355,000	7,678,000	148,033,000	155,910,000
15	2015	131,977,000	10,197,000	142,174,000	7,322,000	149,496,000	156,174,000
16	2016	133,718,000	10,278,000	143,996,000	7,211,000	151,207,000	156,602,000
17	2017	135,462,000	10,356,000	145,818,000	7,183,000	153,001,000	157,155,000
18	2018	137,202,000	10,438,000	147,640,000	7,094,000	154,734,000	157,844,000
19	2019	138,939,000	10,519,000	149,458,000	7,094,000	156,552,000	158,640,000
20	2020	140,677,000	10,597,000	151,274,000	7,111,000	158,385,000	159,541,000

(e) Transmission, transformer and other losses and energy unaccounted for.

(f) The amount of energy generated or estimated to be generated within the pool.
The difference between Column (16) Net Generation and Column (13) Net Energy for Load is the energy purchases or sales of the pool. If (16-13) is positive, the difference represents sales; if (16-13) is negative, the difference represents purchases.

FORM FE1-1C
Part 2

FORM FE1-3
Part 1

COLUMBUS SOUTHERN POWER COMPANY

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts) (a)
REFLECTING DSM ADJUSTMENTS

NATIVE LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	3,378	215	6.8	2,720	124	4.8
-4	1996	3,335	-43	-1.3	2,898	178	6.5
-3	1997	3,354	19	0.6	2,529	-369	-12.7
-2	1998	3,551	197	5.9	2,916	387	15.3
-1	1999	3,804	253	7.1	3,030	114	3.9
0	2000	3,758	-46	-1.2	3,051	21	0.7
1	2001	3,848	90	2.4	3,127	76	2.5
2	2002	3,937	89	2.3	3,196	69	2.2
3	2003	4,028	91	2.3	3,270	74	2.3
4	2004	4,122	94	2.3	3,345	75	2.3
5	2005	4,217	95	2.3	3,420	75	2.2
6	2006	4,312	95	2.3	3,494	74	2.2
7	2007	4,406	94	2.2	3,569	75	2.1
8	2008	4,501	95	2.2	3,644	75	2.1
9	2009	4,596	95	2.1	3,719	75	2.1
10	2010	4,691	95	2.1	3,793	74	2.0
11	2011	4,786	95	2.0	3,868	75	2.0
12	2012	4,880	94	2.0	3,943	75	1.9
13	2013	4,975	95	1.9	4,018	75	1.9
14	2014	5,070	95	1.9	4,093	75	1.9
15	2015	5,166	96	1.9	4,167	74	1.8
16	2016	5,260	94	1.8	4,243	76	1.8
17	2017	5,355	95	1.8	4,318	75	1.8
18	2018	5,450	95	1.8	4,393	75	1.7
19	2019	5,545	95	1.7	4,467	74	1.7
20	2020	5,640	95	1.7	4,546	79	1.8

(a) Company's service area is located solely in Ohio.
(b) Excludes interruptible load.
(c) Winter load reference is to peak loads which occur in the following winter.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.

FORM FE1-3
Part 2

COLUMBUS SOUTHERN POWER COMPANY

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts) (a)
REFLECTING DSM ADJUSTMENTS

INTERNAL LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	3,378	199	6.3	2,729	118	4.5
-4	1996	3,335	-43	-1.3	2,917	188	6.9
-3	1997	3,354	19	0.6	2,547	-370	-12.7
-2	1998	3,551	197	5.9	2,931	384	15.1
-1	1999	3,804	253	7.1	3,036	105	3.6
0	2000	3,782	-22	-0.6	3,078	42	1.4
1	2001	3,872	90	2.4	3,154	76	2.5
2	2002	3,961	89	2.3	3,223	69	2.2
3	2003	4,052	91	2.3	3,297	74	2.3
4	2004	4,146	94	2.3	3,372	75	2.3
5	2005	4,241	95	2.3	3,447	75	2.2
6	2006	4,336	95	2.2	3,521	74	2.1
7	2007	4,430	94	2.2	3,596	75	2.1
8	2008	4,525	95	2.1	3,671	75	2.1
9	2009	4,620	95	2.1	3,746	75	2.0
10	2010	4,715	95	2.1	3,820	74	2.0
11	2011	4,810	95	2.0	3,895	75	2.0
12	2012	4,904	94	2.0	3,970	75	1.9
13	2013	4,999	95	1.9	4,045	75	1.9
14	2014	5,094	95	1.9	4,120	75	1.9
15	2015	5,190	96	1.9	4,194	74	1.8
16	2016	5,284	94	1.8	4,270	76	1.8
17	2017	5,379	95	1.8	4,345	75	1.8
18	2018	5,474	95	1.8	4,420	75	1.7
19	2019	5,569	95	1.7	4,494	74	1.7
20	2020	5,664	95	1.7	4,573	79	1.8

(a) Company's service area is located solely in Ohio.
(b) Includes interruptible load.
(c) Winter load reference is to peak loads which occur in the following winter.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.

FORM FE1-3A
Part 1

OHIO POWER COMPANY
(OHIO PORTION) (a)

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts)
REFLECTING DSM ADJUSTMENTS

NATIVE LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	5,264	134	2.6	4,978	56	1.1
-4	1996	5,202	-62	-1.2	4,867	-111	-2.2
-3	1997	5,140	-62	-1.2	4,683	-184	-3.8
-2	1998	5,329	189	3.7	4,982	299	6.4
-1	1999	5,237	-92	-1.7	4,812	-170	-3.4
0	2000	4,458	-779	-14.9	3,977	-835	-17.4
1	2001	4,518	60	1.3	4,042	65	1.6
2	2002	4,578	60	1.3	4,100	58	1.4
3	2003	4,652	74	1.6	4,143	43	1.0
4	2004	4,707	55	1.2	4,184	41	1.0
5	2005	4,762	55	1.2	4,227	43	1.0
6	2006	4,819	57	1.2	4,269	42	1.0
7	2007	4,874	55	1.1	4,311	42	1.0
8	2008	4,930	56	1.1	4,353	42	1.0
9	2009	4,985	55	1.1	4,397	44	1.0
10	2010	5,042	57	1.1	4,439	42	1.0
11	2011	5,100	58	1.2	4,481	42	0.9
12	2012	5,155	55	1.1	4,523	42	0.9
13	2013	5,211	56	1.1	4,567	44	1.0
14	2014	5,266	55	1.1	4,610	43	0.9
15	2015	5,323	57	1.1	4,653	43	0.9
16	2016	5,378	55	1.0	4,696	43	0.9
17	2017	5,434	56	1.0	4,739	43	0.9
18	2018	5,490	56	1.0	4,783	44	0.9
19	2019	5,547	57	1.0	4,825	42	0.9
20	2020	5,603	56	1.0	4,868	43	0.9

(a) Excludes Sales to Wheeling Power Company, an AEP affiliate.
(b) Excludes interruptible load.
(c) Winter load reference is to peak loads which occur in the following winter.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.

FORM FE1-3A
Part 2

OHIO POWER COMPANY
(OHIO PORTION) (a)

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts)
REFLECTING DSM ADJUSTMENTS

INTERNAL LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	5,378	215	4.2	5,122	141	2.8
-4	1996	5,291	-87	-1.6	4,980	-142	-2.8
-3	1997	5,289	-2	0.0	4,938	-42	-0.8
-2	1998	5,363	74	1.4	5,211	273	5.5
-1	1999	5,423	60	1.1	4,952	-259	-5.0
0	2000	4,986	-437	-8.1	4,513	-439	-8.9
1	2001	4,962	-24	-0.5	4,523	10	0.2
2	2002	5,022	60	1.2	4,581	58	1.3
3	2003	5,096	74	1.5	4,624	43	0.9
4	2004	5,151	55	1.1	4,665	41	0.9
5	2005	5,206	55	1.1	4,708	43	0.9
6	2006	5,263	57	1.1	4,750	42	0.9
7	2007	5,318	55	1.0	4,792	42	0.9
8	2008	5,374	56	1.1	4,834	42	0.9
9	2009	5,429	55	1.0	4,878	44	0.9
10	2010	5,486	57	1.0	4,920	42	0.9
11	2011	5,544	58	1.1	4,962	42	0.9
12	2012	5,599	55	1.0	5,004	42	0.8
13	2013	5,655	56	1.0	5,048	44	0.9
14	2014	5,710	55	1.0	5,091	43	0.9
15	2015	5,767	57	1.0	5,134	43	0.8
16	2016	5,822	55	1.0	5,177	43	0.8
17	2017	5,878	56	1.0	5,220	43	0.8
18	2018	5,934	56	1.0	5,264	44	0.8
19	2019	5,991	57	1.0	5,306	42	0.8
20	2020	6,047	56	0.9	5,349	43	0.8

(a) Excludes Sales to Wheeling Power Company, an AEP affiliate.
(b) Includes interruptible load.
(c) Winter load reference is to peak loads which occur in the following winter.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.

FORM FE1-3B
Part 1

OHIO POWER COMPANY
(TOTAL SYSTEM) (a)

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts)
REFLECTING DSM ADJUSTMENTS

NATIVE LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	5,527	150	2.8	5,229	48	0.9
-4	1996	5,445	-82	-1.5	5,128	-101	-1.9
-3	1997	5,357	-88	-1.6	4,902	-226	-4.4
-2	1998	5,547	190	3.5	5,216	314	6.4
-1	1999	5,498	-49	-0.9	5,051	-165	-3.2
0	2000	4,703	-795	-14.5	4,226	-825	-16.3
1	2001	4,759	56	1.2	4,294	68	1.6
2	2002	4,823	64	1.3	4,356	62	1.4
3	2003	4,900	77	1.6	4,401	45	1.0
4	2004	4,958	58	1.2	4,445	44	1.0
5	2005	5,016	58	1.2	4,490	45	1.0
6	2006	5,075	59	1.2	4,535	45	1.0
7	2007	5,133	58	1.1	4,580	45	1.0
8	2008	5,192	59	1.1	4,625	45	1.0
9	2009	5,250	58	1.1	4,671	46	1.0
10	2010	5,309	59	1.1	4,716	45	1.0
11	2011	5,369	60	1.1	4,761	45	1.0
12	2012	5,427	58	1.1	4,806	45	0.9
13	2013	5,486	59	1.1	4,852	46	1.0
14	2014	5,544	58	1.1	4,897	45	0.9
15	2015	5,603	59	1.1	4,943	46	0.9
16	2016	5,661	58	1.0	4,989	46	0.9
17	2017	5,720	59	1.0	5,035	46	0.9
18	2018	5,779	59	1.0	5,081	46	0.9
19	2019	5,838	59	1.0	5,126	45	0.9
20	2020	5,897	59	1.0	5,172	46	0.9

(a) Includes sales to Wheeling Power Company, an AEP affiliate.
(b) Excludes interruptible load.
(c) Winter load reference is to peak loads which occur in the following winter.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.

FORM FE1-3B
Part 2

OHIO POWER COMPANY
(TOTAL SYSTEM) (a)

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts)
REFLECTING DSM ADJUSTMENTS

INTERNAL LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	5,641	231	4.3	5,373	133	2.5
-4	1996	5,547	-94	-1.7	5,254	-119	-2.2
-3	1997	5,519	-28	-0.5	5,177	-77	-1.5
-2	1998	5,588	69	1.3	5,465	288	5.6
-1	1999	5,705	117	2.1	5,212	-253	-4.6
0	2000	5,245	-460	-8.1	4,776	-436	-8.4
1	2001	5,217	-28	-0.5	4,789	13	0.3
2	2002	5,281	64	1.2	4,851	62	1.3
3	2003	5,358	77	1.5	4,896	45	0.9
4	2004	5,416	58	1.1	4,940	44	0.9
5	2005	5,474	58	1.1	4,985	45	0.9
6	2006	5,533	59	1.1	5,030	45	0.9
7	2007	5,591	58	1.0	5,075	45	0.9
8	2008	5,650	59	1.1	5,120	45	0.9
9	2009	5,708	58	1.0	5,166	46	0.9
10	2010	5,767	59	1.0	5,211	45	0.9
11	2011	5,827	60	1.0	5,256	45	0.9
12	2012	5,885	58	1.0	5,301	45	0.9
13	2013	5,944	59	1.0	5,347	46	0.9
14	2014	6,002	58	1.0	5,392	45	0.8
15	2015	6,061	59	1.0	5,438	46	0.9
16	2016	6,119	58	1.0	5,484	46	0.8
17	2017	6,178	59	1.0	5,530	46	0.8
18	2018	6,237	59	1.0	5,576	46	0.8
19	2019	6,296	59	0.9	5,621	45	0.8
20	2020	6,355	59	0.9	5,667	46	0.8

(a) Includes sales to Wheeling Power Company, an AEP affiliate.
(b) Includes interruptible load.
(c) Winter load reference is to peak loads which occur in the following winter.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.

FORM FE1-3C

Part 1

AMERICAN ELECTRIC POWER SYSTEM (a)

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts)
REFLECTING DSM ADJUSTMENTS

NATIVE LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1994	19,431	1,579	8.8	19,314	854	4.6
-4	1995	18,721	-710	-3.7	19,101	-213	-1.1
-3	1996	18,792	71	0.4	17,362	-1,739	-9.1
-2	1997	19,365	573	3.0	18,386	1,024	5.9
-1	1998	19,847	482	2.5	18,918	532	2.9
0	1999	18,921	-926	-4.7	18,413	-505	-2.7
1	2000	19,259	338	1.8	18,777	364	2.0
2	2001	19,598	339	1.8	19,099	322	1.7
3	2002	19,965	367	1.9	19,398	299	1.6
4	2003	20,288	323	1.6	19,697	299	1.5
5	2004	20,612	324	1.6	19,999	302	1.5
6	2005	20,936	324	1.6	20,300	301	1.5
7	2006	21,260	324	1.5	20,602	302	1.5
8	2007	21,584	324	1.5	20,904	302	1.5
9	2008	21,908	324	1.5	21,206	302	1.4
10	2009	22,232	324	1.5	21,508	302	1.4
11	2010	22,556	324	1.5	21,809	301	1.4
12	2011	22,880	324	1.4	22,112	303	1.4
13	2012	23,204	324	1.4	22,414	302	1.4
14	2013	23,528	324	1.4	22,716	302	1.3
15	2014	23,852	324	1.4	23,023	307	1.4
16	2015	24,177	325	1.4	23,329	306	1.3
17	2016	24,502	325	1.3	23,636	307	1.3
18	2017	24,827	325	1.3	23,941	305	1.3
19	2018	25,152	325	1.3	24,243	302	1.3
20	2019	25,476	324	1.3	24,556	313	1.3

(a) Represents multi-state integrated power system, of which the Company is a member.

(b) Excludes interruptible load.

(c) Winter load reference is to peak loads which occur in the following winter.

(d) Difference between reporting year and previous year.

(e) Difference expressed as a percent of previous year.

FORM FE1-3C
Part 2

AMERICAN ELECTRIC POWER SYSTEM (a)

SYSTEM SEASONAL PEAK LOAD FORECAST (Megawatts)
REFLECTING DSM ADJUSTMENTS

INTERNAL LOAD (b)

		Summer			Winter (c)		
	Year	Load	Change (d)	Percent Change (e)	Load	Change (d)	Percent Change (e)
-5	1995	19,516	1,446	8.0	19,557	924	5.0
-4	1996	18,864	-652	-3.3	19,381	-176	-0.9
-3	1997	19,119	255	1.4	17,841	-1,540	-7.9
-2	1998	19,414	295	1.5	18,546	705	4.0
-1	1999	19,952	538	2.8	19,167	621	3.3
0	2000	19,585	-367	-1.8	19,084	-83	-0.4
1	2001	19,839	254	1.3	19,367	283	1.5
2	2002	20,178	339	1.7	19,689	322	1.7
3	2003	20,545	367	1.8	19,988	299	1.5
4	2004	20,868	323	1.6	20,287	299	1.5
5	2005	21,192	324	1.6	20,589	302	1.5
6	2006	21,516	324	1.5	20,890	301	1.5
7	2007	21,840	324	1.5	21,192	302	1.4
8	2008	22,164	324	1.5	21,494	302	1.4
9	2009	22,488	324	1.5	21,796	302	1.4
10	2010	22,812	324	1.4	22,098	302	1.4
11	2011	23,136	324	1.4	22,399	301	1.4
12	2012	23,460	324	1.4	22,702	303	1.4
13	2013	23,784	324	1.4	23,004	302	1.3
14	2014	24,108	324	1.4	23,306	302	1.3
15	2015	24,432	324	1.3	23,613	307	1.3
16	2016	24,757	325	1.3	23,919	306	1.3
17	2017	25,082	325	1.3	24,226	307	1.3
18	2018	25,407	325	1.3	24,531	305	1.3
19	2019	25,732	325	1.3	24,833	302	1.2
20	2020	26,056	324	1.3	25,146	313	1.3

(a) Represents multi-state integrated power system, of which the Company is a member.
(b) Includes interruptible load.
(c) Winter load reference is to peak loads which occur in the following winter.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.

FORM FE1-4

COLUMBUS SOUTHERN POWER COMPANY

RANGE OF FORECASTS (a)
REFLECTING DSM ADJUSTMENTS

		Energy Forecast (MWH/yr) (Net Energy for Load)			Peak Load Forecast (MW) (Summer)		
	Year	Lowest	Most Likely(b)	Highest	Lowest	Most Likely(c)	Highest
0	2000	18,088,000	18,321,000	18,476,000	3,734	3,782	3,812
1	2001	18,545,000	18,836,000	18,998,000	3,812	3,872	3,905
2	2002	19,006,000	19,341,000	19,665,000	3,892	3,961	4,027
3	2003	19,445,000	19,812,000	20,248,000	3,977	4,052	4,141
4	2004	19,873,000	20,304,000	20,853,000	4,058	4,146	4,258
5	2005	20,308,000	20,796,000	21,501,000	4,142	4,241	4,385
6	2006	20,722,000	21,288,000	22,078,000	4,221	4,336	4,497
7	2007	21,140,000	21,781,000	22,651,000	4,300	4,430	4,607
8	2008	21,551,000	22,274,000	23,220,000	4,378	4,525	4,717
9	2009	21,944,000	22,766,000	23,797,000	4,453	4,620	4,829
10	2010	22,323,000	23,260,000	24,364,000	4,525	4,715	4,939
11	2011	22,706,000	23,753,000	24,930,000	4,598	4,810	5,048
12	2012	23,091,000	24,246,000	25,486,000	4,670	4,904	5,155
13	2013	23,471,000	24,739,000	26,043,000	4,743	4,999	5,262
14	2014	23,835,000	25,232,000	26,599,000	4,812	5,094	5,370
15	2015	24,149,000	25,726,000	27,204,000	4,872	5,190	5,488
16	2016	24,473,000	26,219,000	27,813,000	4,932	5,284	5,605
17	2017	24,830,000	26,713,000	28,437,000	5,000	5,379	5,726
18	2018	25,177,000	27,207,000	29,093,000	5,066	5,474	5,853
19	2019	25,516,000	27,701,000	29,739,000	5,130	5,569	5,979
20	2020	25,828,000	28,193,000	30,409,000	5,189	5,664	6,109

(a) Company's service area is located solely in Ohio.

(b) Same as Column 13 on Form FE1-1.

(c) Same as highest of Summer or Winter Internal Load on Form FE1-3.

FORM FE1-4A

OHIO POWER COMPANY
(OHIO PORTION) (a)

RANGE OF FORECASTS
REFLECTING DSM ADJUSTMENTS

		Energy Forecast (MWH/yr) (Net Energy for Load)			Peak Load Forecast (MW) (Summer)		
	Year	Lowest	Most Likely(b)	Highest	Lowest	Most Likely(c)	Highest
0	2000	30,603,000	30,998,000	31,336,000	4,900	4,986	5,003
1	2001	30,103,000	30,575,000	30,838,000	4,863	4,962	4,983
2	2002	30,288,000	30,822,000	31,338,000	4,914	5,022	5,083
3	2003	30,691,000	31,270,000	31,957,000	4,979	5,096	5,185
4	2004	30,888,000	31,558,000	32,411,000	5,019	5,151	5,267
5	2005	31,103,000	31,849,000	32,928,000	5,062	5,206	5,359
6	2006	31,285,000	32,140,000	33,333,000	5,100	5,263	5,433
7	2007	31,477,000	32,432,000	33,727,000	5,138	5,318	5,505
8	2008	31,662,000	32,723,000	34,113,000	5,177	5,374	5,577
9	2009	31,822,000	33,015,000	34,510,000	5,210	5,429	5,649
10	2010	31,965,000	33,307,000	34,888,000	5,242	5,486	5,722
11	2011	32,118,000	33,599,000	35,263,000	5,276	5,544	5,793
12	2012	32,274,000	33,889,000	35,621,000	5,309	5,599	5,859
13	2013	32,429,000	34,181,000	35,982,000	5,341	5,655	5,926
14	2014	32,565,000	34,473,000	36,341,000	5,371	5,710	5,993
15	2015	32,635,000	34,766,000	36,764,000	5,389	5,767	6,071
16	2016	32,725,000	35,060,000	37,193,000	5,410	5,822	6,148
17	2017	32,860,000	35,353,000	37,634,000	5,439	5,878	6,230
18	2018	32,987,000	35,646,000	38,117,000	5,468	5,934	6,317
19	2019	33,104,000	35,939,000	38,583,000	5,493	5,991	6,403
20	2020	33,190,000	36,230,000	39,077,000	5,515	6,047	6,494

(a) Excludes Sales to Wheeling Power Company, an AEP affiliate.

(b) Same as Column 13 on Form FE1-1A.

(c) Same as highest of Summer or Winter Internal Load on Form FE1-3A.

(d) Winter load reference is to peak loads which occur in the following Winter.

FORM FE1-4B

OHIO POWER COMPANY
(TOTAL SYSTEM) (a)

RANGE OF FORECASTS
REFLECTING DSM ADJUSTMENTS

		Energy Forecast (MWH/yr) (Net Energy for Load)			Peak Load Forecast (MW) (Summer)		
	Year	Lowest	Most Likely(b)	Highest	Lowest	Most Likely(c)	Highest
0	2000	32,338,000	32,755,000	33,107,000	5,178	5,245	5,287
1	2001	31,772,000	32,270,000	32,548,000	5,136	5,217	5,262
2	2002	31,963,000	32,526,000	33,071,000	5,190	5,281	5,369
3	2003	32,375,000	32,986,000	33,711,000	5,259	5,358	5,476
4	2004	32,574,000	33,281,000	34,181,000	5,301	5,416	5,563
5	2005	32,791,000	33,578,000	34,716,000	5,346	5,474	5,660
6	2006	32,975,000	33,876,000	35,133,000	5,386	5,533	5,738
7	2007	33,168,000	34,174,000	35,539,000	5,426	5,591	5,814
8	2008	33,354,000	34,472,000	35,936,000	5,467	5,650	5,890
9	2009	33,514,000	34,770,000	36,344,000	5,502	5,708	5,966
10	2010	33,656,000	35,069,000	36,734,000	5,535	5,767	6,041
11	2011	33,808,000	35,367,000	37,119,000	5,570	5,827	6,116
12	2012	33,964,000	35,664,000	37,487,000	5,605	5,885	6,186
13	2013	34,119,000	35,962,000	37,857,000	5,639	5,944	6,257
14	2014	34,254,000	36,261,000	38,226,000	5,670	6,002	6,327
15	2015	34,319,000	36,560,000	38,661,000	5,689	6,061	6,409
16	2016	34,405,000	36,860,000	39,102,000	5,711	6,119	6,491
17	2017	34,540,000	37,160,000	39,558,000	5,742	6,178	6,577
18	2018	34,665,000	37,459,000	40,056,000	5,772	6,237	6,669
19	2019	34,780,000	37,759,000	40,537,000	5,799	6,296	6,759
20	2020	34,863,000	38,056,000	41,047,000	5,822	6,355	6,855

(a) Includes sales to Wheeling Power Company, an AEP affiliate.

(b) Same as Column 13 on Form FE1-1B.

(c) Same as highest of Summer or Winter Internal Load on Form FE1-3B.

(d) Winter load reference is to peak loads which occur in the following Winter.

FORM FE1-4C

AMERICAN ELECTRIC POWER SYSTEM (a)

RANGE OF FORECASTS
REFLECTING DSM ADJUSTMENTS

		Energy Forecast (MWH/yr) (Net Energy for Load)			Peak Load Forecast (MW) (Summer)		
	Year	Lowest	Most Likely (b)	Highest	Lowest	Most Likely(c)	Highest
0	2000	113,706,000	115,172,000	116,093,000	19,336	19,585	19,742
1	2001	114,564,000	116,360,000	117,363,000	19,533	19,839	20,010
2	2002	116,199,000	118,246,000	120,226,000	19,829	20,178	20,516
3	2003	118,688,000	120,378,000	123,025,000	20,164	20,545	20,997
4	2004	119,595,000	122,192,000	125,497,000	20,425	20,868	21,432
5	2005	121,100,000	124,007,000	128,209,000	20,695	21,192	21,910
6	2006	122,474,000	125,822,000	130,491,000	20,944	21,516	22,314
7	2007	123,880,000	127,638,000	132,735,000	21,197	21,840	22,712
8	2008	125,255,000	129,455,000	134,953,000	21,445	22,164	23,105
9	2009	126,531,000	131,271,000	137,213,000	21,676	22,488	23,506
10	2010	127,725,000	133,088,000	139,407,000	21,893	22,812	23,895
11	2011	128,958,000	134,905,000	141,589,000	22,116	23,136	24,282
12	2012	130,207,000	136,722,000	143,712,000	22,342	23,460	24,659
13	2013	131,438,000	138,538,000	145,839,000	22,565	23,784	25,037
14	2014	132,587,000	140,355,000	147,959,000	22,774	24,108	25,414
15	2015	133,458,000	142,174,000	150,343,000	22,934	24,432	25,836
16	2016	134,406,000	143,996,000	152,752,000	23,108	24,757	26,262
17	2017	135,539,000	145,818,000	155,228,000	23,314	25,082	26,701
18	2018	136,627,000	147,640,000	157,875,000	23,512	25,407	27,168
19	2019	137,668,000	149,458,000	160,453,000	23,702	25,732	27,625
20	2020	138,582,000	151,274,000	163,165,000	23,870	26,056	28,140

(a) Represents multi-state integrated power system, of which the Company is a member.

(b) Same as Column 13 on Form FE1-1C.

(c) Same as highest of Summer or Winter Internal Load on Form FE1-3C.

(d) Winter load reference is to peak loads which occur in the following Winter.

FORM FE1-5
Part 1

COLUMBUS SOUTHERN POWER AND AMERICAN ELECTRIC POWER SYSTEM

NET MONTHLY ENERGY FORECAST (Thousands of Megawatt-Hours)
REFLECTING DSM ADJUSTMENTS

Year 0 (2000)	OHIO (a)	SYSTEM (a)	POOL (b) AEP System
January (c)	1,652		10,708
February (c)	1,449		9,424
March	1,498		9,857
April	1,345	Same as	8,736
May	1,384	"Ohio"	8,831
June	1,582	column	9,406
July	1,741		10,090
August	1,716		10,144
September	1,490		9,174
October	1,403		8,989
November	1,431		9,224
December	1,607		10,338
Year 1 (2001)			
January	1,680		10,776
February	1,533		9,809
March	1,544		9,953
April	1,377	Same as	8,814
May	1,420	"Ohio"	8,888
June	1,625	column	9,532
July	1,789		10,217
August	1,759		10,242
September	1,542		9,296
October	1,441		9,072
November	1,472		9,307
December	1,656		10,456

(a) Company's service area is located solely in Ohio.

(b) Represents multi-state integrated power system, of which the Company is a member.

(c) Actual

FORM FE1-5
Part 2

COLUMBUS SOUTHERN POWER AND AMERICAN ELECTRIC POWER SYSTEM

NET MONTHLY INTERNAL PEAK LOAD FORECAST (Megawatts)
REFLECTING DSM ADJUSTMENTS

Year 0 (2000)	OHIO (a)	SYSTEM (a)	POOL (b) AEP System
January (c)	3,036		19,167
February (c)	2,671		17,052
March	2,648		17,081
April	2,276	Same as	15,276
May	2,909	"Ohio"	16,057
June	3,488	column	18,591
July	3,687		19,185
August	3,782		19,585
September	3,265		17,938
October	2,225		14,788
November	2,576		16,433
December	2,877		17,913
Year 1 (2001)			
January	3,078		19,084
February	2,918		18,288
March	2,720		17,259
April	2,320	Same as	15,415
May	2,990	"Ohio"	16,232
June	3,577	column	18,689
July	3,786		19,471
August	3,872		19,839
September	3,364		18,034
October	2,277		14,914
November	2,636		16,574
December	2,951		18,117

(a) Company's service area is located solely in Ohio.

(b) Represents multi-state integrated power system, of which the Company is a member.

(c) Actual

FORM FE1-5
Part 1

OHIO POWER AND AMERICAN ELECTRIC POWER SYSTEM

NET MONTHLY ENERGY FORECAST (Thousands of Megawatt-Hours)
REFLECTING DSM ADJUSTMENTS

Year 0 (2000)	OHIO (a)	SYSTEM (b)	POOL (c) AEP System
January (d)	2,700	2,868	10,708
February (d)	2,472	2,632	9,424
March	2,695	2,850	9,857
April	2,431	2,574	8,736
May	2,471	2,614	8,831
June	2,514	2,655	9,406
July	2,638	2,791	10,090
August	2,694	2,845	10,144
September	2,478	2,614	9,174
October	2,457	2,596	8,989
November	2,493	2,633	9,224
December	2,712	2,866	10,338
Year 1 (2001)			
January	2,777	2,931	10,776
February	2,547	2,685	9,809
March	2,643	2,792	9,953
April	2,392	2,532	8,814
May	2,404	2,541	8,888
June	2,501	2,640	9,532
July	2,629	2,777	10,217
August	2,658	2,803	10,242
September	2,457	2,588	9,296
October	2,425	2,557	9,072
November	2,455	2,589	9,307
December	2,690	2,838	10,456

(a) Excludes sales to Wheeling Power Company, an AEP affiliate.

(b) Includes sales to Wheeling Power Company, an AEP affiliate.

(c) Represents multi-state integrated power system, of which the Company is a member.

(d) Actual

FORM FE1-5
Part 2

OHIO POWER AND AMERICAN ELECTRIC POWER SYSTEM

NET MONTHLY INTERNAL PEAK LOAD FORECAST (Megawatts)
REFLECTING DSM ADJUSTMENTS

Year 0 (2000)	OHIO (a)	SYSTEM (b)	POOL (c) AEP System
January (d)	4,491	4,756	19,167
February (d)	4,318	4,587	17,052
March	4,525	4,779	17,081
April	4,174	4,421	15,276
May	4,262	4,504	16,057
June	4,792	5,039	18,591
July	4,838	5,095	19,185
August	4,986	5,245	19,585
September	4,661	4,899	17,938
October	4,049	4,279	14,788
November	4,332	4,572	16,433
December	4,523	4,777	17,913
Year 1 (2001)			
January	4,488	4,751	19,084
February	4,502	4,754	18,288
March	4,460	4,707	17,259
April	4,125	4,370	15,415
May	4,186	4,422	16,232
June	4,769	5,016	18,689
July	4,846	5,101	19,471
August	4,962	5,217	19,839
September	4,605	4,840	18,034
October	4,006	4,229	14,914
November	4,295	4,528	16,574
December	4,499	4,748	18,117

(a) Excludes sales to Wheeling Power Company, an AEP affiliate.

(b) Includes sales to Wheeling Power Company, an AEP affiliate.

(c) Represents multi-state integrated power system, of which the Company is a member.

(d) Actual

COLUMBUS SOUTHERN POWER COMPANY (A)
FORM FE1-5 PART 3
MONTHLY FORECAST OF PEAK LOAD AND RESOURCES, 2000 - 2001
REFLECTING DSM ADJUSTMENTS
(MW)

Current Calendar Year (2000)

	Jan.(B)	Feb.(B)	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Net Demonstrated Capability	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595
Net Seasonal Capability	2,595	2,595	2,595	2,595	2,565	2,564	2,564	2,564	2,564	2,594	2,595	2,595
Purchases	50	47	32	32	50	56	56	56	47	0	0	0
Sales	44	45	37	37	37	37	37	36	36	36	36	36
Available Capability	2,601	2,597	2,590	2,590	2,578	2,583	2,583	2,584	2,575	2,558	2,559	2,559
Native Load	3,030	2,656	2,621	2,249	2,885	3,464	3,663	3,758	3,241	2,198	2,549	2,850
Available Reserve	(429)	(59)	(31)	341	(307)	(881)	(1,080)	(1,174)	(666)	360	10	(291)
Internal Load (C)	3,036	2,671	2,648	2,276	2,909	3,488	3,687	3,782	3,265	2,225	2,576	2,877
Reserve	(435)	(74)	(58)	314	(331)	(905)	(1,104)	(1,198)	(690)	333	(17)	(318)

Next Calendar Year (2001)

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Net Demonstrated Capability	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595
Net Seasonal Capability	2,595	2,595	2,595	2,595	2,565	2,564	2,564	2,564	2,564	2,594	2,595	2,595
Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Sales	37	37	37	37	37	37	37	36	36	36	36	36
Available Capability	2,558	2,558	2,558	2,558	2,528	2,527	2,527	2,528	2,528	2,558	2,559	2,559
Native Load	3,051	2,891	2,693	2,293	2,966	3,553	3,762	3,848	3,340	2,250	2,609	2,924
Available Reserve	(493)	(333)	(135)	265	(438)	(1,026)	(1,235)	(1,320)	(812)	308	(50)	(365)
Internal Load (C)	3,078	2,918	2,720	2,320	2,990	3,577	3,786	3,872	3,364	2,277	2,636	2,951
Reserve	(520)	(360)	(162)	238	(462)	(1,050)	(1,259)	(1,344)	(836)	281	(77)	(392)

Notes: (A) Inasmuch as Columbus Southern Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

(B) Actual data. The Internal Load does not reflect the impact of demand-side-management programs or customer generation.

(C) Equals Native Load plus Interruptible Load.

OHIO POWER COMPANY (A)
FORM FE1-5 PART 3
MONTHLY FORECAST OF PEAK LOAD AND RESOURCES, 2000 - 2001
REFLECTING DSM ADJUSTMENTS
(MW)

Current Calendar Year (2000)

	Jan.(B)	Feb.(B)	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Net Demonstrated Capability	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520
Net Seasonal Capability	8,520	8,520	8,520	8,520	8,470	8,445	8,395	8,395	8,445	8,490	8,520	8,520
Purchases	212	164	113	113	173	195	195	195	165	0	0	0
Sales	67	77	273	273	273	273	273	271	271	271	271	271
Available Capability	8,665	8,607	8,360	8,360	8,370	8,367	8,317	8,319	8,339	8,219	8,249	8,249
Native Load	4,565	4,411	4,154	3,796	3,890	4,471	4,553	4,703	4,285	3,654	3,947	4,201
Available Reserve	4,100	4,196	4,206	4,564	4,480	3,896	3,764	3,616	4,054	4,565	4,302	4,048
Internal Load (C)	4,756	4,587	4,779	4,421	4,504	5,039	5,095	5,245	4,899	4,279	4,572	4,777
Reserve	3,909	4,020	3,581	3,939	3,866	3,328	3,222	3,074	3,440	3,940	3,677	3,472

Next Calendar Year (2001)

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Net Demonstrated Capability	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520
Net Seasonal Capability	8,520	8,520	8,520	8,520	8,470	8,445	8,395	8,395	8,445	8,490	8,520	8,520
Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Sales	320	320	320	320	320	320	320	320	320	320	320	320
Available Capability	8,200	8,200	8,200	8,200	8,150	8,125	8,075	8,075	8,125	8,170	8,200	8,200
Native Load	4,282	4,259	4,163	3,826	3,892	4,558	4,644	4,759	4,356	3,685	3,984	4,253
Available Reserve	3,918	3,941	4,037	4,374	4,258	3,567	3,431	3,316	3,769	4,485	4,216	3,947
Internal Load (C)	4,751	4,754	4,707	4,370	4,422	5,016	5,102	5,217	4,840	4,229	4,528	4,748
Reserve	3,449	3,446	3,493	3,830	3,728	3,109	2,973	2,858	3,285	3,941	3,672	3,452

Notes: (A) Inasmuch as Ohio Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

(B) Actual data. The Internal Load does not reflect the impact of demand-side-management programs or customer generation.

(C) Equals Native Load plus Interruptible Load.

AMERICAN ELECTRIC POWER SYSTEM
FORM FE1-5 PART 3
MONTHLY FORECAST OF PEAK LOAD AND RESOURCES, 2000 - 2001
REFLECTING DSM ADJUSTMENTS
(MW)

Current Calendar Year (2000)

	Jan.(A)	Feb.(A)	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Net Demonstrated Capability	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509
Net Seasonal Capability	23,509	23,509	23,509	23,514	23,372	23,278	23,203	23,203	23,237	23,399	23,497	23,509
Purchases	516	468	316	316	487	547	547	547	463	0	0	0
Sales	257	257	436	436	436	436	436	436	436	436	436	436
Available Capability	23,768	23,720	23,389	23,394	23,423	23,389	23,314	23,314	23,264	22,963	23,061	23,073
Native Load	18,918	16,574	16,071	14,266	15,026	17,736	18,521	18,921	16,907	13,778	15,423	17,051
Available Reserve	4,850	7,146	7,318	9,128	8,397	5,653	4,793	4,393	6,357	9,185	7,638	6,022
Internal Load (B)	19,167	17,052	17,081	15,276	16,057	18,591	19,185	19,585	17,938	14,788	16,433	17,913
Reserve	4,601	6,668	6,308	8,118	7,366	4,798	4,129	3,729	5,326	8,175	6,628	5,160

Next Calendar Year (2001)

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Net Demonstrated Capability	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509
Net Seasonal Capability	23,509	23,509	23,509	23,514	23,372	23,278	23,203	23,203	23,237	23,399	23,497	23,509
Purchases	24	27	28	15	30	20	15	16	21	30	33	27
Sales	491	491	491	491	491	491	491	491	491	491	491	491
Available Capability	23,042	23,045	23,046	23,038	22,911	22,807	22,727	22,728	22,767	22,938	23,039	23,045
Native Load	18,494	17,507	16,330	14,486	15,285	18,109	18,891	19,259	17,263	13,985	15,645	17,336
Available Reserve	4,548	5,538	6,716	8,552	7,626	4,698	3,836	3,469	5,504	8,953	7,394	5,709
Internal Load (B)	19,084	18,288	17,259	15,415	16,232	18,689	19,471	19,839	18,034	14,914	16,574	18,117
Reserve	3,958	4,757	5,787	7,623	6,679	4,118	3,256	2,889	4,733	8,024	6,465	4,928

Notes: (A) Actual data. The Internal Load does not reflect the impact of demand-side-management programs or customer generation.

(B) Equals Native Load plus Interruptible Load.

FORM FE1-5
Part 3

CSP/OPCo 2000

3. ELECTRICITY RESOURCE FORECAST FORMS

FORM FE2-1

COLUMBUS SOUTHERN POWER COMPANY

SUMMARY OF EXISTING ELECTRIC GENERATION FACILITIES (as of 1/1/00)

Station Name and Location	Unit Numbers	Type of Units	Date of First On-Line Service	Expected Retirement Date	Generation Capability Summer (MW)	Generation Capability Winter (MW)	Environmental Protection Measures
Picway Lockbourne, Ohio	5	Steam, Coal-Fired	11-8-55	Unknown	90	100	See Sheet 2
Conesville Conesville, Ohio	1	Steam, Coal-Fired	2-16-59	Unknown	115	125	See Sheet 2
	2		12-23-57	Unknown	115	125	
	3		10-1-62	Unknown	165	165	
	4		6-8-73	Unknown	339(1)	339(1)	
	5		11-24-76	Unknown	375	375	
	6		6-1-78	Unknown	375	375	
J.M. Stuart Aberdeen, Ohio	1	Steam, Coal-Fired	5-17-71	Unknown	152(1)	152(1)	(2)
	2		10-11-70	Unknown	152(1)	152(1)	
	3		5-10-72	Unknown	152(1)	152(1)	
	4		6-21-74	Unknown	152(1)	152(1)	
W. C. Beckjord New Richmond, Ohio	6	Steam, Coal-Fired	7-1-69	Unknown	52(1)	53(1)	(3)
W. H. Zimmer Moscow, Ohio	1	Steam, Coal-Fired	3-30-91	Unknown	330(1)	330(1)	(3)

Note: (1) CSP's share of jointly owned units. See page 3 of this form for total unit capabilities and participating utilities.
(2) See DP&L Long-Term Forecast Report.
(3) See Cinergy Long-Term Forecast Report.

FORM FE2-1

COLUMBUS SOUTHERN POWER COMPANY

SUMMARY OF EXISTING ELECTRIC GENERATION FACILITIES (as of 1/1/00)

Environmental Protection Measures

Picway Plant

Habitat Enhancement - Bird Box
Electrostatic precipitators
Stack
Wastewater treatment
Study of thermal effects on the Scioto River
Spill Prevention, Control and Countermeasure Plan for Oil
Emergency Planning and Community Right to Know
Underground Tank has been removed
Low NOx Burners
Fugitive dust control -- Ash storage pile, coal pile, and plant roadways
Waste minimization program
Pollution prevention program
Replacement and Retrofill (w/non-PCB oil) of PCB and PCB contaminated equipment

Conesville Plant

EPA Facility Response Plan and EPA Risk Management Program
Mechanical-draft cooling towers (Units 4-6)
Electrostatic precipitators
Flue-gas desulfurizers (Units 5 & 6)
Washed coal
Stacks
Fugitive dust control equipment for scrubber lime (Units 5 & 6), water treatment lime system, dry fly ash handling system (Units 4, 5 & 6), plant roadways and parking areas, drop chutes on coal systems (Units 4, 5 and 6).
Secondary and tertiary sewage treatment with chlorination prior to discharge
Wastewater treatment
Groundwater monitoring wells
Study of thermal effluent effects on Muskingum River
Fish entrainment and impingement studies
Spill Prevention, Control and Countermeasure Plan for Oil
Emergency Planning and Community Right to Know
Replacement and retrofill (with non-PCB oil) of pure PCB and PCB-contaminated equipment
Metal Cleaning Waste Treatment Tank
Fuel switch to natural gas (Units 1-3)
Underground tank removal and upgrade
FGD waste landfill
Implementation of Thermal Management Plan
FGD waste Landfill Runoff/Leachate Collection and Treatment Ponds
Low NOx Burners (Unit 3)
Waste minimization program
Pollution Prevention program
Potable water treatment system
Over-fired air burners to control NO_x (Units 5 and 6)

J. M. Stuart Plant

See DP&L Long-Term Forecast report.

W. C. Beckjord and W. H. Zimmer Plants

See Cinergy Long-Term Forecast report.

FORM FE2-1

COLUMBUS SOUTHERN POWER COMPANY

SUMMARY OF EXISTING ELECTRIC GENERATION FACILITIES (as of 1/1/00)

JOINTLY OWNED
GENERATING STATIONS

Net Generating Capability
(MW)

Station Name and Location	Unit Numbers	Operating Utility	Total		CG&E		CSP		DP&L	
			Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
W. C. Beckjord New Richmond, Ohio	6	Cinergy	414	420	155	157	52	53	207	210
Conesville Conesville, Ohio	4	CSP	780	780	312	312	339	339	129	129
J. M. Stuart Aberdeen, Ohio	1	DP&L	585	585	228	228	152	152	205	205
	2		585	585	228	228	152	152	205	205
	3		585	585	228	228	152	152	205	205
	4		585	585	228	228	152	152	205	205
W. H. Zimmer Moscow, Ohio	1	Cinergy	1,300	1,300	605	605	330	330	365	365

FORM FE2-1

OHIO POWER COMPANY

SUMMARY OF EXISTING ELECTRIC GENERATION FACILITIES (as of 1/1/00)

Station Name and Location	Unit Numbers	Type of Units	Date of First On-Line Service	Expected Retirement Date	Generation Capability Summer (MW)	Generation Capability Winter (MW)	Environmental Protection Measures
Cardinal Brilliant, Ohio [1]	1	Steam, Coal-Fired	2/1/67	Unknown	585	600	See Sheet 2
General James M. Gavin Cheshire, Ohio	1	Steam, Coal-Fired	10/20/74	Unknown	1,300	1,300	See Sheet 2
	2		7/6/75	Unknown	1,300	1,300	
Muskingum River Beverly, Ohio	1	Steam, Coal-Fired	12/28/53	Unknown	190	205	See Sheet 3
	2		6/1/54	Unknown	190	205	
	3		12/1/57	Unknown	205	215	
	4		5/31/58	Unknown	205	215	
	5		10/1/68	Unknown	575	585	
Racine Racine, Ohio	1	Hydro-Electric	1/15/83	Unknown	24	24	See Sheet 5
	2		9/24/82	Unknown	24	24	
John E. Amos St. Albans, W.Va.	3	Steam, Coal-Fired	10/22/73	Unknown	1,300[2]	1,300[2]	See Sheet 3
Kammer Captina, W.Va.	1	Steam, Coal-Fired	7/1/58	Unknown	200	210	See Sheet 4
	2		11/7/58	Unknown	200	210	
	3		3/30/59	Unknown	200	210	
Mitchell Captina, W.Va.	1	Steam, Coal-Fired	5/31/71	Unknown	800	800	See Sheet 4
	2		5/31/71	Unknown	800	800	
Philip Sporn Graham Station W.Va.	1	Steam, Coal-Fired	1/1/50	Unknown	145[3]	150[3]	See Sheet 5
	2		7/1/50	Unknown	145[3]	150[3]	
	3		8/1/51	Unknown	145[3]	150[3]	
	4		2/1/52	Unknown	145[3]	150[3]	
	5		12/31/60	Unknown	440[3]	450[3]	

Notes: [1] The Cardinal Plant consists of three units, with Unit No. 1 owned by Ohio Power Company and Unit Nos. 2 and 3 owned by Buckeye Power, Inc.

[2] Ohio Power Company owns two-thirds of Unit 3 (867 MW) with Appalachian Power Company owning one-third (433 MW).

[3] The Philip Sporn Plant is jointly owned by Ohio Power Company and Appalachian Power Company. Ohio Power owns Units 2, 4 and 5.

FORM FE2-1

OHIO POWER COMPANY

SUMMARY OF EXISTING ELECTRIC GENERATION FACILITIES (as of 1/1/00)

Environmental Protection Measures

Cardinal Plant

- EPA Facility Response Plan
- Stacks
- Electrostatic precipitators (99.5% design efficiency)
- Tertiary sewage treatment with chlorination and dechlorination prior to discharge (Units 1-2)
- Tertiary sewage treatment with UV disinfection (Unit 3)
- Study of effects of thermal effluents on Ohio River
- Waste water treatment and recirculation system
- Fish entrainment and impingement studies
- Chlorine minimization study
- Low-sulfur coal - Units 2-3
- Washed coal- Unit 1
- Fugitive dust control equipment for coal handling system, plant roadways and parking areas
- Natural draft cooling tower - Unit 3
- Once-through cooling water dechlorination
- Groundwater monitoring wells
- Spill Prevention, Control and Countermeasure Plan for Oil
- Emergency Planning and Community Right to Know
- Replacement and retrofill (with non-PCB oil) of pure PCB and PCB-contaminated equipment
- Metal Cleaning Waste Tank
- Waste minimization program
- Pollution Prevention program
- Underground storage tank removal and upgrade
- Low NO_x burners (Units 1 and 3)

General Gavin Plant

- Stacks
- Electrostatic precipitators (99.8% design efficiency)
- Tertiary sewage treatment with ultraviolet disinfection prior to discharge
- Waste water treatment and recirculation system
- Natural draft cooling towers
- Fish entrainment and impingement studies
- Coal washing plant
- Spill Prevention, Control and Countermeasure Plan for Oil
- Emergency Planning and Community Right to Know
- Replacement and retrofill (with non-PCB oil) of pure PCB and PCB-contaminated equipment
- Metal cleaning waste tank
- Flue Gas Desulfurization System
- FGD waste landfill
- FGD runoff/leachate collection/treatment ponds
- Overland FGD waste conveyor to stockpile pad facility
- Groundwater Monitoring Wells
- Stormwater Pollution Prevention Plan
- Underground Tank Removal and Upgrade
- Dry Fly Ash Handling
- Fugitive Dust controls for scrubber components, lime, coal, and dry fly ash handling systems
- Fugitive Dust control for plant roadways and parking areas
- Waste minimization program
- Pollution Prevention program
- Underground storage tank removals and state-of-the-art upgrades to above ground tanks
- EPA Facility Response Plan
- Low NO_x burners (Unit 1)

FORM FE2-1
OHIO POWER COMPANY

SUMMARY OF EXISTING ELECTRIC GENERATION FACILITIES (as of 1/1/00)

Muskingum River Plant

Stacks
Electrostatic precipitators (Units 1-4, 98.5% design efficiency; Unit 5, 99.7% design efficiency)
Tertiary sewage treatment with chlorination prior to discharge
Study of effects of thermal effluents on Muskingum River
Waste water treatment and recirculation system (Unit 5)
Natural draft cooling tower (Unit 5)
Fish entrainment and impingement studies
Washed coal
Spill Prevention, Control and Countermeasure Plan for Oil
Emergency Planning and Community Right to Know
Ash pond dam seepage collection system
Replacement and retrofill (with non-PCB oil) of pure PCB and PCB-contaminated equipment
Metal cleaning waste tank
Once-through cooling water dechlorination
Real-time Thermal Management System for once-through cooling water
Low-sulfur coal (Unit 5)
Ammonia Injection System for Opacity Control (Units 3-4)
Low NOx Burners (Unit 5)
Rail Car Unloader (low sulfur coal)
Fugitive dust control systems on coal handling, roadways and parking, rail unloader
Waste minimization program
Pollution Prevention program
Underground storage tank removals and state-of-the-art upgrades to above ground tanks
EPA Facility Response Plan
Stormwater Pollution Prevention Plan

Amos Plant

Stacks
Low sulfur coal
Electrostatic precipitator (99.9% efficiency)
Secondary sewage treatment with chlorination prior to discharge
Wastewater treatment and recirculation system
Fish entrainment and impingement studies
Natural draft cooling towers
Spill Prevention, Control and Countermeasure Plan for Oil
Emergency Planning and Community Right to Know
Replacement and retrofill (with non-PCB oil) of pure PCB and PCB-contaminated equipment
Metal cleaning waste tank
Dry fly ash handling system (Units 1 & 2) and a wet fly ash handling system (Unit 3)
Ash landfill
Low NO_x burners (Units 1-3)
Pollution Prevention Program
Stormwater ponds
Groundwater protection plan
Engineered solid waste (Ash) landfill with liner and ground water monitoring
EPA Facility Response Plan
Underground storage tank removal and upgrade
SO_3 Flue Gas Conditioning System (Unit 3)

FORM FE2-1

OHIO POWER COMPANY

SUMMARY OF EXISTING ELECTRIC GENERATION FACILITIES (as of 1/1/00)

Kammer Plant

Stack
Electrostatic precipitator (99.4% efficiency)
Washed coal
Secondary sewage treatment with chlorination prior to discharge
Study of effects of thermal effluents on the Ohio River
Fish entrainment and impingement studies
Wastewater treatment system (including ash disposal)
Spill Prevention, Control and Countermeasure Plan for Oil
Emergency Planning and Community Right to Know
Replacement and retrofill (with non-PCB oil) of pure PCB and PCB-contaminated equipment
Coal Barge Unloader
Pollution Prevention program
Groundwater protection plan
Underground storage tank removal and upgrade
Over-fired air burners to control NO_x (Unit 2)

Mitchell Plant

Stack
Electrostatic precipitator (99.8% efficiency)
Secondary sewage treatment using recirculating sand filters with uv disinfection
Natural draft cooling towers
Wastewater treatment system (including ash disposal)
Spill Prevention, Control and Countermeasure Plan for Oil
Emergency Planning and Community Right to Know
Replacement and retrofill (with non-PCB oil) of pure PCB and PCB-contaminated equipment
Metal cleaning waste tank
Low NOx Burners (Units 1 & 2)
Pollution Prevention program
Underground storage tank removal and upgrade
Groundwater protection plan
Stormwater pollution prevention plan
EPA Facility Response Plan

FORM FE2-1

OHIO POWER COMPANY

SUMMARY OF EXISTING ELECTRIC GENERATION FACILITIES (as of 1/1/00)

Philip Sporn Plant

Stacks
Low sulfur coal
Electrostatic precipitator (99.8% efficiency)
Secondary sewage treatment with chlorination prior to discharge
Wastewater treatment system
Dry fly ash (Units 1-4) handling system and a wet fly ash system (Unit 5)
Spill Prevention, Control and Countermeasure Plan for Oil
Cooling water dechlorination system
Study of effects of thermal effluents on Ohio River
Emergency Planning and Community Right to Know
Replacement and retrofill (with non-PCB oil) of pure PCB and PCB-contaminated equipment
Fish entrainment and impingement studies
Metal cleaning waste tank
Pollution Prevention Program
Groundwater Protection Plan
EPA Facility Response Plan (Oil)
Engineered solid waste landfill (Ash) with liner and ground water monitoring
Underground storage tank removal and upgrade
Low No_x Burners (Units 1-4)

Racine Hydro

Secondary sewage treatment with chlorination and dechlorination prior to discharge
Spill Prevention, Control and Countermeasure Plan for Oil
Study of water quality effects from project operation
Emergency Planning and Community Right to Know
Studies of fish passage effects from turbines
Study of tail race effects on fish
Air injection system
Underground storage tank removal and upgrade

COLUMBUS SOUTHERN POWER COMPANY (A)
FORM FE2-2 PART 1
SUMMARY OF ACTUAL AND REQUIRED GENERATING CAPABILITY, 1995 - 1999
(MW)

	(Year -5) 1995		(Year -4) 1996		(Year -3) 1997		(Year -2) 1998		(Year -1) 1999	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required										
(a) Net Utility Service Area Peak Load (+)	3,378	2,729	3,335	2,917	3,354	2,547	3,551	2,931	3,804	3,036
(b) Purchased Power Used to Meet Peak Load (-)	177	0	60	0	30	0	43	27	56	50
(c) Power Sales Coincident with Service Area Peak Load (+)	411	129	169	58	67	39	43	43	55	44
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))	(SEE NOTE (A) BELOW)									
Net Capability Required (Not including reserve requirements)	3,612	2,858	3,444	2,975	3,391	2,586	3,551	2,947	3,803	3,030
2. Reporting Utility's Actual Historic Generating Capability										
(a) Previous Year Capability (+)	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595
(b) Retirements and Other Decreases in Capacity (-)	0	0	0	0	0	0	0	0	0	0
(c) Upratings and Increases in Capacity (+)	0	0	0	0	0	0	0	0	0	0
(d) Seasonal Deratings (-)	31	0	31	0	31	0	31	0	31	0
Net Capability	2,564	2,595	2,564	2,595	2,564	2,595	2,564	2,595	2,564	2,595
3. Differential Between Net Capability Required and Net Capability Each Year (2)-(1)	(1,048)	(263)	(880)	(380)	(827)	9	(987)	(352)	(1,239)	(435)

Note: (A) Inasmuch as Columbus Southern Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

FORM FE2-2 Part 1

CSP/OPCo 2000

OHIO POWER COMPANY (A)
FORM FE2-2 PART 1
SUMMARY OF ACTUAL AND REQUIRED GENERATING CAPABILITY, 1995 - 1999
(MW)

	(Year -5) 1995		(Year -4) 1996		(Year -3) 1997		(Year -2) 1998		(Year -1) 1999	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required										
(a) Net Utility Service Area Peak Load (+)	5,641	5,373	5,547	5,254	5,519	5,177	5,588	5,465	5,705	5,212
(b) Purchased Power Used to Meet Peak Load (-) (B)	498	120	147	0	293	188	127	250	209	125
(c) Power Sales Coincident with Service Area Peak Load (+) (C)	705	262	768	581	122	66	490	82	82	447
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))	(SEE NOTE (A) BELOW)									
Net Capability Required (Not including reserve requirements)	5,848	5,515	6,168	5,835	5,348	5,055	5,951	5,297	5,578	5,534
2. Reporting Utility's Actual Historic Generating Capability										
(a) Previous Year Capability (+)	8,517	8,524	8,524	8,524	8,524	8,525	8,527	8,520	8,520	8,520
(b) Retirements and Other Decreases in Capacity (-)	0	0	0	0	0	5	7	0	0	0
(c) Upratings and Increases in Capacity (+)	7	0	0	1	3	0	0	0	0	0
(d) Seasonal Deratings (-)	126	0	126	0	126	0	125	0	125	0
Net Capability	8,398	8,524	8,398	8,525	8,401	8,520	8,395	8,520	8,395	8,520
3. Differential Between Net Capability Required and Net Capability Each Year (2)-(1)	2,550	3,009	2,230	2,690	3,053	3,465	2,444	3,223	2,817	2,986

Notes: (A) Inasmuch as Ohio Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

(B) Includes Cardinal Units 2-3 capability in excess, if any, of Buckeye Power's load requirements.

(C) Includes Buckeye Power's load requirements in excess, if any, of Cardinal Units 2-3 capability.

FORM FE2-2
Part 1

CSP/OPCo 2000

AMERICAN ELECTRIC POWER SYSTEM
FORM FE2-2 PART 1
SUMMARY OF ACTUAL AND REQUIRED GENERATING CAPABILITY, 1995 - 1999
(MW)

	(Year -5) 1995		(Year -4) 1996		(Year -3) 1997		(Year -2) 1998		(Year -1) 1999	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required										
(a) Net Utility Service Area Peak Load (+)	19,516	19,557	18,864	19,381	19,119	17,841	19,414	18,546	19,952	19,167
(b) Purchased Power Used to Meet Peak Load (-)	1,324	230	471	33	412	0	421	259	547	516
(c) Power Sales Coincident with Service Area Peak Load (+)	2,643	829	1,566	897	461	724	375	290	326	257
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))	-	-	-	-	-	-	-	-	-	-
Net Capability Required (Not including reserve requirements)	20,835	20,156	19,959	20,245	19,168	18,565	19,368	18,577	19,731	18,908
2. Reporting Utility's Actual Historic Generating Capability										
(a) Previous Year Capability (+)	23,054	23,054	23,054	23,054	23,054	23,054	23,054	23,054	23,054	23,054
(b) Retirements and Other Decreases in Capacity (-)	0	0	0	0	0	0	0	0	0	0
(c) Upratings and Increases in Capacity (+)	0	0	0	0	0	0	0	0	0	455
(d) Seasonal Deratings (-)	306	0	306	0	306	0	306	0	306	0
Net Capability	22,748	23,054	22,748	23,054	22,748	23,054	22,748	23,054	22,748	23,509
3. Differential Between Net Capability Required and Net Capability Each Year (2)-(1)	1,913	2,898	2,789	2,809	3,580	4,489	3,380	4,477	3,017	4,601

FORM FE2-2 Part 1

CSP/OPCo 2000

COLUMBUS SOUTHERN POWER COMPANY (A)
FORM FE2-2 PART 2
SUMMARY OF FORECAST AND REQUIRED GENERATING CAPABILITY, 2000 - 2020
(MW)

	(Year 0) 2000		(Year 1) 2001		(Year 2) 2002		(Year 3) 2003		(Year 4) 2004	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required in each Forecast Year										
(a) Forecasted Net Utility Service Area Peak Load (+)	3,782	3,078	3,872	3,154	3,961	3,223	4,052	3,297	4,146	3,372
(b) Purchased Power Available to Meet Peak Load (-)	56	0	0	0	0	0	0	0	0	0
(c) Power Committed to Sale Coincident with Service Area Peak Load (+)	36	37	36	37	37	37	37	37	37	38
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))	(SEE NOTE (A) BELOW)									
Net Capability Required (Not including reserve requirements)	3,762	3,115	3,908	3,191	3,998	3,260	4,089	3,334	4,183	3,410
2. Reporting Utility's Forecast Generation Capability										
(a) Previous Year Capability (+)	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595
(b) Retirements and Minor Decreases in Capability (-)	0	0	0	0	0	0	0	0	0	0
(c) Upratings and Minor Increases in Capability (+)	0	0	0	0	0	0	0	0	0	0
(d) Seasonal Deratings (-)	31	0	31	0	31	0	31	0	31	0
Net Capability	2,564	2,595	2,564	2,595	2,564	2,595	2,564	2,595	2,564	2,595
3. Differential Between Net Capability Required and Net Capability for each Year of Forecast (2)-(1)	(1,198)	(520)	(1,344)	(596)	(1,434)	(665)	(1,525)	(739)	(1,619)	(815)
4. Planned Capability of New Facilities										
(a) Previous Additions (+)	0	0	0	0	0	0	0	0	0	0
(b) Planned Generating Capability of New Facilities (+)	0	0	0	0	0	0	0	0	0	0
Total Planned Additional Capability	0	0	0	0	0	0	0	0	0	0
5. Total Projected Capability (2)+(4)	2,564	2,595	2,564	2,595	2,564	2,595	2,564	2,595	2,564	2,595
6. Projected Reserves (5)-(1)	(1,198)	(520)	(1,344)	(596)	(1,434)	(665)	(1,525)	(739)	(1,619)	(815)

Note: (A) Inasmuch as Columbus Southern Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

FORM FE2-2
Part 2

CSP/OPCo 2000

COLUMBUS SOUTHERN POWER COMPANY (A)
FORM FE2-2 PART 2
SUMMARY OF FORECAST AND REQUIRED GENERATING CAPABILITY, 2000 - 2020
(MW)

	(Year 5) 2005		(Year 6) 2006		(Year 7) 2007		(Year 8) 2008		(Year 9) 2009	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required in each Forecast Year										
(a) Forecasted Net Utility Service Area Peak Load (+)	4,241	3,447	4,336	3,521	4,430	3,596	4,525	3,671	4,620	3,746
(b) Purchased Power Available to Meet Peak Load (-)	0	0	0	0	0	0	0	0	0	0
(c) Power Committed to Sale Coincident with Service Area Peak Load (+)	37	38	38	38	38	38	38	39	38	39
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))	(SEE NOTE (A) BELOW)									
Net Capability Required (Not including reserve requirements)	4,278	3,485	4,374	3,559	4,468	3,634	4,563	3,710	4,658	3,785
2. Reporting Utility's Forecast Generation Capability										
(a) Previous Year Capability (+)	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595
(b) Retirements and Minor Decreases in Capability (-)	0	0	0	0	0	0	0	0	0	0
(c) Upratings and Minor Increases in Capability (+)	0	0	0	0	0	0	0	0	0	0
(d) Seasonal Deratings (-)	31	0	31	0	31	0	31	0	31	0
Net Capability	2,564	2,595	2,564	2,595	2,564	2,595	2,564	2,595	2,564	2,595
3. Differential Between Net Capability Required and Net Capability for each Year of Forecast (2)-(1)	(1,714)	(890)	(1,810)	(964)	(1,904)	(1,039)	(1,999)	(1,115)	(2,094)	(1,190)
4. Planned Capability of New Facilities										
(a) Previous Additions (+)	0	0	0	0	0	0	0	0	0	400
(b) Planned Generating Capability of New Facilities (+)	0	0	0	0	0	0	0	400	400	0
Total Planned Additional Capability	0	0	0	0	0	0	0	400	400	400
5. Total Projected Capability (2)+(4)	2,564	2,595	2,564	2,595	2,564	2,595	2,564	2,995	2,964	2,995
6. Projected Reserves (5)-(1)	(1,714)	(890)	(1,810)	(964)	(1,904)	(1,039)	(1,999)	(715)	(1,694)	(790)

Note: (A) Inasmuch as Columbus Southern Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

COLUMBUS SOUTHERN POWER COMPANY (A)
FORM FE2-2 PART 2
SUMMARY OF FORECAST AND REQUIRED GENERATING CAPABILITY, 2000 - 2020
(MW)

	(Year 10) 2010		(Year 11) 2011		(Year 12) 2012		(Year 13) 2013		(Year 14) 2014	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required in each Forecast Year										
(a) Forecasted Net Utility Service Area Peak Load (+)	4,715	3,820	4,810	3,895	4,904	3,970	4,999	4,045	5,094	4,120
(b) Purchased Power Available to Meet Peak Load (-)	0	0	0	0	0	0	0	0	0	0
(c) Power Committed to Sale Coincident with Service Area Peak Load (+)	39	0	0	0	0	0	0	0	0	0
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))	(SEE NOTE (A) BELOW)									
Net Capability Required (Not including reserve requirements)	4,754	3,820	4,810	3,895	4,904	3,970	4,999	4,045	5,094	4,120
2. Reporting Utility's Forecast Generation Capability										
(a) Previous Year Capability (+)	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,180	2,180	2,180
(b) Retirements and Minor Decreases in Capability (-)	0	0	0	0	0	415	415	0	0	0
(c) Upratings and Minor Increases in Capability (+)	0	0	0	0	0	0	0	0	0	0
(d) Seasonal Deratings (-)	31	0	31	0	31	0	11	0	11	0
Net Capability	2,564	2,595	2,564	2,595	2,564	2,180	2,169	2,180	2,169	2,180
3. Differential Between Net Capability Required and Net Capability for each Year of Forecast (2)-(1)	(2,190)	(1,225)	(2,246)	(1,300)	(2,340)	(1,790)	(2,830)	(1,865)	(2,925)	(1,940)
4. Planned Capability of New Facilities										
(a) Previous Additions (+)	400	400	400	700	700	900	900	1,600	1,600	1,700
(b) Planned Generating Capability of New Facilities (+)	0	300	300	200	200	700	700	100	100	600
Total Planned Additional Capability	400	700	700	900	900	1,600	1,600	1,700	1,700	2,300
5. Total Projected Capability (2)+(4)	2,964	3,295	3,264	3,495	3,464	3,780	3,769	3,880	3,869	4,480
6. Projected Reserves (5)-(1)	(1,790)	(525)	(1,546)	(400)	(1,440)	(190)	(1,230)	(165)	(1,225)	360

Note: (A) Inasmuch as Columbus Southern Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

COLUMBUS SOUTHERN POWER COMPANY (A)
FORM FE2-2 PART 2
SUMMARY OF FORECAST AND REQUIRED GENERATING CAPABILITY, 2000 - 2020
(MW)

	(Year 15) 2015		(Year 16) 2016		(Year 17) 2017		(Year 18) 2018		(Year 19) 2019		(Year 20) 2020	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required in each Forecast Year												
(a) Forecasted Net Utility Service Area Peak Load (+)	5,190	4,194	5,284	4,270	5,379	4,345	5,474	4,420	5,569	4,494	5,664	4,573
(b) Purchased Power Available to Meet Peak Load (-)	0	0	0	0	0	0	0	0	0	0	0	0
(c) Power Committed to Sale Coincident with Service Area Peak Load (+)	0	0	0	0	0	0	0	0	0	0	0	0
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))					(SEE NOTE (A) BELOW)							
Net Capability Required (Not including reserve requirements)	5,190	4,194	5,284	4,270	5,379	4,345	5,474	4,420	5,569	4,494	5,664	4,573
2. Reporting Utility's Forecast Generation Capability												
(a) Previous Year Capability (+)	2,180	2,180	2,180	2,080	2,080	2,080	2,080	2,080	2,080	2,080	2,080	2,080
(b) Retirements and Minor Decreases in Capability (-)	0	100	100	0	0	0	0	0	0	0	0	0
(c) Upratings and Minor Increases in Capability (+)	0	0	0	0	0	0	0	0	0	0	0	0
(d) Seasonal Deratings (-)	11	0	1	0	1	0	1	0	1	0	1	0
Net Capability	2,169	2,080	2,079	2,080	2,079	2,080	2,079	2,080	2,079	2,080	2,079	2,080
3. Differential Between Net Capability Required and Net Capability for each Year of Forecast (2)-(1)	(3,021)	(2,114)	(3,205)	(2,190)	(3,300)	(2,265)	(3,395)	(2,340)	(3,490)	(2,414)	(3,585)	(2,493)
4. Planned Capability of New Facilities												
(a) Previous Additions (+)	1,700	2,300	2,300	2,600	2,600	2,800	2,800	2,900	2,900	3,100	3,100	3,200
(b) Planned Generating Capability of New Facilities (+)	600	300	300	200	200	100	100	200	200	100	100	200
Total Planned Additional Capability	2,300	2,600	2,600	2,800	2,800	2,900	2,900	3,100	3,100	3,200	3,200	3,400
5. Total Projected Capability (2)+(4)	4,469	4,680	4,679	4,880	4,879	4,980	4,979	5,180	5,179	5,280	5,279	5,480
6. Projected Reserves (5)-(1)	(721)	486	(605)	610	(500)	635	(495)	760	(390)	786	(385)	907

Note: (A) Inasmuch as Columbus Southern Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

FORM FE2-2 Part 2

CSP/OPCo 2000

COLUMBUS SOUTHERN POWER COMPANY
COMPOSITION OF PURCHASED POWER AVAILABLE TO MEET PEAK LOAD
(SUPPLEMENT TO FORM FE2-2 PART 2)
(MW)

Sources of Purchased Power, Line 1(b):

	2000		2001		2002		2003		2004 - 2020	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
OVEC Surplus Power (A)	56	-	-	-	-	-	-	-	-	-
Total	56	-	-	-	-	-	-	-	-	-

Note: (A) Based on CSP's surplus power reservation share of AEP System.

FORM FE2-2 Part 2 Supplement

CSP/OPCo 2000

COLUMBUS SOUTHERN POWER COMPANY
COMPOSITION OF POWER COMMITTED TO SALE COINCIDENT WITH SERVICE AREA PEAK LOAD
(SUPPLEMENT TO FORM FE2-2 PART 2)
(MW)

Recipients of Power
Committed to Sale, Line 1(c):

	2000		2001		2002		2003		2004		2005	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
NCEMC (A)	36	37	36	37	37	37	37	37	37	38	37	38
Total	36	37	36	37	37	37	37	37	37	38	37	38

	2006		2007		2008		2009		2010		2011 - 2020	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
NCEMC (A)	38	38	38	38	38	39	38	39	39	-	-	-
Total	38	38	38	38	38	39	38	39	39	-	-	-

Note: (A) CSP's member-load-ratio share of AEP System sales.

FORM FE2-2 Part 2 Supplement

CSP/OPCo 2000

OHIO POWER COMPANY (A)
FORM FE2-2 PART 2
SUMMARY OF FORECAST AND REQUIRED GENERATING CAPABILITY, 2000 - 2020
(MW)

	(Year 0) 2000		(Year 1) 2001		(Year 2) 2002		(Year 3) 2003		(Year 4) 2004	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required in each Forecast Year										
(a) Forecasted Net Utility Service Area Peak Load (+)	5,245	4,777	5,217	4,790	5,281	4,852	5,358	4,897	5,416	4,941
(b) Purchased Power Available to Meet Peak Load (-)	195	0	0	0	0	0	0	0	0	0
(c) Power Committed to Sale Coincident with Service Area Peak Load (+)	271	271	320	360	360	396	395	432	431	465
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))	(SEE NOTE (A) BELOW)									
Net Capability Required (Not including reserve requirements)	5,321	5,048	5,537	5,150	5,641	5,248	5,753	5,329	5,847	5,406
2. Reporting Utility's Forecast Generation Capability										
(a) Previous Year Capability (+)	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520
(b) Retirements and Minor Decreases in Capability (-)	0	0	0	0	0	0	0	0	0	0
(c) Upratings and Minor Increases in Capability (+)	0	0	0	0	0	0	0	0	0	0
(d) Seasonal Deratings (-)	125	0	125	0	125	0	125	0	125	0
Net Capability	8,395	8,520	8,395	8,520	8,395	8,520	8,395	8,520	8,395	8,520
3. Differential Between Net Capability Required and Net Capability for each Year of Forecast (2)-(1)	3,074	3,472	2,858	3,370	2,754	3,272	2,642	3,191	2,548	3,114
4. Planned Capability of New Facilities										
(a) Previous Additions (+)	0	0	0	0	0	0	0	0	0	0
(b) Planned Generating Capability of New Facilities (+)	0	0	0	0	0	0	0	0	0	0
Total Planned Additional Capability	0	0	0	0	0	0	0	0	0	0
5. Total Projected Capability (2)+(4)	8,395	8,520	8,395	8,520	8,395	8,520	8,395	8,520	8,395	8,520
6. Projected Reserves (5)-(1)	3,074	3,472	2,858	3,370	2,754	3,272	2,642	3,191	2,548	3,114

Note: (A) Inasmuch as Ohio Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

FORM FE2-2
Part 2

CSP/OPCo 2000

OHIO POWER COMPANY (A)
FORM FE2-2 PART 2
SUMMARY OF FORECAST AND REQUIRED GENERATING CAPABILITY, 2000 - 2020
(MW)

	(Year 5) 2005		(Year 6) 2006		(Year 7) 2007		(Year 8) 2008		(Year 9) 2009	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required in each Forecast Year										
(a) Forecasted Net Utility Service Area Peak Load (+)	5,474	4,986	5,533	5,031	5,591	5,076	5,650	5,121	5,708	5,166
(b) Purchased Power Available to Meet Peak Load (-)	0	0	0	163	148	163	148	163	148	163
(c) Power Committed to Sale Coincident with Service Area Peak Load (+)	465	502	502	49	48	49	48	48	48	48
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))	(SEE NOTE (A) BELOW)									
Net Capability Required (Not including reserve requirements)	5,939	5,488	6,035	4,917	5,491	4,962	5,550	5,006	5,608	5,051
2. Reporting Utility's Forecast Generation Capability										
(a) Previous Year Capability (+)	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	7,050
(b) Retirements and Minor Decreases in Capability (-)	0	0	0	0	0	0	0	1,470	1,470	0
(c) Upratings and Minor Increases in Capability (+)	0	0	0	0	0	0	0	0	0	0
(d) Seasonal Deratings (-)	125	0	125	0	125	0	125	0	45	0
Net Capability	8,395	8,520	8,395	8,520	8,395	8,520	8,395	7,050	7,005	7,050
3. Differential Between Net Capability Required and Net Capability for each Year of Forecast (2)-(1)	2,456	3,032	2,360	3,603	2,904	3,558	2,845	2,044	1,397	1,999
4. Planned Capability of New Facilities										
(a) Previous Additions (+)	0	0	0	0	0	0	0	0	0	0
(b) Planned Generating Capability of New Facilities (+)	0	0	0	0	0	0	0	0	0	0
Total Planned Additional Capability	0	0	0	0	0	0	0	0	0	0
5. Total Projected Capability (2)+(4)	8,395	8,520	8,395	8,520	8,395	8,520	8,395	7,050	7,005	7,050
6. Projected Reserves (5)-(1)	2,456	3,032	2,360	3,603	2,904	3,558	2,845	2,044	1,397	1,999

Note: (A) Inasmuch as Ohio Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

OHIO POWER COMPANY (A)
FORM FE2-2 PART 2
SUMMARY OF FORECAST AND REQUIRED GENERATING CAPABILITY, 2000 - 2020
(MW)

	(Year 10) 2010		(Year 11) 2011		(Year 12) 2012		(Year 13) 2013		(Year 14) 2014	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required in each Forecast Year										
(a) Forecasted Net Utility Service Area Peak Load (+)	5,767	5,211	5,827	5,256	5,885	5,301	5,944	5,347	6,002	5,393
(b) Purchased Power Available to Meet Peak Load (-)	148	163	148	163	148	0	0	0	0	0
(c) Power Committed to Sale Coincident with Service Area Peak Load (+)	47	0	0	0	0	0	0	0	0	0
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))	(SEE NOTE (A) BELOW)									
Net Capability Required (Not including reserve requirements)	5,666	5,048	5,679	5,093	5,737	5,301	5,944	5,347	6,002	5,393
2. Reporting Utility's Forecast Generation Capability										
(a) Previous Year Capability (+)	7,050	7,050	7,050	6,750	6,750	6,750	6,750	6,750	6,750	6,750
(b) Retirements and Minor Decreases in Capability (-)	0	300	300	0	0	0	0	0	0	0
(c) Upratings and Minor Increases in Capability (+)	0	0	0	0	0	0	0	0	0	0
(d) Seasonal Deratings (-)	45	0	35	0	35	0	35	0	35	0
Net Capability	7,005	6,750	6,715	6,750	6,715	6,750	6,715	6,750	6,715	6,750
3. Differential Between Net Capability Required and Net Capability for each Year of Forecast (2)-(1)	1,339	1,702	1,036	1,657	978	1,449	771	1,403	713	1,357
4. Planned Capability of New Facilities										
(a) Previous Additions (+)	0	0	0	0	0	0	0	0	0	0
(b) Planned Generating Capability of New Facilities (+)	0	0	0	0	0	0	0	0	0	0
Total Planned Additional Capability	0	0	0	0	0	0	0	0	0	0
5. Total Projected Capability (2)+(4)	7,005	6,750	6,715	6,750	6,715	6,750	6,715	6,750	6,715	6,750
6. Projected Reserves (5)-(1)	1,339	1,702	1,036	1,657	978	1,449	771	1,403	713	1,357

Note: (A) Inasmuch as Ohio Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

FORM FE2-2
Part 2

CSP/OPCo 2000

OHIO POWER COMPANY (A)
FORM FE2-2 PART 2
SUMMARY OF FORECAST AND REQUIRED GENERATING CAPABILITY, 2000 - 2020
(MW)

	(Year 15) 2015		(Year 16) 2016		(Year 17) 2017		(Year 18) 2018		(Year 19) 2019		(Year 20) 2020	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required in each Forecast Year												
(a) Forecasted Net Utility Service Area Peak Load (+)	6,061	5,439	6,119	5,484	6,178	5,530	6,237	5,576	6,296	5,621	6,355	5,667
(b) Purchased Power Available to Meet Peak Load (-)	0	0	0	0	0	0	0	0	0	0	0	0
(c) Power Committed to Sale Coincident with Service Area Peak Load (+)	0	0	0	0	0	0	0	0	0	0	0	0
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))					(SEE NOTE (A) BELOW)							
Net Capability Required (Not including reserve requirements)	6,061	5,439	6,119	5,484	6,178	5,530	6,237	5,576	6,296	5,621	6,355	5,667
2. Reporting Utility's Forecast Generation Capability												
(a) Previous Year Capability (+)	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750
(b) Retirements and Minor Decreases in Capability (-)	0	0	0	0	0	0	0	0	0	0	0	0
(c) Upratings and Minor Increases in Capability (+)	0	0	0	0	0	0	0	0	0	0	0	0
(d) Seasonal Deratings (-)	35	0	35	0	35	0	35	0	35	0	35	0
Net Capability	6,715	6,750	6,715	6,750	6,715	6,750	6,715	6,750	6,715	6,750	6,715	6,750
3. Differential Between Net Capability Required and Net Capability for each Year of Forecast (2)-(1)	654	1,311	596	1,266	537	1,220	478	1,174	419	1,129	360	1,083
4. Planned Capability of New Facilities												
(a) Previous Additions (+)	0	0	0	0	0	0	0	0	0	0	0	0
(b) Planned Generating Capability of New Facilities (+)	0	0	0	0	0	0	0	0	0	0	0	0
Total Planned Additional Capability	0	0	0	0	0	0	0	0	0	0	0	0
5. Total Projected Capability (2)+(4)	6,715	6,750	6,715	6,750	6,715	6,750	6,715	6,750	6,715	6,750	6,715	6,750
6. Projected Reserves (5)-(1)	654	1,311	596	1,266	537	1,220	478	1,174	419	1,129	360	1,083

Note: (A) Inasmuch as Ohio Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

FORM FE2-2 Part 2

CSP/OPCo 2000

OHIO POWER COMPANY
COMPOSITION OF PURCHASED POWER AVAILABLE TO MEET PEAK LOAD
(SUPPLEMENT TO FORM FE2-2 PART 2)
(MW)

Sources of Purchased Power, Line 1(b):

	2000		2001 - 2005		2006		2007		2008	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
OVEC Surplus Power (A)	195	-	-	-	-	-	-	-	-	-
Buckeye Power	-	-	-	-	-	163	148	163	148	163
Total	-	-	-	-	-	163	148	163	148	163

	2009		2010		2011		2012		2013 - 2020	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Buckeye Power	148	163	148	163	148	163	148	-	-	-
Total	148	163	148	163	148	163	148	-	-	-

Note: (A) Based on OPCo's surplus power reservation share of AEP System.

FORM FE2-2
Part 2
Supplement

CSP/OPCo 2000

OHIO POWER COMPANY
COMPOSITION OF POWER COMMITTED TO SALE COINCIDENT WITH SERVICE AREA PEAK LOAD
(SUPPLEMENT TO FORM FE2-2 PART 2)
(MW)

Recipients of Power
Committed to Sale, Line 1(c):

	2000		2001		2002		2003		2004		2005	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
NCEMC (A)	53	53	51	50	50	50	49	50	49	49	49	49
Buckeye Power	218	218	269	310	310	346	346	382	382	416	416	453
Total	271	271	320	360	360	396	395	432	431	465	465	502

	2006		2007		2008		2009		2010		2011 - 2020	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
NCEMC (A)	49	49	48	49	48	48	48	48	47	-	-	-
Buckeye Power	453	-	-	-	-	-	-	-	-	-	-	-
Total	502	49	48	49	48	48	48	48	47	-	-	-

Note: (A) OPCo's member-load-ratio share of AEP System sales.

FORM FE2-2
Part 2
Supplement

CSP/OPCo 2000

AMERICAN ELECTRIC POWER SYSTEM
FORM FE2-2 PART 2
SUMMARY OF FORECAST AND REQUIRED GENERATING CAPABILITY, 2000 - 2020
(MW)

	(Year 0) 2000		(Year 1) 2001		(Year 2) 2002		(Year 3) 2003		(Year 4) 2004	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required in each Forecast Year										
(a) Forecasted Net Utility Service Area Peak Load (+)	19,585	19,084	19,839	19,367	20,178	19,689	20,545	19,988	20,868	20,287
(b) Purchased Power Available to Meet Peak Load (-)	547	24	16	24	16	24	16	24	16	24
(c) Power Committed to Sale Coincident with Service Area Peak Load (+)	436	491	491	515	515	551	551	587	587	621
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))	-	-	-	-	-	-	-	-	-	-
Net Capability Required (Not including reserve requirements)	19,474	19,551	20,314	19,858	20,677	20,216	21,080	20,551	21,439	20,884
2. Reporting Utility's Forecast Generation Capability										
(a) Previous Year Capability (+)	23,054	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509
(b) Retirements and Minor Decreases in Capability (-)	0	0	0	0	0	0	0	0	0	0
(c) Upratings and Minor Increases in Capability (+)	455	0	0	0	0	0	0	0	0	0
(d) Seasonal Deratings (-)	306	0	306	0	306	0	306	0	306	0
Net Capability	23,203	23,509	23,203	23,509	23,203	23,509	23,203	23,509	23,203	23,509
3. Differential Between Net Capability Required and Net Capability for each Year of Forecast (2)-(1)	3,729	3,958	2,889	3,651	2,526	3,293	2,123	2,958	1,764	2,625
4. Planned Capability of New Facilities										
(a) Previous Additions (+)	0	0	0	0	0	0	0	0	0	0
(b) Planned Generating Capability of New Facilities (+)	0	0	0	0	0	0	0	0	0	400
Total Planned Additional Capability	0	0	0	0	0	0	0	0	0	400
5. Total Projected Capability (2)+(4)	23,203	23,509	23,203	23,509	23,203	23,509	23,203	23,509	23,203	23,909
6. Projected Reserves (5)-(1)	3,729	3,958	2,889	3,651	2,526	3,293	2,123	2,958	1,764	3,025

FORM FE2-2 Part 2

CSP/OPCo 2000

AMERICAN ELECTRIC POWER SYSTEM
FORM FE2-2 PART 2
SUMMARY OF FORECAST AND REQUIRED GENERATING CAPABILITY, 2000 - 2020
(MW)

	(Year 5) 2005		(Year 6) 2006		(Year 7) 2007		(Year 8) 2008		(Year 9) 2009	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required in each Forecast Year										
(a) Forecasted Net Utility Service Area Peak Load (+)	21,192	20,589	21,516	20,890	21,840	21,192	22,164	21,494	22,488	21,796
(b) Purchased Power Available to Meet Peak Load (-)	16	24	16	187	164	187	164	187	164	187
(c) Power Committed to Sale Coincident with Service Area Peak Load (+)	621	658	658	205	205	205	205	205	205	205
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))	-	-	-	-	-	-	-	-	-	-
Net Capability Required (Not including reserve requirements)	21,797	21,223	22,158	20,908	21,881	21,210	22,205	21,512	22,529	21,814
2. Reporting Utility's Forecast Generation Capability										
(a) Previous Year Capability (+)	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	23,509	22,039
(b) Retirements and Minor Decreases in Capability (-)	0	0	0	0	0	0	0	1,470	1,470	0
(c) Upratings and Minor Increases in Capability (+)	0	0	0	0	0	0	0	0	0	250
(d) Seasonal Deratings (-)	306	0	306	0	306	0,	306	0	226	0
Net Capability	23,203	23,509	23,203	23,509	23,203	23,509	23,203	22,039	21,813	22,289
3. Differential Between Net Capability Required and Net Capability for each Year of Forecast (2)-(1)	1,406	2,286	1,045	2,601	1,322	2,299	998	527	(716)	475
4. Planned Capability of New Facilities										
(a) Previous Additions (+)	0	400	400	800	800	800	800	1,100	1,100	2,900
(b) Planned Generating Capability of New Facilities (+)	400	400	400	0	0	300	300	1,800	1,800	100
Total Planned Additional Capability	400	800	800	800	800	1,100	1,100	2,900	2,900	3,000
5. Total Projected Capability (2)+(4)	23,603	24,309	24,003	24,309	24,003	24,609	24,303	24,939	24,713	25,289
6. Projected Reserves (5)-(1)	1,806	3,086	1,845	3,401	2,122	3,399	2,098	3,427	2,184	3,475

FORM FE2-2
Part 2

CSP/OPCo 2000

AMERICAN ELECTRIC POWER SYSTEM
FORM FE2-2 PART 2
SUMMARY OF FORECAST AND REQUIRED GENERATING CAPABILITY, 2000 - 2020
(MW)

	(Year 10) 2010		(Year 11) 2011		(Year 12) 2012		(Year 13) 2013		(Year 14) 2014	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required in each Forecast Year										
(a) Forecasted Net Utility Service Area Peak Load (+)	22,812	22,098	23,136	22,399	23,460	22,702	23,784	23,004	24,108	23,306
(b) Purchased Power Available to Meet Peak Load (-)	164	187	164	187	164	24	16	24	16	24
(c) Power Committed to Sale Coincident with Service Area Peak Load (+)	205	0	0	0	0	0	0	0	0	0
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))	-	-	-	-	-	-	-	-	-	-
Net Capability Required (Not including reserve requirements)	22,853	21,911	22,972	22,212	23,296	22,678	23,768	22,980	24,092	23,282
2. Reporting Utility's Forecast Generation Capability										
(a) Previous Year Capability (+)	22,039	22,289	22,289	21,689	21,689	21,689	21,689	21,274	21,274	20,874
(b) Retirements and Minor Decreases in Capability (-)	0	600	600	0	0	415	415	400	400	1,090
(c) Upratings and Minor Increases in Capability (+)	250	0	0	0	0	0	0	0	0	0
(d) Seasonal Deratings (-)	226	0	206	0	206	0	186	0	176	0
Net Capability	22,063	21,689	21,483	21,689	21,483	21,274	21,088	20,874	20,698	19,784
3. Differential Between Net Capability Required and Net Capability for each Year of Forecast (2)-(1)	(790)	(222)	(1,489)	(523)	(1,813)	(1,404)	(2,680)	(2,106)	(3,394)	(3,498)
4. Planned Capability of New Facilities										
(a) Previous Additions (+)	2,900	3,000	3,000	3,700	3,700	4,100	4,100	4,800	4,800	5,600
(b) Planned Generating Capability of New Facilities (+)	100	700	700	400	400	700	700	800	800	1,400
Total Planned Additional Capability	3,000	3,700	3,700	4,100	4,100	4,800	4,800	5,600	5,600	7,000
5. Total Projected Capability (2)+(4)	25,063	25,389	25,183	25,789	25,583	26,074	25,888	26,474	26,298	26,784
6. Projected Reserves (5)-(1)	2,210	3,478	2,211	3,577	2,287	3,396	2,120	3,494	2,206	3,502

FORM FE2-2
Part 2

CSP/OPCo 2000

AMERICAN ELECTRIC POWER SYSTEM
FORM FE2-2 PART 2
SUMMARY OF FORECAST AND REQUIRED GENERATING CAPABILITY, 2000 - 2020
(MW)

	(Year 15) 2015		(Year 16) 2016		(Year 17) 2017		(Year 18) 2018		(Year 19) 2019		(Year 20) 2020	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Total Electric Power Peak Generating Capability Required in each Forecast Year												
(a) Forecasted Net Utility Service Area Peak Load (+)	24,432	23,613	24,757	23,919	25,082	24,226	25,407	24,531	25,732	24,833	26,056	25,146
(b) Purchased Power Available to Meet Peak Load (-)	16	24	16	24	16	24	16	24	16	24	16	24
(c) Power Committed to Sale Coincident with Service Area Peak Load (+)	0	0	0	0	0	0	0	0	0	0	0	0
(d) Power Pooling (Net Power Available from Power Pool (-) or Committed to Pool (+))	-	-	-	-	-	-	-	-	-	-	-	-
Net Capability Required (Not including reserve requirements)	24,416	23,589	24,741	23,895	25,066	24,202	25,391	24,507	25,716	24,809	26,040	25,122
2. Reporting Utility's Forecast Generation Capability												
(a) Previous Year Capability (+)	20,874	19,784	19,784	19,684	19,684	19,684	19,684	19,444	19,444	19,444	19,444	19,444
(b) Retirements and Minor Decreases in Capability (-)	1,090	100	100	0	0	240	240	0	0	0	0	0
(c) Upratings and Minor Increases in Capability (+)	0	0	0	0	0	0	0	0	0	0	0	0
(d) Seasonal Deratings (-)	156	0	146	0	146	0	141	0	141	0	141	0
Net Capability	19,628	19,684	19,538	19,684	19,538	19,444	19,303	19,444	19,303	19,444	19,303	19,444
3. Differential Between Net Capability Required and Net Capability for each Year of Forecast (2)-(1)	(4,788)	(3,905)	(5,203)	(4,211)	(5,528)	(4,758)	(6,088)	(5,063)	(6,413)	(5,365)	(6,737)	(5,678)
4. Planned Capability of New Facilities												
(a) Previous Additions (+)	5,600	7,000	7,000	7,500	7,500	7,800	7,800	8,400	8,400	8,800	8,800	9,200
(b) Planned Generating Capability of New Facilities (+)	1,400	500	500	300	300	600	600	400	400	400	400	300
Total Planned Additional Capability	7,000	7,500	7,500	7,800	7,800	8,400	8,400	8,800	8,800	9,200	9,200	9,500
5. Total Projected Capability (2)+(4)	26,628	27,184	27,038	27,484	27,338	27,844	27,703	28,244	28,103	28,644	28,503	28,944
6. Projected Reserves (5)-(1)	2,212	3,595	2,297	3,589	2,272	3,642	2,312	3,737	2,387	3,835	2,463	3,822

FORM FE2-2 Part 2

CSP/OPCo 2000

AMERICAN ELECTRIC POWER SYSTEM
COMPOSITION OF PURCHASED POWER AVAILABLE TO MEET PEAK LOAD
(SUPPLEMENT TO FORM FE2-2 PART 2)
(MW)

Sources of Purchased Power, Line 1(b):

	2000		2001 - 2005		2006		2007		2008	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
OVEC Surplus Power	547	-	-	-	-	-	-	-	-	-
Summersville Hydro QF	-	24	16	24	16	24	16	24	16	24
Buckeye Power	-	-	-	-	-	163	148	163	148	163
Total	547	24	16	24	16	187	164	187	164	187

	2009		2010		2011		2012		2013 - 2020	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Summersville Hydro QF	16	24	16	24	16	24	16	24	16	24
Buckeye Power	148	163	148	163	148	163	148	-	-	-
Total	164	187	164	187	164	187	164	24	16	24

FORM FE2-2
Part 2
Supplement

CSP/OPCo 2000

AMERICAN ELECTRIC POWER SYSTEM
COMPOSITION OF POWER COMMITTED TO SALE COINCIDENT WITH SERVICE AREA PEAK LOAD
(SUPPLEMENT TO FORM FE2-2 PART 2)
(MW)

Recipients of Power
Committed to Sale, Line 1(c):

	2000		2001		2002		2003		2004		2005	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
RP&L	13	17	17	-	-	-	-	-	-	-	-	-
NCEMC	205	205	205	205	205	205	205	205	205	205	205	205
Buckeye Power	218	269	269	310	310	346	346	382	382	416	416	453
Total	436	491	491	515	515	551	551	587	587	621	621	658

	2006		2007		2008		2009		2010		2011 - 2020	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
NCEMC	205	205	205	205	205	205	205	205	205	-	-	-
Buckeye Power	453	-	-	-	-	-	-	-	-	-	-	-
Total	658	205	205	205	205	205	205	205	205	-	-	-

FORM FE2-2
Part 2
Supplement

CSP/OPCo 2000

FORM FE2-2
Part 3

COLUMBUS SOUTHERN POWER COMPANY

ACTUAL GENERATING CAPABILITY CHANGES (1)

Year/Season		Unit Designation		Capability Changes (MW)	Seasonal Total (MW)
1995	Summer (August)	-	-	-	-
	Winter (Feb. 1996)	-	-	-	-
1996	Summer (August)	-	-	-	-
	Winter (Jan. 1997)	-	-	-	-
1997	Summer (June)	-	-	-	-
	Winter (March 1998)	-	-	-	-
1998	Summer (July)	-	-	-	-
	Winter (Jan. 1999)	-	-	-	-
1999	Summer (July)	-	-	-	-
	Winter (Jan. 2000)	-	-	-	-

Note: (1) The entries on this form correspond to the yearly change Summer and Winter columns on FE2-2, Part I for each year.

FORM FE2-2
Part 3

OHIO POWER COMPANY

PROJECTED GENERATING CAPABILITY CHANGES[1]

Year/Season		Unit Designation		Capability Changes (MW)	Seasonal Total (MW)
1995	Summer (August)	Sporn Plant	(Entitlement Variation)	7	7
	Winter (Jan. 1996)	-	-	-	-
1996	Summer (August)	-	-	-	-
	Winter (Jan. 1997)	Sporn Plant	(Entitlement Variation)	1	1
1997	Summer (July)	Sporn Plant	(Entitlement) Variation)	3	3
	Winter (Feb. 1998)	Sporn Plant	(Entitlement) Variation)	-5	-5
1998	Summer (June)	Sporn Plant	(Entitlement Variation)	-7	-7
	Winter (Jan. 1999)	-	-	-	-
1999	Summer (June)	-	-	-	-
	Winter (Dec. 1999)	-	-	-	-

Notes: (1) The entries on this form correspond to the yearly change Summer and Winter columns on FE2-2, Part 1 for each year.

FORM FE2-2
Part 3

AMERICAN ELECTRIC POWER SYSTEM

ACTUAL GENERATING CAPABILITY CHANGES[1]

Year/Season	Unit Designation		Capability Changes (MW)	Seasonal Total (MW)
1995 Summer (August)	-	-	-	-
Winter (Feb. 1996)	-	-	-	-
1996 Summer (August)	-	-	-	-
Winter (Jan. 1997)	-	-	-	-
1997 Summer (July)	-	-	-	-
Winter (March 1998)	-	-	-	-
1998 Summer (July)	-	-	-	-
Winter (Jan. 1999)	-	-	-	-
1999 Summer (July)	-	-	-	-
Winter (Jan. 2000)	Rockport 1	(Unit-power sale ends)	455	455

Notes: [1] The entries on this form correspond to the yearly change Summer and Winter Columns on FE2-2, Part 1 for each year.

CSP/OPCo 2000

FORM FE2-2
Part 4

COLUMBUS SOUTHERN POWER COMPANY

PROJECTED GENERATING CAPABILITY CHANGES[1, 2]

Year/Season		Unit Designation		Capability Changes (MW)	Seasonal Total (MW)
2000 through 2007	Summer	-	-	-	-
	Winter	-	-	-	-
2008	Summer	-	-	-	-
	Winter	Undesignated	(Addition)	400	400
2009	Summer	Undesignated	(Addition)	400	400
	Winter	-	-	-	-
2010	Summer	-	-	-	-
	Winter	Undesignated	(Addition)	300	300
2011	Summer	Undesignated	(Addition)	300	300
	Winter	Undesignated	(Addition)	200	200
2012	Summer	Undesignated	(Addition)	200	200
	Winter	Undesignated	(Addition)	700	
		Conesville 1-3	(Retirement)	-415	285
2013	Summer	Undesignated	(Addition)	700	
		Conesville 1-3	(Retirement)	-415	285
	Winter	Undesignated	(Addition)	100	100
2014	Summer	Undesignated	(Addition)	100	100
	Winter	Undesignated	(Addition)	600	600
2015	Summer	Undesignated	(Addition)	600	600
	Winter	Undesignated	(Addition)	300	
		Picway 5	(Retirement)	-100	200
2016	Summer	Undesignated	(Addition)	300	
		Picway 5	(Retirement)	-100	200
	Winter	Undesignated	(Addition)	200	200

FORM FE2-2
Part 4

COLUMBUS SOUTHERN POWER COMPANY

PROJECTED GENERATING CAPABILITY CHANGES[1, 2]

Year/Season		Unit Designation		Capability Changes (MW)	Seasonal Total (MW)
2017	Summer	Undesignated	(Addition)	200	200
	Winter	Undesignated	(Addition)	100	100
2018	Summer	Undesignated	(Addition)	100	100
	Winter	Undesignated	(Addition)	200	200
2019	Summer	Undesignated	(Addition)	200	200
	Winter	Undesignated	(Addition)	100	100
2020	Summer	Undesignated	(Addition)	100	100
	Winter	Undesignated	(Addition)	200	200

Notes: (1) The entries on this form correspond to the yearly change Summer and Winter columns on FE 2-2, Part 2 for each year.
(2) At the present time, there are no specific plans for capacity additions or retirements.

FORM FE2-2
Part 4

OHIO POWER COMPANY

PROJECTED GENERATING CAPABILITY CHANGES[1, 2]

Year/Season		Unit Designation		Capability Changes (MW)	Seasonal Total (MW)
2000 through 2007	Summer	-	-	-	-
	Winter	-	-	-	-
2008	Summer	-	-	-	-
	Winter	Kammer 1-3	(Retirement)	-630	
		Muskingum River 1-4	(Retirement)	-840	-1,470
2009	Summer	Kammer 1-3	(Retirement)	-630	
		Muskingum River 1-4	(Retirement)	-840	-1,470
	Winter	-	-	-	-
2010	Summer	-	-	-	-
	Winter	Sporn 2 & 4	(Retirement)	-300	-300
2011	Summer	Sporn 2 & 4	(Retirement)	-300	-300
	Winter	-	-	-	-
2012 through 2020	Summer	-	-	-	-
	Winter	-	-	-	-

Notes: (1) The entries on this form correspond to the yearly change Summer and Winter columns on FE2-2, Part 2 for each year.

(2) At the present time, there are no specific plans for capacity additions or retirements.

FORM FE2-2
Part 4

AMERICAN ELECTRIC POWER SYSTEM

PROJECTED GENERATING CAPABILITY CHANGES[1,2]

Year/Season	Unit Designation		Capability Changes (MW)	Seasonal Total (MW)
2000 Summer	Rockport 1	(Unit-power sale ends)	455	455
Winter	-	-	-	-
2001 Summer	-	-	-	-
Winter	-	-	-	-
2002 Summer	-	-	-	-
Winter	-	-	-	-
2003 Summer	-	-	-	-
Winter	-	-	-	-
2004 Summer	-	-	-	-
Winter	Undesignated	(Addition)	400	400
2005 Summer	Undesignated	(Addition)	400	400
Winter	Undesignated	(Addition)	400	400
2006 Summer	Undesignated	(Addition)	400	400
Winter	-	-	-	-
2007 Summer	-	-	-	-
Winter	Undesignated	(Addition)	300	300

FORM FE2-2
Part 4

AMERICAN ELECTRIC POWER SYSTEM

PROJECTED GENERATING CAPABILITY CHANGES[1,2]

Year/Season	Unit Designation		Capability Changes (MW)	Seasonal Total (MW)
2008 Summer	Undesignated	(Addition)	300	300
Winter	Undesignated	(Addition)	1,800	
	Kammer 1-3	(Retirement)	-630	
	Muskingum River 1-4	(Retirement)	-840	330
2009 Summer	Undesignated	(Addition)	1,800	
	Kammer 1-3	(Retirement)	-630	
	Muskingum River 1-4	(Retirement)	-840	330
Winter	Rockport 2	(Unit-power sale ends)	250	
	Undesignated	(Addition)	100	350
2010 Summer	Rockport 2	(Unit-power sale ends)	250	
	Undesignated	(Addition)	100	350
Winter	Undesignated	(Addition)	700	
	Sporn 1-4	(Retirement)	-600	100
2011 Summer	Undesignated	(Addition)	700	
	Sporn 1-4	(Retirement)	-600	100
Winter	Undesignated	(Addition)	400	400
2012 Summer	Undesignated	(Addition)	400	400
Winter	Undesignated	(Addition)	700	
	Conesville 1-3	(Retirement)	-415	285
2013 Summer	Undesignated	(Addition)	700	
	Conesville 1-3	(Retirement)	-415	285
Winter	Undesignated	(Addition)	800	
	Kanawha River 1-2	(Retirement)	-400	300
2014 Summer	Undesignated	(Addition)	800	
	Kanawha River 1-2	(Retirement)	-400	300
Winter	Undesignated	(Addition)	1,400	
	Tanners Creek 1-4	(Retirement)	-995	
	Glen Lyn 5	(Retirement)	-95	410

FORM FE2-2
Part 4

AMERICAN ELECTRIC POWER SYSTEM

PROJECTED GENERATING CAPABILITY CHANGES[1,2]

Year/Season	Unit Designation		Capability Changes (MW)	Seasonal Total (MW)
2015 Summer	Undesignated	(Addition)	1,400	
	Tanners Creek 1-4	(Retirement)	-995	
	Glen Lyn 5	(Retirement)	-95	410
Winter	Undesignated	(Addition)	500	
	Picway 5	(Retirement)	-100	400
2016 Summer	Undesignated	(Addition)	500	
	Picway 5	(Retirement)	-100	400
Winter	Undesignated	(Addition)	300	300
2017 Summer	Undesignated	(Addition)	300	300
Winter	Undesignated	(Addition)	600	
	Glen Lyn 6	(Retirement)	-240	360
2018 Summer	Undesignated	(Addition)	600	
	Glen Lyn 6	(Retirement)	-240	360
Winter	Undesignated	(Addition)	400	400
2019 Summer	Undesignated	(Addition)	400	400
Winter	Undesignated	(Addition)	400	400
2020 Summer	Undesignated	(Addition)	400	400
Winter	Undesignated	(Addition)	300	300

Notes: (1) The entries on this form correspond to the yearly change Summer and Winter columns on FE2-2 Part 2 for each year.
(2) At the present time, there are no specific plans for capacity additions or retirements.

COLUMBUS SOUTHERN POWER COMPANY (A)
FORM FE2-3 PART 1
ACTUAL AND FORECAST PEAK LOAD AND RESOURCES, 1995 - 2020
(MW)

SUMMER SEASON

	(-5) 1995	(-4) 1996	(-3) 1997	(-2) 1998	(-1) 1999	(0) 2000	(1) 2001	(2) 2002	(3) 2003	(4) 2004	(5) 2005	(6) 2006	(7) 2007
Net Demonstrated Capability	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595
Net Seasonal Capability	2,564	2,564	2,564	2,564	2,564	2,564	2,564	2,564	2,564	2,564	2,564	2,564	2,564
Purchases	177	60	30	43	56	56	0	0	0	0	0	0	0
Sales	411	169	67	43	55	36	36	37	37	37	37	38	38
Available Capability	2,330	2,455	2,527	2,564	2,565	2,584	2,528	2,527	2,527	2,527	2,527	2,526	2,526
Native Load	3,378	3,335	3,354	3,551	3,804	3,758	3,848	3,937	4,028	4,122	4,217	4,312	4,406
Available Reserve	(1,048)	(880)	(827)	(987)	(1,239)	(1,174)	(1,320)	(1,410)	(1,501)	(1,595)	(1,690)	(1,786)	(1,880)
Internal Load (B)	3,378	3,335	3,354	3,551	3,804	3,782	3,872	3,961	4,052	4,146	4,241	4,336	4,430
Reserve	(1,048)	(880)	(827)	(987)	(1,239)	(1,198)	(1,344)	(1,434)	(1,525)	(1,619)	(1,714)	(1,810)	(1,904)

	(8) 2008	(9) 2009	(10) 2010	(11) 2011	(12) 2012	(13) 2013	(14) 2014	(15) 2015	(16) 2016	(17) 2017	(18) 2018	(19) 2019	(20) 2020
Net Demonstrated Capability	2,595	2,995	2,995	3,295	3,495	3,780	3,880	4,480	4,680	4,880	4,980	5,180	5,280
Net Seasonal Capability	2,564	2,964	2,964	3,264	3,464	3,769	3,869	4,469	4,679	4,879	4,979	5,179	5,279
Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales	38	38	39	0	0	0	0	0	0	0	0	0	0
Available Capability	2,526	2,926	2,925	3,264	3,464	3,769	3,869	4,469	4,679	4,879	4,979	5,179	5,279
Native Load	4,501	4,596	4,691	4,786	4,880	4,975	5,070	5,166	5,260	5,355	5,450	5,545	5,640
Available Reserve	(1,975)	(1,670)	(1,766)	(1,522)	(1,416)	(1,206)	(1,201)	(697)	(581)	(476)	(471)	(366)	(361)
Internal Load (B)	4,525	4,620	4,715	4,810	4,904	4,999	5,094	5,190	5,284	5,379	5,474	5,569	5,664
Reserve	(1,999)	(1,694)	(1,790)	(1,546)	(1,440)	(1,230)	(1,225)	(721)	(605)	(500)	(495)	(390)	(385)

Notes: (A) Inasmuch as Columbus Southern Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

(B) Equals Native Load plus Interruptible Load.

OHIO POWER COMPANY (A)
FORM FE2-3 PART 1
ACTUAL AND FORECAST PEAK LOAD AND RESOURCES, 1995 - 2020
(MW)

SUMMER SEASON

	(-5) 1995	(-4) 1996	(-3) 1997	(-2) 1998	(-1) 1999	(0) 2000	(1) 2001	(2) 2002	(3) 2003	(4) 2004	(5) 2005	(6) 2006	(7) 2007
Net Demonstrated Capability	8,524	8,524	8,527	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520
Net Seasonal Capability	8,398	8,398	8,401	8,395	8,395	8,395	8,395	8,395	8,395	8,395	8,395	8,395	8,395
Purchases (B)	498	147	293	127	209	195	0	0	0	0	0	0	148
Sales (C)	705	768	122	490	82	271	320	360	395	431	465	502	48
Available Capability	8,191	7,777	8,572	8,032	8,522	8,319	8,075	8,035	8,000	7,964	7,930	7,893	8,495
Native Load	5,527	5,445	5,357	5,547	5,498	4,703	4,759	4,823	4,900	4,958	5,016	5,075	5,133
Available Reserve	2,664	2,332	3,215	2,485	3,024	3,616	3,316	3,212	3,100	3,006	2,914	2,818	3,362
Internal Load (D)	5,641	5,547	5,519	5,588	5,705	5,245	5,217	5,281	5,358	5,416	5,474	5,533	5,591
Reserve	2,550	2,230	3,053	2,444	2,817	3,074	2,858	2,754	2,642	2,548	2,456	2,360	2,904

	(8) 2008	(9) 2009	(10) 2010	(11) 2011	(12) 2012	(13) 2013	(14) 2014	(15) 2015	(16) 2016	(17) 2017	(18) 2018	(19) 2019	(20) 2020
Net Demonstrated Capability	8,520	7,050	7,050	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750
Net Seasonal Capability	8,395	7,005	7,005	6,715	6,715	6,715	6,715	6,715	6,715	6,715	6,715	6,715	6,715
Purchases (B)	148	148	148	148	148	0	0	0	0	0	0	0	0
Sales (C)	48	48	47	0	0	0	0	0	0	0	0	0	0
Available Capability	8,495	7,105	7,106	6,863	6,863	6,715	6,715	6,715	6,715	6,715	6,715	6,715	6,715
Native Load	5,192	5,250	5,309	5,369	5,427	5,486	5,544	5,603	5,661	5,720	5,779	5,838	5,897
Available Reserve	3,303	1,855	1,797	1,494	1,436	1,229	1,171	1,112	1,054	995	936	877	818
Internal Load (D)	5,650	5,708	5,767	5,827	5,885	5,944	6,002	6,061	6,119	6,178	6,237	6,296	6,355
Reserve	2,845	1,397	1,339	1,036	978	771	713	654	596	537	478	419	360

Notes: (A) Inasmuch as Ohio Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

(B) Includes Cardinal Units 2-3 capability in excess, if any, of Buckeye Power's load requirements.

(C) Includes Buckeye Power's load requirements in excess, if any, of Cardinal Units 2-3 capability.

(D) Equals Native Load plus Interruptible Load.

FORM FE2-3
Part 1

CSP/OPCo 2000

AMERICAN ELECTRIC POWER SYSTEM
FORM FE2-3 PART 1
ACTUAL AND FORECAST PEAK LOAD AND RESOURCES, 1995 - 2020
(MW)

SUMMER SEASON

	(-5) 1995	(-4) 1996	(-3) 1997	(-2) 1998	(-1) 1999	(0) 2000	(1) 2001	(2) 2002	(3) 2003	(4) 2004	(5) 2005	(6) 2006	(7) 2007
Net Demonstrated Capability	23,054	23,054	23,054	23,054	23,054	23,509	23,509	23,509	23,509	23,509	23,909	24,309	24,309
Net Seasonal Capability	22,748	22,748	22,748	22,748	22,748	23,203	23,203	23,203	23,203	23,203	23,603	24,003	24,003
Purchases	1,324	471	412	421	547	547	16	16	16	16	16	16	164
Sales	2,643	1,566	461	375	326	436	491	515	551	587	621	658	205
Available Capability	21,429	21,653	22,699	22,794	22,969	23,314	22,728	22,704	22,668	22,632	22,998	23,361	23,962
Native Load	19,431	18,721	18,792	19,365	19,847	18,921	19,259	19,598	19,965	20,288	20,612	20,936	21,260
Available Reserve	1,998	2,932	3,907	3,429	3,122	4,393	3,469	3,106	2,703	2,344	2,386	2,425	2,702
Internal Load (A)	19,516	18,864	19,119	19,414	19,952	19,585	19,839	20,178	20,545	20,868	21,192	21,516	21,840
Reserve	1,913	2,789	3,580	3,380	3,017	3,729	2,889	2,526	2,123	1,764	1,806	1,845	2,122

	(8) 2008	(9) 2009	(10) 2010	(11) 2011	(12) 2012	(13) 2013	(14) 2014	(15) 2015	(16) 2016	(17) 2017	(18) 2018	(19) 2019	(20) 2020
Net Demonstrated Capability	24,609	24,939	25,289	25,389	25,789	26,074	26,474	26,784	27,184	27,484	27,844	28,244	28,644
Net Seasonal Capability	24,303	24,713	25,063	25,183	25,583	25,888	26,298	26,628	27,038	27,338	27,703	28,103	28,503
Purchases	164	164	164	164	164	16	16	16	16	16	16	16	16
Sales	205	205	205	0	0	0	0	0	0	0	0	0	0
Available Capability	24,262	24,672	25,022	25,347	25,747	25,904	26,314	26,644	27,054	27,354	27,719	28,119	28,519
Native Load	21,584	21,908	22,232	22,556	22,880	23,204	23,528	23,852	24,177	24,502	24,827	25,152	25,476
Available Reserve	2,678	2,764	2,790	2,791	2,867	2,700	2,786	2,792	2,877	2,852	2,892	2,967	3,043
Internal Load (A)	22,164	22,488	22,812	23,136	23,460	23,784	24,108	24,432	24,757	25,082	25,407	25,732	26,056
Reserve	2,098	2,184	2,210	2,211	2,287	2,120	2,206	2,212	2,297	2,272	2,312	2,387	2,463

Note: (A) Equals Native Load plus Interruptible Load.

COLUMBUS SOUTHERN POWER COMPANY (A)
FORM FE2-3 PART 2
ACTUAL AND FORECAST PEAK LOAD AND RESOURCES, 1995 - 2020
(MW)

WINTER SEASON

	(-5) 1995/96	(-4) 96/97	(-3) 97/98	(-2) 98/99	(-1) 99/00	(0) 00/01	(1) 01/02	(2) 02/03	(3) 03/04	(4) 04/05	(5) 05/06	(6) 06/07	(7) 07/08
Net Demonstrated Capability	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595
Net Seasonal Capability	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595	2,595
Purchases	0	0	0	27	50	0	0	0	0	0	0	0	0
Sales	129	58	39	43	44	37	37	37	37	38	38	38	38
Available Capability	2,466	2,537	2,556	2,579	2,601	2,558	2,558	2,558	2,558	2,557	2,557	2,557	2,557
Native Load	2,720	2,898	2,529	2,916	3,030	3,051	3,127	3,196	3,270	3,345	3,420	3,494	3,569
Available Reserve	(254)	(361)	27	(337)	(429)	(493)	(569)	(638)	(712)	(788)	(863)	(937)	(1,012)
Internal Load (B)	2,729	2,917	2,547	2,931	3,036	3,078	3,154	3,223	3,297	3,372	3,447	3,521	3,596
Reserve	(263)	(380)	9	(352)	(435)	(520)	(596)	(665)	(739)	(815)	(890)	(964)	(1,039)

	(8) 08/09	(9) 09/10	(10) 10/11	(11) 11/12	(12) 12/13	(13) 13/14	(14) 14/15	(15) 15/16	(16) 16/17	(17) 17/18	(18) 18/19	(19) 19/20	(20) 20/21
Net Demonstrated Capability	2,995	2,995	3,295	3,495	3,780	3,880	4,480	4,680	4,880	4,980	5,180	5,280	5,480
Net Seasonal Capability	2,995	2,995	3,295	3,495	3,780	3,880	4,480	4,680	4,880	4,980	5,180	5,280	5,480
Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales	39	39	0	0	0	0	0	0	0	0	0	0	0
Available Capability	2,956	2,956	3,295	3,495	3,780	3,880	4,480	4,680	4,880	4,980	5,180	5,280	5,480
Native Load	3,644	3,719	3,793	3,868	3,943	4,018	4,093	4,167	4,243	4,318	4,393	4,467	4,546
Available Reserve	(688)	(763)	(498)	(373)	(163)	(138)	387	513	637	662	787	813	934
Internal Load (B)	3,671	3,746	3,820	3,895	3,970	4,045	4,120	4,194	4,270	4,345	4,420	4,494	4,573
Reserve	(715)	(790)	(525)	(400)	(190)	(165)	360	486	610	635	760	786	907

Notes: (A) Inasmuch as Columbus Southern Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

(B) Equals Native Load plus Interruptible Load.

OHIO POWER COMPANY (A)
FORM FE2-3 PART 2
ACTUAL AND FORECAST PEAK LOAD AND RESOURCES, 1995 - 2020
(MW)

WINTER SEASON

	(-5) 1995/96	(-4) 96/97	(-3) 97/98	(-2) 98/99	(-1) 99/00	(0) 00/01	(1) 01/02	(2) 02/03	(3) 03/04	(4) 04/05	(5) 05/06	(6) 06/07	(7) 07/08
Net Demonstrated Capability	8,524	8,525	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520
Net Seasonal Capability	8,524	8,525	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520	8,520
Purchases (B)	120	0	188	250	125	0	0	0	0	0	0	163	163
Sales (C)	262	581	66	82	447	271	360	396	432	465	502	49	49
Available Capability	8,382	7,944	8,642	8,688	8,198	8,249	8,160	8,124	8,088	8,055	8,018	8,634	8,634
Native Load	5,229	5,128	4,902	5,216	5,051	4,201	4,295	4,357	4,402	4,446	4,491	4,536	4,581
Available Reserve	3,153	2,816	3,740	3,472	3,147	4,048	3,865	3,767	3,686	3,609	3,527	4,098	4,053
Internal Load (D)	5,373	5,254	5,177	5,465	5,212	4,777	4,790	4,852	4,897	4,941	4,986	5,031	5,076
Reserve	3,009	2,690	3,465	3,223	2,986	3,472	3,370	3,272	3,191	3,114	3,032	3,603	3,558

	(8) 08/09	(9) 09/10	(10) 10/11	(11) 11/12	(12) 12/13	(13) 13/14	(14) 14/15	(15) 15/16	(16) 16/17	(17) 17/18	(18) 18/19	(19) 19/20	(20) 20/21
Net Demonstrated Capability	7,050	7,050	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750
Net Seasonal Capability	7,050	7,050	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750
Purchases (B)	163	163	163	163	0	0	0	0	0	0	0	0	0
Sales (C)	48	48	0	0	0	0	0	0	0	0	0	0	0
Available Capability	7,165	7,165	6,913	6,913	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750	6,750
Native Load	4,626	4,671	4,716	4,761	4,806	4,852	4,898	4,944	4,989	5,035	5,081	5,126	5,172
Available Reserve	2,539	2,494	2,197	2,152	1,944	1,898	1,852	1,806	1,761	1,715	1,669	1,624	1,578
Internal Load (D)	5,121	5,166	5,211	5,256	5,301	5,347	5,393	5,439	5,484	5,530	5,576	5,621	5,667
Reserve	2,044	1,999	1,702	1,657	1,449	1,403	1,357	1,311	1,266	1,220	1,174	1,129	1,083

Notes: (A) Inasmuch as Ohio Power Company is a member of the wholly integrated AEP System, the load, capability and reserve data indicated herein must be viewed within the framework and the provisions of the AEP Interconnection Agreement.

(B) Includes Cardinal Units 2-3 capability in excess, if any, of Buckeye Power's load requirements.

(C) Includes Buckeye Power's load requirements in excess, if any, of Cardinal Units 2-3 capability.

(D) Equals Native Load plus Interruptible Load.

FORM FE2-3
Part 2

CSP/OPCo 2000

AMERICAN ELECTRIC POWER SYSTEM
FORM FE2-3 PART 2
ACTUAL AND FORECAST PEAK LOAD AND RESOURCES, 1995 - 2020
(MW)

WINTER SEASON

	(-5) 1995/96	(-4) 96/97	(-3) 97/98	(-2) 98/99	(-1) 99/00	(0) 00/01	(1) 01/02	(2) 02/03	(3) 03/04	(4) 04/05	(5) 05/06	(6) 06/07	(7) 07/08
Net Demonstrated Capability	23,054	23,054	23,054	23,054	23,509	23,509	23,509	23,509	23,509	23,909	24,309	24,309	24,609
Net Seasonal Capability	23,054	23,054	23,054	23,054	23,509	23,509	23,509	23,509	23,509	23,909	24,309	24,309	24,609
Purchases	230	33	0	259	516	24	24	24	24	24	24	187	187
Sales	829	897	724	290	257	491	515	551	587	621	658	205	205
Available Capability	22,455	22,190	22,330	23,023	23,768	23,042	23,018	22,982	22,946	23,312	23,675	24,291	24,591
Native Load	19,314	19,101	17,362	18,386	18,918	18,494	18,777	19,099	19,398	19,697	19,999	20,300	20,602
Available Reserve	3,141	3,089	4,968	4,637	4,850	4,548	4,241	3,883	3,548	3,615	3,676	3,991	3,989
Internal Load (A)	19,557	19,381	17,841	18,546	19,167	19,084	19,367	19,689	19,988	20,287	20,589	20,890	21,192
Reserve	2,898	2,809	4,489	4,477	4,601	3,958	3,651	3,293	2,958	3,025	3,086	3,401	3,399

	(8) 08/09	(9) 09/10	(10) 10/11	(11) 11/12	(12) 12/13	(13) 13/14	(14) 14/15	(15) 15/16	(16) 16/17	(17) 17/18	(18) 18/19	(19) 19/20	(20) 20/21
Net Demonstrated Capability	24,939	25,289	25,389	25,789	26,074	26,474	26,784	27,184	27,484	27,844	28,244	28,644	28,944
Net Seasonal Capability	24,939	25,289	25,389	25,789	26,074	26,474	26,784	27,184	27,484	27,844	28,244	28,644	28,944
Purchases	187	187	187	187	24	24	24	24	24	24	24	24	24
Sales	205	205	0	0	0	0	0	0	0	0	0	0	0
Available Capability	24,921	25,271	25,576	25,976	26,098	26,498	26,808	27,208	27,508	27,868	28,268	28,668	28,968
Native Load	20,904	21,206	21,508	21,809	22,112	22,414	22,716	23,023	23,329	23,636	23,941	24,243	24,556
Available Reserve	4,017	4,065	4,068	4,167	3,986	4,084	4,092	4,185	4,179	4,232	4,327	4,425	4,412
Internal Load (A)	21,494	21,796	22,098	22,399	22,702	23,004	23,306	23,613	23,919	24,226	24,531	24,833	25,146
Reserve	3,427	3,475	3,478	3,577	3,396	3,494	3,502	3,595	3,589	3,642	3,737	3,835	3,822

Note: (A) Equals Native Load plus Interruptible Load.

FORM FE2-3
Part 2

CSP/OPCo 2000

FORM FE2-4

AMERICAN ELECTRIC POWER SYSTEM

SPECIFICATIONS OF PLANNED ELECTRIC GENERATION FACILITIES

1. Facility Name — Undetermined.
2. Facility Location — Undetermined.
3. Facility Type — Undetermined.
4. Anticipated Capability — Undetermined.
5. Anticipated Capital Cost — Undetermined.
6. Application Timing — Undetermined.
7. Construction Timing

In-Service Date	Resource Additions	MW Total	MW CSP Portion	MW OPCo Portion
1/1/05	Undesignated	400	-	-
1/1/06	Undesignated	400	-	-
1/1/08	Undesignated	300	-	-
1/1/09	Undesignated	1,800	400	-
1/1/10	Undesignated	100	-	-
1/1/11	Undesignated	700	300	-
1/1/12	Undesignated	400	200	-
1/1/13	Undesignated	700	700	-
1/1/14	Undesignated	800	100	-
1/1/15	Undesignated	1,400	600	-
1/1/16	Undesignated	500	300	-
1/1/17	Undesignated	300	200	-
1/1/18	Undesignated	600	100	-
1/1/19	Undesignated	400	200	-
1/1/20	Undesignated	400	100	-

8. Planned Pollution Control Measures — Undetermined.
9. Fuel — Undetermined.
10. Miscellaneous — -----

Note: At the present time, there are no specific plans for new generation resources on the AEP System.

4. TRANSMISSION FORECAST FORMS

FORM FE3-1
COLUMBUS SOUTHERN POWER COMPANY
CHARACTERISTICS OF EXISTING TRANSMISSION LINES

Line No.	Line Name (Origin – Terminus)	Voltage (kV) Oper.	Des.	Right-of-Way Length (Miles)	Width (Ft.) Avg.	Max.	Min.	Type of Supporting Structure	No. of Circ.	Year of First Serv.	Substations On Line
345-1	Backjord-Pierce	345	345	0.32	150	150	150	Steel tower	1	1969	
345-2	Pierce-Foster	345	345	23.95	150	150	150	Steel tower	2	1967	
345-3	Sugarcreek-Greene	345	345	0.09	150	150	150	Steel tower	2	1974	
				0.36	150	150	150	Steel pole	2	1974	
				2.72	150	150	150	Steel tower	2	1974	
				4.36	150	150	150	Steel tower	1	1967	
				0.39	150	150	150	Steel pole	1	1967	
				3.55	150	150	150	Steel tower	1	1967	
345-6	Greene-Beatty	345	345	5.42	150	150	150	Steel tower	2	1968	
				39.92	150	150	150	Steel tower	1	1968	
				3.70	150	150	150	Steel tower	2	1968	
345-7	Don Marquis-Bixby	345	345	2.45	150	150	150	Steel tower	2	1969	
				43.41	150	150	150	Steel tower	1	1969	
				17.30	150	150	150	Steel tower	1	1973	
				8.52	150	150	150	Steel tower	2	1971	
345-9	Stuart-Greene	345	345	0.30	150	150	150	Steel tower	2	1970	Clinton
				78.80	150	150	150	Steel tower	1	1970	
				1.20	150	150	150	Steel tower	2	1970	
				0.10	150	150	150	Steel tower	2	1970	
345-10	Stuart-Killen	345	345	NOTE: See Dayton Power & Light Company forecasts for details.							
345-11	Stuart-Foster	345	345	0.60	150	150	150	Steel tower	2	1971	
				55.20	150	150	150	Steel tower	1	1971	
				3.20	150	150	150	Steel tower	2	1971	
345-24	Foster-Sugarcreek	345	345	3.20	150	150	150	Steel tower	2	1967	
				24.10	150	150	150	Steel tower	1	1967	
				0.09	150	150	150	Steel tower	2	1974	
				0.36	150	150	150	Steel tower	2	1974	
				2.72	150	150	150	Steel tower	2	1974	
345-31	Beatty-Bixby	345	345	4.69	150	150	60	Steel tower	1	1971	
				8.52	150	150	60	Steel tower	2	1971	
345-33	Bixby-Corridor	345	345	23.07	150	150	100	Wood pole	1	1973	Kirk
				14.87	150	150	100	Steel tower	2	1973	
345-40	Conesville-Hyatt	345	345	56.98	150	200	100	Steel tower	1	1976	
				9.09	150	200	100	Steel tower	2	1976	
				1.78	150	200	100	Steel pole	2	1976	
				0.48	150	200	100	Steel H-frame	2	1976	
345-41	Stuart-Zimmer	345	345	NOTE: See Cincinnati Gas & Electric Company forecasts for details.							
345-42	Beatty-Altanta (DP&L)	345	345	3.70	150	150	150	Steel tower	2	1969	
				15.20	150	150	150	Steel tower	1	1969	
345-43	Conesville-Bixby	345	345	4.80	150	150	150	Steel tower	1	1974	
				14.87	150	150	150	Steel tower	2	1973	
				50.86	150	150	150	Wood pole	1	1973	
345-44	Zimmer-Port Union	345	345	NOTE: See Cincinnati Gas & Electric Company forecasts for details.							
345-45	Zimmer-Red Bank	345	345	NOTE: See Cincinnati Gas & Electric Company forecasts for details.							
345-46	Red Bank-Terminal	345	345	NOTE: See Cincinnati Gas & Electric Company forecasts for details.							
345-49	Killen-Don Marquis	345	345	NOTE: See Dayton Power & Light Company forecasts for details.							
345-52	Stuart-Atlanta (DP&L)	345	345	0.30	150	150	150	Steel tower	2	1970	
				69.90	150	150	150	Steel tower	1	1974	

NOTE: The preceding lines are commonly owned with the Cincinnati Gas & Electric Company and the Dayton Power & Light Company. Total line mileages are shown.

FORM FE3-1
COLUMBUS SOUTHERN POWER COMPANY
CHARACTERISTICS OF EXISTING TRANSMISSION LINES

Line No.	Line Name (Origin – Terminus)	Voltage (kV) Oper.	Des.	Right-of-Way Length (Miles)	Width (Ft.) Avg.	Max.	Min.	Type of Supporting Structure	No. of Circ.	Year of First Serv.	Substations On Line
345-32	Beatty-Hayden	345	345	0.23	150	150	150	Steel pole	2	1976	
				16.93	150	150	150	Steel tower	2	1976	
				0.21	150	150	150	Steel pole	2	1976	
345-34	Conesville-Corridor	345	345	54.19	100	200	100	Steel tower	1	1957	
345-37	Hayden-Hyatt	345	345	0.23	150	150	150	Steel pole	2	1976	
				12.36	150	150	150	Steel tower	2	1976	
				0.07	150	150	150	Steel pole	2	1976	
345-38	Hayden-Roberts	345	345	5.58	100	100	75	Steel pole	2	1977	
345-39	Hyatt-Corridor	345	345	0.49	150	150	150	Steel H-frame	2	1976	
				1.78	150	150	150	Steel pole	2	1976	
				9.09	150	150	150	Steel tower	2	1976	
				6.32	150	150	150	Steel tower	1	1978	
				6.12	150	150	150	Steel tower	2	1978	
138-1	Roberts-Bethel	138	138	0.19	Company land			Wood pole	1	1975	
				5.16	75	150	50	Steel tower	2	1955	
138-2	Roberts-Kenny	138	138	1.18	50	50	15	Wood pole	1	1975	
				3.18	---	---	---	Underground	1	1975	
138-3	Roberts-Bethel	138	138	5.16	75	150	50	Steel tower	2	1995	Davidson
				0.19	Company land			Wood pole	1	1995	
				0.33	100	100	100	Steel pole	2	1995	
138-4	Bethel-Linworth	138	138	3.02	50	50	50	Steel tower	2	1957	
				2.43	50	50	50	Wood pole	1	1972	
138-5	Picway-Harrison	138	138	1.21	Company land			Steel tower	2	1955	
138-6	Walnut-Bixby	138	138	0.43	Company land			Wood pole	1	1971	
138-8	Groves-Bexley	138	138	4.37	60	60	60	Steel pole	1	1972	
138-9	Bexley-St. Clair	138	138	4.00	Public & RR R/W			Wood pole	1	1972	
138-10	Bixby-LS II	138	138	0.51	100	100	100	Steel tower	2	1949	
				2.03	100	100	100	Wood pole	1	1949	
				0.27	100	100	100	Steel tower	2	1949	
				1.69	90	100	80	Steel pole	2	1990	
138-11	Bixby-W. Lancaster (OP)	138	138	19.03	Undefined			Wood pole	1	1949	
138-12	Poston-Ross	138	138	41.81	100	100	100	Wood pole	1	1950	
				1.01	100	100	100	Steel tower	2	1950	
138-13	Ross-Delano	138	138	0.89	100	100	100	Steel tower	2	1951	
				3.75	100	100	100	Wood pole	1	1951	
138-14	Circleville-Harrion	138	138	14.00	Undefined			Wood pole	1	1951	
				1.18	Undefined			Steel tower	2	1951	
138-15	LS II-Marion	138	138	1.69	90	100	80	Steel pole	2	1990	
				2.94	100	100	100	Steel tower	2	1949	
138-16	Marion-Canal	138	138	3.88	---	---	---	Underground	1	1957	
138-17	St. Clair-Clinton	138	138	4.05	---	---	---	Underground	1	1951	
138-18	Harrison-Marion	138	138	7.01	100	100	100	Wood pole	1	1951	
				3.21	100	100	100	Steel tower	2	1951	
138-19	Bixby-Astor-Groves	138	138	4.67	50	50	10	Wood pole	1	1952	
				3.90	50	50	50	Wood pole	1	1967	Groves
				0.09	50	50	50	Wood pole	1	1974	
				0.10	50	50	50	Wood pole	1	1992	Shannon

FORM FE3-1
COLUMBUS SOUTHERN POWER COMPANY
CHARACTERISTICS OF EXISTING TRANSMISSION LINES

Line No.	Line Name (Origin -- Terminus)	Voltage (kV) Oper.	Des.	Right-of-Way Length (Miles)	Width (Ft.) Avg.	Max.	Min.	Type of Supporting Structure	No. of Circ.	Year of First Serv.	Substations On Line
138-20	Poston-Harrison	138	138	53.64	179	200	80	Wood pole	1	1954	
138-21	Beatty-Wilson	138	138	7.15	100	200	100	Steel tower	2	1953	
				1.42	100	200	100	Steel tower	3	1953	
138-22	Beatty-Wilson	138	138	7.15	100	200	100	Steel tower	2	1968	
				1.42	100	200	100	Steel tower	3	1968	
				0.50	100	100	100	Steel pole	2	1989	Hall Road
138-23	Waverly-Sargents (OVEC)	138	138	3.17	100	200	100	Wood pole	1	1953/81	
				12.72	100	200	100	Wood pole	1	1954	
138-24	Waverly-Seaman	138	138	24.60	100	100	100	Wood pole	1	1954	Adams
				7.95	100	100	100	Wood pole	1	1968	
				3.30	100	100	100	Wood pole	2	1981	
138-25	Scippo-Circleville	138	138	1.89	100	100	100	Wood pole	1	1951	
				0.09	70	70	70	Wood pole	1	1991	
				0.84	70	70	70	Wood pole	2	1991	
				0.15	80	80	80	Wood pole	1	1996	Praxair (cust.)
138-26	Poston-Lick	138	138	0.48	100	100	100	Steel tower	2	1956	
				34.19	100	100	100	Wood pole	1	1956	
				0.28	100	100	100	Wood pole	1	1990	Corwin
138-27	Waverly-Lick	138	138	15.50	100	100	100	Wood pole	1	1980	
				11.38	100	100	100	Steel tower	2	1980	
138-28	Morse-Karl-Genoa	138	138	4.39	50	100	10	Steel tower	2	1958	
				2.05	50	100	10	Steel pole	1	1969	
				3.20	50	100	10	Wood pole	1	1969	
				1.70	50	100	10	Wood pole	1	1969	
				0.04	50	50	50	Wood pole	1	1981	City of Westerville
138-29	OSU-Hess	138	138	0.95	---	---	---	Underground	1	1974	
138-30	Wilson-Hess	138	138	3.17	100	100	53	Steel tower	1	1956	Fifth Ave.
				1.94	---	---	---	Underground	1	1956	
				1.94	---	---	---	Underground	1	1969	
138-31	Wilson-Roberts	138	138	1.42	75	150	50	Steel tower	3	1955	
				3.33	75	150	50	Steel tower	2	1955	
				0.19	75	150	50	Wood pole	1	1975	
---	Wilson-Fisher Road	138	138	1.42	75	150	50	Steel tower	3	1955	
				0.04	75	150	50	Steel tower	2	1955	
				0.31	80	100	50	Steel pole	2	1999	
---	Fisher Road-Roberts	138	138	0.31	80	100	50	Steel pole	2	1999	
				1.29	75	150	50	Steel tower	2	1955	
				1.24	80	100	50	Steel pole	2	1991	Trabue
138-32	Bixby-Buckeye Steel	138	138	0.02	100	100	40	Steel pole	1	1978	
				0.52	100	100	40	Steel tower	2	1971	
				2.19	100	100	40	Wood pole	1	1971	
				2.93	100	100	40	Steel tower	2	1971	
				0.81	100	100	40	Steel pole	1	1971	
138-33	Gay-Vine	138	138	1.22	---	---	---	Underground	1	1970	
				0.28	---	---	---	Underground	1	1975	
138-34	East Broad-Gahanna	138	138	3.42	100	200	100	Wood pole	1	1952	
				1.65	100	200	100	Steel pole	2	1977	
138-35	Hyatt-Sawmill	138	138	5.42	50	100	50	Wood pole	1	1957/79	
138-36	Gahanna-Morse	138	138	5.05	100	200	100	Wood pole	1	1952	
138-37	Corridor-Morse	138	138	2.40	100	100	100	Steel tower	2	1957	
				1.34	100	100	100	Wood pole	2	1981	

FORM FE3-1
COLUMBUS SOUTHERN POWER COMPANY
CHARACTERISTICS OF EXISTING TRANSMISSION LINES

Line No.	Line Name (Origin -- Terminus)	Voltage (kV) Oper.	Des.	Right-of-Way Length (Miles)	Width (Ft.) Avg.	Max.	Min.	Type of Supporting Structure	No. of Circ.	Year of First. Serv.	Substations On Line
138-38	Corridor-Morse	138	138	7.42	100	100	100	Steel tower	2	1957	
138-39	Kirk-East Broad	138	138	10.36	100	100	100	Steel tower	2	1958	Taylor
138-40	Kirk-East Broad	138	138	10.36	100	100	100	Steel tower	2	1958	
138-41	Mound-Canal	138	138	0.44	---	---	---	Underground	1	1977	
				1.39	---	---	---	Underground	1	1957	
138-43	Conesville-Trent	138	138	51.85	100	100	50	Steel tower	2	1962	
				0.06	100	100	50	Steel pole	1	1977	
138-44	Trent-Delaware	138	138	13.26	100	100	50	Steel tower	2	1962	
138-46	Stelzer-St. Clair	138	138	6.93	50	50	15	Wood pole	1	1965	Mifflin
				0.13	50	100	10	Steel tower	2	1976	
138-47	Karl-Kenny	138	138	3.89	50	100	10	Steel tower	2	1958	
				3.08	---	---	---	Underground	1	1975	
138-48	Morse-Clinton-Huntley	138	138	8.28	50	100	10	Steel tower	2	1958	
				3.49	50	100	10	Wood pole	1	1971	Huntley
138-49	Bixby-Groves	138	138	3.00	200	200	200	Steel tower	2	1967	
				1.34	200	200	200	Steel pole	1	1967	
				0.22	50	50	50	Wood pole	1	1981	Griffin Wheel
	Bixby-Groves (2nd Ckt.)	138	138	3.00	200	200	200	Steel tower	2	1957	
138-51	Poston-Strouds Run/ Crooksville (OP)	138	138	0.48	100	100	30	Steel tower	2	1966	
				6.74	100	100	30	Wood pole	1	1966	
138-52	Hyatt-Delaware	138	138	4.07	100	100	100	Wood pole	1	1967	
138-53	Beatty-Canal	138	138	3.50	30	50	15	Wood pole	2	1968	
				3.28	30	50	15	Wood pole	1	1968	
				4.10	30	50	15	Steel pole	1	1968	
				2.13	30	50	15	Steel pole	2	1968	
138-55	Conesville-Ohio Ctl. (OP)	138	138	12.10	100	100	60	Wood pole	1	1973	
138-56	East Broad-Astor	138	138	0.10	50	50	10	Wood pole	1	1974	
				2.64	50	50	10	Wood pole	1	1952	
138-57	Harrison-Beatty	138	138	8.20	100	100	25	Steel tower	2	1953	
138-58	Harrison-S. Central Co-op	138	138	0.26	Company land			Wood pole	1	1970	
138-60	Beatty-McComb	138	138	3.43	30	100	15	Wood pole	2	1973	
				2.33	30	100	15	Wood pole	1	1973	
138-61	Stelzer-Morse	138	138	1.70	50	50	15	Wood pole	1	1965	
138-62	Huntley-Linworth	138	138	0.37	30	30	30	Wood pole	1	1977	
				2.84	30	30	30	Steel pole	1	1977	
138-65	Hyatt-Genoa	138	138	0.40	45	50	35	Wood pole	2	1980	
				8.32	45	50	35	Steel pole	2	1980	
				4.62	45	50	35	Wood pole	1	1980	
				0.84	45	50	35	Wood pole	2	1969	
138-66	Buckeye Steel-Gay	138	138	0.02	40	40	40	Steel pole	1	1978	
				0.71	40	40	40	Steel pole	1	1971	
				2.13	40	40	40	Steel pole	2	1971	
				1.08	---	---	---	Underground	1	1970	
138-67	Poston-Elliott/Dexter (OP)	138	138	7.13	100	100	100	Wood pole	1	1976	

FORM FE3-1
COLUMBUS SOUTHERN POWER COMPANY
CHARACTERISTICS OF EXISTING TRANSMISSION LINES

Line No.	Line Name (Origin -- Terminus)	Voltage (kV) Oper.	Des.	Right-of-Way Length (Miles)	Width (Ft.) Avg.	Max.	Min.	Type of Supporting Structure	No. of Circ.	Year of First Serv.	Substations On Line
138-68	Hyatt-Huntley	138	138	0.40	75	100	30	Wood pole	2	1979	
				6.07	75	100	30	Steel pole	2	1979	
				0.64	75	100	30	Wood pole	1	1979	
				2.10	75	100	30	Steel pole	2	1979	
				2.31	75	100	30	Wood pole	1	1979	
				0.53	75	100	30	Steel pole	2	1979	
138-69	Lick/Addison-Sporn (OP)	138	138	29.09	100	100	100	Wood pole	1	1953	Rio
138-70	Scippo-Scioto Trail	138	138	0.56	100	100	100	Wood pole	1	1951	
				0.78	100	100	100	Wood pole	1	1952	DuPont
				0.84	70	70	70	Wood pole	2	1991	
				0.10	70	70	70	Wood pole	1	1991	
138-71	Scioto Trail-Delano	138	138	10.95	100	100	100	Wood pole	1	1977	
				0.63	100	10	100	Wood pole	1	1982	Dupont
138-72	Sawmill-Bethel	138	138	4.76	50	100	50	Steel tower	2	1957/79	Brookside
138-74	Scippo-Hargus (customer)	138	138	1.46	60	60	60	Wood pole	1	1994	
138-75	St. Clair-Mound	138	138	0.43	---	---	---	Underground	1	1977	
				1.85	---	---	---	Underground	1	1957	
138-77	Mulberry-Waverly	138	138	12.07	100	200	100	Wood pole	1	1953	
				3.11	100	200	100	Wood pole	1	1981	
				1.74	100	100	100	Wood pole	1	1991	
138-78	McComb-Gay	138	138	1.96	---	---	---	Underground	1	1979	
				5.27	50	50	50	Wood pole	1	1979	
138-79	Mulberry-Ross	138	138	1.74	100	100	100	Wood pole	2	1991	
				3.21	100	200	100	Wood pole	1	1953	
				0.72	100	200	100	Wood pole	1	1981	
138-81	Hyatt-Genoa	138	345	11.03	---	---	--	Wood pole	1	1993	
138-82	Corridor-Genoa	138	345	5.22	100	100	100	Wood pole	2	1993	
138-83	Corridor-Gahanna	138	345	6.87	---	---	---	Wood pole	1	1993	
138-85	Kirk-W. Millersport (OP)	138	138	7.94	Undefined			Wood pole	1	1949	
---	Conesville-Newark Ctr. (OP)	138	138	27.00	100	100	100	Steel tower	2	1958/98	
---	Kirk-Newark Ctr. (OP)	138	138	18.50	100	100	100	Steel tower	2	1958/98	
138-88	Hess-Vine	138	138	2.19	---	---	---	Underground	1	1970	
				0.30	---	---	---	Underground	1	1975	
138-92	Vine-City of Columbus-E.	138	138	1.05	Railroad R/W			Wood pole	1	1977	
138-98	Vine-City of Columbus-W.	138	138	1.21	Railroad R/W			Wood pole	1	1976	
138-96	Poston-W. Lancaster (OP)	138	138	34.97	Undefined			Wood pole	1	1949	
138-99	St. Clair-Vine	138	138	1.09	60	60	60	Steel pole	1	1993	
				1.30	---	---	---	Underground	1		
138-102	Clinton-OSU	138	138	4.48	---	---	---	Underground	1	1979	
69-7	Stuart-Seaman	69	138	24.88	100	100	100	Wood pole	1	1969	Raven
69-63	Dublin-Sawmill	69	138	6.16	30	50	10	Wood pole	1	1977	
69-70	Highland-Wilmington (DP&L)	69	138	6.67	100	150	100	Wood pole	1	1967	
69-72	Addison-Haners	69	138	4.07	100	100	100	Wood pole	1	1968	
69-73	Seaman-Highland	69	138	17.05	100	100	100	Wood pole	1	1970	

FORM FE3-1
COLUMBUS SOUTHERN POWER COMPANY
CHARACTERISTICS OF EXISTING TRANSMISSION LINES

Line No.	Line Name (Origin -- Terminus)	Voltage (kV) Oper.	Des.	Right-of-Way Length (Miles)	Width (Ft.) Avg.	Max.	Min.	Type of Supporting Structure	No. of Circ.	Year of First Serv.	Substations On Line
FC80	E. Broad-Yearling	138	138	3.50	60	100	30	Wood pole	1	1977	
				1.00	60	100	30	Wood pole	2	1977	
FD80	Bexley-Yearling	138	138	2.00	60	100	30	Wood pole	1	1977	

FACILITIES UNDER CONSTRUCTION

- None -

FORM FE3-1
OHIO POWER COMPANY
CHARACTERISTICS OF EXISTING TRANSMISSION LINES

Line No.	Line Name (Origin – Terminus)	Voltage (kV) Oper.	Voltage (kV) Des.	Right-of-Way Length (Miles)	Right-of-Way Width (Ft.) Avg.	Max.	Min.	Type of Supporting Structure	No. of Circ.	Year of First Serv.	Substations On Line
BM00	Kammer-Marysville	765	765	49.90 100.19	200	200	200	Steel tower Al. tower	1	1972	
BV20	Gavin-Mountaineer (AP)	765	765	2.61	200	200	200	Steel tower	1	1974	
BM15	Gavin-Marysville	765	765	124.40	200	200	200	Steel tower	1	1974	
BM20	Don Marquis-Hanging Rock	765	765	6.73 28.44	200	200	200	Steel tower Al. tower	1	1969/76	
BM25	Kammer-S. Canton	765	765	79.60	200	200	200	Steel tower	1	1981	
BV25	Amos (AP)-Hanging Rock	765	765	31.23	200	200	200	Steel tower	1	1976	N. Proctorville
BV40	Culloden (AP)-Gavin	765	765	0.50	200	200	200	Steel tower	1	1974/76	
BW35	Baker (KP)-Hanging Rock	765	765	1.67	200	200	200	Steel tower	1	1969/76	
BX31	Dumont (I&M)-Marysville	765	765	76.24	200	200	200	Steel tower	1	1972	
BX50	Hanging Rock-Jefferson (I&M)	765	765	6.14	200	200	200	Steel tower	1	1984	
DA05	Collier (DL)-Tidd	345	345	0.31	150	150	150	Steel tower	1	1970	
DA13	Fostoria Central-Galion (OE)	345	345	2.39 44.96	150	150	150	Steel tower Al. tower	1	1971	
DA15	Fostoria Central-Lemoyne (TE)	345	345	19.29	150	150	150	Steel tower	1	1969	
DA18	Galion (OE)-Muskingum River	345	345	16.87 86.47	150	150	150	Steel tower Al. tower	1	1971	Ohio Central
DA22	Fostoria Central-Bayshore (TE)	345	345	19.29	150	150	150	Steel tower	1	1972	
DA28	Miami (DP&L)-S.W. Lima	345	345	0.97 18.04	150	150	150	Steel tower Al. tower	1	1969	
DA45	South Canton-Star (OE)	345	345	0.69	150	150	150	Steel tower	1	1968	
DA50	Sammis (OE)-South Canton	345	345	0.70	150	150	150	Steel tower	1	1968	
DA01	Hanna (OE)-Canton Central	345	345	1.20 4.77	150	150	150	Steel tower Al. tower	1	1972	
DA51	Hyatt-Tangy (OE)	345	345	0.25	150	150	150	Steel tower	1	1975/87	
DA52	Marysville-Tangy (OE)	345	345	23.05	150	150	150	Steel tower	1	1975/87	
DA65	Tidd-Wylie Ridge (MP)	345	345	0.31	150	150	150	Steel tower	1	1973	
DC63	Tidd-Canton Central	345	345	52.40	150	150	150	Steel tower	1	1972	
DE40	E. Lima-Fostoria Central	345	345	5.35 34.47	150	150	150	Steel tower Al. tower	1	1969	
DE60	E. Lima-S.W. Lima	345	345	22.00	150	150	150	Steel tower	1	1969	
DE65	E. Lima-Marysville	345	345	47.15	150	150	150	Steel tower	1	1955	
DH74	Marysville-Hyatt #2	345	345	23.30	150	150	150	Steel tower	1	1975	
DH75	Hyatt-W. Millersport	345	345	37.80	150	150	150	Steel tower	1	1975	
DM41	Kammer-Muskingum River	345	345	52.30	150	150	150	Steel tower	1	1967	
DM42	Kammer-Tidd	345	345	32.00	150	150	150	Steel tower	1	1967	W. Bellaire
DM80	Muskingum River-Tidd	345	345	83.57	150	150	150	Steel tower	1	1965	
DM90	Muskingum River-W. Millersport #1	345	345	54.00	150	150	150	Steel tower	1	1973	

FORM FE3-1
OHIO POWER COMPANY
CHARACTERISTICS OF EXISTING TRANSMISSION LINES

Line No.	Line Name (Origin -- Terminus)	Voltage (kV) Oper.	Des.	Right-of-Way Length (Miles)	Width (Ft.) Avg.	Max.	Min.	Type of Supporting Structure	No. of Circ.	Year of First Serv.	Substations On Line
DM95	Muskingum River-W. Millersport #2	345	345	54.00	150	150	150	Steel tower	1	1976	
DM05	Marysville-S.W. Lima	345	345	55.40	150	150	150	Steel tower	1	1975	
DV51	Muskingum River-Sporn	345	345	46.51	150	150	150	Steel tower	2	1959	
DX55	E. Lima-Robison Park (I&M)	345	345	42.99	150	150	150	Steel tower	1	1957	
DC80	S. Canton-Canton Central #1	345	345	8.12	150	150	150	Steel tower	1	1978	Southeast Canton
DC81	S. Canton-Canton Central #2	345	345	8.15	150	150	150	Steel tower	1	1978	
FA00	Bluebell (OE)-Canton Central	138	138	0.36	100	100	100	Wood pole	1	1968	
FA03	Canton Central-Cloverdale (OE)	138	138	0.38	100	100	100	Wood pole	1	1968	
FA04	E. Wooster-Cloverdale (OE)	138	138	0.50	70	70	70	Wood pole	1	1987	
FA07	Corner (MP)-Muskingum	138	138	0.33 4.37	100	100	100	Steel tower Wood pole	1	1968	
FA10	E. Liverpool-Wylie Rider (MP)	138	138	0.96	100	100	100	Steel tower	1	1962	
FA15	E. Lima-Richland (TE)	138	138	27.74 6.57	100 100	100 100	100 100	Wood pole Steel pole	1 2	1967 1992	Campbell Rd. E. Leipsic
FA20	Hillsboro-Hutchings (DP&L)	138	138	37.36	100	100	100	Wood pole	1	1967	
FA21	Hillsboro-Maysville (KU)	138	138	33.55 0.81	100 80	100 80	100 80	Wood pole Wood pole	1 1	1951 1995	
FA25	Howard-Brookside (OE)	138	138	7.99	100	100	100	Steel tower	1	1930	
FA26	Howard-City of Shelby	138	138	1.84 0.53	100 70	100 70	100 70	Steel tower Wood pole	1	1982	
FA27	Lockwood Rd.-Richland (TE)	138	138	0.21	100	100	100	Wood pole	1	1966/82	
FA31	Millbrook Pk.-W.T. Love (Hamilton)	138	138	1.60	100	100	100	Steel tower	1	1982	
FA40	N. Portsmouth-Sargents (OVEC)	138	138	16.30	100	100	100	Wood pole	1	1967/76	S. Lucasville, Wakefield
FA50	Tidd-Weirton (MP)	138	138	3.71 2.52	100	100	100	Steel tower Wood pole	1	1955	
FA51	S. Toronto-Tidd/Wierton (MP)	138	138	1.03	100	100	100	Steel tower	1	1957	
FA60	Torrey-Cloverdale (OE)	138	138	0.37	100	100	100	Steel tower	1	1954	
FA70	W. Canton-S. Akron (OE)	138	138	0.82	100	100	100	Steel tower	1	1955	
FA80	Fremont Center-Lemoyne (TE)	138	138	18.80 19.92	100	100	100	Steel tower Wood pole	1	1974	Fremont
FA81	West End-Lemoyne (TE)	138	138	18.55	100	100	100	Steel pole	1	1963	
FC05	Academia-Howard	138	138	38.15 0.23	100	100	100	Steel tower Wood pole	1 1	1962/76 1994	N. Lexington
FC06	Academia-Ohio Central	138	138	37.35	100	100	100	Steel tower	1	1968/76	
FC07	Academia-West Mt. Vernon	138	138	6.00	100	100	100	Steel tower	1	1976	
FC34	Fostoria Central-Buckley Road	138	138	4.00 2.60	100	150	50	Steel tower Wood pole	1	1976	
FC40	Bucyrus Center-Howard	138	138	16.70	100	100	100	Steel tower	1	1962	Sulphur Springs
FC60	S.E. Canton-Canton Central	138	138	3.41	100	100	100	Steel tower	1	1966/78	

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Line No.	Line Name (Origin – Terminus)	Voltage (kV) Oper.	Voltage (kV) Des.	Right-of-Way Length (Miles)	Right-of-Way Width (Ft.) Avg.	Right-of-Way Width (Ft.) Max.	Right-of-Way Width (Ft.) Min.	Type of Supporting Structure	No. of Circ.	Year of First Serv.	Substations On Line
FC64	Carrolton-Sunnyside	138	138	19.67	100	100	100	Steel tower	1	1975	
FC65	Carrolton-Tidd	138	138	29.79	100	100	100	Steel tower	1	1975	S. Cadiz
FC70	Canton Central-Wagenhals #1	138	138	2.00	100	100	100	Steel tower	1	1969	
FC71	Canton Central-Wagenhals #2	138	138	2.00	100	100	100	Steel tower	1	1969	
FC72	N. Portsmouth-Ctl. Portsmouth	138	138	6.00	100	100	100	Wood pole	1	1976	
FC76	Crooksville-N. Newark	138	138	32.60	100	100	100	Wood pole	1	1970	
FC85	Crooksville-Muskingum	138	138	40.50	100	100	100	Steel tower	1	1970	N. Muskingum, Cannelville
FD08	Crooksville-S. Lancaster	138	138	26.80	100	100	100	Steel tower	1	1952/78	
FD20	E. Lima-Ford	138	138	3.40	100	100	100	Steel tower	1	1956	
FD40	E. Lima-Haviland	138	138	35.10	100	100	100	Steel tower	1	1956	
FD62	E. Lima-New Liberty	138	138	25.90	100	100	100	Steel tower	1	1955/80	
FD64	E. Lima-N. Findlay	138	138	29.20	100	100	100	Steel tower	1	1955/80	N. Woodcook
FD80	E. Lima-Rockhill	138	138	4.40	100	100	100	Steel tower	1	1955	
FD90	E. Lima-S. Kenton	138	138	7.20 22.60	100	100	100	Steel tower Wood pole	1	1967	W. Newton
FD98	E. Lima-Sterling	138	138	8.40 5.95	100	100	100	Steel tower Wood pole	1	1970	Thayer Road
FE20	E. Lima-W. Lima	138	138	12.40	100	100	100	Steel tower	1	1955	N.W. Lima, Woodlawn
FE60	E. Wheelersburg-Millbrook Park	138	138	8.70	100	100	100	Steel tower	1	1962	Dogwood Ridge
FE63	E. Wheelersburg-Texas Eastern	138	138	2.00	100	100	100	Steel tower	1	1962	
FE68	E. Wooster-Wooster	138	138	5.15 3.43	100	100	100	Steel tower Wood pole	1	1974	
FE69	E. Wooster-S. Canton	138	138	6.75 25.25	100	100	100	Steel tower Wood pole	1	1974	Canal Road, Apple Creek
FE73	Fostoria Central-New Liberty	138	138	13.30 6.66	100	100	100	Steel tower Steel tower	1	1955	Findlay Ct.
FE74	Fostoria Central-N. Findlay	138	138	10.28 1.60 0.10	100	100	100	Steel tower Steel tower Wood pole	1	1955	N.E. Findlay
FE75	Fostoria Central-Greenlawn/ Howard	138	138	47.47 4.95	75	100	50	Steel tower Wood pole	1	1974/76	
FE77	Fostoria Central-West End	138	138	1.70	100	100	100	Steel tower	1	1976	
FE80	Ford-Rockhill	138	138	1.60	100	100	100	Steel tower	1	1956	
FE83	Fremont Center-Tiffin Center	138	138	2.12 10.48	50	100	50	Steel tower Wood pole	1	1974	
FD85	Greenlawn-Tiffin Center	138	138	3.30	100	100	50	Wood pole	1	1974	
FD90	Hillsboro-Millbrook Park	138	138	51.80	100	100	100	Wood pole	1	1967	
FD91	Gavin-Millbrook Park	138	138	49.45	100	100	100	Steel tower	1	1974/93	
FD92	Gavin-N. Proctorville	138	138	49.25	100	100	100	Steel tower	1	1974/94	N. Crown City

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Line No.	Line Name (Origin -- Terminus)	Voltage (kV) Oper.	Des.	Right-of-Way Length (Miles)	Width (Ft.) Avg.	Max.	Min.	Type of Supporting Structure	No. of Circ.	Year of First Serv.	Substations On Line
FF20	Howard-Philo	138	138	80.90	100	100	100	Steel tower	1	1955	Millwood
FF40	West End-Howard	138	138	44.90	100	100	100	Steel tower	1	1955	S. Tiffin, Chatfield
FF60	Kammer-OFA	138	138	2.45	100	100	100	Wood pole	1	1958	
FF80	Kammer-Ormet 1	138	138	1.71	100	100	100	Steel tower	1	1957	
FF81	Kammer-Ormet 2	138	138	1.71	100	100	100	Steel tower	1	1957	
FF82	Kammer-Ormet 3	138	138	1.55	100	100	100	Steel tower	1	1958	
FF83	Kammer-Ormet 4	138	138	1.55	100	100	100	Steel tower	1	1958	
FF87	Kammer-W. Bellaire	138	138	12.85	100	100	100	Steel tower	1	1971	
FG00	Millbrook Park-South Point	138	138	34.60	100	100	100	Steel tower	1	1949	
FG05	Millbrook Park-N. Portsmouth	138	138	3.40	100	100	100	Wood pole	1	1967/76	
FG80	Muskingum-Summerfield	138	138	25.31 10.87	100	100	100	Steel tower Wood pole	1	1956	S. Cumberland, S. Caldwell
FG84	Muskingum-W. Cambridge	138	138	42.97	100	100	100	Steel tower	1	1969	East New Concord
FH20	Newcomerstown-S. Coshocton	138	138	14.35	100	100	100	Wood pole	1	1957	
FH44	W. Cambridge-Newcomerstown	138	138	14.94	100	100	100	Steel tower	1	1969	
FH45	Newcomerstown-W. New Philadelphia	138	138	17.60	100	100	100	Steel tower	1	Not Available	Hillview
FH66	W. Millersport-S. Central Co-op (N. Fairfield)	138	138	0.23	70	70	70	Wood pole	1	1981	
FH80	N. Newark-Ohio Central	138	138	21.50	100	100	100	Wood pole	1	1964	Frazeysburg
FJ23	West Millersport-N. Newark	138	138	11.44 6.91	100	100	100	Steel tower Wood pole	1	1974	Heath
FJ40	N. Newark-W. Mt. Vernon	138	138	1.48 20.28	100	100	100	Steel tower Wood pole	1	1954	Sharp Road
FJ45	N. Proctorville-South Point	138	138	10.86	100	100	100	Steel tower	1	1974	
FJ59	Ohio Central-S. Coshocton	138	138	14.44 1.93	100	100	100	Steel tower Wood pole	1	1975	
FJ61	Ohio Central-Wooster	138	138	14.74 37.87 0.85	100	100	100	Steel tower Wood pole Wood pole	1	1975 1995	W. Coshocton, S. Millersburg, W. Millersburg
FJ62	Ohio Central-Zanesville	138	138	1.86 10.37	80	80	80	Steel tower Wood pole	1	1975	N. Zanesville, Powelson
FJ65	Ohio Central-Philo	138	138	18.02 0.45	100	100	100	Steel tower Wood pole	1	1962	E. Zanesville
FJ74	Ordnance Jct.-Sterling	138	138	1.50	100	100	100	Steel tower	1	1970/78	
FJ75	Ordnance Jct.-S.W. Lima	138	138	3.90	100	100	100	Steel tower	1	1970/78	Shawnee Road
FK13	Philo-S. Canton	138	138	68.21 6.31	100	100	100	Steel tower Wood pole	2	1965/78	Bridgeville, W. Dover, N. Strasburg, Sugar Creek
FK40	Philo-Zanesville	138	138	12.20	100	100	100	Steel tower	1	1952	W. Philo

FORM FE3-1
OHIO POWER COMPANY
CHARACTERISTICS OF EXISTING TRANSMISSION LINES

Line No.	Line Name (Origin -- Terminus)	Voltage (kV) Oper.	Des.	Right-of-Way Length (Miles)	Width (Ft.) Avg.	Max.	Min.	Type of Supporting Structure	No. of Circ.	Year of First Serv.	Substations On Line
FK83	Rockhill-W. Lima	138	138	9.90	100	100	100	Steel tower	1	1970	Eastown Road
FK84	S.E. Canton-S. Canton	138	138	7.20	100	100	100	Steel tower	1	1968/78	Faircrest
FK87	S. Canton-Wayview	138	138	4.02 10.08	50	50	50	Steel tower Steel pole	1	1975	Promway
FK90	S. Canton-W. New Philadelphia	138	138	19.20	100	100	100	Steel tower	2	1968	Bolivar
FK93	S. Canton-Timken (Richville)	138	138	2.67	100	100	100	Steel tower	1	1965/78	
FK95	S. Canton-Torrey	138	138	2.90	100	100	100	Steel tower	1	1968	
FL00	W. Mt. Vernon-S. Kenton	138	138	59.10	100	100	100	Wood pole	1	1954	Fulton,N. Waldo Hedding Rd.
FL06	S.E. Canton-Sunnyside	138	138	3.20	100	100	100	Steel tower	1	1968/78	
FL07	S.E. Canton-Timken	138	138	7.06 0.16	100 80	100 80	100 80	Steel tower Wood pole	1	1966/78	AGA Gas
FL09	S. Lancaster-W. Lancaster	138	138	3.90	100	100	100	Steel tower	1	1952/78	
FL30	S.W. Lima-W. Moulton	138	138	13.30	100	100	100	Wood pole	1	1969	
FL35	S.W. Lima-W. Lima	138	138	4.60	100	100	100	Steel tower	1	1970	
FL45	Steubenville-Tidd	138	138	7.30	100	100	100	Steel tower	1	1970	
FL50	Summerfield-Texas Eastern (Berne)	138	138	3.50	100	100	100	Wood pole	1	1961	
FL80	Sunnyside-Torrey	138	138	3.90	100	100	100	Steel tower	1	Not Available	
FM00	Sunnyside-Wagenhals	138	138	2.23 1.44	100	100	100	Wood pole Steel tower	1	1966	
FM44	Timken-Timken (Richville)	138	138	1.90	100	100	100	Steel tower	1	1965/78	
FM80	Tidd-Satralloy	138	138	1.70	80	80	80	Wood pole	1	1952	
FN00	Tidd-Wagenhals	138	138	53.40	100	100	100	Steel tower	1	1945	E. Amsterdam, Malvern, Broadacre
FN40	Tidd-Wheeling Steel 1	138	138	5.10	100	100	100	Steel tower	1	1964	
FN41	Tidd-Wheeling Steel 2	138	138	1.27 3.88	100	100	100	Steel tower Wood pole	1	1964	
FN80	Torrey-W. Canton	138	138	2.65 5.22	100	100	100	Steel tower Steel pole	1	1955	Reedurban Miles Avenue
FP20	Wagenhals-W. Canton	138	138	10.10	100	100	100	Steel tower	1	1955	N.E. Canton
FP55	Wagenhals-Republic Steel 1	138	138	0.65	100	100	100	Steel tower	1	1966	
FP56	Wagenhals-Republic Steel 2	138	138	0.68	100	100	100	Steel tower	1	1966	
FP65	Wayview-W. Canton	138	138	0.85 3.31	50	50	50	Steel tower Steel pole	1	1975	Belden Village
FP80	W. Lancaster-W. Millersport	138	138	14.40	100	100	100	Wood pole	1	1973	S. Baltimore
FP81	W. Lancaster-Zanesville	138	138	45.82	100	100	100	Steel tower	1	1970	
FV28	Darrah (AP)-N. Proctorville	138	138	3.50	100	100	100	Steel tower	1	1974	E. Proctorville
FV33	Dexter-Sporn	138	138	24.90	100	100	100	Steel tower	1	1973	Meigs No. 1

FORM FE3-1
OHIO POWER COMPANY
CHARACTERISTICS OF EXISTING TRANSMISSION LINES

Line No.	Line Name (Origin -- Terminus)	Voltage (kV) Oper.	Des.	Length (Miles)	Right-of-Way Width (Ft.) Avg.	Max.	Min.	Type of Supporting Structure	No. of Circ.	Year of First Serv.	Substations On Line
FV34	E. Huntington (AP)-N. Proctorville	138	138	3.86	100	100	100	Steel tower	1	1974	
FV36	Gavin-Sporn #1	138	138	5.40	100	100	100	Steel tower	1	1958/94	
FV38	Gavin-Sporn #2	138	138	7.80	100	100	100	Steel tower	1	1974/93	
FV45	Sporn-Lick/Addison (CS)	138	138	24.05	100	100	100	Steel tower	1	1951	
FV60	South Point-Sporn	138	138	59.78 0.09	100	100	100	Steel tower Wood pole	1	1949 1992	
FV75	South Point-Tristate (AP)	138	138	0.48	100	100	100	Steel tower	1	1967	
FW40	Bellefonte (KP)-E. Wheelersburg	138	138	26.90	100	100	100	Steel tower	1	1962	Hanging Rock
FW45	Bellefonte (KP)-N. Proctorville	138	138	19.65 0.09	100	100	100	Steel tower Wood pole	1	1974	
FX30	Haviland-Milan (I&M)	138	138	11.03	100	100	100	Steel tower	1	1964	
FX60	Lincoln (&M)-Sterling	138	138	43.68 5.96	100	100	100	Steel tower Wood pole	1	1970	North Delphos East Side
FX65	Lockwood Rd-Robison Park (I&M)	138	138	14.74	100	100	100	Wood pole	1	1966	South Hicksville
FY00	W. Bellaire-Windsor (MP)	138	138	5.39 11.49	100	100	100	Steel tower Wood pole	1	1971	Tiltonville
FY10	Brues (WP)-W. Bellaire	138	138	4.7	100	100	100	Steel tower	1	1971	
FY40	George Washington (WP)-Tidd	138	138	0.26	100	100	100	Steel tower	1	1953	
FY60	Kammer-Tidd/Brues (WP)	138	138	0.41	100	100	100	Steel tower	1	1957	
FY70	Muskingum-Natrium (WP)	138	138	59.10	100	100	100	Steel tower	1	1953	Caldwell, Somerton
FY80	Natrium (WP)-Summerfield	138	138	27.00	100	100	100	Steel tower	1	1953	Switzer
FZ93	College Corner (I&M)-Trenton 1 (CG&E)	138	138	---	100	100	100	Steel tower	1	1941	
FZ94	College Corner (I&M) Trenton 2 (CG&E)	138	138	23.92	100	100	100	Steel tower	1	1941	
FZ95	Hutchings (DP&L)-Trenton (CG&E)	138	138	4.89	100	100	100	Wood pole	1	1967	
FZ96	Sporn-Kaiser No. 4	138	138	5.67	100	100	100	Steel tower	1	1958	
FZ97	Sporn-Kaiser No. 3	138	138	5.67	100	100	100	Steel tower	1	1958	
FZ98	Sporn-Kaiser No. 2	138	138	4.25	100	100	100	Steel tower	1	1957	
FZ99	Sporn-Kaiser No. 1	138	138	4.25	100	100	100	Steel tower	1	1956	
F151	Crooksville-Poston/Strouds Run (CS)	138	138	27.80	100	100	100	Steel tower	1	1973	Sunnyhill #9
F153	Conesville Prep. Plant Tap	138	138	0.63	80	80	80	Wood pole	1	1984	
F167	Dexter-Poston/Elliott (CS)	138	138	17.04	100	100	100	Steel tower	1	1973	Meigs #2
F169	Addison/Lick (CS)-Sporn	138	138	24.05 0.29	100 80	100 80	100 80	Steel tower Wood pole	1	1960/81	
F185	W. Millersport-Kirk (CS)	138	138	8.06	100	100	100	Steel tower Wood pole	1 1	1974	Millersport, W. Hebron

FORM FE3-1
OHIO POWER COMPANY
CHARACTERISTICS OF EXISTING TRANSMISSION LINES

Line No.	Line Name (Origin -- Terminus)	Voltage (kV) Oper.	Des.	Length (Miles)	Right-of-Way Width (Ft.) Avg.	Max.	Min.	Type of Supporting Structure	No. of Circ.	Year of First Serv.	Substations On Line
HA02	Fremont-City of Clyde (East)	69	138	12.23	75	80	50	Wood pole	1	1975	
HG42	E. Amsterdam-Carroll Co-op	69	138	8.24	100	100	100	Wood pole	1	1980	
HI82	Millbrook Park-Pedro (CS)	69	138	6.50	100	100	100	Steel tower	1	1960	
				0.62	70	70	70	Wood pole	1	1982	
HM99	Wayview-Hoover North	69	138	1.06	50	50	50	Steel tower	1	1975	Timken
				0.66	50	50	50	Wood pole	1		Research
HW50	Millbrook Park-Siloam (KP)	69	138	1.70	100	100	100	Steel tower	1	1969	
---	Meigs #2-Wilkesville (CS)	138	138	0.20	80	80	80	Wood pole	1	1974	
KQ16	Sterling-Teledyne #2	34.5	138	0.91	50	50	50	Wood pole	1	1973	
	138 KV FACILITIES GRANTED POWER SITING CERTIFICATE										
P-17	Fostoria Central-Upper Sandusky Ctr.	138	138	22.70	90	100	80	Wood pole	1	---	

FACILITIES UNDER CONSTRUCTION

- None -

FORM FE3-2
COLUMBUS SOUTHERN POWER COMPANY
SUMMARY OF EXISTING SUBSTATIONS

Substation Name	Voltage (kV)	Line Association(s)		Line Existing or Prop.
Beatty	345	Greene-Beatty	345-6	E
	345	Beatty-Bixby	345-31	E
	345	Stuart-Beatty	345-42	E
	345	Beatty-Hayden	345-32	E
	138	Beatty-Wilson	138-21	E
	138	Beatty-Wilson	138-22	E
	138	Beatty-Canal	138-53	E
	138	Harrison-Beatty	138-57	E
	138	Beatty-McComb	138-60	E
Beckjord	345	Beckjord-Pierce	345-1	E
Bixby	345	Don Marquis-Bixby	345-7	E
	345	Beatty-Bixby	345-31	E
	345	Conesville-Bixby	345-43	E
	345	Bixby-Corridor	345-33	E
	138	Walnut-Bixby	138-6	E
	138	Bixby-W. Lancaster (OP)	138-11	E
	138	Bixby-LS II	138-150	E
	138	Bixby-Astor	138-19	E
	138	Bixby-Buckeye Steel	138-32	E
	138	Bixby-Groves	138-49	E
	138	Bixby-Groves (2nd ckt.)		E
Conesville	345	Conesville-Bixby	345-43	E
	345	Conesville-Corridor	345-34	E
	345	Conesville-Hyatt	345-40	E
	138	Conesville-Trent	138-43	E
	138	Conesville-Ohio Central	138-55	E
	138	Conesville-Newark Ctr.	---	E
Corridor	345	Bixby-Corridor	345-33	E
	345	Hyatt-Corridor	345-39	E
	345	Corridor-Conesville	345-34	E
	138	Corridor-Morse	138-38	E
	138	Corridor-Blendon	138-50	E
	138	Corridor-Gahanna	138-83	E
	138	Corridor-Genoa	138-82	E
Don Marquis	345	Don Marquis-Bixby	345-7	E
	345	Killen-Don Marquis	345-49	E
Foster	345	Pierce-Foster	345-2	E
	345	Stuart-Foster	345-11	E
	345	Foster-Sugarcreek	345-24	E
Greene	345	Sugarcreek-Greene	345-3	E
	345	Greene-Beatty	345-6	E
	345	Stuart-Greene	345-9	E
Hayden	345	Beatty-Hayden	345-32	E
	345	Hayden-Hyatt	345-37	E
	345	Hayden-Roberts	345-38	E
Hyatt	345	Hyatt-Hyatt (OP) #1 and #2	---	E
	345	Hyatt-Corridor	345-39	E
	345	Hyatt-Hayden	345-37	E
	345	Hyatt-Conesville	345-40	E
	138	Hyatt-Sawmill	138-35	E
	138	Hyatt-Delaware	138-52	E
	138	Hyatt-Genoa	138-65	E
	138	Hyatt-Genoa	138-81	E
	138	Hyatt-Huntley	138-68	E
	138	Hyatt-Sawmill	CS-P12	P
Kirk	345	Bixby-Corridor	345-33	E
	138	Kirk-East Broad	138-39	E
	138	Kirk-East Broad	138-40	E
	138	Kirk-Newark Ctr.	---	E
	138	Kirk-W. Millersport (OP)	138-85	E
Pierce	345	Beckjord-Pierce	345-1	E
	345	Pierce-Foster	345-2	E
Roberts	345	Hayden-Roberts	345-38	E
	138	Roberts-Bethel	138-1	E
	138	Roberts-Kenny	138-2	E
	138	Wilson-Roberts	138-31	E
	138	Roberts-Bethel	138-3	E
	138	Roberts-Trabue-Wilson	---	E
Stuart	345	Stuart-Greene	345-9	E
	345	Stuart-Killen	345-10	E
	345	Stuart-Foster	345-11	E
	345	Stuart-Zimmer	345-41	E
	345	Stuart-Beatty	345-42	E
	69	Stuart-Seaman	69-7	E
Zimmer	345	Zimmer-Red Bank	345-45	E
	345	Zimmer-Port Union	345-44	E
	345	Stuart-Zimmer	345-41	E
Adams	138	Waverly-Seaman	138-24	E
Addison	138	Lick-Addison-Sporn (OP)	138-69	E
	69	Addison-Haners	69-72	E
Astor	138	Bixby-Astor	138-19	E
	138	East Broad-Astor	138-56	E
Bethel	138	Bethel-Roberts	138-1	E
	138	Bethel-Roberts	138-3	E
	138	Bethel-Linworth	138-4	E
	138	Bethel-Sawmill	138-72	E
Bexley	138	Groves-Bexley	138-8	E
	138	Bexley-St. Clair	138-9	E
	138	Bexley-Yearling	FD80	E
Blendon	138	Corridor-Morse	138-37	E
Brookside	138	Bethel-Sawmill	138-72	E
Buckeye Steel	138	Bixby-Buckeye Steel	138-32	E
	138	Buckeye Steel-Gay	138-66	E
Canal	138	Marion-Canal	138-16	E
	138	Mound-Canal	138-41	E
	138	Beatty-Canal	138-53	E
Circleville	138	Circleville-Harrison	138-14	E
	138	Circleville-Scippo	138-25	E
City of Columbus	138	Vine-City of Columbus (E)	138-92	E
	138	Vine-City of Columbus (W)	138-98	E
Clinton	138	St. Clair-Clinton	138-17	
	138	Morse-Clinton-Huntley	138-48	
	138	Clinton-OSU	138-102	
Corwin	138	Poston-Lick	138-26	E
Davidson	138	Roberts-Bethel	138-3	E
Delano	138	Ross-Delano	138-13	E
	138	Scioto Trail-Delano	138-71	E
Delaware	138	Trent-Delaware	138-44	E
	138	Hyatt-Delaware	138-52	E
DuPont	138	Scioto Trail-Circleville	138-25	E
	138	Scioto Trail-Delano	138-71	E

FORM FE3-2
COLUMBUS SOUTHERN POWER COMPANY
SUMMARY OF EXISTING SUBSTATIONS

Substation Name	Voltage (kV)	Line Association(s)		Line Existing or Prop.
East Broad	138	East Broad-Gahanna	138-34	E
	138	Kirk-East Broad	138-39	E
	138	Kirk-East Broad	138-40	E
	138	East Broad-Astor	138-56	E
	138	East Broad-Yearling	FC80	E
Elliott	138	Poston-Elliott/Dexter (OP)	138-67	E
Fifth Avenue	138	Wilson-Hess	138-30	E
Gahanna	138	East Broad-Gahanna	138-34	E
	138	Gahanna-Corridor	138-83	E
	138	Gahanna-Morse	138-36	E
Gay	138	Gay-Vine	138-33	E
	138	Buckeye Steel-Gay	138-66	E
	138	McComb-Gay	138-78	E
Genoa	138	Morse-Karl-Genoa	138-28	E
	138	Genoa-Hyatt	138-65	E
	138	Genoa-Hyatt	138-81	E
	138	Genoa-Corridor	138-82	E
Groves	138	Groves-Bexley	138-8	E
	138	Bixby-Astor	138-19	E
	138	Bixby-Groves	138-49	E
	138	Bixby-Groves (2nd ckt)		E
Hall Road	138	Wilson-Beatty	138-22	E
Harrison	138	Picway-Harrison	138-5	E
	138	Circleville-Harrison	138-14	E
	138	Harrison-Marion	138-18	E
	138	Poston-Harrison	138-20	E
	138	Harrison-Beatty	138-57	E
	138	Harrison-South Central	138-58	E
Hess	138	OSU-Hess	138-29	E
	138	Hess-Wilson	138-30	E
	138	Hess-Vine	138-88	E
Huntley	138	Morse-Clinton-Huntley	138-48	E
	138	Huntley-Linworth	138-62	E
	138	Hyatt-Huntley	138-68	E
	138	Huntley-Orange	CSP-14	P
Karl	138	Morse-Karl-Genoa	138-28	
	138	Karl-Kenny	138-47	E
Kenny	138	Roberts-Kenny	138-2	E
	138	Kenny-Karl	138-47	E
Lick	138	Poston-Lick	138-26	E
	138	Lick-Waverly	138-27	E
	138	Lick-Addison-Sporn (OP)	138-69	E
Linworth	138	Bethel-Linworth	138-4	E
	138	Huntley-Linworth	138-62	E
LS II	138	LS II-Bixby	138-10	E
	138	LS II-Marion	138-15	E
Marion	138	LS II-Marion	138-15	E
	138	Marion-Canal	138-16	E
	138	Harrison-Marion	138-18	E
McComb	138	Beatty-McComb	138-60	E
	138	McComb-Gay	138-78	E
Mifflin	138	Stelzer-St. Clair	138-46	E
Morse	138	Morse-Karl-Genoa	138-28	E
	138	Gahanna-Morse	138-36	E
	138	Blendon-Morse	138-37	E
	138	Corridor-Morse	138-38	E
	138	Morse-Stelzer	138-61	E
	138	Morse-Clinton-Huntley	138-48	E
Mound	138	Mound-Canal	138-41	E
	138	St. Clair-Mound	138-75	E
Mulberry	138	Mulberry-Ross	138-79	E
	138	Mulberry-Waverly	138-7	E
OSU	138	OSU-Hess	138-29	E
	138	Clinton-OSU	138-102	E
Picway	138	Picway-Harrison	138-5	E
Poston	138	Poston-Ross	138-12	E
	138	Poston-Harrison	138-20	E
	138	Poston-Lick	138-26	E
	138	Poston-Strouds Run/ Crooksville (OP)	138-51	E
	138	Poston-Elliott/Dexter (OP)	138-67	E
	138	Poston-W. Lancaster	138-96	E
Rio	138	Lick-Addison-Sporn (OP)	138-69	E
Ross	138	Poston-Ross	138-12	E
	138	Ross-Delano	138-13	E
	138	Ross-Mulberry	138-79	E
Sargents	138	Waverly-Sargents (OVEC)	138-23	E
Sawmill	138	Hyatt-Sawmill	138-35	E
	69	Dublin-Sawmill	138-63	E
	138	Sawmill-Bethel	138-72	E
	138	Sawmill-Hyatt	CS-P12	P
	138	Sawmill-Linworth Z	CS-P1	P
Scioto Trail	138	Scioto Trail-Delano	138-71	E
	138	Scioto Trail-Scippo	138-70	E
Scippo	138	Scippo-Circleville	138-25	E
	138	Scippo-Scioto Trail	138-70	E
	138	Scippo-Hargus	138-74	E
Seaman	69	Stuart-Seaman	138-59	E
	138	Seaman-Waverly	138-24	E
	69	Seaman-Highland	138-73	E
Shannon	138	Bixby-Astor-Groves	138-19	E
St. Clair	138	Bexley-St. Clair	138-9	E
	138	St. Clair-Clinton	138-17	E
	138	St. Clair-Mound	138-75	E
	138	St. Clair-Vine	138-99	E
	138	St. Clair-Stelzer	138-46	E
Stelzer	138	Stelzer-Morse	138-61	E
	138	Stelzer-St. Clair	138-46	E
Strouds Run	138	Poston-Strouds Run/ Crooksville (OP)	138-51	E
Taylor	138	Kirk-E. Broad	138-39	E
Trabue	138	Roberts-Wilson	---	E

FORM FE3-2
COLUMBUS SOUTHERN POWER COMPANY
SUMMARY OF EXISTING SUBSTATIONS

Substation Name	Voltage (kV)	Line Association(s)		Line Existing or Prop.
Trent	138	Conesville-Trent	138-53	E
	138	Trent-Delaware	138-44	E
Vine	138	Gay-Vine	138-33	E
	138	Hess-Vine	138-88	E
	138	Vine-City of Columbus (E)	138-92	E
	138	Vine-City of Columbus (W)	138-98	E
	138	Vine-St. Clair	138-99	E
Walnut	138	Walnut-Bixby	138-6	E
Waverly	138	Waverly-Sargents	138-23	E
	138	Waverly-Seaman	138-24	E
	138	Waverly-Lick	138-27	E
	138	Waverly-Mulberry	138-77	E
Wilson	138	Beatty-Wilson	138-21	E
	138	Beatty-Wilson	138-22	E
	138	Wilson-Hess	138-30	E
	138	Wilson-Roberts	138-31	E
	138	Wilson-Trabue-Roberts	---	E
Yearling	138	Yearling-E. Broad	FC80	E
	138	Yearling-Bexley	FD80	E

FORM FE3-2
OHIO POWER COMPANY
SUMMARY OF EXISTING SUBSTATIONS

Substation Name	Voltage (kV)	Line Association(s)		Line Existing or Prop.
Don Marquis	765	Don Marquis-Hanging Rock	BM20	E
	345	Don Marquis-X530 (DOE)	---	E
	345	Don Marquis-X533 (DOE)	---	E
	345	Don Marquis-Killen (DP&L)	345-49	E
	345	Don Marquis-Bixby (CS)	345-7	E
Gavin	765	Gavin-Marysville	BM15	E
	765	Gavin-Mountaineer (AP)	BV20	E
	765	Gavin-Culloden (AP)	BV40	E
	138	Gavin-Sporn #1	FV36	E
	138	Gavin-Sporn #2	FV38	E
	138	Gavin-Millbrook	FE91	E
	138	Gavin-N. Proctorville	FE92	E
Hanging Rock	765	Hanging Rock-Amos (AP)	BV25	E
	765	Hanging Rock-Baker (KP)	BW35	E
	765	Hanging Rock-Jefferson (I&M)	BX50	E
	765	Hanging Rock-Don Marquis	BM20	E
Marysville	765	Marysville-Dumont (I&M)	BX31	E
	765	Marysville-Kammer	BM00	E
	765	Marysville-Gavin	BM15	E
	345	Marysville-Hyatt #2	DH74	E
	345	Marysville-Southwest Lima	DM05	E
	345	Marysville-E. Lima	DE65	E
	345	Marysville-Tangy (OE)	DA52	E
N Proctorville	765	Hanging Rock-Amos (AP)	BV25	E
	138	N Proctorville-Darrah (AP)	EV28	E
	138	N Proctorville-E Huntington (AP)	FV34	E
	138	N Proctorville-Bellefonte (KP)	FJ45	E
	138	N Proctorville-Bellefonte (KP)	FW45	E
	138	N Proctorville-Gavin	FE92	E
S Canton	765	S Canton-Kammer	BM25	E
	345	S Canton-Star (OE)	DA45	E
	345	S Canton-Sammis (OE)	DA50	E
	345	S Canton-Canton Central #1	DC80	E
	345	S Canton-Canton Central #2	DC81	E
	138	S Canton-Timken (Richville)	FK93	E
	138	S Canton-Philo	FK13	E
	138	S Canton-E Wooster	FE69	E
	138	S Canton-SE Canton	FK84	E
	138	S Canton-Wayview	FK87	E
	138	S Canton-W New Philadelphia	FK90	E
	138	S Canton-Torrey	FK95	E
Canton Ctrl.	345	Canton Central-Tidd	DC63	E
	345	Canton Central-Hanna (OE)	DA01	E
	345	Canton Central-S Canton #1	DC80	E
	345	Canton Central-S Canton #2	DC81	E
	138	Canton Central-SE Canton	FC60	E
	138	Canton Central-Bluebell (OE)	FA00	E
	138	Canton Central-Wagenhals #1	FC70	E
	138	Canton Central-Wagenhals #2	FC71	E
	138	Canton Central-Cloverdale (OE)	FA03	E
E Lima	345	E Lima-Fostoria Central	DE40	E
	345	E Lima-Marysville	DE65	E
	345	E Lima-Robison Park (I&M)	DX55	E
	345	E Lima-Southwest Lima	DE60	E
	138	E Lima-Richland (TE)	FA15	E
	138	E Lima-Ford	FD20	E
	138	E Lima-Haviland	FD40	E
	138	E Lima-New Liberty	FD62	E
	138	E Lima-Rockhill	FD80	E
	138	E Lima-S Kenton	FD90	E
	138	E Lima-Sterling	FD98	E
	138	E Lima-N Findlay	FD64	E
	138	E Lima-W Lima	FE20	E
Fostoria Ctrl.	345	Fostoria Central-Galion (OE)	DA13	E
	345	Fostoria Central-Lemoyne (TE)	DA15	E
	345	Fostoria Central-Bayshore (TE)	DA22	E
	345	Fostoria Central-E Lima	DE40	E
	138	Fostoria Central-West End	FE77	E
	138	Fostoria Central-New Liberty	FE73	E
	138	Fostoria Central-Buckley Road	FC34	E
	138	Fostoria Central-Greenlawn-Howard	FE75	E
	138	Fostoria Central-N Findlay	FE74	E
Hyatt	345	Hyatt-West Millersport	DH75	E
	345	Hyatt-Marysville #2	DH74	E
	345	Hyatt-Hyatt (CS) #1 and #2		E
	345	Hyatt-Tangy (OE)	DA51	E
Muskingum	345	Muskingum-Galion (OE)	DA18	E
	345	Muskingum-Kammer	DM41	E
	345	Muskingum-Tidd	DM80	E
	345	Muskingum-W Millersport #1	DM90	E
	345	Muskingum-W Millersport #2	DM95	E
	345	Muskingum-Sporn (AP)	DV51	E
	138	Muskingum-Crooksville	FC85	E
	138	Muskingum-W Cambridge	FG84	E
	138	Muskingum-Summerfield	FG80	E
	138	Muskingum-Natrium (WP)	FY70	E
	138	Muskingum-Corner (MP)	FA07	E
Ohio Central	345	Muskingum-Galion (OE)	DA18	E
	138	Ohio Central-N Newark	FH80	E
	138	Ohio Central-Philo	FJ65	E
	138	Ohio Central-S Coshocton	FJ59	E
	138	Ohio Central-Wooster	FJ61	E
	138	Ohio Central-Zanesville	FJ62	E
	138	Ohio Central-Academia	FC06	E
	138	Ohio Central-Conesville (CS)	F155	E
SE Canton	345	S Canton-Canton Central #1	DC80	E
	138	SE Canton-Sunnyside	FL06	E
	138	SE Canton-South Canton	FK84	E
	138	SE Canton-Timken	FL07	E
	138	SE Canton-Canton Central	FC60	E
SW Lima	345	SW Lima-Miami (DP&L)	DA28	E
	345	SW Lima-E Lima	DE60	E
	345	SW Lima-Marysville	DM05	E
	138	SW Lima-Ordnance Jct.	FJ75	E
	138	SW Lima-W Lima	FL35	E
	138	SW Lima-W Moulton	FL30	E
Tidd	345	Tidd-Collier (DL)	DA05	E
	345	Tidd-Canton Central	DC63	E
	345	Tidd-Wylie Ridge (MP)	DA65	E
	345	Tidd-Kammer	DM42	E
	345	Tidd-Muskingum River	DM80	E
	138	Tidd-Weirton (MP) #2	FA50	E
	138	Tidd-Weirton (MP) #1	FA49	E
	138	Tidd-Steubenville	FL45	E
	138	Tidd-Wagenhals	FN00	E
	138	Tidd-Wheeling Steel 1	FN40	E
	138	Tidd-Wheeling Steel 2	FN41	E
	138	Tidd-Kammer-Brues (WP)	FY60	E
	138	Tidd-George Washington (WP)	FY40	E
	138	Tidd-Carrollton	FC65	E
	138	Tidd-Satralloy	FM80	E
W Bellaire	345	Kammer-Tidd	DM42	E
	138	W Bellaire-Kammer	FF87	E

FORM FE3-2
OHIO POWER COMPANY
SUMMARY OF EXISTING SUBSTATIONS

Substation Name	Voltage (kV)	Line Association(s)		Line Existing or Prop.
W Bellaire (cont'd)	138	W Bellaire-Brues	FY10	E
	138	W Bellaire-Windsor (MP)	FY00	E
W Millersport	345	W Millersport-Muskingum #1	DM90	E
	345	W Millersport-Muskingum #2	DM95	E
	345	W Millersport-Hyatt	DH75	E
	138	W Millersport-N Newark	FJ22	E
	138	W Millersport-Heath	FE88	E
	138	W Millersport-W Lancaster	FP80	E
	138	W Millersport-N Fairfield (BP)	FH66	E
	138	W Millersport-Kirk (CS)	F185	E
Academia	138	Academia-Ohio Central	FC06	E
	138	Academia-West Mt. Vernon	FC07	E
	138	Academia-Howard	FC05	E
Apple Creek	138	E Wooster-S Canton	FE69	E
Belden Village	138	Wayview-West Canton	FP65	E
Bolivar	138	S Canton-W New Philadelphia	FK90	E
Bridgeville	138	Philo-S Canton	FK13	E
Broadacre	138	Tidd-Wagenhals	FN00	E
Buckley Rd.	138	Buckley Rd.-Fostoria Central	FC34	E
Bucyrus Ctr.	138	Bucyrus Ctr.-Howard	FC40	E
Caldwell	138	Muskingum-Natrium (WP)	FY70	E
Campbell Rd.	138	E Lima-Richalnd (TE)	FA15	E
Canal Road	138	E Wooster-S Canton	FE69	E
Carrollton	138	Carrollton-Sunnyside	FC64	E
	138	Carrollton-Tidd	FC65	E
Central Portsmouth	138	Central Portsmouth-N Portsmouth	FC72	E
Chatfield	138	West End-Howard	FF40	E
Conesville Prep. Plant	138	Conesville Prep. Plant Tap	F153	E
Crooksville	138	Crooksville-N Newark	FC76	E
	138	Crooksville-S Lancaster	FD08	E
	138	Crooksville-Muskingum	FC85	E
	138	Crooksville-Poston/ Strouds Run (CS)	F151	E
Dexter	138	Dexter-Sporn	FV33	E
	138	Dexter-Poston/Elliott (CS)	F167	E
Dogwood Ridge	138	E Wheelersburg-Millbrook Park	FE60	E
E Amsterdam	138	Tidd-Wagenhals	FN00	E
	69	E Amsterdam-Carroll Co-op	HG42	E
E Leipsic	138	E Lima-Richland (TE)	FA15	E
E Liverpool	138	E Liverpool-Wylie Ridge (MP)	FA10	E
E New Concord	138	Muskingum-W Cambridge	FG84	E
E Proctorville	138	Bellefonte (KP)-N Proctorville	FV10	E
E Wheelersburg	138	E Wheelersburg-Millbrook Park	FE63	E
	138	E Wheelersburg-Bellefonte (KP)	FW40	E
	138	E Wheelersburg-Texas Eastern	FE63	E
E Wooster	138	E Wooster-Wooster	FE68	E
	138	E Wooster-S Canton	FE69	E
	138	E Wooster-Cloverdale (OE)	FA04	E
E Zanesville	138	Ohio Central-Philo	FJ65	E
Eastown Road	138	Rockhill-W Lima	FK83	E
Faircrest	138	S Canton-SE Canton	FK84	E
Findlay Center	138	New Liberty-Fostoria Central	FE73	E
Fremont	138	Fremont Center-Lemoyne (TE)	FA80	E
	69	Fremont-City of Clyde	HA02	E
Fremont Center	138	Fremont Center-Lemoyne (TE)	FA80	E
	138	Fremont Center-Tiffin Center	FE83	E
Frazeysburg	138	Ohio Central-North Newark	FH80	E
Fulton	138	W Mt. Vernon-S Kenton	FL00	E
Greenlawn	138	Fostoria Ctl.-Howard-Greenlawn	FE75	E
	138	Greenlawn-Tiffin Center	FE85	E
Hanging Rock	138	Bellefonte (KP)-E Wheelersburg	FW40	E
Haviland	138	Haviland-E Lima	FD40	E
	138	Haviland-Milan (I&M)	FX30	E
Heath	138	W Millersport-N Newark	FJ23	E
Hedding Road	138	W Mt. Vernon-S Kenton	FJ00	E
Hillsboro	138	Hillsboro-O.H.Hutchings	FA20	E
	138	Hillsboro-Millbrook Park (DP&L)	FE90	E
	138	Hillsboro-Maysville (KU)	FA21	E
Hillview	138	Newcomerstown-W New Philadelphia	FH45	E
Howard	138	Howard-Academia	FC05	E
	138	Howard-Greenlawn-Fostoria Central	FE75	E
	138	Howard-Philo	FF20	E
	138	Howard-West End	FF40	E
	138	Howard-Bucyrus Center	FC40	E
	138	Howard-Brookside (OE)	FA25	E
	138	Howard-Shelby	FA26	E
Lockwood Road	138	Lockwood Road-Richland (TE)	FA27	E
	138	Lockwood Road-Robison Park (I&M)	FX65	E
Malvern	138	Tidd-Wagenhals	FN00	E
Meigs No. 1	138	Dexter-Sporn	FV33	E
Meigs No. 2	138	Poston (CS)-Dexter	F167	E
	34	Meigs #2-Wilkesville	---	E
Miles Avenue	138	Torrey-W Canton	FN80	E

FORM FE3-2
OHIO POWER COMPANY
SUMMARY OF EXISTING SUBSTATIONS

Substation Name	Voltage (kV)	Line Association(s)	Line	Existing or Prop.
Millbrook Park	138	Millbrook Park-E Wheelersburg	FE60	E
	138	Millbrook Park-Hillsboro	FE90	E
	138	Millbrook Park-S Point	FG00	E
	138	Millbrook Park-Gavin	FE91	E
	138	Millbrook Park-N Portsmouth	FG05	E
	138	Millbrook Park-W.T. Love (Hamilton)	FA31	E
	69	Millbrook Park-Siloam (KP)	HW50	E
	69	Millbrook Park-Pedro (CS)	HI82	E
Millwood	138	Howard-Philo	FF20	E
New Liberty	138	New Liberty-E Lima	FD62	E
	138	New Liberty-Fostoria Central	FE73	E
Newark Ctr.	138	Newark Center-Conesville (CS)	---	E
	138	Newark Center-Kirk (CS)	---	E
Newcomers-town	138	Newcomerstown-W Cambridge	FH44	E
	138	Newcomerstown-W New Philadelphia	FH45	E
	138	Newcomerstown-S Coshocton	FH20	E
N Crown City	138	N Proctorville-Gavin	FE92	E
N Delphos	138	Lincoln (I&M)-Sterling	FX60	E
NE Findlay	138	N Findlay-Fostoria Central	FE74	E
N Findlay	138	N Findlay-E Lima	FD64	E
	138	N Findlay-Fostoria Central	FE74	E
N Lexington	138	Academia-Howard	FC05	E
N Muskingum	138	Crooksville-Muskingum	FC85	E
N Newark	138	N Newark-Crooksville	FC76	E
	138	N Newark-W Millersport	FJ22	E
	138	N Newark-Ohio Central	FH80	E
	138	N Newark-W Mt. Vernon	FJ40	E
N Portsmouth	138	N Portsmouth-Millbrook Park	FG05	E
	138	N Portsmouth-Sargents (OVEC)	FA40	E
	138	N Portsmouth-Ctrl. Portsmouth	FC72	E
N Strasburg	138	Philo-S Canton	FK13	E
N Waldo	138	W Mt. Vernon-S Kenton	FL00	E
N Woodcock	138	E Lima-N Findlay	FD64	E
N Zanesville	138	Ohio Central-Zanesville	FJ62	E
NE Canton	138	Wagenhals-W Canton	FP20	E
NW Lima	138	E Lima-W Lima	FE20	E
Ordnance Jct.	138	Ordance Junction-Sterling	FJ74	E
	138	Ordance Junction-SW Lima	FJ75	E
Philo	138	Philo-S Canton	FK13	E
	138	Philo-Howard	FF20	E
	138	Philo-Ohio Central	FJ65	E
	138	Philo-Zanesville	FK40	E
Powelson	138	Ohio Central-Zanesville	FJ62	E
Promway	138	S Canton-Wayview	FK87	E
Reedurban	138	Torrey-W Canton	FN80	E
Rockhill	138	Rockhill-E Lima	FD80	E
	138	Rockhill-W Lima	FK83	E
	138	Rockhill-Ford	FE80	E
Rutland	138	Sporn-Dexter	FV33	E
Sharp Road	138	N Newark-W Mt. Vernon	FJ40	E
Shawnee Road	138	SW Lima-Ordance Junction	FJ75	E
Somerton	138	Muskingum-Natrium (WP)	FY70	E
S Baltimore	138	W Lancaster-W Millersport	FP80	E
S Cadiz	138	Tidd-Carrollton	FL65	E
S Caldwell	138	Muskingum-Summerfield	FG80	E
S Coshocton	138	S Coshocton-Newcomerstown	FH20	E
	138	S Coshocton-Ohio Central	FJ59	E
S Cumberland	138	Muskingum-Summerfield	FG80	E
S Hicksville	138	Robison Park (I&M)-Lockwood Road	FX65	E
S Kenton	138	S Kenton-E Lima	FD90	E
	138	S Kenton-W Mt. Vernon	FL00	E
S Lancaster	138	S Lancaster-W Lancaster	FL09	E
	138	S Lancaster-Crooksville	FD08	E
S Millersburg	138	Ohio Central-Wooster	FJ61	E
S Point	138	S Point-Millbrook Park	FG00	E
	138	S Point-N Proctorville	FJ45	E
	138	S Point-Sporn	FV60	E
	138	S Point-Tri-State (AP)	FV75	E
S Tiffin	138	West End-Howard	FF40	E
S Toronto	138	S Toronto-Weirton (MP)	FA51	E
Sterling	138	Sterling-E Lima	FD98	E
	138	Sterling-Ordnance Junction	FJ74	E
	138	Sterling-Lincoln (I&M)	FX60	E
	34	Sterling-Teledyne #2	KQ16	E
Steubenville	138	Steubenville-Tidd	FL45	E
Sugar Creek	138	Philo-S Canton	FK13	E
Sulfur Springs	138	Howard-Bucyrus Center	FC40	E
Summerfield	138	Summerfield-Muskingum	FG80	E
	138	Summerfield-Texas Eastern (Berne)	FL50	E
	138	Summerfield-Natrium (WP)	FY80	E
Sunnyhill #9 Mine	138	Crooksville-Poston/Strouds Run (CS)	F151	E
Sunnyside	138	Sunnyside-SE Canton	FL06	E
	138	Sunnyside-Torrey	FL80	E
	138	Sunnyside-Wagenhals	FM00	E
	138	Sunnyside-Carrollton	FC64	E
Switzer	138	Natrium (WP)-Summerfield	FY80	E

FORM FE3-2
OHIO POWER COMPANY
SUMMARY OF EXISTING SUBSTATIONS

Substation Name	Voltage (kV)	Line Association(s)		Line Existing or Prop.
Thayer Road	138	E Lima-Sterling	FD98	E
Tiffin Center	138	Tiffin Center-Fremont Center	FE83	E
	138	Tiffin Center-Greenlawn	FE85	E
Tiltonsville	138	W. Bellaire-Windsor (MP)	FY00	E
Timken	138	Timken-SE Canton	FL07	E
	138	Timken-Timken (Richville)	FN44	E
Torrey	138	Torrey-W Canton	FN80	E
	138	Torrey-Sunnyside	FL80	E
	138	Torrey-Cloverdale (OE)	FA60	E
	138	Torrey-S Canton	FK95	E
Wagenhals	138	Wagenhals-Republic Steel #1	FP55	E
	138	Wagenhals-Republic Steel #2	FP56	E
	138	Wagenhals-W Canton #1	FP20	E
	138	Wagenhals-Sunnyside	FM00	E
	138	Wagenhals-Canton Ctrl. #1	FC70	E
	138	Wagenhals-Canton Ctrl. #2	FC71	E
	138	Wagenhals-Tidd	FN00	E
Wakefield	138	N Portsmouth-Sargents (OVEC)	FA40	E
Wayview	138	Wayview-S Canton	FK87	E
	138	Wayview-W Canton	FP65	E
	69	Wayview-Hoover North	HM99	E
W Cambridge	138	W Cambridge-Muskingum	FG84	E
	138	W Cambridge-Newcomerstown	FH44	E
W Canton	138	W Canton-S Akron (OE)	FA70	E
	138	W Canton-Torrey	FN80	E
	138	W Canton-Wagenhals #1	FP20	E
	138	W Canton-Wayview	FP65	E
W Coshocton	138	Ohio Central-Wooster	FJ61	E
W Dover	138	Philo-S Canton	FK13	E
W End	138	West End-Fostoria Central	FE77	E
	138	West End-Lemoyne (TE)	FA81	E
	138	West End-Howard	FF40	E
W Hebron	138	W Millersport-Heath	FJ22	E
W Lancaster	138	W Lancaster-W Millersport	FP80	E
	138	W Lancaster-S Lancaster	FL09	E
	138	W Lancaster-Bixby (CS)	F111	E
	138	W Lancaster-Poston	F196	E
	138	W Lancaster-Zanesville	FP81	E
W Lima	138	W Lima-Rockhill	FK83	E
	138	W Lima-E Lima	FE20	E
	138	W Lima-SW Lima	FL35	E
W Millersburg	138	Ohio Central-Wooster	FJ61	E
W Moulton	138	S Moulton-SW Lima	FL30	E
W Mt. Vernon	138	W Mt. Vernon-N Newark	FJ40	E
	138	W Mt. Vernon-S Kenton	FL00	E
	138	W Mt. Vernon-Academia	FC07	E
W New Philadelphia	138	W New Philadelphia-Newcomerstown	FH45	E
	138	W New Philadelphia-S Canton	FK90	E
W Philo	138	Philo-W Lancaster	FK30	E
W Trinway	138	Academia-Ohio Central	FC06	E
Woodlawn	138	E Lima-W Lima	FE20	E
Wooster	138	Wooster-Ohio Central	FJ61	E
	138	Wooster-E Wooster	FE68	E
Zanesville	138	Zanesville-Philo	FK40	E
	138	Zanesville-Ohio Central	FJ62	E
	138	Zanesville-W Lancaster	FP81	E

FORM FE3-3
COLUMBUS SOUTHERN POWER COMPANY
SPECIFICATIONS OF PLANNED TRANSMISSION LINES

1. LINE NAME AND NUMBER:	Sawmill-Linworth Z [CS-P1]	Tap #1 to Orange Station [CS-P2]
2. POINTS OF ORIGIN AND TERMINATION:	Sawmill (Franklin County) Linworth Z (Franklin County)	Hyatt/Genoa (Delaware County) Orange (Delaware County)
3. RIGHT-OF-WAY: LENGTH/WIDTH/CIRCUITS -	2.18 miles/--/second circuit	0.1 mile/80 feet/two
4. VOLTAGE: DESIGN/OPERATE	138 kV/138 kV	138 kV/138 kV
5. APPLICATION FOR CERTIFICATE:	Letter of Notification to be filed in 2002	Application approved 12/99
6. CONSTRUCTION:	To be completed by June 2003	Expected to be completed by June 2001
7. CAPITAL INVESTMENT:	Not yet determined	Not yet determined
8. PLANNED SUBSTATIONS: NAME - TRANS. VOLTAGE - ACREAGE - LOCATION	---	Orange 765/345/138 kV About 35 acres Delaware County (Orange Township)
9. SUPPORTING STRUCTURES:	Steel tower	Double-circuit steel pole
10. PARTICIPATION WITH OTHER UTILITIES:	---	---
11. PURPOSE OF THE PLANNED TRANSMISSION LINE:	Reinforce support to load area	To integrate new EHV station into load area
12. CONSEQUENCES OF LINE CONSTRUCTION DEFERMENT OR TERMINATION:	Reduced reliability of service	Reduced reliability of service
13. MISCELLANEOUS:	---	The existing Hyatt/Genoa 138 kV line (138-65) will be looped into Orange substation.

FORM FE3-3
COLUMBUS SOUTHERN POWER COMPANY
SPECIFICATIONS OF PLANNED TRANSMISSION LINES

1. LINE NAME AND NUMBER:	Tap to Buckeye Rural Co-op [CS-P17] (Bolins Mills Station)	Tap to Zuber [CS-P7]
2. POINTS OF ORIGIN AND TERMINATION:	Poston/Lick (Athens/Jackson County) Bowlins Mills (customer-owned) (Vinton County)	Beatty/Harrison (Franklin/Pickaway County) Zuber (Franklin County)
3. RIGHT-OF-WAY: LENGTH/WIDTH/CIRCUITS -	0.1 mile/80 feet/one	0.2 mile/80 feet/one
4. VOLTAGE: DESIGN/OPERATE	138 kV/138 kV	138 kV/138 kV
5. APPLICATION FOR CERTIFICATE:	Letter of Notification to be filed in 2000	Letter of Notification to be filed in 2000
6. CONSTRUCTION:	To be completed in 2000	To be completed by June 2001
7. CAPITAL INVESTMENT:	$50,000 (est.)	Not yet determined
8. PLANNED SUBSTATIONS: NAME - TRANS. VOLTAGE - ACREAGE - LOCATION	Bowlins Mill (customer-owned)	Zuber 138 kV --- Vicinity of Zuber Road and Borror Road (Franklin County)
9. SUPPORTING STRUCTURES:	Wood pole	Steel pole
10. PARTICIPATION WITH OTHER UTILITIES:	Buckeye Rural Co-op	---
11. PURPOSE OF THE PLANNED TRANSMISSION LINE:	To provide service requested by co-op	Provide service to new Zuber station
12. CONSEQUENCES OF LINE CONSTRUCTION DEFERMENT OR TERMINATION:	Inability to serve new co-op station	Reduced reliability of service
13. MISCELLANEOUS:	---	---

FORM FE3-3
COLUMBUS SOUTHERN POWER COMPANY
SPECIFICATIONS OF PLANNED TRANSMISSION LINES

1. LINE NAME AND NUMBER:	Hyatt-Sawmill (2nd circuit) [CS-P12]	Tap #2 to Orange [CS-P13]
2. POINTS OF ORIGIN AND TERMINATION:	Hyatt (Delaware County) Sawmill (Franklin County)	Orange (Delaware County) Hyatt (Delaware County)
3. RIGHT-OF-WAY: LENGTH/WIDTH/CIRCUITS -	Existing ---/---/two	Company-owned land 0.1 mile/80 feet/2 circuits
4. VOLTAGE: DESIGN/OPERATE	138 kV/138 kV	138 kV/138 kV
5. APPLICATION FOR CERTIFICATE:	Letter of Notification approved in 3/99	Application approved 12/99
6. CONSTRUCTION:	To be completed by 12/00	To be completed by June 2001
7. CAPITAL INVESTMENT:	Not yet determined	Not yet determined
8. PLANNED SUBSTATIONS: NAME - TRANS. VOLTAGE - ACREAGE - LOCATION	---	Orange 765/345/138 kV About 35 acres Delaware County (Orange Township)
9. SUPPORTING STRUCTURES:	Double-circuit steel poles	Double-circuit wood pole
10. PARTICIPATION WITH OTHER UTILITIES:	---	---
11. PURPOSE OF THE PLANNED TRANSMISSION LINE:	Improved service reliability to load area	To integrate new EHV station into load areas
12. CONSEQUENCES OF LINE CONSTRUCTION DEFERMENT OR TERMINATION:	Reduced reliability of service	Reduced reliability of service
13. MISCELLANEOUS:	Rebuild existing single-circuit line with double-circuit steel poles	Incorporates existing Hyatt-Huntley circuit into station development

FORM FE3-3
COLUMBUS SOUTHERN POWER COMPANY
SPECIFICATIONS OF PLANNED TRANSMISSION LINES

1. LINE NAME AND NUMBER:	Orange-Huntley [CS-P14]	Hyatt-Genoa Relocation [CS-P15]
2. POINTS OF ORIGIN AND TERMINATION:	Orange (Delaware County) Huntley (Franklin County)	Hyatt (Delaware County) Genoa (Franklin County)
3. RIGHT-OF-WAY: LENGTH/WIDTH/CIRCUITS -	Existing (Rebuild existing towers)	1 mile/80 feet/one
4. VOLTAGE: DESIGN/OPERATE	138 kV/138 kV	138 kV/138 kV
5. APPLICATION FOR CERTIFICATE:	Application approved 12/99	Letter of Notification to be filed in 2000
6. CONSTRUCTION:	To be completed by June 2001	To be completed in 2001
7. CAPITAL INVESTMENT:	Not yet determined	Not yet determined
8. PLANNED SUBSTATIONS: NAME - TRANS. VOLTAGE - ACREAGE - LOCATION	Orange 765/345/138 kV About 35 acres Delaware County (Orange Township)	-- none --
9. SUPPORTING STRUCTURES:	Double-circuit steel pole	Wood pole
10. PARTICIPATION WITH OTHER UTILITIES:	---	---
11. PURPOSE OF THE PLANNED TRANSMISSION LINE:	To integrate new EHV station into load area	Permit construction of mall
12. CONSEQUENCES OF LINE CONSTRUCTION DEFERMENT OR TERMINATION:	Reduced reliability of service	Affect construction of mall
13. MISCELLANEOUS:	Incorporates existing Hyatt-Huntley circuit into station development	---

FORM FE3-3
COLUMBUS SOUTHERN POWER COMPANY
SPECIFICATIONS OF PLANNED TRANSMISSION LINES

1. LINE NAME AND NUMBER:	Tap to Beaver 138 kV Station [CS-P16]	Tap to Hap Cremean [CS-P17]
2. POINTS OF ORIGIN AND TERMINATION:	Lick/Waverly (Pike County) Beaver (Pike County)	Morse/Gahanna Hap Cremean (customer-owned)
3. RIGHT-OF-WAY: LENGTH/WIDTH/CIRCUITS -	0.3 mile/80 feet/two	0.5 mile/80 feet/one
4. VOLTAGE: DESIGN/OPERATE	138 kV/138 kV	138 kV/138 kV
5. APPLICATION FOR CERTIFICATE:	Letter of Notification to be filed in 2000	Letter of Notification to be filed in 2001
6. CONSTRUCTION:	To be completed in 2000	To be completed in 6/01 (depends on customer)
7. CAPITAL INVESTMENT:	$329,000 (est.)	Not yet determined
8. PLANNED SUBSTATIONS:		
NAME -	Beaver 138 kV (OP)	Hap Cremean (customer-owned)
TRANS. VOLTAGE -	138 kV	
ACREAGE -		
LOCATION	Pike County	
9. SUPPORTING STRUCTURES:	Wood pole	H-frame/wood pole
10. PARTICIPATION WITH OTHER UTILITIES:	Ohio Power Company	City of Columbus - Division of Electricity
11. PURPOSE OF THE PLANNED TRANSMISSION LINE:	Improve service reliability to load area	To provide service to new customer station
12. CONSEQUENCES OF LINE CONSTRUCTION DEFERMENT OR TERMINATION:	Reduced reliability of service	Inability to serve customer station
13. MISCELLANEOUS:	---	---

FORM FE3-3
COLUMBUS SOUTHERN POWER COMPANY
SPECIFICATIONS OF PLANNED TRANSMISSION LINES

1. LINE NAME AND NUMBER:	Tap to E. Logan (CS-P3)
2. POINTS OF ORIGIN AND TERMINATION:	Poston/W. Lancaster (Hocking County) E. Logan (OP) (Hocking County)
3. RIGHT-OF-WAY: LENGTH/WIDTH/CIRCUITS -	1.0 mile/100 feet/two
4. VOLTAGE: DESIGN/OPERATE	138 kV/138 kV
5. APPLICATION FOR CERTIFICATE:	Application expected to be filed in 2001
6. CONSTRUCTION:	To be completed in 2001
7. CAPITAL INVESTMENT:	To be determined
8. PLANNED SUBSTATIONS: NAME - TRANS. VOLTAGE - ACREAGE - LOCATION	To be determined
9. SUPPORTING STRUCTURES:	Ohio Power Company
10. PARTICIPATION WITH OTHER UTILITIES:	Reinforce support to load area
11. PURPOSE OF THE PLANNED TRANSMISSION LINE:	Reduced reliability of service
12. CONSEQUENCES OF LINE CONSTRUCTION DEFERMENT OR TERMINATION:	
13. MISCELLANEOUS:	

FORM FE3-3
OHIO POWER COMPANY
SPECIFICATIONS OF PLANNED TRANSMISSION LINES

1.	LINE NAME AND NUMBER:	Tap to Orange Station [OP-P1]
2.	POINTS OF ORIGIN AND TERMINATION:	Kammer/Marysville Orange (Delaware County)
3.	RIGHT-OF-WAY: LENGTH/WIDTH/CIRCUITS -	 0.2 mile/200/1
4.	VOLTAGE: DESIGN/OPERATE	 765 kV/765 kV
5.	APPLICATION FOR CERTIFICATE:	Application approved 12/99
6.	CONSTRUCTION:	To be completed in 2001
7.	CAPITAL INVESTMENT:	To be determined
8.	PLANNED SUBSTATIONS: NAME - TRANS. VOLTAGE - ACREAGE - LOCATION	 Orange (CS) 765/345/138 kV About 35 acres Delaware County (Orange Township)
9.	SUPPORTING STRUCTURES:	Steel tower
10.	PARTICIPATION WITH OTHER UTILITIES:	Columbus Southern Power
11.	PURPOSE OF THE PLANNED TRANSMISSION LINE:	To integrate new EHV station into load area
12.	CONSEQUENCES OF LINE CONSTRUCTION DEFERMENT OR TERMINATION:	Reduced reliability of service
13.	MISCELLANEOUS:	---

FORM FE3-4
COLUMBUS SOUTHERN POWER COMPANY
SUMMARY OF PROPOSED SUBSTATIONS

Substation Name	Voltages (kV)	On-Line Timing	Line Association(s)		Line Existing or Proposed
Central Avenue	138	2003	McComb-Gay	138-78	E
Alma	138	2002	Mulberry-Ross	138-79	E
Orange (Delaware County)	765	2001	Marysville-Kammer (OPCo)	BM00	E
	138		Hyatt-Genoa	138-65	E
			Hyatt-Huntley	138-68[CS-P14]	E/P
			Tap #1 to Orange	CS-P2	P
			Tap #2 to Orange	CS-P13	P
OSU (Franklin County)	138	2001	OSU-Hess	138-29	E
Zuber (Franklin County)	138	2000	Beatty-Harrison	138-57	E
			Tap to Zuber	CS-P7	P

FORM FE3-4
OHIO POWER COMPANY
SUMMARY OF PROPOSED SUBSTATIONS

Substation Name	Voltages (kV)	On-Line Timing	Line Association(s)		Line Existing or Proposed
Beaver	138	2001	Waverly-Lick	138-27	E
E. Logan	138	2001	Poston-W. Lancaster	138-27	E
E. Point	138	2000	Ohio Central-Philo	FJ65	E
S. Kenton (expand existing station) (Hardin County)	138	2002	E. Lima-Kenton	OPFD90	E
Strasburg (Tuscarawas County)	138	2005	Philo-S. Canton	OPFK13	E

Appendix A to the
Proxy Statement

American Electric Power

1999 Annual Report

Audited Financial Statements and
Management's Discussion and Analysis

AMERICAN ELECTRIC POWER
1 Riverside Plaza
Columbus, Ohio 43215-2373

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

Year Ended December 31,	1999	1998	1997	1996	1995
INCOME STATEMENTS DATA (in millions):					
Total Revenues	$6,916	$6,397	$5,928	$5,861	$5,673
Operating Income	1,305	1,247	1,346	1,369	1,254
Income Before Extraordinary Item	520	536	620	587	530
Extraordinary Loss - UK Windfall Tax	-	-	109	-	-
Net Income	520	536	511	587	530

December 31,	1999	1998	1997	1996	1995
BALANCE SHEETS DATA (in millions):					
Property, Plant and Equipment	$22,205	$21,351	$20,005	$19,289	$18,815
Accumulated Depreciation and Amortization	9,150	8,549	8,087	7,656	7,206
Net Property, Plant and Equipment	$13,055	$12,802	$11,918	$11,633	$11,609
Total Assets	$21,488	$19,483	$16,615	$15,883	$15,900
Common Shareholders' Equity	5,006	4,842	4,677	4,545	4,340
Cumulative Preferred Stocks of Subsidiaries:					
Not Subject to Mandatory Redemption	45	46	47	90	148
Subject to Mandatory Redemption*	119	128	128	510	5[illegible]
Long-term Debt*	7,447	7,006	5,424	4,884	5,057
Obligations Under Capital Leases*	520	533	538	414	405

*Including portion due within one year

Year Ended December 31,	1999	1998	1997	1996	1995
COMMON STOCK DATA:					
Earnings per Common Share:					
Before Extraordinary Item	$2.69	$ 2.81	$3.28	$3.14	$2.85
Extraordinary Loss - UK Windfall Tax	-	-	(0.58)	-	-
Net Income	$2.69	$ 2.81	$2.70	$3.14	$2.85
Average Number of Shares Outstanding (in millions)	193	191	189	187	186
Market Price Range: High	$48-3/16	$53-5/16	$ 52	$44-3/4	$40-5/8
Low	30-9/16	42-1/16	39-1/8	38-5/8	31-1/4
Year-end Market Price	32-1/8	47-1/16	51-5/8	41-1/8	40-1/2
Cash Dividends Paid	$2.40	$2.40	$2.40	$2.40	$2.40
Dividend Payout Ratio	89.1%	85.4%	88.7%(a)	76.5%	84.1%
Book Value per Share	$25.79	$25.24	$24.62	$24.15	$23.25

(a) Dividend Payout Ratio before Extraordinary Loss - UK Windfall Tax is 73.1%.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

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 that could cause actual results to differ materially from forward looking statements are: electric load and customer growth; abnormal weather conditions; available sources and costs of fuels; availability of generating capacity; the impact of the proposed merger with Central and South West Corporation (CSW) including any regulatory conditions imposed on the merger or the inability to consummate the merger; the speed and degree to which competition is introduced to our power generation business, the structure and timing of a competitive market and its impact on energy prices or fixed rates; the ability to recover net regulatory assets and other stranded costs in connection with deregulation of generation; new legislation and government regulations; the ability of the Company to successfully control its costs; the success of new business ventures; international developments affecting our foreign investments; the economic climate and growth in our service territory; unforeseen events affecting the Company's efforts to restart its nuclear generating units which are on an extended safety related shutdown; the outcome of litigation with the Internal Revenue Service related to certain interest deductions for a corporate owned life insurance program; the ability of the Company to successfully challenge new environmental regulations and to successfully litigate claims that the Company violated the Clean Air Act; inflationary trends; changes in electricity and gas market prices; interest rates; and other risks and unforeseen events.

American Electric Power (AEP or the Company), one of the United States' (U.S.) largest investor-owned electric utilities, is a global energy company. Its domestic regulated electric utility operations provide electric power to 3 million retail customers in Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia and markets, trades and transmits electricity in most of the Northern and Eastern U.S. AEP's worldwide electric and gas operations has holdings in the U.S., the United Kingdom (U.K.), Australia, China and Mexico. These holdings include electric distribution systems in the U.K. and Australia; generation assets in China; a Louisiana gas storage facility, an intrastate gas pipeline operation and a gas trading business in the U.S.; generation facilities under construction in Mexico; and an energy trading business in a developmental stage in Europe. Subsidiaries also provide power engineering and construction, energy consulting and energy management services worldwide. The businesses that comprise worldwide operations are not cost-based rate regulated for accounting purposes, although they are generally subject to different forms of price regulation. As a result regulatory assets and liabilities are not recorded for the worldwide operations. In December 1997 the Company announced plans to merge with CSW, another investor owned electric utility with regulated operations in Arkansas, Louisiana, Oklahoma and Texas; global energy investments in the U.K., Brazil, Chile and Mexico and ownership interests in non-regulated generating plants in Florida, Texas and Colorado.

Management faced many challenges in 1999 including:

- Managing the Cook Nuclear Plant restart efforts under Nuclear Regulatory Commission (NRC) supervision and the recovery of the restart costs in regulated rates,
- Working with regulators to secure approval of the AEP-CSW merger,
- Managing energy-related investments in the U.K., China and Australia,
- Operating the newly acquired Louisiana Intrastate Gas (LIG), a fully

integrated natural gas gathering, processing, storage and transportation operation in Louisiana,

- Growing the electricity and gas trading operations,
- Implementing laws, passed in 1999, for electric competition in Ohio and Virginia,
- Working to shape restructuring legislation to make it fair and advantageous to all interested stakeholders and to recover generation related stranded costs including regulatory assets,
- Dealing with actions and litigation against the Company's coal-fired generating plants by the U.S. Environmental Protection Agency (Federal EPA) and certain northeastern states, and
- Working to mitigate new U.K. price constraints.

Although earnings will continue to be adversely affected by the expenditures to restart the Cook nuclear units, we expect positive things to occur in 2000 including the restart of the Cook Plant units and the consummation of the merger with CSW. Management expects earnings to recover in 2001 when both Cook nuclear units are expected to be in service for the full year. Although AEP's three-year total shareholder return was in the top quartile of the S&P Electric Utility Index for 1997, AEP's three-year total shareholder return ranked 25th among the companies in the S&P Electric Utility Index for 1999, reflecting the decline in AEP's common stock price. The decline in AEP's stock price in 1999, in management's opinion, reflects the uncertainties associated with the Cook Plant restart and the consummation of the merger with CSW as well as a general decline in the utility sector.

Results of Operations - Net Income

Net income for 1999 declined 3% to $520 million or $2.69 per share from $536 million or $2.81 per share in 1998 primarily due to increased costs of the Cook Plant restart efforts and moderation of extreme weather experienced in the summer of 1998. In 1998 net income increased 5% to $536 million or $2.81 per share from $511 million or $2.70 per share in 1997 primarily due to the effect of a 1997 extraordinary loss of $109 million. The extraordinary loss, recorded in 1997, was a result of the U.K.'s one-time windfall tax which was based on a revision or recomputation of the original privatization value of certain privatized utilities, including Yorkshire Electricity Group plc (Yorkshire).

Income Before Extraordinary Item

In 1998 income before the extraordinary loss, recorded in 1997, decreased 14% to $536 million or $2.81 per share from $620 million or $3.28 per share in 1997. Several major items reduced 1998 earnings including the cost of restart activities at the Cook Plant, a write-down of Yorkshire's investment in Ionica, a U.K. telecommunications company, severance accruals for reductions in power generation and energy delivery staff and mild winter and fall weather.

Revenues Increase

Total revenues increased 8% in 1999 and 1998. Revenues increased in 1999 primarily due to the worldwide electric and gas operations' sale of electricity in Australia and China and gas in the U.S. These transactions are primarily from the activities of businesses acquired in December 1998, CitiPower in Australia and LIG, and the commencement of commercial operation of a two-unit 250 megawatt (MW) coal-fired generating plant in China. The 1998 increase was primarily due to increased revenues from retail, wholesale and transmission service customers in the Company's domestic regulated electric utility operations.

The table below shows the changes in the components of revenues from domestic regulated electric utility operations and the increase in worldwide electric and gas operations. Revenues from the domestic regulated electric utility operations decreased slightly in 1999 and increased 8% in 1998. The worldwide electric and gas operations revenues increased significantly in 1999 following a 6% increase in 1998.

	Increase (Decrease) From Previous Year			
(Dollars in Millions)	1999		1998	
	Amount	%	Amount	%
Domestic Regulated Electric Utility Operations:				
Retail:				
Residential	$ 66		$ 37	
Commercial	47		57	
Industrial	(11)		90	
Other	1		4	
	103	2.0	188	3.8
Wholesale	(191)	(19.0)	207	25.9
Transmission	(6)	(3.3)	68	61.7
Other	63	106.1	3	4.8
Total Domestic Regulated Electric Utility Operations	(31)	(0.5)	466	7.9
Worldwide Electric and Gas Operations	550	N.M.	3	6.3
Total	$ 519	8.1	$469	7.9

N.M. = Not Meaningful.

In 1999 retail revenues increased 2% reflecting a 2% increase in retail sales. Sales to residential and commercial customers increased 4% reflecting colder winter weather and customer growth.

Retail revenues increased 4% in 1998 reflecting a 2% rise in sales and increased retail fuel cost recoveries. The increase in retail fuel recoveries reflects the greater use of internal higher cost coal fired generation and purchased power partially resulting from the need to replace nuclear power usually generated at the Cook Plant. Although residential sales were flat reflecting mild winter and fall weather in 1998, revenues from residential customers increased 2%. The accrual of fuel-related revenues for the recovery of the higher cost Cook Plant replacement energy accounted for the increase in residential revenues. The rise in commercial revenues resulted from a 4% increase in sales reflecting increased usage and growth in the number of commercial customers. Industrial revenues increased 6% reflecting a sales increase of 2% following the resumption of operations by a major industrial customer after an extended labor strike. Also contributing to the increase in industrial revenues were favorable contract price adjustments to certain major industrial customers and the pass-through of higher power costs during periods of peak demand.

Wholesale revenues declined 19% in 1999 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 margins reflects the moderation of extreme weather and capacity shortages experienced in the summer of 1998. The Company engages in the trading of electricity with other utilities and power marketers in the Company's traditional marketing area. Revenues from the trading of electricity are recorded net of purchases. Regulated trading activities are conducted as part of AEP's electric power wholesale marketing and trading operations and involve the purchase and sale of substantial amounts of electricity.

The 26% increase in wholesale revenues in 1998 is attributable to net revenues from trading of electricity and increased power marketing sales. Although wholesale revenues rose, total wholesale sales declined due to a reduction in coal conversion service sales. These sales are for

the generation of electricity from the purchaser's coal and as a result do not include fuel costs. Consequently, the drop in coal conversion service sales did not have a significant effect on wholesale revenues.

The 62% increase in transmission service revenues in 1998 is attributable to a substantial rise in the quantity of energy transmitted for other entities over AEP's transmission lines. Open transmission access rules issued in 1996 by the FERC and the expansion of wholesale power marketing has contributed to growth in the use of AEP's transmission services.

In 1999 other revenues increased substantially due to a favorable adjustment to a provision for revenue refund in the Company's Virginia jurisdiction in connection with the commission's final order and increased rental income. The increase in rental income reflects agreed to revisions in the billings for pole attachments with telecommunications companies.

The level of wholesale transactions, including transmission services, 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, the weather and the economy. The FERC rules which introduced a greater degree of competition into the wholesale energy market have had a major effect on wholesale sales and transmission service revenues as more electricity is traded in the short-term market.

Operating Expenses Increase

Operating expenses increased 9% in 1999 and 12% in 1998. The increases were attributable to acquisitions in late 1998 of new worldwide electricity and gas operations and the costs to restart the shutdown Cook Plant nuclear generating units. Exclusive of these factors operating expenses actually declined in 1999. Changes in the components of operating expenses were as follows:

	Increase (Decrease) From Previous Year			
(Dollars in Millions)	1999		1998	
	Amount	%	Amount	%
Fuel and Purchased Power	$(38)	(1.8)	$392	22.2
Maintenance and Other Operation	22	1.2	135	7.9
Depreciation and Amortization	20	3.4	(11)	(1.9)
Taxes Other Than Income Taxes	1	0.2	6	1.3
Worldwide Electric and Gas Operations	456	480.0	46	93.9
Total	$461	9.0	$568	12.4

The decline in fuel and purchased power expense in 1999 is primarily due to a decrease in fuel expense as generation declined 2% reflecting lower demand for electricity by the Company's firm wholesale customers. Firm wholesale customers include municipal distribution systems that purchase electricity at wholesale to supply the needs of their retail customers and unaffiliated electric utilities that buy power under long-term contracts. The expiration in July 1998 of a contract to supply several municipal customers and the outage of an AEP generating unit with a long-term unit power agreement accounted for the reduced demand.

Fuel and purchased power expense increased significantly in 1998 primarily due to additional purchases of electricity for resale to other utilities and power marketers and for replacement of energy usually generated by the Cook Plant. Both of Cook's nuclear generating units were unavailable due to the unplanned safety related shutdown which began in September 1997 and continued throughout 1999. Also contributing to the increase in fuel and purchased power expense was an increase in the average cost of fuel consumed reflecting the reduced availability of lower cost nuclear generation.

The increase in maintenance and other operation expense in 1999 is primarily due to the cost of restart efforts at the Cook Plant. The increased Cook Plant restart

expenditures were partially offset by cost containment efforts in power generation, transmission and distribution and lower costs to restore service after severe weather damage to the Company's transmission and distribution system in 1998. The increase in maintenance and other operation expenses in 1998 is primarily due to the extended Cook Plant outage, power marketing and trading costs associated with the efforts of AEP to build a major power trading business, severance accruals for reductions in power generation and energy delivery staff and costs to restore service interrupted by two severe snowstorms in the winter of 1998.

Expenses of the Company's worldwide electric and gas operations increased significantly in 1999 and 1998 due to the addition of expenses of the businesses acquired in December 1998 and the commercial operation of the generating units constructed in China. LIG was acquired on December 1, 1998 resulting in one month of operating costs being included in AEP's 1998 operating costs and CitiPower, an Australian electric distribution business, was acquired on December 31, 1998. Both acquisitions were accounted for using the purchase method which recognizes revenues and costs from the purchase date.

Interest and Preferred Dividends

The significant increase in interest and preferred dividends in 1999 reflects increased borrowings to support the expansion of AEP's worldwide electric and gas operations and related acquisitions including CitiPower and LIG in December 1998.

Income Taxes

Income taxes declined in 1999 primarily due to an increase in foreign tax credits and a decrease in state income taxes.

The decrease in income tax expense in 1998 was primarily due to a decrease in pre-tax income excluding the extraordinary loss for the U.K. windfall tax.

Business Outlook - Domestic Regulated Electric Utility Operations

The most significant factors affecting the Company's future earnings from its domestic regulated electric utility operations are the restart of the Cook Plant; weather in the Company's service territory; the ability to recover costs including a fair return on equity in the Company's regulated electric distribution business and its generation business which is being restructured in certain regulatory jurisdictions to a competitive market; the ability to manage costs and risks in the Company's domestic regulated electric utility operations; the consummation of the CSW merger and the realization of related net cost savings and the outcome of ongoing environmental litigation and proposed air quality standards. In 1999 significant progress was made related to many of these major challenges.

Nuclear Plant Restart Effort

Management 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. The NRC issued a Confirmatory Action Letter in September 1997 requiring the Company to address certain issues identified in the letter. In 1998 the NRC notified the Company that it had convened a Restart Panel for Cook Plant and provided a list of required restart activities. In order to identify and resolve all issues necessary to restart the Cook units, the Company is working with the NRC and will be meeting with the Panel on a regular basis until the units are returned to service. In a February 2, 2000 letter from the NRC, the Company was notified that the Confirmatory Action Letter had been closed. Closing of the Confirmatory Action Letter is one of the key approvals needed to restart the nuclear units.

The Company's plan to restart the Cook Plant units has Unit 2 scheduled to restart in April 2000 and Unit 1 scheduled to restart in September 2000. The restart plan was developed based upon a comprehensive

systems readiness review of all operating systems at the Cook Plant. When maintenance and other work including testing required for restart are complete, the Company will seek concurrence from the NRC to restart the Cook Plant units. Any issues or difficulties encountered in testing of equipment as part of the restart process could delay the scheduled restart dates. Earnings for 2000 will be adversely affected by restart expenses expected to be incurred in 2000, which are estimated to be $200 million, and amortization of previously deferred non-fuel restart costs and fuel-related revenues of $78 million.

Replacement of the steam generator for Unit 1 will be completed before it is returned to service. Costs associated with the steam generator replacement are estimated to be approximately $165 million, which will be accounted for as a capital investment unrelated to the restart. At December 31, 1999, $119 million has been spent on the steam generator replacement.

The cost of electricity supplied to retail customers increased due to the outage of the two Cook Plant nuclear units since higher cost coal-fired generation and coal-based purchased power is being substituted for the unavailable low cost nuclear generation. With regulator approvals, actual replacement energy fuel costs that exceeded the costs reflected in billings were recorded as a regulatory asset under the Indiana and Michigan retail jurisdictional fuel cost recovery mechanisms.

On March 30, 1999, the Indiana Utility Regulatory Commission (IURC) approved a settlement agreement 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, a replacement fuel billing credit of $55 million, including interest, to Indiana retail customers' bills; the deferral of unrecovered fuel revenues accrued between September 9, 1997 and December 31, 1999, including the billing credit; 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 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 until March 1, 2004. The $55 million credit was applied to retail customers' bills during the months of July, August and September 1999.

On December 16, 1999, the Michigan Public Service Commission (MPSC) approved a settlement agreement for two open Michigan power supply cost recovery reconciliation cases which resolves all issues related to the Cook Plant extended outage. The settlement agreement limits the Company's ability to increase base rates and freezes the power supply cost recovery factor for five years; permits the deferral of up to $50 million in 1999 of jurisdictional non-fuel restart nuclear operation and maintenance expenses and 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 costs deferrals over a five-year period ending December 31, 2003.

Expenditures to restart the Cook units are estimated to total approximately $574 million. Through December 31, 1999, $373 million has been spent. These expenditures are not capital in nature and as such have negatively affected current earnings and will negatively affect earnings in 2000, and through amortization of the above described deferrals through December 31, 2003. In 1999 the restart costs incurred were $289 million of which $200 million were deferred for amortization over a five-year period beginning January 1, 1999 in accordance with the settlement agreements. Consequently, $129 million of restart costs negatively affected 1999 earnings inclusive of $40 million of amortization of deferred restart costs. At December 31, 1999, regulatory assets included $160 million of deferred restart related operation and maintenance costs.

Also deferred as a regulatory asset at December 31, 1999 was $150 million of Cook fuel-related revenues.

The costs of the extended outage and restart efforts will have a material adverse effect on future results of operations and possibly financial condition through 2003 and on cash flows through 2000. Management believes that the Cook units will be successfully restarted in April and September 2000, however, if for some unknown reason the units are not returned to service or their restart is delayed significantly it would have an even greater adverse effect on future results of operations, cash flows and financial condition.

Ohio Restructuring and The Transition To Market Pricing For Generation

The Ohio Electric Restructuring Act of 1999 (the Act) became law in October 1999. The Act provides for customer choice of electricity supplier, a residential rate reduction of 5% for the generation portion of rates and a freezing of the unbundled generation rates including fuel rates beginning on January 1, 2001. The Act also provides for a five-year transition period to move from cost based rates to market pricing for generation services. It authorizes the Public Utilities Commission of Ohio (PUCO) to address certain major transition issues including unbundling of rates and the recovery of transition costs including stranded costs. Transition costs include generation-related regulatory assets, (which include, among other expense deferrals, unrecovered deferred fuel costs, deferred tax benefits that were flowed through to reduce past rates and deferred affiliated mine shutdown costs), impaired tangible generating asset values, and future contract costs. Stranded costs are those costs of generation above market that would not be recoverable in a competitive market. Transition costs also include customer choice education costs, development costs of new billing and metering systems, costs of filing a transition plan, employee severance and retraining costs and other costs.

Retail electric services that will be competitive are defined in the Act as electric generation service, aggregation service, and power marketing and brokering. Under the Act the PUCO is granted broad oversight responsibility and is required to approve by October 31, 2000 a transition plan for each electric utility company. Ohio electric utilities were required to file their transition plans by January 3, 2000. The Company filed its plan in December 1999.

The Act provides Ohio electric utilities with an opportunity to recover PUCO approved allowable transition costs through the generation portion of transition rates paid through December 31, 2005 by customers who do not switch generation suppliers and through a transition charge for customers who switch generation suppliers. Under the Act recovery of the regulatory asset portion of transition costs can, under certain circumstances, extend beyond the five-year transition period but cannot continue beyond December 31, 2010.

The Act also provides for a reduction in property tax assessments; exemption of electric utilities from the gross receipts tax; and the imposition of a franchise tax, income taxes, and a new kilowatthour (kwh) excise tax. The property tax assessment percentage on electric generation property will be lowered from 100% to 25% of value effective January 1, 2001 and electric utilities will become subject to the Ohio Corporate Franchise Tax and municipal income taxes on January 1, 2002. The last year for which electric utilities will pay a 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, which will terminate for electric utilities, is paid by the Company at the beginning of the tax year, deferred 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. The change in the tax law to impose an excise tax based on kwh sold to Ohio customers commencing

before the expiration of the gross receipts tax privilege period will result in a 12 month period (May 1, 2001 to April 30, 2002) when our Ohio electric utilities are recording as an expense both the gross receipts tax and the kwh excise tax. In the Company's Ohio transition plan filing, recovery of $90 million was sought for this overlap of the gross receipts and excise taxes.

The PUCO is required to issue a transition order no later than October 31, 2000 regarding the Company's transition filings which included the following elements:

- a rate unbundling plan including tariff terms and conditions necessary for restructuring,
- a corporate separation plan,
- an application for transition revenues,
- a plan for independent operation of transmission facilities and
- other components for the implementation of restructuring.

The rate unbundling portion of the Company's transition plan filing provides for the Company's Ohio retail jurisdictional companies to offer two transition period tariffs beginning January 1, 2001, the standard tariff and the open access distribution tariff. The Company's proposed standard tariff applies to customers who do not choose an alternative energy supplier. This tariff schedule includes detailed charges for generation, transmission and distribution and riders to fund universal service, to promote energy efficiency and to recover regulatory assets and taxes. Taxes include charges for municipal income, excise and franchise taxes and tax credits for gross receipts and property taxes. For customers who choose an alternative electric supplier, the proposed open access distribution tariff will apply. This tariff includes charges for distribution and riders to fund universal service, to promote energy efficiency and to recover regulatory assets and taxes. These riders are the same as those in the standard tariff except there is no property tax credit.

The Company's corporate separation plan proposal requires that each of the Company's Ohio jurisdictional companies establish separate subsidiaries to own and operate their transmission and distribution assets. The separation plan will be implemented in a manner that recognizes the current overlap of financing arrangements. This would permit an orderly and economically efficient separation of each operating company so that additional transition costs from prematurely retiring of financial instruments can be avoided. Prior to the actual legal separation, the Ohio jurisdictional companies will functionally separate generation from transmission and distribution.

The transition plan filing requests recovery of stranded generation costs over a five year period and recovery of generation-related regulatory assets and other transition costs of $974 million over a 10-year period through transition revenues. The amount requested for recovery of regulatory assets includes current and new regulatory assets including those arising from compliance with the electric restructuring law. Also included in the requested recovery amount were deferred fuel and affiliated mine closure costs.

In the Ohio jurisdiction the Company is subject to certain limitations on the current recovery of affiliated coal costs under PUCO approved agreements, which are discussed in Note 3 of the Notes to Consolidated Financial Statements. Under the terms of the agreements full recovery of the Ohio jurisdictional portion of deferred unrecovered costs of affiliated mining operations including future mine closure costs was expected to occur before the expiration of the PUCO approved agreements in 2009. Management closed the Muskingum mine in 1999 and plans to close the Windsor mine in 2000 and the Meigs mine in 2001. Provisions for Muskingum and Windsor mine shutdown costs totaling $45 million and $48 million were recorded in 1998 for Muskingum mine and 1999 for the Windsor mine, respectively. Management deferred these provisions in the Ohio jurisdiction under the PUCO approved agreements because it believed that these deferrals for the cost of the mine shutdowns are

probable of future recovery through the agreements. However, since the Act will supersede the agreements effective January 1, 2001, the Company has filed under the provisions of the Act for recovery of all of its stranded regulatory assets including the affiliated coal costs deferred under the agreements of $196 million at December 31, 1999 plus the projected amount that will be deferred by the beginning of the transition period, January 1, 2001, which includes the accrual for the closure costs of the Meigs mine.

Included in the transition plan is a proposal to implement independent operation of the transmission system. The Company proposes to join a regional transmission organization (RTO) whose approval is currently pending before the Federal Energy Regulatory Commission (FERC).

See Note 5 of the Notes to Consolidated Financial Statements for further discussion.

Virginia Restructuring

In March 1999 a law was enacted in Virginia to restructure the electric utility industry. Under the restructuring law, a transition to choice of electricity supplier for retail customers will commence on January 1, 2002 and be completed, subject to a finding by the Virginia State Corporation Commission (Virginia SCC) that an effective competitive market exists, on or before January 1, 2004.

The law also provides an opportunity to recover 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 law provides for the establishment of capped rates prior to January 1, 2001 and the establishment of a wires charge by the fourth quarter of 2001.

West Virginia Restructuring

On January 28, 2000, after over three years of workshops, hearings and negotiations, the Public Service Commission of West Virginia (WVPSC) issued an order approving an electricity restructuring plan for West Virginia. The restructuring plan has been submitted to the West Virginia Legislature for approval or rejection which is expected to occur during the current legislative session that ends in March 2000. Until approved by the West Virginia Legislature, the restructuring plan cannot take effect. The Company's subsidiaries, Appalachian Power Company (APCo) and Wheeling Power Company, which do business in West Virginia, will be affected by the proposed restructuring.

The provisions of the proposed restructuring plan provide for customer choice to begin on January 1, 2001, or at a later date set by the WVPSC after all necessary rules are in place (the "starting date"); deregulation of generation assets occurring on the starting date; functional separation of the generation, transmission and distribution businesses on the start 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 the period January 1, 2001 through December 31, 2010 intended to provide for recovery of any stranded cost including net regulatory assets; establishment of a rate stabilization deferred balance by AEP of $81 million by the end of year ten of the transition period to be used as determined by the WVPSC to offset prices paid in the eleventh, twelfth, and thirteenth year of the transition period by residential and small commercial customers that do not choose a supplier.

Default rates for residential and small commercial customers are capped for four years after the starting date and then increased 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.

Restructuring In Other Jurisdictions

All of the other states within our service territory have initiatives to implement or review customer choice, although the timing of any implementation is uncertain. The Company 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 Company could experience when restructuring occurs in these jurisdictions depends on the timing and extent to which competition is introduced to its 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.

Regulatory/Restructuring Accounting

Under the provisions of Statement of Financial Accounting Standards (SFAS) 71. "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) are included in the consolidated balance sheets of cost-based regulated utilities in accordance with regulatory actions in order to match expenses and revenues. In order to maintain net regulatory assets on the balance sheet, SFAS 71 requires that rates charged to customers be cost based and provide for the probable recovery of regulatory assets over future accounting periods. Management has concluded that as of December 31, 1999 the requirements to apply SFAS 71 continue to be met for AEP's jurisdictions. However, the recent legislation in Ohio and Virginia will result in the discontinuance of SFAS 71 regulatory accounting for the generation portion of the Ohio and Virginia jurisdictions. If the West Virginia Legislature approves the restructuring plan as submitted by the WVPSC it will result in the discontinuance of SFAS 71 regulatory accounting for the generation portion of the West Virginia jurisdiction.

In the event a portion of AEP's business no longer meets the requirements of SFAS 71, SFAS 101 "Accounting for the Discontinuance of Application of Statement 71" requires that net regulatory assets be written off for that portion of the business. The provisions of SFAS 71 and SFAS 101 did not anticipate or provide accounting guidance for an extended transition period and for recovery of stranded costs during and after a transition period through a wires charge or regulated distribution rates. In 1997 the Financial Accounting Standards Board's Emerging Issues Task Force (EITF) addressed such a situation with the consensus reached on issue 97-4 that requires that the application of SFAS 71 to a segment of a regulated electric utility cease when that segment is subject to a legislatively approved plan for transition to competitive market pricing from cost-based regulated rates and/or a rate order is issued containing sufficient detail for the utility to reasonably determine what the restructuring plan would entail and how it will affect the utility's financial statements. The EITF indicated that the cessation of application of SFAS 71 regulatory accounting would require that regulatory assets and impaired stranded plant cost applicable to the portion of the business that was no longer cost-based regulated, be written off unless they are recoverable in the

future through transition rates and/or post-transition cost based regulated rates.

Potential For Write Offs In Ohio, Virginia And West Virginia Jurisdictions

The Company's accounting for generation will continue to be in accordance with SFAS 71 in the Ohio and Virginia jurisdictions and will continue to be considered to be cost-based regulated for accounting purposes until the amount of transition rates and stranded cost wires charges are determined and known. The establishment of transition rates and wire charges should enable management to determine the Company's ability to recover stranded costs including regulatory assets and transition costs, a requirement under EITF 97-4 to discontinue application of SFAS 71. When the amount of unbundled frozen generation transition rates and distribution stranded cost wires charges are known for the Ohio jurisdiction, the application of SFAS 71 will be discontinued for the Ohio retail jurisdictional portion of the Company's generation business. Management expects this to occur when the PUCO issues its order to approve a transition plan for the Company's Ohio jurisdictional electric operating subsidiaries. The Act requires that the PUCO issue its order no later than October 31, 2000. The application of SFAS 71 will be discontinued for the Virginia retail jurisdictional portion of the Company's generation business when the capped rates and the wires charge are known in Virginia which is expected to occur by the fourth quarter of 2000. In the West Virginia jurisdiction accounting for generation will continue to be in accordance with SFAS 71 and the generation business will continue to be considered to be cost-based regulated for accounting purposes until the proposed restructuring plan is enacted into law. The application of SFAS 71 for the generation portion of the West Virginia jurisdiction will be discontinued when the West Virginia Legislature approves the restructuring plan and when the WVPSC approves the rate stipulation filed with the Commission, which are both expected to occur in March 2000. Together these two documents provides sufficient information for management to determine the impact of restructuring on the Company's financial statements.

Upon the discontinuance of SFAS 71 the Company will have to write off its Ohio, Virginia and West Virginia jurisdictional generation-related regulatory assets to the extent that they cannot be recovered under the frozen transition rates and stranded costs distribution wires charges and record any asset accounting impairments. An impairment loss would be recorded to the extent that the cost of generation assets cannot be recovered through non-discounted generation-related revenues during the transition period and future market prices. Absent the determination in the legislative or regulatory process of transition rates, any wires charge and other pertinent information, it is not possible at this time for management to determine if any of the Company's generating assets are impaired for accounting purposes on an undiscounted cash flow basis.

The amount of regulatory assets recorded on the books at December 31, 1999 applicable to the Ohio, Virginia and West Virginia retail jurisdictional generation business before related tax effects is estimated to be $666 million, $64 million and $131 million, respectively. Due to the planned closing of the Company's affiliated mines, including the Meigs mine, projected generation-related regulatory assets as of December 31, 2000 (the date that recoverable generation related regulatory assets are measured under the Ohio law) allocable to the Ohio retail jurisdiction are estimated to exceed $800 million, before income tax effects. Recovery of these Ohio generation related regulatory assets was sought as a part of the Company's Ohio transition plan filing. Based on current projections of future market prices, the Company does not anticipate that it will experience material tangible asset accounting impairment write-offs. Whether the Company will experience material regulatory asset write-offs will depend on whether the PUCO approves the Company's request for their recovery and whether the capped transition

rates and allowed wires charges in Virginia and West Virginia will permit their recovery.

An estimated determination of whether the Company will experience any asset impairment loss regarding its Ohio, Virginia and West Virginia retail jurisdictional generating assets and any loss from the possible inability to recover Ohio, Virginia and West Virginia generation related regulatory assets and other transition costs cannot be made until such time as the transition rates and the wires charges are determined through the regulatory or legislative process. Should the PUCO or the Virginia SCC fail to approve transition rates and wires charges that are sufficient to provide for recovery or the West Virginia Legislature approves a restructuring plan that does not provide for recovery of the Company's generation-related regulatory assets, any other stranded costs and transition costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

AEP supports the orderly transition to market pricing for electricity because we believe our low cost generating units provide us with a competitive advantage provided the legislators and/or regulators provide a level playing field for all competitors. AEP is working to develop and acquire the necessary skills and competencies to succeed in a competitive electricity commodity market. AEP has developed an extensive wholesale electricity trading business. However, many factors, some of which AEP does not control, could negatively impact AEP's future success in a market priced, competitive environment.

Customer choice and competition in AEP's other domestic jurisdictions 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 Company to recover its stranded costs including net regulatory assets during a transition or subsequent period through a wires charge or other recovery mechanism. We believe that enabling state legislation and the regulatory process should provide for the full recovery of generation related net regulatory assets and other reasonable stranded costs. However, if in the future any portion of AEP's generation business in 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.

Completion of the Merger

In 1999 the Company and CSW made significant progress towards receiving all the approvals necessary to complete their merger which was announced in December 1997. FERC and the Securities and Exchange Commission (SEC) approvals are needed to consummate the merger.

In 1998 the appropriate shareholder approvals were acquired and the NRC and the Arkansas Public Service Commission approved the merger. In 1998 the FERC issued an order which confirmed that a 250 MW firm contract path with the Ameren System was available to meet the Public Utility Holding Company Act of 1935 (1935 Act) requirement that the two electric transmission systems operate on an integrated and coordinated basis. During 1999 the regulatory commissions of Louisiana, Texas and Oklahoma approved the merger and related settlement agreements, and settlements were reached with the FERC staff and certain other parties who had intervened in the FERC proceeding or who had asserted a right to review the merger. The Company reached agreements in 1999 with its state regulatory commissions in Indiana, Michigan and Kentucky and in 2000 the Department of Justice closed its investigation.

In granting approval of the merger, the CSW state regulatory commissions, Arkansas, Louisiana, Oklahoma and Texas, required the Company to take several steps to protect the interest of their constituents. Among those requirements are sharing of net merger savings at a rate of approximately 55% to customers and 45% to the Company's shareholders; a freezing or capping of base

rates for defined periods of three to five years; joining an RTO; implementing standards to insure quality of service; divesting 1,604 MW of generation in Texas; agreeing to comply with code of conduct standards for affiliated transactions, shared cost allocations and prevention of cross subsidization of non-regulated operations by regulated operations and other provisions facilitating competition. See Note 8 of the Notes to Consolidated Financial Statement for additional detail.

Merger settlement agreements were approved in 1999 by the IURC, MPSC and the Kentucky Public Service Commission (KPSC). The terms of the settlement agreements provide for, among other things, a 55%/45% sharing of net merger savings with Indiana, Michigan and Kentucky customers; a one-year extension through January 1, 2005 of a freeze in base rates in Indiana and Michigan; additional annual deposits of $6 million to the nuclear decommissioning trust fund for the Indiana jurisdiction for the years 2001 through 2003; quality-of-service standards for customer service and reliability; and participation in an RTO; and other steps to protect and promote fair competition. As part of the settlement agreements, the IURC, MPSC and the key parties to the Kentucky settlement agreed not to oppose the merger in the FERC and the SEC proceedings.

AEP and CSW also reached settlements in 1999 with the Missouri Public Service Commission, the International Brotherhood of Electrical Workers, representing employees of AEP and CSW, the Utility Worker's Union of America representing AEP employees, and certain wholesale customers who had intervened in the FERC proceeding. All have agreed not to oppose the merger in the FERC and the SEC proceedings. In October 1999 the PUCO withdrew its opposition to the Company's pending merger with CSW in the FERC proceeding.

During 1999 FERC reviewed the proposed merger addressing issues of competition, market power and customer protection. AEP and CSW reached settlements with the FERC trial staff resolving competition, rate and other issues relating to the merger. The settlements have been submitted to the FERC for approval. Under the terms of the settlements, AEP filed an RTO proposal with the FERC whereby it will transfer the operation and control of AEP's bulk transmission facilities to an RTO known as the Alliance RTO. The settlements also cover rates for transmission services and ancillary service as well as resolving issues related to system integration agreements and confirm, subject to FERC guidance on certain elements, that a proposed generation divestiture of up to 550 MW of capacity will satisfy the FERC staff's market power concerns. Hearings on the merger and related settlement agreements were held before a FERC administrative law judge (ALJ) in 1999. In November 1999 the ALJ issued a favorable decision finding the merger and the proposed settlement agreements to be in the public interest. The FERC is expected to issue a final order in the first quarter of 2000. SEC approval of the merger under the 1935 Act is expected to follow the FERC's issuance of a final order.

The proposed merger of CSW into AEP would result in common ownership of two U.K. regional electricity companies (RECs), Yorkshire Electricity Group plc (Yorkshire) and SEEBOARD, plc. AEP has a 50% ownership interest in Yorkshire and CSW has a 100% interest in SEEBOARD. On January 25, 2000, the U.K. Department of Trade and Industry approved the common ownership of two RECs which will result from the consummation of the AEP-CSW merger. The approval was conditioned on agreement to certain assurances concerning the U.K. operations of Yorkshire and SEEBOARD including meeting customer service obligations, maintaining debt ratings of investment grade or above and separate distribution and supply activities. This approval is the final clearance for the merger in the U.K.

At December 31, 1999, AEP had deferred $42 million of transaction and transition costs related to the merger, which

will be charged to expense if AEP and CSW are not successful in completing their proposed merger. If the merger is consummated, the deferred costs allocable to those regulated electric operating subsidiaries with merger settlement agreements will be amortized over a five- to eight-year recovery period depending on the specific terms of their settlement agreements. The remainder of the deferred merger costs will be expensed upon consummation of the merger. Merger transition costs are expected to continue to be incurred and expensed or deferred for amortization as appropriate for several years after the merger is consummated.

The merger with CSW is conditioned upon, among other things, the approval of certain state and federal regulatory agencies. The transaction must satisfy many conditions, a number of which may not be waived by the parties, including the condition that the merger must be accounted for as a pooling of interests. The merger agreement has been extended for six months until June 30, 2000 by both AEP's and CSW's boards of directors. Should the merger approval process extend beyond June, either AEP or CSW could terminate the merger agreement. Although consummation of the merger is expected to occur in the second quarter of 2000, the Company is unable to predict the outcome or the timing of the remaining required regulatory proceedings. If realized merger savings do not match or exceed the estimated savings included in 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.

Environmental Concerns and Issues

We take great pride in our efforts to economically produce and deliver electricity while minimizing the impact on the environment. AEP has spent over a billion dollars to equip its facilities with the latest cost effective clean air and water technologies and to research new technologies. We are also proud of our award winning efforts to reclaim our mining properties. We intend to continue in a leadership role fostering economically prudent efforts to protect and preserve the environment while providing a vital commodity, electricity, to our customers at a fair price.

Air Quality

In 1998 Federal EPA issued a final rule which requires substantial reductions in nitrogen oxide (NOx) emissions in 22 eastern states, including the states in which the Company's generating plants are located. A number of utilities, including the Company, filed petitions seeking a review of the final rule in the U.S. Court of Appeals for the District of Columbia Circuit (Appeals Court). On March 3, 2000, the Appeals Court issued a decision generally upholding Federal EPA's final rule on NOx emission reductions.

On April 30, 1999, Federal EPA took final action with respect to petitions filed by eight northeastern states pursuant to the Clean Air Act (Section 126 Rule). The Rule approved portions of the states' petitions and imposed NOx reduction requirements on AEP System generating units which are approximately equivalent to the reductions contemplated by the NOx emission reduction final rule. The AEP System companies with coal-fired generating plants, as well as other utility companies, filed a petition in the Appeals Court seeking review of the Section 126 Rule. In 1999, three additional northeastern states and the District of Columbia filed petitions with Federal EPA similar to those originally filed by the eight northeastern states. Since the petitions relied in part on compliance with an 8-hour ozone standard remanded by the Appeals Court, Federal EPA indicated its intent to decouple compliance with the 8-hour standard and issue a revised rule.

On December 17, 1999, Federal EPA issued a revised Section 126 Rule requiring 392 industrial plants, including certain generating plants owned by the Company, to reduce their NOx emissions by May 1, 2003. This rule approves petitions of four northeastern states which contend that their

failure to meet Federal EPA smog standards is due to coal-fired generating plants in upwind states, including many of the Company's plants, and not their automobiles and other local sources.

Preliminary estimates indicate that compliance with the Federal EPA's final rule on NOx emission reductions that was upheld by the Appeals Court could result in required capital expenditures of approximately $1.6 billion for the Company. It should be noted, however, that compliance costs cannot be estimated with certainty since actual costs incurred to comply could be significantly different from this preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless compliance costs are recovered from customers through regulated rates and, where generation is being deregulated, unbundled generation transition rates, wires charges and the future market price of electricity, such compliance costs will have an adverse effect on future results of operations, cash flows and possibly financial condition.

Federal EPA Complaint and Notice of Violation

Under the Clean Air Act, if a plant undergoes a major modification that results in a significant 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.

On November 3, 1999, the Department of Justice, at the request of Federal EPA, filed a complaint in the U.S. District Court for the Southern District of Ohio that alleges the Company made modifications to certain of its coal-fired generating plants over the course of the past 25 years that extend their operating lives or increase their generating capacity in violation of the Clean Air Act. Federal EPA also issued Notices of Violation to the Company alleging violations of certain provisions of the Clean Air Act at certain AEP plants. A number of unaffiliated utilities also received Notices of Violation, complaints or administrative orders.

The states of New Jersey, New York and Connecticut were subsequently allowed to join Federal EPA's action against the Company under the Clean Air Act. On November 18, 1999, a number of environmental groups filed a lawsuit against power plants owned by the Company alleging similar violations to those in the Federal EPA complaint and Notices of Violation. This action has been consolidated with the Federal EPA action. The complaints and Notices of Violation named 11 of AEP's 17 coal-fired generating plants. Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act provisions and intends to vigorously pursue its defense of this matter.

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 all of Federal EPA's contentions, could be substantial. In the event the Company does 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, approved unbundled transition generation rates, wires charges and future market prices for electricity.

Business Outlook - Worldwide Electric and Gas Operations

In 1999 no significant new investments were made in the worldwide electric and gas operations outside the U.S. Management

continues to evaluate its current investments and opportunities for growth with the goal of maximizing shareholder value. In January 2000 European trading of electricity and gas began. In 1999 the construction of two generating units in China was completed on schedule and the Company acquired a 50% investment interest in a Mexican generation project and commenced energy trading operations in Canada. This follows acquisitions made in December 1998 to expand AEP's electric and gas operations overseas and in the U.S. which included the purchase of CitiPower, an Australian electric distribution utility, and the purchase of LIG's gas operations in Louisiana and gas trading operation in Houston, Texas.

The most significant factor affecting the Company's future earnings from its worldwide electric and gas operations is the performance of its energy investments and business ventures including the ability to control costs as the U.K. and Australian electricity supply markets are deregulated and electricity distribution rate regulation becomes more performance based. The Company continues to evaluate the U.S. and international energy markets for investment opportunities to create share-holder value. Future earnings will also be impacted by the performance of any future acquisitions, mergers and investments.

Pursuant to the 1935 Act, AEP's investment in certain types of non-regulated energy ventures is limited. SEC authorization under the 1935 Act limits AEP to issuing and selling securities in an amount up to 100% of its average quarterly consolidated retained earnings balance (such average balance was approximately $1.7 billion for the twelve months ended December 31, 1999) for investment in exempt wholesale generators (EWGs) and foreign utility companies (FUCOs). At December 31, 1999, AEP's investment in EWGs and FUCOs was $885 million. Management expects to continue to pursue new and existing energy projects and to provide energy related services worldwide.

In December 1999 the Company contributed $47 million to acquire a 50% interest in a Mexican power project. The power project (Bajio) is a 600 MW natural gas-fired, combined cycle plant located approximately 160 miles from Mexico City. An affiliate of the Company's partner will build the facility, which is estimated to cost $430 million. The Company is not expected to contribute any additional capital to the project; the remainder of the funding will be provided by third party debt some of which will be supported by letters of credit issued on behalf of the Company. The facility will be operated and managed by companies jointly owned by the Company and its partner. Bajio has a 25-year contract to sell 495 MW of the plant's output to Mexico's federally owned electric system. The remainder is expected to be sold to industrial customers in the region. The Bajio power project is expected to be completed in the fall of 2001.

The $1.1 billion acquisition of CitiPower, completed on December 31, 1998, was accounted for using the purchase method of accounting. CitiPower provides electricity and electric distribution service to approximately 250,000 customers in the city of Melbourne.

In March 1998 the Company acquired a 20% equity interest in Pacific Hydro. Pacific Hydro operates four hydroelectric power stations in Australia with an installed capacity of 40 MW and has interests in two hydroelectric projects under construction in the Philippines.

Two newly constructed 250 MW coal-fired generating units in China, owned 70% by the Company with the remaining 30% owned by two Chinese partners, began commercial operation in 1999. Although the units incurred a loss in 1999, a higher tariff rate approved by the Central Chinese government in January 2000 should result in the units contributing to the Company's future earnings.

In addition, the Company has a 50% investment in Yorkshire, a U.K. supplier of electricity and gas and electric service distribution company. The investment was made in April 1997 and contributed $45 million and $39 million of equity earnings in 1999 and 1998, respectively, which is included in worldwide electric and gas operations revenues. Since May 1999 all residential and commercial customers in the U.K. could choose their electricity supplier. Yorkshire has been successful in maintaining its customer base since the start of full competition. However, as expected, margins on retail electric sales have been declining due to competition. In December 1999 the Office of Gas and Electricity Markets (OFGEM), the U.K. gas and electric regulatory body, published final proposals for Yorkshire's new rates in its distribution business and for price caps in its supply business. The final proposals reduce distribution rates and electricity supply price caps beginning on April 1, 2000. The rate reductions and reduced price caps are expected to reduce the Company's equity earnings from its Yorkshire investment. This reduction may be significant if it is not offset by increased revenues and/or cost savings.

On December 1, 1998, the Company purchased LIG, a midstream natural gas operation for approximately $340 million including working capital funds. The midstream operations include a fully integrated natural gas gathering, processing, storage and transportation operation in Louisiana and a gas trading and marketing operation in Houston, Texas. Assets include an intrastate pipeline system, natural gas processing plants and natural gas storage facilities. The gas trading operation included in this purchase was merged with AEP's existing gas trading organization which began operating in December 1997. This acquisition is expected to enhance AEP's gas trading operations by improving management's knowledge of the Henry Hub gas market.

SEC rules under the 1935 Act permit AEP to invest up to 15% of consolidated capitalization (such amount was $2 billion at December 31, 1999) in energy-related companies that engage in marketing and/or trading electricity, gas and other energy commodities. The Company's gas trading business is reported as an investment under this rule and at December 31, 1999, AEP's investment was $337 million.

Financial Condition

AEP's financial condition continues to be strong. The Cook Plant extended outage and related restart expenditures negatively affected 1999 earnings and will continue to adversely impact earnings in 2000. The 1999 dividend payout ratio was 89.1% and is expected to increase in 2000 as the Cook Plant restart is completed. Nonetheless, it has been a management objective to reduce the payout ratio by increasing earnings.

AEP's ratio of common equity to total capitalization including long-term debt due within one year was 39.7% on December 31, 1999, compared with 40.3% on December 31, 1998 and 45.5% on December 31, 1997. The decline in 1999 and 1998 primarily reflects borrowing to support the acquisitions and investments made by the worldwide electric and gas operations. AEP issued 2,287,000 shares of common stock in 1999, 1,826,000 shares in 1998 and 1,755,000 shares in 1997 through a Dividend Reinvestment and Direct Stock Purchase Plan and the Employee Savings Plan raising $91 million, $86 million and $77 million, respectively. Additional sales of common stock and/or equity linked securities may be necessary in the future to support the Company's growth.

Consolidated construction expenditures for all subsidiaries are expected to be $2.8 billion over the next three years. All expenditures for domestic regulated electric utility construction, estimated to be $2.5 billion for the next three years, are expected to be financed with internally generated funds.

Capital Resources - Structure and Liquidity

The Company and its subsidiaries issued $810 million principal amount of long-

term obligations in 1999 at interest rates ranging from 5.15% to 7.45%. The Company also increased its borrowing under two long-term revolving credit agreement: $60 million under an agreement which expires in June 2000 and $30 million under an agreement which expires in December 2002. The principal amount of long-term debt retirements, including maturities, totaled $506 million with interest rates ranging from 6.42% to 9.6%. The ratings of the subsidiaries' first mortgage bonds are listed in the following table:

Company	Moody's	S&P	Fitch	D & P
APCo	A3	A	A	A
CSPCo	A3	A-	A-	A
I&M	Baa1	A-	BBB+	BBB+
KPCo	Baa1	A	BBB+	BBB+
OPCo	A3	A-	A-	A

The Company's subsidiaries also issue senior unsecured debt. Their senior unsecured debt ratings are listed in the following table:

Company	Moody's	S&P	D & P
AEP Resources*	Baa2	BBB+	N/A
APCo	Baa1	BBB+	A-
CitiPower	Baa2	BBB+	N/A
CSPCo	Baa1	BBB+	A-
I&M	Baa2	BBB	BBB
KPCo	Baa2	BBB	BBB
OPCo	Baa1	BBB+	A-

* The rating is for a series of senior notes issued with a Support Agreement from AEP.

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 AEP Co., Inc. 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 (through revolving credit facilities) and capital contributions by the parent company to provide for interim financing of capital expenditures and acquisitions. Short-term debt is replaced with long-term debt when financial market conditions are favorable. Some acquisition transactions of existing business entities include the assumption of their outstanding debt.

Short-term debt increased $271 million and $62 million in 1999 and 1998, respectively. At December 31, 1999, AEP Co., Inc. (the parent company) and its subsidiaries had unused short-term lines of credit of $1,056 million, and another subsidiary had $20 million available under a $50 million revolving credit agreement that expires in December 2002. An AEP subsidiary engaged in the acquisitions of worldwide energy investments and businesses had no funds available under a $600 million revolving credit agreement that expires in June 2000.

Unless the domestic electric utility subsidiaries meet certain earnings or coverage tests, they cannot issue additional mortgage bonds. In order to issue mortgage bonds (without refunding existing debt), each subsidiary must have pre-tax earnings equal to at least two times the annual interest charges on mortgage bonds after giving effect to the issuance of the new debt.

The following debt coverages of AEP's principal domestic electric utility subsidiaries remained strong in 1999 and were as follows:

	Coverages at December 31, 1999 Mortgage
APCo	5.29
CSPCo	7.42
I&M	4.81
KPCo	5.57
OPCo	11.78

As the above table indicates, the major domestic electric utility subsidiaries presently exceed the minimum coverage requirements.

Market Risks

The Company 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 the Company to market risk. Market risk represents the risk of loss that may impact the Company due to adverse 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 three-day holding period. Throughout 1999 and 1998, the highest, lowest and average VaR in the wholesale electricity and gas trading portfolio was less than $14 million and $11 million, respectively. Based on this VaR analysis, at December 31, 1999 a near term change in commodity prices is not expected to have a material effect on the Company's results of operations, cash flows or financial condition.

Investments in foreign ventures expose the Company to risk of foreign currency fluctuations. The Company'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.

The Company is exposed to changes in interest rates primarily due to short- and long-term borrowings to fund its business operations. The debt portfolio has both fixed and variable interest rates with terms from one day to forty years and an average duration of four years at December 31, 1999. The Company 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 the Company's exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $575 million at December 31, 1999 and $589 million at December 31, 1998. The Company 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 the Company. The Company is currently utilizing interest rate swaps as a hedge to manage its exposure to interest rate fluctuations in Australia.

The Company has investments in debt and equity securities which are held in nuclear trust funds. Approximately 80% of the trust fund value is invested in tax exempt and taxable bonds, short-term debt instruments or cash. The trust investments and their fair value are discussed in Note 14 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.

Inflation affects AEP's cost of replacing utility plant and the cost of operating and maintaining its plant. The rate-making process limits our 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.

Litigation

Corporate Owned Life Insurance

The Internal Revenue Service (IRS) agents auditing the AEP System's consolidated federal income tax returns requested a ruling from their National Office that certain interest deductions claimed by the Company relating to AEP's corporate owned life insurance (COLI) program should not be allowed. As a result of a suit filed in U.S. District Court (discussed below) this request for ruling was withdrawn by the IRS agents. Adjustments have been or will be proposed by the IRS disallowing COLI interest deductions for taxable years 1991-96. A disallowance of the COLI interest deductions through December 31, 1999 would reduce earnings by approximately $317 million inclusive of interest.

The Company made payments of taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of any additional above market rate interest on the contested amount. The payments to the IRS are included on the consolidated balance sheet in other assets pending the resolution of this matter. The Company is seeking refund through litigation of all amounts paid plus interest.

In order to resolve this issue, the Company filed suit against the U.S. in the U.S. District Court for the Southern District of Ohio in March 1998. In 1999 a U.S. Tax Court judge decided in the Winn-Dixie Stores v. Commissioner case that a corporate taxpayer's COLI deductions should be disallowed. Notwithstanding the decision in Winn-Dixie management has made no provision for any possible adverse earnings impact from this matter because it believes, and has been advised by outside counsel, that it has a meritorious position and will vigorously pursue its lawsuit. In the event the resolution of this matter is unfavorable, it will have a material adverse impact on results of operations, cash flows and possibly financial condition.

AEP is 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.

Other Matters

Superfund

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and spent nuclear fuel (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, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. We are currently incurring costs to safely dispose of such substances. Additional costs could be incurred to comply with new laws and regulations if enacted.

The Comprehensive Environmental Response, Compensation and Liability Act (Superfund) addresses clean-up of hazardous substances at disposal sites and authorized Federal EPA to administer the clean-up programs. As of year-end 1999, we are involved in litigation with respect to two sites overseen by the Federal EPA and have been named by the Federal EPA as a potentially responsible party (PRP) for three other sites. There are three additional sites for which AEP has received information requests which could lead to PRP designation. The Company has also been named a PRP at one site under state law. Our liability has been resolved for a number of sites with no significant effect on results of operations. In those instances where we have been named a PRP or defendant, our 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 our potential future liability. AEP's 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, our present estimates do not anticipate material cleanup costs for identified sites for which we have been declared PRPs. If significant cleanup costs are attributed to AEP in the future, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be recovered from customers.

The Clean Air Act Amendments (CAAA) required Federal EPA to issue rules to implement the law. In 1996 Federal EPA issued final rules governing NOx emissions that must be met after January 1, 2000 (Phase II of CAAA). The final rules required substantial reductions in NOx emissions from certain types of boilers including those in AEP's power plants. To comply with Phase II of CAAA, the Company installed NOx emission control equipment on certain units and switched fuel at other units. The Company is operating under the Phase II rules which require reporting at the end of each year. The Company does not anticipate any material problems complying with the rules.

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, President Clinton has indicated that he will not submit the treaty to the Senate for consideration until it contains 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 been negotiated. At the Fourth Conference of the Parties, held in Buenos Aires, Argentina, 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. We 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, the costs for the Company to comply with the 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 or implemented in the U.S. in its current form.

Costs for Spent Nuclear Fuel and Decommissioning

AEP, as the owner of the Cook Plant, like other nuclear power plants, has a significant future financial commitment to safely dispose of SNF and decommission and decontaminate the plant. 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 the Company participates in the Department of Energy's (DOE) SNF disposal program which is described in Note 6 of the Notes to Consolidated Financial Statements. Since 1983 we have collected

$272 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. $115 million of these funds have been deposited in external trust funds to provide for the future disposal of spent nuclear fuel and $157 million has been remitted to the DOE. 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 December 1996, the DOE notified AEP 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 along with a number of unaffiliated utilities and states filed suit in the Appeals Court requesting, among other things, that the Appeals Court order DOE to meet its obligations under the law. The Appeals 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 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. On April 6, 1999, the court granted DOE's motion to dismiss a lawsuit filed by another utility. On May 20, 1999, the other utility appealed this decision to the U.S. Court of Appeals for the Federal Circuit. The Company's case has been stayed pending final resolution of the other utility's appeal. 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 will continue to increase.

The cost to decommission the Cook Plant is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 1997 estimate the cost to decommission the Cook Plant ranges from $700 million to $1,152 million in 1997 nondiscounted dollars. This estimate could escalate due to continued uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 1999, the total decommissioning trust fund balance was $498 million which includes earnings on the trust investments. We will work with regulators and customers to recover the remaining estimated cost of decommissioning the Cook Plant. However, AEP's future results of operations, cash flows and possibly its financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Year 2000 Readiness Disclosure

On or about midnight on December 31, 1999, digital computing systems could have produced erroneous results or failed, unless these systems had been modified or replaced, because such systems may have been programmed incorrectly and interpreted the date of January 1, 2000 as being January 1st of the year 1900 or another incorrect date. In addition, certain systems may fail to detect that the year 2000 is a leap year or otherwise incorrectly interpret a year 2000 date.

The Company has not experienced any material failures of generation and delivery of electric energy due to Year 2000 because of its preparations. Such preparations included the modification or replacement of certain computer hardware and software to minimize Year 2000-related failures and repair. This included both information technology systems (IT), which are mainframe and client server applications, and embedded logic systems (non-IT), such as process controls for energy production and delivery. Externally, the problem was addressed with entities that interact with the Company, including suppliers, customers, creditors, financial

service organizations and other parties essential to the Company's operations. In the course of the external evaluation, the Company sought written assurances from third parties regarding their state of Year 2000 readiness. Another issue addressed was the impact of electric power grid problems that may have occurred outside of our transmission system.

Through December 31, 1999, the Company spent $46 million on its Year 2000 project. Most Year 2000 costs were for IT contractors and consultants and for salaries of internal IT professionals and were expensed; however, in certain cases the Company acquired hardware and new software that was capitalized.

New Accounting Standards

The FASB issued SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" in June 1998. SFAS 133 establishes accounting and reporting standards for derivative instruments. It requires that all derivatives be recognized as either an asset or a liability and measured at fair value in the financial statements. If certain conditions are met a derivative may be designated as a hedge of possible changes in fair value of an asset, liability or firm commitment; variable cash flows of forecasted transactions; or foreign currency exposure. The accounting/reporting for changes in a derivative's fair value (gains and losses) depend on the intended use and resulting designation of the derivative. Management is currently studying the provisions of SFAS 133 and reviewing the Company's contracts and transactions to determine the impact on the Company's results of operations, cash flows and financial condition when SFAS 133 is adopted on January 1, 2001.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF INCOME

(in millions - except per share amounts)

	Year Ended December 31,		
	1999	1998	1997
REVENUES:			
Domestic Regulated Electric Utility Operations	$6,315	$6,346	$5,880
Worldwide Electric and Gas Operations	601	51	48
TOTAL	6,916	6,397	5,928
OPERATING EXPENSES:			
Fuel and Purchased Power	2,116	2,154	1,762
Maintenance and Other Operation	1,868	1,846	1,711
Depreciation and Amortization	600	580	591
Taxes Other Than Income Taxes	476	475	469
Worldwide Electric and Gas Operations	551	95	49
TOTAL EXPENSES	5,611	5,150	4,582
OPERATING INCOME	1,305	1,247	1,346
OTHER INCOME (net)	15	-	18
INCOME BEFORE INTEREST, PREFERRED DIVIDENDS AND INCOME TAXES	1,320	1,247	1,364
INTEREST AND PREFERRED DIVIDENDS	540	430	424
INCOME BEFORE INCOME TAXES	780	817	940
INCOME TAXES	260	281	320
INCOME BEFORE EXTRAORDINARY ITEM	520	536	62[illegible]
EXTRAORDINARY ITEM - U.K. WINDFALL TAX	-	-	(1[illegible])
NET INCOME	$ 520	$ 536	$ 511
AVERAGE NUMBER OF SHARES OUTSTANDING	193	191	189
EARNINGS PER SHARE:			
Before Extraordinary Item	$2.69	$2.81	$ 3.28
Extraordinary Item - U.K. Windfall Tax	-	-	(0.58)
Net Income	$2.69	$2.81	$ 2.70
CASH DIVIDENDS PAID PER SHARE	$2.40	$2.40	$2.40

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Year Ended December 31,		
	1999	1998	1997
Net Income	$520	$536	$511
Other Comprehensive Gain (Loss)	15	(1)	-
COMPREHENSIVE INCOME	$535	$535	$511

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	1999	1998	1997
OPERATING ACTIVITIES:			
Net Income	$ 520	$ 536	$ 511
Adjustments for Noncash Items:			
Depreciation and Amortization	714	620	608
Deferred Federal Income Taxes	144	41	(7)
Deferred Investment Tax Credits	(25)	(25)	(25)
Amortization (Deferral) of Operating Expenses and Carrying Charges (net)	(151)	15	12
Equity in Earnings of Yorkshire Electricity Group plc	(45)	(38)	(34)
Extraordinary Item - UK Windfall Tax	-	-	109
Deferred Costs Under Fuel Clause Mechanisms	(116)	(73)	(52)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(31)	(142)	(136)
Fuel, Materials and Supplies	(122)	2	(1)
Accrued Utility Revenues	(32)	3	(14)
Accounts Payable	92	200	147
Taxes Accrued	32	(1)	(33)
Payment of Disputed Tax and Interest Related to COLI	(19)	(303)	(3)
Other (net)	(144)	195	116
Net Cash Flows From Operating Activities	817	1,030	1,198
INVESTING ACTIVITIES:			
Construction Expenditures	(867)	(792)	(760)
Investment in Yorkshire Electricity Group plc	-	-	(364)
Investment in CitiPower	-	(1,054)	-
Investment in Gas Assets	-	(340)	-
Other	(47)	(27)	2
Net Cash Flows Used For Investing Activities	(914)	(2,213)	(1,122)
FINANCING ACTIVITIES:			
Issuance of Common Stock	91	86	77
Issuance of Long-term Debt	892	2,491	880
Retirement of Cumulative Preferred Stock	(10)	(1)	(433)
Retirement of Long-term Debt	(523)	(915)	(348)
Change in Short-term Debt (net)	271	62	235
Dividends Paid on Common Stock	(464)	(458)	(453)
Net Cash Flows From (Used For) Financing Activities	257	1,265	(42)
Net Increase in Cash and Cash Equivalents	160	82	34
Cash and Cash Equivalents January 1	173	91	57
Cash and Cash Equivalents December 31	$ 333	$ 173	$ 91

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(in millions - except share data)

	December 31, 1999	December 31, 1998
ASSETS		
CURRENT ASSETS:		
Cash and Cash Equivalents	$ 333	$ 173
Accounts Receivable:		
Customers	553	557
Miscellaneous	369	333
Allowance for Uncollectible Accounts	(12)	(11)
Fuel - at average cost	307	216
Materials and Supplies - at average cost	311	280
Accrued Utility Revenues	246	214
Energy Marketing and Trading Contracts	1,001	372
Prepayments and Other	108	84
TOTAL CURRENT ASSETS	3,216	2,218
PROPERTY PLANT AND EQUIPMENT:		
Electric:		
Production	9,949	9,615
Transmission	3,832	3,692
Distribution	5,536	5,125
Other (including gas and coal mining assets and nuclear fuel)	2,307	2,118
Construction Work in Progress	581	801
Total Property, Plant and Equipment	22,205	21,351
Accumulated Depreciation and Amortization	9,150	8,549
NET PROPERTY, PLANT AND EQUIPMENT	13,055	12,802
REGULATORY ASSETS	2,171	1,847
OTHER ASSETS	3,046	2,616
TOTAL	$21,488	$19,483

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

LIABILITIES AND SHAREHOLDERS' EQUITY	December 31, 1999	December 31, 1998
CURRENT LIABILITIES:		
Accounts Payable	$ 699	$ 607
Short-term Debt	888	617
Long-term Debt Due Within One Year*	1,111	206
Taxes Accrued	414	382
Interest Accrued	78	75
Obligations Under Capital Leases	91	82
Energy Marketing and Trading Contracts	964	360
Other	425	472
TOTAL CURRENT LIABILITIES	4,670	2,801
LONG-TERM DEBT*	6,336	6,800
DEFERRED INCOME TAXES	2,745	2,601
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	213	222
DEFERRED INVESTMENT TAX CREDITS	326	351
DEFERRED CREDITS AND REGULATORY LIABILITIES	517	263
OTHER NONCURRENT LIABILITIES	1,511	1,429
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES*	164	174
COMMITMENTS AND CONTINGENCIES (Notes 6 and 7)		
COMMON SHAREHOLDERS' EQUITY:		
Common Stock-Par Value $6.50:		
(1999: Shares Authorized. .600,000,000; Shares Issued. . . .203,103,341; 1998: 600,000,000 / 200,816,469; 8,999,992 shares were held in treasury at December 31, 1999 and 1998)	1,320	1,305
Paid-in Capital	1,932	1,854
Accumulated Other Comprehensive Income- Foreign Currency Translation Adjustments	14	(1)
Retained Earnings	1,740	1,684
TOTAL COMMON SHAREHOLDERS' EQUITY	5,006	4,842
TOTAL	$21,488	$19,483

*See Accompanying Schedules.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

(in millions)	Common Stock		Paid-In Capital	Comprehensive Income	Retained Earnings	Total
	Shares	Amount				
JANUARY 1, 1997	197	$1,282	$1,716	$-	$1,548	$4,546
Issuances	2	11	66	-	-	77
Retirements and Other	-	-	(3)	-	-	(3)
Net Income	-	-	-	-	511	511
Cash Dividends Declared	-	-	-	-	(453)	(453)
Foreign Currency Translation Adjustments	-	-	-	-	-	-
DECEMBER 31, 1997	199	1,293	1,779	-	1,606	4,678
Issuances	2	12	74	-	-	86
Retirements and Other	-	-	1	-	-	1
Net Income	-	-	-	-	536	536
Cash Dividends Declared	-	-	-	-	(458)	(458)
Foreign Currency Translation Adjustments	-	-	-	(1)	-	(1)
DECEMBER 31, 1998	201	1,305	1,854	(1)	1,684	4,842
Issuances	2	15	76	-	-	91
Retirements and Other	-	-	2	-	-	2
Net Income	-	-	-	-	520	520
Cash Dividends Declared	-	-	-	-	(464)	(464)
Foreign Currency Translation Adjustments	-	-	-	15	-	15
DECEMBER 31, 1999	203	$1,320	$1,932	$14	$1,740	$5,006

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies:

Organization - American Electric Power Company, Inc. (AEP or the Company) is one of the United States' (U.S.) largest investor-owned public utility holding companies engaged in the generation, purchase, transmission and distribution of electric power to 3 million retail customers in its seven state service territory which covers portions of Ohio, Michigan, Indiana, Kentucky, West Virginia, Virginia and Tennessee. Electric power is also supplied at wholesale to neighboring utility systems and power marketers. AEP also has energy holdings in the U.S., the United Kingdom (UK), China and Australia.

The organization of AEP consists of American Electric Power Company, Inc. (AEP Co., Inc.), the parent holding company; seven domestic regulated electric utility operating companies (domestic utility subsidiaries); a domestic generating subsidiary, AEP Generating Company (AEGCo); two active coal-mining companies; a service company, American Electric Power Service Corporation (AEPSC); AEP Resources, Inc. (AEPR) a subsidiary which invests in, owns and operates energy-related domestic and international projects and companies; AEP Energy Services, Inc. (AEPES) a non-regulated subsidiary which markets and trades energy commodities; and other subsidiaries that provide energy and communication services.

The following domestic utility subsidiaries pool their generating and transmission facilities and operate them as an integrated system: Appalachian Power Company (APCo), Columbus Southern Power Company (CSPCo), Indiana Michigan Power Company (I&M), Kentucky Power Company (KPCo) and Ohio Power Company (OPCo). The remaining two domestic utility subsidiaries, Kingsport Power Company (KGPCo) and Wheeling Power Company (WPCo) are distribution companies that purchase power from APCo and OPCo, respectively. AEPSC provides management, professional and other services to the AEP System subsidiaries. The active coal-mining companies are wholly-owned by OPCo (see Note 3 for information regarding shutdown of affiliated mines). AEGCo has a 50% interest in the Rockport Plant which is comprised of two of the AEP System's six 1,300 megawatt (MW) generating units. AEPR owns 50% of Yorkshire Electricity Group plc (Yorkshire), a supply and distribution utility company in the UK (see Note 9); 70% of Nanyang General Light Electric Co., Ltd., owner of a two-unit power plant in China; 20% of Pacific Hydro, an Australian hydroelectric generating company; all of the assets of a midstream natural gas operation in Louisiana and 100% of CitiPower, a Melbourne, Australia supply and distribution utility. AEPES principally markets and trades natural gas. Two non-regulated subsidiaries, AEP Resources Service Company and AEP Communications are engaged in providing power engineering, consulting and management services around the world and fiber, wireless and information communication services in the U.S.

Although the domestic utility subsidiaries are managed centrally by AEPSC and operate as American Electric Power they and AEPSC have not changed their names and remain separate legal entities.

Rate Regulation - The AEP System is subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (1935 Act). The rates charged by the domestic utility subsidiaries are approved by the Federal Energy Regulatory Commission (FERC) and the state utility commissions. The FERC regulates wholesale electricity rates and transmission rates and the state commissions regulate retail generation and distribution rates.

Principles of Consolidation - The consolidated financial statements include AEP Co., Inc. and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-

owned subsidiaries. Significant intercompany items are eliminated in consolidation. Yorkshire and Pacific Hydro are accounted for using the equity method with their equity earnings included in revenues from worldwide electric and gas operations.

Basis of Accounting - As the owner of cost-based rate-regulated electric public utility companies, AEP Co., Inc.'s consolidated financial statements 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 Statement of Financial Accounting Standards (SFAS) 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues.

Use of Estimates - The preparation of these financial statements in conformity with generally accepted accounting principles requires in certain instances the use of estimates. Actual results could differ from those estimates.

Property, Plant and Equipment - Property, plant and equipment are stated at original cost of the acquirer. Additions, major replacements and betterments are added to the plant accounts. 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 utility 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 1999, 1998 and 1997 were not significant. Worldwide operations capitalize interest during construction in accordance with SFAS 34, "Capitalization of Interest Costs."

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 1999
Production:	
Steam-Nuclear	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	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 3.8%

Functional Class of Property	Annual Composite Depreciation Rates Ranges 1997
Production:	
Steam-Nuclear	3.4%
Steam-Fossil-Fired	3.2% to 4.4%
Hydroelectric-Conventional and Pumped Storage	2.7% to 3.2%
Transmission	1.7% to 2.7%
Distribution	3.3% to 4.2%
Other	2.5% to 3.8%

Depreciation, depletion and amortization of 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 $2.32 per ton in 1999, $1.85 per ton in 1998 and $1.91 per ton in 1997. These costs are included in the cost of coal charged to fuel expense. See Note 3 regarding closure of affiliated mines.

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

Foreign Currency Translation - The financial statements of subsidiaries outside the U.S. are measured using the local currency as the functional currency. 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 accumulated in shareholders' equity. Currency transaction gains and losses are recorded in income.

Energy Marketing and Trading Transactions - The Company makes 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 represents physical forward electricity contracts in the Company's traditional marketing area and are typically settled by entering into offsetting contracts. The net revenues from these transactions in the Company's traditional marketing area are included in regulated revenues for ratemaking, accounting and financial and regulatory reporting purposes.

The Company 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 for gas. These transactions represent non-regulated trading activities that are included in worldwide revenues.

In the first quarter of 1999 the Company adopted the Financial Accounting Standards Board's Emerging Issues Task Force Consensus (EITF) 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities". The EITF requires that all energy trading contracts be marked-to-market. The effect on the Consolidated Statements of Income of marking open trading contracts to market is deferred as regulatory assets or liabilities for those open electricity trading transactions within the Company's marketing area that are included in cost of service on a settlement basis for ratemaking purposes in the Company's non-Virginia jurisdictions. A Virginia jurisdiction net mark-to-market after-tax gain of $3 million as of December 31, 1999 is included in net income as a result of an agreed prohibition against establishing new regulatory assets in a February 1999 Virginia State Corporation Commission (Virginia SCC) approved settlement agreement. Non-regulated open trading contracts are accounted for on a mark-to-market basis and included in worldwide electric and gas operations revenues. Unrealized mark-to-market gains and losses from all trading activity are reported as assets and liabilities, respectively. The adoption of the EITF did not have a material effect on results of operations, cash flows or financial condition.

The Company enters 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 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, 1999 or 1998.

See Note 14 - Financial Instruments, Credit and Risk Management for further discussion.

Revenues and Fuel Costs - Regulated revenues include the accrual of electricity consumed but unbilled at month-end as well as billed revenues. Fuel costs are matched, in accordance with SFAS 71, with their recovery from/to customers through regulated revenues in accordance with rate commission orders. Generally in order to accomplish a proper matching in the retail jurisdictions, changes in fuel costs are deferred or revenues accrued until approved by the regulatory commission for billing or refund to customers in later months. Wholesale jurisdictional fuel cost changes are expensed and billed as incurred.

Levelization of Nuclear Refueling Outage Costs - In order to match costs with regulated revenues, incremental operation and maintenance costs associated with refueling outages at I&M's Cook Plant are deferred commensurate with their rate-making treatment 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 Indiana Utility Regulatory Commission (IURC) and the Michigan Public Service Commission (MPSC) to resolve all issues related to an extended outage of the Cook Plant, I&M deferred certain operation and maintenance costs in 1999. The settlement agreements provide for the deferral of $150 million of Indiana jurisdictional and $50 million of Michigan jurisdictional incremental operation and maintenance costs incurred in 1999. The deferred amount will be amortized to expense on a straight-line basis over five years beginning January 1, 1999. I&M deferred $200 million and amortized $40 million in 1999 leaving $160 million as an SFAS 71 regulatory asset at December 31, 1999 on the Consolidated Balance Sheet. See Note 2 "Nuclear Plant Shutdown" for a discussion of the settlement agreements.

Income Taxes - The Company 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.

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 - 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 are generally deferred except in Virginia and amortized over the term of the replacement debt commensurate with their recovery in rates.

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.

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.

Other Assets - Other assets are comprised primarily of nuclear decommissioning and spent nuclear fuel disposal trust funds; licenses for CitiPower operating franchises; amounts for corporate owned life insurance and related disputed tax payments; the investments in Yorkshire and Pacific Hydro which are accounted for under the equity method of accounting; and goodwill. Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are recorded 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. The recoverability of goodwill (evaluated on the basis of undiscounted operating cash flow analysis) is reviewed when events or changes in circumstances indicate that the carrying amount may exceed fair value.

EPS - Earnings per share is determined based upon the weighted average number of shares outstanding. There are no dilutive potential common shares. Therefore, earnings per share is the same for basic earnings per share and diluted earnings per share.

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

2. Nuclear Plant Shutdown:

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (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. The NRC issued a Confirmatory Action Letter in September 1997 requiring I&M to address certain issues identified in the letter. In 1998 the NRC notified I&M that it had convened a Restart Panel for Cook Plant and provided a list of required restart activities. In order to identify and resolve the issues necessary to restart the Cook units, I&M is working with the NRC and will be meeting with the Panel on a regular basis until the units are returned to service. In a February 2, 2000 letter from the NRC, I&M was notified that the Confirmatory Action Letter had been closed. Closing of the Confirmatory Action Letter is one of the key approvals needed to restart the nuclear units.

I&M's plan to restart the Cook Plant units has Unit 2 scheduled to return to service in April 2000 and Unit 1 scheduled to return to service in September 2000. The restart plan was developed based upon a comprehensive systems readiness review of all operating systems at the Cook Plant. When maintenance and other work including testing required for restart are complete, I&M will seek concurrence from the NRC to return the Cook Plant to service. Any issues or difficulties encountered in testing of equipment as part of the restart process could delay the scheduled restart dates.

Replacement of the steam generator for Unit 1 will be completed before it is returned to service. Costs associated with the steam generator replacement are estimated to be approximately $165 million, which will be accounted for as a capital investment unrelated to the restart. At December 31, 1999, $119 million has been spent on the steam generator replacement.

The cost of electricity supplied to certain retail customers increased due to the outage of the two Cook Plant nuclear units since higher cost coal-fired generation and coal-based purchased power is being substituted for the unavailable low cost nuclear generation. With regulator approvals I&M's actual replacement

energy fuel costs that exceeded the costs reflected in billings were recorded as a regulatory asset under Indiana and Michigan retail jurisdictional fuel cost recovery mechanisms.

On March 30, 1999, the IURC approved a settlement agreement 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, a replacement fuel billing credit of $55 million, including interest, to Indiana retail customers' bills; the deferral of unrecovered fuel revenues accrued between September 9, 1997 and December 31, 1999, including the billing credit; 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 $55 million credit was applied to retail customers' bills during the months of July, August and September 1999.

On December 16, 1999, the MPSC approved a settlement agreement for two open Michigan power supply cost recovery reconciliation cases which 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.

Expenditures to restart the Cook units are estimated to total approximately $574 million. Through December 31, 1999, $373 million has been spent. The restart costs incurred in 1997 and 1998 were $6 million and $78 million, respectively, and were recorded in other operation and maintenance expense. In 1999 the costs incurred were $289 million and were recorded in accordance with the Indiana and Michigan settlement agreements whereby $150 million and $50 million, respectively, of operation and maintenance costs were deferred in 1999 for amortization through December 31, 2003. The amortization of the non-fuel operation and maintenance restart cost deferrals through December 31, 1999 was $40 million. Consequently, maintenance and other operation expenses included $129 million of Cook restart expense for 1999. Restart costs incurred in 2000 will be accounted for as a current period operation and maintenance expense. At December 31, 1999, the unamortized balance of restart related operation and maintenance costs was $160 million and is included in the Company's regulatory assets. Also deferred as a regulatory asset at December 31, 1999 was $150 million of fuel-related revenues.

The costs of the extended outage and restart efforts will have a material adverse effect on future results of operations and possibly financial condition through 2003 and on cash flows through 2000. Management believes that the Cook units will be successfully returned to service in April and September 2000. However, if for some unknown reason the units are not returned to service or their return is delayed significantly it would have an even greater adverse effect on future results of operations, cash flows and financial condition.

3. Rate Matters:

OPCo's Recovery of Fuel Costs - Under the terms of a 1992 stipulation agreement the cost of coal burned at the Gavin Plant is subject to a 15-year predetermined price of $1.575 per million Btu's with quarterly escalation adjustments through November 2009. A 1995 Settlement Agreement set the fuel component of the electric fuel component

(EFC) factor at 1.465 cents per kilowatthour (kwh) for the period June 1, 1995 through November 30, 1998. The 1995 Settlement Agreement requires for the two year period from December 1, 1998 through November 30, 2000 that coal from Central Ohio Coal Company's Muskingum mine and Windsor Coal Company's mine be priced at the market price for comparable quality coal. The Company is allowed to defer the difference for future recovery. Effective December 1, 1998 the 1992 stipulation continued to control the recovery of fuel costs at the Gavin Plant and the ability of OPCo to recover the costs to shut down its affiliated mines. To the extent the actual cost of coal burned at the Gavin Plant is below the predetermined prices, the stipulation agreement provides 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 predetermined rate and deferred for future recovery under the agreements. These agreements will be superseded effective January 1, 2001 by the Ohio Electric Restructuring Act of 1999 (see Note 5).

The Muskingum coal mine which supplied all of its output to OPCo was closed in October 1999. During 1999 efforts began to reclaim the properties, sell or scrap all mining equipment, terminate both capital and operating leases and perform other activities necessary to shut down the mine. Mine reclamation activities should be completed by December 31 2002; postremediation monitoring is anticipated to continue for five years after completion of reclamation.

In 1999 the Company announced that the affiliated Windsor coal mine would close April 30, 2000. After the mine closes, efforts will begin to reclaim the property, sell or scrap all mining equipment and perform other activities necessary to shut down the mine. Reclamation activities should be completed within two to three years after shutdown.

The Company recorded mine closing costs of $45 million in 1998 for the Muskingum mine and $48 million in 1999 for the Windsor mine. Pursuant to terms of the 1992 and 1995 agreements, the Company deferred accrued mine closure costs of $19 million in 1998 for the Muskingum mine and $25 million in 1999 for the Windsor mine. Fuel expense included $23 million and $26 million in 1999 and 1998, respectively, of mine closure costs. At December 31, 1999, the accrued liabilities for reclamation, mine closing costs and post shutdown costs were $119 million for the Muskingum mine and $84 million for the Windsor mine.

Revenues and net income for the Muskingum mining operation in 1999 up to the shutdown date were $64 million and $1,000, respectively. For the years ended December 31, 1998 and 1997 revenues and net income from the Muskingum mining operation were $110 million and $1,000 and $66 million and zero, respectively. For the years ended December 31, 1999, 1998 and 1997 revenues and net income from the Windsor mining operation were $123 million and $18,000, $65 million and $123,000, and $69 million and $1 million, respectively.

Management believes that existing deferrals for the Ohio jurisdictional portion of the cost of the mine shutdowns can be deferred for future recovery through the Ohio fuel clause mechanism under terms of the Ohio fuel clause predetermined price agreements. At December 31, 1999 the Company has deferred $196 million under the terms of the Ohio fuel clause predetermined price agreements. However, since the Ohio Electric Restructuring Act of 1999 (the Act) supersedes the agreements, the Company has filed under the provisions of the Act for recovery of all of its generation related regulatory assets which includes the fuel deferral at December 31, 1999 plus the projected balance that will be deferred for the accrual of the Meigs mine closure costs by the beginning of the transition period, January 1, 2001. Under the provisions of the Act the Company is seeking a total of $360 million for the regulatory assets deferred under the above agreements through transition rates and a post generation deregulation five year

wires charge. Unless the cost of the remaining coal production and deferred mine shutdowns are recovered through the remaining Ohio fuel clause rates and Ohio restructuring transition rates and/or a post deregulation wires charge, future results of operations and cash flows will be adversely affected.

Management intends to continue to recover from non-Ohio jurisdictional ratepayers the non-Ohio jurisdictional portion of the investment in and the liabilities and closing costs of the Meigs, Muskingum and Windsor mines. The non-Ohio jurisdictional portion of shutdown costs for these mines which includes the investment in the mines, leased asset buy-outs, reclamation costs and employee benefits is estimated to be approximately $62 million after tax at December 31, 1999.

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, by requiring them to use 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 which 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. The Company made a provision in September 1999 for the refund including interest.

On December 10, 1999, AEP filed a settlement agreement with the FERC resolving the issues on rehearing of the July 30, 1999 order. Under terms of the settlement, AEP will make refunds retroactive to September 7, 1993 to certain customers affected by the July 30, 1999 FERC order. The refunds will be made in two payments. The first payment was made February 2, 2000 pursuant to a FERC order granting AEP's request to make interim refunds. The remainder will be paid after the FERC issues a final order and approves a compliance filing that AEP will make pursuant to the final order. In addition, a new rate was made effective January 1, 2000, subject to FERC approval, for all transmission service customers and a future rate was established to take effect upon the consummation of the AEP and Central and South West Corporation merger unless a superseding rate is made effective prior to the merger.

West Virginia - On May 12, 1999, the Company's subsidiary, APCo, filed with the Public Service Commission of West Virginia (WVPSC) for a base rate increase of $50 million annually and a reduction in expanded net energy cost (ENEC) rates of $38 million annually. On February 7, 2000, APCo and other parties to the proceeding filed a Joint Stipulation and Agreement for Settlement (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 of approximately 0.5 mills per kwh); annual ENEC recovery proceedings

are suspended and deferral accounting for over or under recovery is discontinued effective January 1, 2000; the net cumulative deferred ENEC recovery balance as established by a WVPSC order on December 27, 1996, which is $66 million at December 31, 1999, shall remain on the books as a regulatory liability. However, if deregulation of generation occurs in West Virginia (WV), APCo will use this regulatory liability to reduce unrecoverable generation-related regulatory assets and, to the extent possible, any additional cost or obligations that deregulation may impose. APCo's share of any net savings from the pending merger between AEP and Central and South West Corporation prior to December 31, 2004 shall be retained by APCo. All cost incurred in the merger that are allocated to APCo, whether the merger is consummated or not, shall be fully charged to expense as of December 31, 2004 and shall not be included in any WV rate proceeding after that date. After December 31, 2004, any 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 rates. If deregulation of generation occurs in WV the net retained generation related merger savings should be used to recover any generation related regulatory assets that are not recovered under the 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 recovery 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 adjustments provided in the Joint Stipulation and the 0.5 mills per kwh wires charge in the WV Restructuring Plan (see Note 5 for discussion of WV Restructuring Plan).

4. Effects of Regulation and Phase-In Plans:

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 Company'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 Company continues to meet the requirements to apply SFAS 71. In the event a portion of the Company's business no longer met those requirements, net regulatory assets would have to be written off for that portion of the business and assets attributable to that portion of the business would have to be tested for possible impairment and, if required, an impairment loss recorded unless the net regulatory assets and impairment losses are recoverable as a stranded cost. (See Note 5 "Restructuring Legislation".)

Recognized regulatory assets and liabilities are comprised of the following at:

	December 31,	
	1999	1998
	(in millions)	
Regulatory Assets:		
Amounts Due From Customers For Future Income Taxes	$1,278	$1,324
Deferred Fuel Costs	424	193
Unamortized Loss on Reacquired Debt	84	91
Other	385	239
Total Regulatory Assets	$2,171	$1,847
Regulatory Liabilities:		
Deferred Investment Tax Credits	$326	$351
Other Regulatory Liabilities*	300	148
Total Regulatory Liabilities	$626	$499

* Included in Deferred Credits and Regulatory Liabilities on Consolidated Balance Sheets.

Rate phase-in plans in the Indiana and the FERC jurisdictions provided for the recovery and straight-line amortization of deferred Rockport Plant Unit 1 costs over a ten year period that ended in 1997. In 1997 amortization and recovery of the deferred Rockport Plant Unit 1 phase-in plan costs were $11.9 million. During the recovery period net income was unaffected by the recovery of the phase-in deferrals.

5. Restructuring Legislation:

Ohio - The Ohio Electric Restructuring Act of 1999 (the Act) became law in October 1999. The Act provides for customer choice of electricity supplier, a residential rate reduction of 5% for the generation portion of rates and a freezing of generation rates including fuel rates beginning on January 1, 2001. The Act also provides for a five-year transition period to move from cost based rates to market pricing for generation services. It authorizes the Public Utilities Commission of Ohio (PUCO) to address certain major transition issues including unbundling of rates and the recovery of transition costs. Under the Act, transition costs can include regulatory assets, generating asset impairments and other stranded costs, employee severance and retraining costs, consumer education costs and other costs. Stranded generation costs are those costs of generation above the market price for electricity that potentially would not be recoverable in a competitive market.

Retail electric services that will be competitive are defined in the Act as electric generation service, aggregation service and power marketing and brokering. Under the legislation the PUCO is granted broad oversight responsibility and is required by the Act to promulgate rules for competitive retail electric generation service and transition plan filings. The Act also gives the PUCO authority to approve a transition plan for each electric utility company and sets a deadline of no later than October 31, 2000 for those approvals.

The Act provides Ohio electric utilities with an opportunity to recover PUCO approved allowable transition costs through generation rates paid through December 31, 2005 by customers who do not switch generation suppliers and through a transition charge for customers who switch generation suppliers. Recovery of the regulatory asset portion of transition costs can, under certain circumstances, extend beyond the five-year transition period but cannot continue beyond December 31, 2010.

The Act also provides for a reduction in property tax assessments, the imposition of 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 will be lowered from 100% to 25% of value effective January 1, 2001 and electric utilities will become subject to the Ohio Corporate Franchise Tax and municipal income taxes on January 1, 2002. The last year for which 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, deferred 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. The change in the tax law to impose an excise tax based on kwh sold to Ohio customers commencing before the expiration of the gross receipts tax privilege period will result in a 12 month period when electric utilities are recording as an expense both the gross receipts tax and the excise tax. In the Company's Ohio transition plan filings, recovery of $90 million was sought for this overlap of the gross receipts and excise taxes.

The Company filed its transition plan for OPCo and CSPCo (its Ohio jurisdictional

subsidiaries) with the PUCO on December 30, 1999. The filings included the following elements:

- a rate unbundling plan including tariff terms and conditions necessary for restructuring,
- a corporate separation plan,
- an application for transition revenues,
- a plan for independent operation of transmission facilities and
- other components for the implementation of restructuring.

Under the rate unbundling plan in the transition plan filing, the Company's Ohio retail jurisdictional companies will offer two transition period tariffs beginning January 1, 2001, the standard tariff and the open access distribution tariff. The proposed standard tariff applies to customers who do not choose an alternative energy supplier. This tariff schedule includes detailed charges for generation, transmission and distribution and riders to fund universal service, to promote energy efficiency and to recover regulatory assets and taxes. Taxes include charges for municipal income, excise and franchise taxes and tax credits for gross receipts and property taxes. For customers who choose an alternative electric supplier, the proposed open access distribution tariff will apply. This tariff includes charges for transmission and distribution and riders to fund universal service, to promote energy efficiency and to recover regulatory assets and taxes. These riders are the same as those in the standard tariff except there is no property tax credit.

The corporate separation plan contains proposals for each of the Company's Ohio jurisdictional companies to establish separate subsidiaries to own and operate their transmission and distribution assets. The separation plan will be implemented in a manner that recognizes the current overlap of financing arrangements. This would permit an orderly and economically efficient separation of each operating company so that additional transition costs can be avoided from premature unwinding of existing financial instruments. Prior to the actual legal separation, the Ohio jurisdictional companies will functionally separate generation from transmission and distribution.

An application to receive transition revenues was included in the transition plan filing. It requests recovery of stranded generation costs over a five year period and recovery of generation-related regulatory assets of $974 million over a 10-year period. The amount requested for recovery of regulatory assets includes current and new regulatory assets including those arising from compliance with the Act and closure of the affiliated mines.

Included in the transition plan is a proposal to implement independent operation of the transmission system. The Company proposes to join a regional transmission organization whose approval is currently pending before the FERC.

A project timeline for activities to implement operational support systems and other technical implementation issues to arrive at and support a competitive electricity market are included in the transition plan.

The Company plans to provide severance, retraining, early retirement, retention, outplacement and other assistance for displaced employees. At this time no employees are identified as affected by electric utility restructuring. Consequently, recovery of such costs was not requested in transition revenues as filed with the transition plan.

The transition plan includes a consumer education plan which will be implemented in conjunction with other electric utilities and the PUCO staff. The transition plan also has terms and conditions for changing suppliers and the commitment of time a customer must accept in a service contract which are two features necessary to accommodate restructuring.

A proposed shopping incentive in the transition plan represents the lower of the market price or the unbundled generation rate in current tariff schedules.

As discussed in Note 4, "Effects of Regulation and Phase-In Plans," the Company defers as regulatory assets and liabilities certain expenses and revenues consistent with the regulatory process in accordance with SFAS 71. Management has concluded that as of December 31, 1999 the requirements to apply SFAS 71 continue to be met since the Company's rates for generation will continue to be cost-based regulated until the PUCO takes action on the transition plan and the proposed tariff schedules contained in it as provided in the Act. The establishment of rates and charges under the transition plan should enable the Company to determine its ability to recover regulatory assets, transition costs and other stranded costs, a requirement to discontinue application of SFAS 71.

When the transition plan and tariff schedules are approved, the application of SFAS 71 will be discontinued for the Ohio retail jurisdictional portion of the generation business. At that time the Company will have to write-off its Ohio jurisdictional generation-related regulatory assets to the extent that they cannot be recovered under the tariff schedules in the transition plan approved by the PUCO and record any asset impairments in accordance with SFAS 121, "Accounting for the Impairment of Long-lived Assets and for Long-lived Assets to Be Disposed Of." An impairment loss would be recorded to the extent that the cost of generation assets cannot be recovered through generation-related revenues during the transition period and future market prices. Until the PUCO completes its regulatory process and issues an order related to the Company's transition plan, it is not possible for management to determine if any of the Company's generating assets are impaired in accordance with SFAS 121. The amount of regulatory assets recorded on the books at December 31, 1999 applicable to the Ohio retail jurisdictional generating business is $666 million before related tax effects. Due to the planned closing of affiliated mines and other anticipated events, generation-related regulatory assets as of December 31, 2000 allocable to the Ohio retail jurisdiction are estimated to exceed $800 million, before income tax effects. Recovery of these regulatory assets and an estimated asset impairment are being sought as a part of the Company's Ohio transition plan filing.

A determination of whether the Company will experience any asset impairment loss regarding its Ohio retail jurisdictional generating assets and any loss from a possible inability to recover Ohio generation-related regulatory assets and other transition costs cannot be made until the PUCO takes action on the Company's transition plan. Management is seeking full recovery of generation-related regulatory assets, stranded costs and other transition costs in its transition plan filing. The PUCO is required to complete its regulatory process including review of the Company's transition plan filing and issue a transition order no later than October 31, 2000. Should the PUCO fail to fully approve the Company's transition plan and its tariff schedules which include recovery of the Company's generation-related regulatory assets, stranded costs and other transition costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Virginia - In March 1999 a law was enacted in Virginia to restructure the electric utility industry. Under the restructuring law a transition to choice of electricity supplier for retail customers will commence on January 1, 2002 and be completed, subject to a finding by the Virginia SCC that an effective competitive market exists, on January 1, 2004.

The 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 law provides for the establishment of capped rates prior to January 1, 2001 and the establishment of a wires charge by the fourth quarter of 2001.

Management has concluded that as of December 31, 1999 the requirements to apply SFAS 71 continue to be met. The Company's Virginia rates for generation will continue to be cost-based regulated until the establishment of capped rates and the wires charge as provided in the law. The establishment of capped rates and the wires charge should enable management to determine its ability to recover stranded costs, a requirement to discontinue application of SFAS 71.

When the capped rates and the wires charge are established in Virginia, the application of SFAS 71 will be discontinued for the Virginia retail jurisdictional portion of the Company's generating business. At that time the Company will have to write-off its generation-related regulatory assets to the extent that they cannot be recovered under the capped rates and wire charges approved by the Virginia SCC under the provisions of the restructuring law and record any asset impairments in accordance with SFAS 121. An impairment loss would be recorded to the extent that the cost of impaired assets cannot be recovered through generation-related revenues during the transition period and future market prices. Absent the determination through the regulatory process, wires charges and other pertinent information of capped rates as required by the restructuring law, it is not possible at this time for management to determine if any generation-related assets are impaired in accordance with SFAS 121 and if generation-related regulatory assets will be recovered. The amount of regulatory assets recorded on the books applicable to the Company's Virginia retail generating business at December 31, 1999 is estimated to be $64 million before related tax effects.

Should it not be possible under the Virginia law to recover all or a portion of the generation-related regulatory assets and/or tangible generating assets, it could have a material adverse impact on results of operations and cash flows. An estimated determination of whether the Company will experience any asset impairment loss regarding its Virginia retail jurisdictional generating assets and any loss from a possible inability to recover generation-related regulatory assets and other transition costs cannot be made until such time as the Company completes economic studies to estimate an asset impairment and until the transition period capped rates and the wires charge are determined under the law, which is expected to occur by the fourth quarter of 2000.

West Virginia - On January 28, 2000, the WVPSC issued an order approving an electricity restructuring plan for West Virginia. The restructuring plan has been submitted to the West Virginia Legislature for approval or rejection which is expected to occur during the current legislative session that ends in March 2000. Until approved by the West Virginia Legislature, the restructuring plan cannot take effect. The Company's subsidiaries, APCo and WPCo, which do business in West Virginia, will be affected by the proposed restructuring.

The provisions of the proposed restructuring plan provide for customer choice to begin on January 1, 2001, or at a later date set by the WVPSC after all necessary rules are in place (the "starting date"); deregulation of generation assets occurring on the starting date; functional separation of the generation, trans-mission and distribution businesses on the start 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 the period January 1, 2001 through December 31, 2010 intended to provide for recovery of any stranded cost including net regulatory assets; establishment of a rate stabilization deferred balance by AEP of $81 million by the end of year ten of the transition period to be used as determined by the WVPSC to offset prices

paid in the eleventh, twelfth, and thirteenth year of the transition period by residential and small commercial customers that do not choose a supplier.

Default rates for residential and small commercial customers are capped for four years after the starting date and then increased 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.

Management has concluded that as of December 31, 1999 the requirements to apply SFAS 71 continue to be met. The Company's West Virginia rates for generation will continue to be cost-based regulated until the West Virginia Legislature approves the restructuring plan. At that time, management should be able to determine its ability to recover stranded costs, a requirement to discontinue application of SFAS 71.

When the restructuring plan is enacted into law, the application of SFAS 71 will be discontinued for the West Virginia retail jurisdictional portion of the Company's generating business. At that time the Company will have to write-off its generation-related regulatory assets to the extent that they cannot be recovered under the provisions of the approved restructuring plan and record any asset impairments in accordance with SFAS 121. An impairment loss would be recorded to the extent that the cost of impaired assets cannot be recovered through generation-related revenues during the transition period and future market prices. Absent the approval through the regulatory and legislative processes of rates and other pertinent information, it is not possible at this time for management to determine if any generation-related assets are impaired in accordance with SFAS 121 and if generation-related regulatory assets will be recovered. The amount of regulatory assets recorded on the books applicable to the Company's West Virginia retail generating business at December 31, 1999 is estimated to be $131 million before related tax effects.

Should it not be possible under the West Virginia restructuring plan to recover all or a portion of the generation-related regulatory assets and/or tangible generating assets, it could have a material adverse impact on results of operations and cash flows. An estimated determination of whether the Company will experience any asset impairment loss regarding its West Virginia retail jurisdictional generating assets and any loss from a possible inability to recover generation-related regulatory assets and other transition costs cannot be made until such time as the Company completes economic studies to estimate an asset impairment and until the West Virginia Legislature approves the restructuring plan and the WVPSC approves the Joint Stipulation (See Note 3), which are both expected to occur in March 2000.

6. Commitments and Contingencies:

Construction and Other Commitments - The AEP System has substantial construction commitments to support its utility operations. Aggregate construction expenditures for 2000-2002 for consolidated domestic and foreign operations are estimated to be $2.8 billion.

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. The contracts provide for periodic price adjustments and contain various clauses that would release the Company from its obligation under certain force majeure conditions.

The AEP System has contracted to sell approximately 1,275 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 2000 to 2010.

Nuclear Plant - I&M owns and operates the two-unit 2,110 MW Cook Plant 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 is partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident. 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 - Public liability is limited by law to $9.9 billion should an incident occur at any 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 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. The number of incidents for which payments could be required is not limited.

Nuclear insurance pools and other insurance policies provide $3 billion of property damage, decommissioning and decontamination coverage for the Cook Plant. Additional insurance provides coverage for extra costs resulting from a prolonged accidental Cook Plant outage. Some of the policies have deferred premium provisions which could be triggered by losses in excess of the insurer's resources. The losses could result from claims at the Cook Plant or certain other unaffiliated nuclear units. I&M could be assessed up to $23 million annually under these policies.

Spent Nuclear Fuel (SNF) Disposal - 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 is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $199 million for fuel consumed prior to April 7, 1983 have been recorded as long-term debt. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 1999, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in trust funds and approximate the liability.

Decommissioning and Low Level Waste Accumulation Disposal - Decommissioning costs are accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units expire in 2014 and 2017. After expiration of the licenses the plant is expected to be decommissioned through dismantlement. The estimated cost of decommissioning and low level radioactive waste accumulation disposal costs ranges from $700 million to $1,152 million in 1997 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 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. I&M records decommissioning costs in other operation expense and records a noncurrent liability equal to the decommissioning cost recovered in rates; such amounts were $28 million in 1999, $29 million in 1998 and $28 million in 1997. Decommissioning costs recovered from customers are deposited in external trusts. In

1999 the Company also deposited in the decommissioning trust $4 million related to a special regulatory commission approved funding method. Trust fund earnings increase the fund assets and the recorded liability and decrease the amount needed to be recovered from ratepayers. During 1999 and 1998 I&M withdrew $8 million and $3 million, respectively, from the trust fund for decommissioning of the original steam generators removed from Unit 2. At December 31, 1999 and 1998, I&M has recognized a decommissioning liability of $501 million and $446 million, respectively.

Federal EPA Complaint and Notice of Violation - 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.

On November 3, 1999 the Department of Justice, at the request of the U.S. Environmental Protection Agency (Federal EPA), filed a complaint in the U.S. District Court for the Southern District of Ohio that alleges the Company made modifications to generating units at certain of its coal-fired generating plants over the course of the past 25 years that extend unit operating lives or increase unit generating capacity without a preconstruction permit in violation of the Clean Air Act. Federal EPA also issued Notices of Violation to the Company alleging similar violations at certain AEP plants. A number of unaffiliated utilities also received Notices of Violation, complaints or administrative orders.

The states of New Jersey, New York and Connecticut were subsequently granted leave to intervene in the Federal EPA's action against the Company under the Clean Air Act. On November 18, 1999 a number of environmental groups filed a lawsuit against power plants owned by the Company alleging similar violations to those in the Federal EPA complaint and Notices of Violation. This action 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.

Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act and intends to vigorously pursue its defense of this matter.

In the event the Company does 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, wires charges and future market prices for energy.

COLI Litigation - The Internal Revenue Service (IRS) agents auditing the AEP System's consolidated federal income tax returns requested a ruling from their National Office that certain interest deductions claimed by the Company relating to AEP's corporate owned life insurance (COLI) program should not be allowed. As a result of a suit filed in U.S. District Court (discussed below) this request for ruling was withdrawn by the IRS agents. Adjustments have been or will be proposed by the IRS disallowing COLI interest deductions for taxable years 1991-96. A disallowance of the COLI interest deductions through December 31, 1999 would reduce earnings by approximately $317 million (including interest).

The Company made payments of taxes and

interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of any additional above market rate interest on the contested amount. The payments to the IRS are included on the consolidated balance sheet in other assets pending the resolution of this matter. The Company is seeking refund through litigation of all amounts paid plus interest.

In order to resolve this issue, the Company filed suit against the United States in the U.S. District Court for the Southern District of Ohio in March 1998. In 1999 a U.S. Tax Court judge decided in the Winn-Dixie Stores v. Commissioner case that a corporate taxpayer's COLI interest deduction should be disallowed. Notwithstanding the decision in Winn-Dixie management has made no provision for any possible adverse earnings impact from this matter because it believes, and has been advised by outside counsel, that it has a meritorious position and will vigorously pursue its lawsuit. In the event the resolution of this matter is unfavorable, it will have a material adverse impact on results of operations, cash flows and possibly financial condition.

Other - The Company is 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 the results of operations, cash flows or financial condition.

7. Subsequent Event - NOx Reductions (March 3, 2000):

On March 3, 2000, the U.S. Court of Appeals for the District of Columbia Circuit (Appeals Court) issued a decision generally upholding Federal EPA's final rule (the NOx rule) that requires substantial reductions in nitrogen oxide (NOx) emissions in 22 eastern states, including the states in which the Company's generating plants are located. A number of utilities, including the Company, had filed petitions seeking a review of the final rule in the Appeals Court. On May 25, 1999, the Appeals Court had indefinitely stayed the requirement that states develop revised air quality programs to impose the NOx reductions but did not, however, stay the final compliance date of May 1, 2003.

On April 30, 1999, Federal EPA took final action with respect to petitions filed by eight northeastern states pursuant to the Clean Air Act (Section 126 Rule). The rule approved portions of the states' petitions and imposed NOx reduction requirements on AEP System generating units which are approximately equivalent to the reductions contemplated by the NOx Rule. The AEP System companies with generating plants, as well as other utility companies, filed a petition in the Appeals Court seeking review of Federal EPA's approval of the northeastern states' petitions. In 1999, three additional northeastern states and the District of Columbia filed petitions with Federal EPA similar to those originally filed by the eight northeastern states. Since the petitions relied in part on compliance with an 8-hour ozone standard remanded by the Appeals Court in May 1999, Federal EPA indicated its intent to decouple compliance with the 8-hour standard and issue a revised rule.

On December 17, 1999, Federal EPA issued a revised Section 126 Rule not based on the 8-hour standard and ordered 392 industrial facilities, including certain coal-fired generating plants owned by the Company, to reduce their NOx emissions by May 1, 2003. This rule approves portions of the petitions filed by four northeastern states which contend that their failure to meet Federal EPA smog standards is due to emissions from upwind states' industrial and coal-fired generating facilities.

Preliminary estimates indicate that compliance with the NOx rule upheld by the Appeals Court could result in required capital expenditures of approximately $1.6 billion for the Company. Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the Company's preliminary estimate depend-

ing upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless such costs are recovered from customers through regulated rates and/or reflected in the future market price of electricity if generation is deregulated, they will have an adverse effect on future results of operations, cash flows and possibly financial condition.

8. Proposed Merger:

The Company and Central and South West Corporation (CSW) announced plans to merge in December 1997. The appropriate shareholder proposals for the consummation of the merger were approved in 1998. Both companies have mutually agreed to extend the closing of the merger available in the original 1997 agreement to gain the final regulatory approvals. The amendment to the merger agreement requires that the companies close the merger before June 30, 2000. The merger has already received approval from state regulatory commissions in Arkansas, Louisiana, Oklahoma and Texas, the four states within CSW's service territory which are required to approve the merger. AEP has reached agreements with its state regulatory commission in Indiana, Michigan, Ohio and Kentucky. These AEP service territory state commissions have agreed not to oppose the merger in federal proceedings. In addition, the Nuclear Regulatory Commission has approved a license transfer application for the transfer of control of CSW subsidiary Central Power and Light's South Texas Nuclear Plant to the Company and the Department of Justice closed its investigation under the Hart-Scott-Rodino Antitrust Improvements Act. Also, in 1998 the FERC issued an order which confirmed that a 250 MW firm contract path with the Ameren System was available. The contract path was obtained by the Company and CSW to meet the requirement of the Public Utility Holding Company Act of 1935 that the two systems operate on an integrated and coordinated basis.

The merger requires additional approvals by the FERC and the SEC. On July 29, 1999 applications were made with the Federal Communication Commission to authorize the transfer of control of licenses of several CSW entities to the Company.

FERC - In November, 1998 the FERC issued an order establishing hearing procedures for the merger. The 1998 FERC order indicated that the review of the proposed merger will address the issues of competition, market power and customer protection. On May 25, 1999 AEP and CSW reached a settlement with the FERC trial staff resolving competition and rate issues relating to the merger. On July 13, 1999 AEP and CSW reached an additional settlement with the FERC trial staff resolving additional issues. The settlements were submitted to the FERC for approval. Under the terms of the settlements, AEP filed with the FERC a regional transmission organization (RTO) proposal whereby it will transfer the operation and control of AEP's bulk transmission facilities to an RTO. The settlements also cover rates for transmission services and ancillary service as well as resolve issues related to system integration agreements and confirm, subject to FERC guidance on certain elements, that the proposed generation divestiture of up to 550 megawatts of capacity will satisfy the staff's market power concerns. FERC hearings began on June 29, 1999 and concluded on July 19, 1999.

On June 28, 1999, the Company and CSW filed a motion asking the FERC to waive the requirement for a post-hearing decision by an administrative law judge (ALJ) who presides over the merger hearing. The motion indicated that the commission could then decide the matter based on the hearing record and briefs submitted by all interested parties. On July 28, 1999, the FERC ordered the ALJ to issue an initial decision as soon as possible, but no later than November 24, 1999. The commission concluded that it needed the benefit of the ALJ's opinion and, therefore, decided not to grant the request. The administrative law judge who presided over the FERC merger hearing filed an initial decision with the commission on November

23, 1999 and found the AEP-CSW merger to be in the public interest. The FERC indicated it will act on the merger no later than February or March 2000.

Arkansas - On December 17, 1998, the Arkansas Commission approved a stipulated agreement related to a proposed merger regulatory plan. The stipulated agreement calls for CSW's Arkansas operating subsidiary, Southwestern Electric Power Company to share net merger savings with its retail customers through a net merger savings rate reduction rider of $6 million over the five-year period following completion of the merger.

Louisiana - In September, 1999 the Louisiana Public Service Commission (LPSC) issued a final order granting approval of the pending merger between the Company and CSW. In granting approval, the LPSC also approved a stipulated settlement in which the Company and CSW agreed to share with SWEPCO's Louisiana customers net merger savings created as a result of the merger over the eight years following its consummation. The net merger savings are estimated to total more than $18 million during that eight-year period. In addition the settlement also includes a cap on base rates for five years after consummation of the merger; sharing of benefits from off-system sales; establishment of conditions for affiliate transactions with other AEP and CSW subsidiaries; provisions to ensure continued quality of service; and provisions to hold SWEPCO's Louisiana customers harmless for adverse effects of the merger, if any.

Oklahoma - On May 11, 1999, the Oklahoma Corporation Commission (OCC) approved the proposed merger between the Company and CSW. The approval follows an administrative law judge's oral decision on a partial settlement between certain principal parties to the Oklahoma merger proceeding which recommended that the OCC approve the merger. The partial settlement provides for sharing of net merger savings with Oklahoma customers; no increase in Oklahoma base rates prior to January 1, 2003; filing by December 31, 2001 with the FERC an application to join a regional transmission organization; and implementing additional quality of service standards for Oklahoma retail customers. Oklahoma's share (approximately $50 million) of net merger savings over the first five years after the merger is consummated will be shared between Oklahoma customers and AEP shareholders. The partial settlement agreement includes a recommendation by the OCC staff that the OCC file with FERC indicating that it does not oppose the merger, but reserves the right to ensure that there are no adverse impacts on the Oklahoma transmission system from the FERC's approval order. Certain municipal and cooperative customers appealed the OCC's merger approval order. On October 13, 1999 this appeal was dismissed by the Oklahoma Supreme Court and the municipal and cooperative customers have since asked the OCC to withdraw or dismiss their appeal.

Texas - On May 4, 1999, AEP and CSW announced that a stipulated settlement had been reached in Texas. The agreement builds upon an earlier settlement agreement signed by AEP, CSW and certain parties to the Texas merger proceeding. In addition to the parties that were signatories to the earlier agreement, the staff of the Public Utility Commission of Texas is a signatory to the new settlement as well as other key parties to the merger proceeding. The stipulated settlement would result in rate reductions for Texas customers totaling $221 million over a six-year period commencing with the merger's consummation. The rate reduction is composed of $84 million of net merger savings and $137 million to resolve existing issues associated with CSW operating subsidiaries' rate and fuel reconciliation proceedings in Texas. Under the terms of the settlement agreement, base rates can not be increased before January 1, 2003 or three years after the merger is consummated, whichever is later. The settlement also calls for the divestiture of a total of 1,604 megawatts of existing and proposed generating capacity within Texas. If it is determined that the divestiture can proceed immediately after the merger closes without jeopardizing pooling-of-

interests accounting treatment for the merger, sale of the plants would begin no later than 90 days after the merger closes. Absent that determination, the divestiture would begin approximately two years after the merger closes to satisfy the requirements to use pooling-of-interests accounting treatment. Other provisions in the settlement agreement provide for, among other things, accelerated stranded cost recovery, quality-of-service standards, continuation of programs for disadvantaged customers and transfer of control of bulk transmission facilities to a regional transmission organization. Hearings on the merger in Texas began August 9, 1999 and concluded on August 10, 1999. Before the hearings began, settlements were reached with all but one of the parties in the case. The settling parties are all wholesale electric customers of CSW's Texas electric operating companies. The settlements call for the withdrawal of their opposition to the merger in all regulatory approval proceedings. In its open meeting on November 4, 1999, the Texas Commission approved the application on the pending merger and the stipulated settlement announced in May.

Indiana - The IURC approved a settlement agreement related to the merger on April 26, 1999. The settlement agreement resulted from an investigation of the proposed merger initiated by the IURC. The terms of the settlement agreement provide for, among other things, a sharing of net merger savings through reductions in customers' bills of approximately $67 million over eight years following consummation of the merger; a one year extension through January 1, 2005 of a freeze in base rates; additional annual deposits of $6 million to the nuclear decommissioning trust fund for the Indiana jurisdiction for the years 2001 through 2003; quality-of-service standards; and participation in a regional transmission organization. As part of the settlement agreement, the IURC agreed not to oppose the merger in the FERC or SEC proceedings.

Michigan - The MPSC has approved a Settlement Agreement with the Company related to the pending merger. In approving the Settlement Agreement, the MPSC has agreed to not oppose the merger at the federal level. AEP has agreed to share net merger savings with Michigan customers as well as AEP shareowners; establish performance standards that will maintain or improve customer service and system reliability; join a regional transmission organization by December 31, 2000; and establish affiliate rules to protect consumers and promote fair competition.

The Michigan jurisdictional customers' share of the net guaranteed merger savings is approximately $14 million over the eight years following the consummation of the merger. Once the merger is consummated, Michigan customers will receive their share of the savings through credits of approximately 1 percent to 1.5 percent every year. The credits will continue for at least eight years and will not be affected by any changes to the current regulatory structure in Michigan.

Kentucky - On April 15, 1999, in compliance with a request from the staff of the Kentucky Public Service Commission (KPSC) AEP filed an application seeking KPSC approval for the indirect change in control of KPCo that will occur as a result of the proposed merger. Although AEP did not believe that the KPSC has the jurisdictional authority to approve the merger, AEP reached a merger settlement agreement on May 24, 1999 with key parties in Kentucky which the KPSC approved on June 14, 1999. Under the terms of the Kentucky settlement, AEP has agreed to share net merger savings with Kentucky customers; establish performance standards that will maintain or improve customer service and system reliability; and to establish rules to protect consumers and promote fair competition. The Kentucky customers' share of the net merger savings are expected to be approximately $28 million. The key parties to the Kentucky settlement agreed not to oppose the merger during the FERC or the SEC proceedings.

Ohio - On October 21, 1999, the PUCO issued a decision stating that it will notify the FERC that it will withdraw its opposition to the Company's pending merger with CSW and will not seek conditions on the merger.

American Municipal Power - Ohio (AMP-Ohio) and AEP reached a settlement addressing outstanding issues. As part of the settlement AMP-Ohio agreed to withdraw as an intervenor in the merger process. AMP-Ohio is the nonprofit wholesale power supplier and service provider for most of Ohio's 84 community-owned public power systems, two West Virginia public power systems and four Pennsylvania public power systems.

Other - AEP and CSW have reached settlements with the Missouri Commission, the International Brotherhood of Electrical Workers, representing employees of AEP and CSW, and the Utility Worker's Union of America representing AEP employees, and certain wholesale customers. All have agreed not to oppose the merger in the FERC or SEC proceedings.

The proposed merger of CSW into AEP would result in common ownership of two United Kingdom (UK) regional electricity companies (RECs), Yorkshire and SEEBOARD, plc. AEP has a 50% ownership interest in Yorkshire and CSW has a 100% interest in SEEBOARD. On January 25, 2000 the UK's Department of Trade and Industry gave its approval to the merger finding no competitive problems with the ownership of two UK RECs. This final clearance was conditional on the companies agreeing to certain assurance concerning operation of the UK interest including meeting customer service obligations, maintaining debt ratings of investment grade or above and separate distribution and supply activities.

Completion of the Merger - As of December 31, 1999, AEP had deferred $42 million of incremental costs related to the merger on its consolidated balance sheet, which will be charged to expense if AEP and CSW are not successful in completing their proposed merger. If the merger is consummated the deferred costs allocable to the domestic utility subsidiaries will be amortized over their recovery period, generally five to eight years, in accordance with state regulator orders. The remainder of the deferred merger costs will be expensed upon consummation of the merger.

The merger is conditioned upon, among other things, the approval of certain state and federal regulatory agencies. The transaction must satisfy many conditions, a number of which may not be waived by the parties, including the condition that the merger must be accounted for as a pooling of interests. To consummate the merger, the Company needs to obtain the approval of the FERC and the SEC. Although consummation of the merger is expected to occur in the second quarter of 2000, the Company is unable to predict the outcome or the timing of the required regulatory proceedings. Also if the merger savings do not approximate the agreed to net merger savings rate reduction riders in the five to eight years after the consummation of the merger, future results of operations, cash flow and possibly financial condition could be adversely affected.

9. Acquisitions:

The Company completed two energy related acquisitions in 1998 through a subsidiary, AEPR. Both acquisitions have been accounted for using the purchase method. One acquisition was of 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. All of the stock of CitiPower was acquired on December 31, 1998 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 1999 consolidated statement of income. 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 has been recorded as goodwill in other assets and is being amortized on a straight-line basis over 40 years.

The other acquisition was of 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 in Houston. The gas operations were acquired for approximately $340 million, including working capital funds, on December 1, 1998 with one month of earnings reflected in AEP's consolidated results of operations for the year ended December 31, 1998. A full year of the midstream gas operations' results of operations is included in the 1999 consolidated statement of income. 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 and has been recorded as goodwill in other assets and is being amortized on a straight-line basis over 40 years and 10 years, respectively.

10. Yorkshire Acquisition and UK Windfall Tax:

In April 1997 the Company and New Century Energies, Inc. through an equally owned joint venture, Yorkshire Power Group Limited (YPG), acquired all of the outstanding shares of Yorkshire. Total consideration paid by the joint venture was approximately $2.4 billion which was financed by a combination of equity and non-recourse debt. The Company uses the equity method of accounting for its investment in YPG. The Company's investment in the joint venture was $368 million and $326 million at December 31, 1999 and 1998, respectively, and is included in other assets.

In July 1997 the British government enacted a new law that imposed a one-time windfall tax on a revised privatization value which originally had been computed in 1990 on certain privatized utilities. The windfall tax is actually an adjustment by the UK government of the original privatization price. The windfall tax liability for Yorkshire was 134 million pounds sterling ($219 million) and was paid in two equal installments made in December 1997 and December 1998. The Company's $109 million share of the tax is reported as an extraordinary loss in 1997.

The 1999 and 1998 equity earnings from the Yorkshire investment are $45 million and $39 million, respectively, and are included in worldwide electric and gas operations revenues. Equity earnings from the Yorkshire investment for 1997, excluding the extraordinary loss, were $34 million.

The following amounts which are not included in AEP's consolidated financial statements represent 100% of YPG's summarized consolidated financial information:

	December 31,	
	1999	1998
	(in millions)	
Assets:		
Property, Plant and Equipment	$1,666	$1,602
Current Assets	450	552
Goodwill (net)	1,461	1,547
Other Assets	289	295
Total Assets	$3,866	$3,996
Capitalization and Liabilities:		
Common Shareholders' Equity	$ 725	$ 666
Long-term Debt	2,031	2,121
Other Noncurrent Liabilities	442	414
Long-term Debt Due Within One Year	14	13
Current Liabilities	654	782
Total Capitalization and Liabilities	$3,866	$3,996

	Twelve Months Ended December 31,		Nine Months Ended December 31,
	(in millions)		
	1999	1998	1997
Income Statement Data:			
Operating Revenues	$2,335	$2,284	$1,493
Operating Income	301	298	202
Income Before Extraordinary Item	90	77	68
Net Income (Loss)	90	77	(151)

In August 1999 the Office of Gas and Electricity Markets (OFGEM, which is the UK regulator of gas and electricity rates), published draft price proposals for the UK's regional distribution businesses including Yorkshire and SEEBOARD that would be effective for the five-year period beginning April 1, 2000. Under the draft price proposals, the distribution rates for Yorkshire would be reduced 15% to 20% from current rates. Yorkshire filed comments on September 17, 1999 with OFGEM expressing various concerns with the analysis used by OFGEM.

On October 8, 1999, OFGEM issued updated draft price proposals for Yorkshire's electric distribution business. The updated proposals would require Yorkshire to reduce distribution rates 15% and transfer 8% of costs to Yorkshire's electricity supply business, an overall reduction in distribution prices of 23%.

Also on October 8, 1999, OFGEM issued draft price proposals for Yorkshire's electric supply business. Under the proposals, a supply price cap for certain domestic UK customers is retained from April 2000 through March 2002. For Yorkshire, these proposals would result in a price reduction of approximately 10.7% on the standard domestic tariff commencing April 2000 and ending March 2001 and a nominal price freeze for the year commencing April 2001 and ending March 2002.

In December 1999 OFGEM issued its final proposals for both Yorkshire's distribution and supply businesses. The final distribution and supply price controls were substantially the same as OFGEM's October 8, 1999 proposals except that the reduction in the standard domestic tariff is 3.6% for the supply business. On December 20, 1999, Yorkshire informed OFGEM of its intention to accept the final proposals.

Yorkshire management also believes that supply prices established in the competitive market may require Yorkshire to charge supply prices that are lower than the maximum prices established by OFGEM for customers Yorkshire wishes to retain and who are subject to supply price controls. If Yorkshire charges lower supply prices, the result will be a further reduction in supply revenues beyond that required by OFGEM.

Yorkshire management intends to take all available opportunities to increase revenues and reduce costs to mitigate the impact of the final OFGEM distribution and supply price reductions. Should Yorkshire be unable to increase revenues and reduce costs in amounts sufficient to offset the impact of the OFGEM distribution and supply price reductions, AEP's equity earnings from its investment in Yorkshire will be significantly reduced in comparison to its current level of earnings.

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. In addition, a review of energy delivery staffing levels in 1998 identified 65 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 were charged to maintenance and other operation expense in the Consolidated Statements of Income. 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.

12. Benefit Plans:

AEP System Pension and Other Postretirement Benefit Plans - The AEP System sponsors a qualified pension plan and a nonqualified pension plan. All employees, except participants in the United Mine Workers of America (UMWA) pension plans are covered by one or both of the pension plans. Other Postretirement Benefit Plans (OPEB) are sponsored by the AEP System to provide medical and death benefits for retired 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, 1999, and a statement of the funded status as of December 31 for both years:

	Pension Plan		OPEB	
	1999	1998	1999	1998
	(in millions)			
Reconciliation of benefit obligation:				
Obligation at January 1	$2,126	$1,909	$1,022	$ 850
Service Cost	50	45	22	17
Interest Cost	146	133	72	59
Participant Contributions	-	-	7	6
Plan Amendments (a)	7	48	-	-
Actuarial (Gain) Loss	(253)	96	19	133
Acquisitions (b)	-	-	-	3
Benefit Payments	(109)	(105)	(53)	(46)
Curtailments	-	-	10(c)	-
Obligation at December 31	$1,967	$2,126	$1,099	$1,022
Reconciliation of fair value of plan assets:				
Fair value of plan assets at January 1	$2,651	$2,370	$396	$312
Actual Return on Plan Assets	248	386	79	53
Company Contributions	-	-	47	72
Participant Contributions	-	-	6	6
Benefit Payments	(109)	(105)	(52)	(47)
Fair value of plan assets at December 31	$2,790	$2,651	$476	$396
Funded status:				
Funded status at December 31	$ 823	$ 525	$(623)	$(626)
Unrecognized Net Transition (Asset) Obligation	(39)	(49)	317	361
Unrecognized Prior-Service Cost	146	157	-	-
Unrecognized Actuarial (Gain) Loss	(1,042)	(757)	179	175
Accrued Benefit Liability	$ (112)	$(124)	$(127)	$ (90)

(a) Early retirement factors for the Company pension plan were changed to provide more generous benefits to participants retiring between ages 55 and 60.
(b) On December 1, 1998 the Company acquired midstream gas operations resulting in approximately 170 new employees becoming participants in the Company's pension and OPEB plans.
(c) Related to the October 31, 1999 shutdown of Central Ohio Coal Company's Muskingum mine and the anticipated April 30, 2000 shutdown of the Windsor Coal Company mine. Both companies are subsidiaries of AEP.

The following table provides the amounts recognized in the consolidated balance sheets as of December 31 of both years:

	Pension Plan		OPEB	
	1999	1998	1999	1998
	(in millions)			
Accrued Benefit Liability	$(112)	$(124)	$(127)	$(90)
Additional Minimum Liability	(8)	(3)	-	-
Intangible Asset	8	3	-	-
Net Amount Recognized	$(112)	$(124)	$(127)	$(90)

The Company's nonqualified pension plan had an accumulated benefit obligation in excess of plan assets of $29 million and $25 million at December 31, 1999 and 1998, respectively. There are no plan assets in the nonqualified plan.

The Company's OPEB plans had accumulated benefit obligations in excess of plan assets of $623 million and $626 million at December 31, 1999 and 1998, respectively.

The following table provides the components of net periodic benefit cost for the plans for fiscal years 1999, 1998 and 1997:

	Pension Plan			OPEB		
	1999	1998	1997	1999	1998	1997
	(in millions)					
Service cost	$ 50	$ 45	$ 36	$ 22	$ 17	$ 14
Interest cost	146	133	129	72	59	55
Expected return on plan assets	(201)	(172)	(154)	(36)	(28)	(22)
Amortization of transition (asset) obligation	(10)	(10)	(10)	32	32	32
Amortization of prior-service cost	18	14	14	-	-	-
Amortization of net actuarial (gain) loss	(15)	(2)	(5)	5		
Net periodic benefit cost	(12)	8	10	95	80	79
Curtailment loss(a)	-	-	-	18	24	-
Net periodic benefit cost after curtailments	$(12)	$ 8	$ 10	$113	$104	$79

(a) Curtailment charges were recognized during 1999 and 1998 for the October 31, 1999 shutdown of Central Ohio Coal Company's Muskingum mine and the anticipated April 30, 2000 shutdown of the Windsor Coal Company mine. Both companies are subsidiaries of AEP.

The assumptions used in the measurement of the Company's benefit obligation are shown in the following table:

	Pension Plan			OPEB		
	1999	1998	1997	1999	1998	1997
Weighted-average assumptions as of December 31						
Discount rate (a)	8.00%	6.75%	7.00%	8.00%	6.75%	7.00%
Expected return on plan assets	9.00%	9.00%	9.00%	8.75%	8.75%	8.75%
Rate of compensation increase	3.2%	3.2%	3.2%	N/A	N/A	N/A

(a) The 1999 expense was re-measured as of July 31, 1999 using a discount rate of 7.50%.

For measurement purposes, a 5.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2000. The rate was assumed to decrease gradually each year to a rate of 5.0% for 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 of service and interest cost components of net periodic postretirement health care benefit cost	$ 12	$ (10)
Effect on the health care component of the accumulated postretirement benefit obligation	123	(109)

CitiPower, a subsidiary acquired on December 31, 1998 sponsors a defined benefit pension plan. At December 31, 1999 and 1998, the fair value of the plan assets was $30 million and $25 million, respectively, and the accumulated benefit obligation of this plan was $27 million and $25 million, respectively. This plan's actuarial assumptions are not significantly different from AEP's.

AEP System Savings Plan - The AEP System Savings Plan is a defined contribution plan offered to non-UMWA employees. The cost for contributions to this plan totaled $21 million in 1999 and 1998 and $20 million in 1997.

Other UMWA Benefits - The Company provides 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 based on hours worked are expensed as paid as part of the cost of active mining operations and were not material in 1999, 1998 and 1997. Based upon the UMWA actuary estimate, the Company's share of unfunded pension liability was $17 million at June 30, 1999. In the event the Company should significantly reduce or cease mining operations or contributions to the UMWA trust funds, a withdrawal obligation will be triggered for the pension plan that equals the unfunded pension liability. If the Meigs mining operations had been closed on December 31, 1999 the estimated annual liability for the UMWA health and welfare plans would have been approximately $1 million.

13. Business Segments:

As of December 31, 1998, the Company adopted SFAS 131, "Disclosure about Segments of an Enterprise and Related Information." SFAS 131 establishes standards for reporting information about operating segments in annual financial statements and requires selected information about operating segments in interim financial reports issued to shareholders. It also established standards for related disclosures about products and services, and geographic areas. Operating segments are defined as components of an enterprise about which separate financial information is available and evaluated regularly by the chief operating decision maker.

The Company's reportable segments are primarily differentiated based on whether the business activity is conducted within a cost-based regulated environment. The Company manages its operations on this basis because of the substantial impact of regulatory oversight on business processes, cost structures and operating results. The accounting policies of the reportable segments are the same as those described in Note 1, "Significant Accounting Policies."

The Company's principal business segment is its cost-based rate regulated domestic regulated electric utility operations consisting of seven domestic regulated utility subsidiaries companies providing retail, commercial, industrial and wholesale electric services in seven Atlantic and Midwestern states. Also included in this segment are the Company's electric power wholesale marketing and trading activities that are conducted in the Company's traditional marketing area as part of regulated operations and subject to regulatory ratemaking oversight.

The worldwide electric and gas operations segment is principally made up of international investments in energy-related projects and operations. It also includes the acquisition, development and management of electricity and gas projects and operations worldwide. Such investment activities include electric generation, supply and distribution, and natural gas pipeline, storage and other natural gas services. Although the businesses in the worldwide operations segment are generally subject to different forms of price regulation, they are not cost-based rate regulated. As a result for reporting purposes under U.S. generally accepted accounting principles they do not record regulatory assets and liabilities in accordance with SFAS 71. The other operations business segment includes electric trading outside the Company's traditional marketing area, gas trading operations, telecommunication services, and the marketing of various energy related products and services. As of December 31, 1999 and 1998, less than 6% of consolidated long-lived assets were located in foreign countries.

Year	Domestic Regulated Electric Utility Operations	Worldwide Electric and Gas Operations	Other Operations	Elimination Reconciling Adjustments	AEP Consolidated
		(in millions)			
1999					
Revenues from external unaffiliated customers	$6,315	$722*	$(121)	-	$6,916
Revenues from transactions with other operating segments	-	72	143	$(215)	-
Interest expense	412	109	7	-	528
Depreciation, depletion and amortization expense	600	55	5	(60)	600
Income tax expense (benefit)	316	(39)	(17)	-	260
Segment net income (loss)	508	41	(29)	-	520
Total assets	18,038	2,482	968	-	21,488
Investments in equity method subsidiaries	-	433	-	-	433
Gross property additions	735	114	18	-	867
1998					
Revenues from external unaffiliated customers	$6,346	$94*	$(43)	-	$6,397
Revenues from transactions with other operating segments	-	2	14	$(16)	-
Interest expense	399	17	3	-	419
Depreciation, depletion and amortization expense	580	1	1	(2)	580
Income tax expense (benefit)	317	(15)	(21)	-	281
Segment net income (loss)	564	12	(40)	-	536
Total assets	16,837	2,063	583	-	19,483
Investments in equity method subsidiaries	-	335	-	-	335
Gross property additions	700	1,463	23	-	2,186
1997					
Revenues from external unaffiliated customers	$5,880	$48*	$ -	$ -	$ 5,928
Revenues from transactions with other operating segments	-	-	-	-	-
Interest expense	390	15	1	-	406
Depreciation, depletion and amortization expense	591	-	-	-	591
Income tax expense (benefit)	352	(25)	(7)	-	320
Extraordinary Loss - UK Windfall Tax	-	(109)	-	-	(109)
Segment net income (loss)	603	(80)	(12)	-	511
Total assets	16,224	367	24	-	16,615
Investments in equity method subsidiaries	-	287	-	-	287
Gross property additions	694	62	4	-	760

* Worldwide electric and gas revenues for the years ended December 31, 1999 and 1998 include net income from subsidiaries accounted for under the equity method of $45 million and $39 million, respectively. For the year ended December 31, 1997 worldwide electric and gas revenues include $34 million of earnings excluding an extraordinary loss from subsidiaries accounted for under the equity method.

14. Financial Instruments, Credit and Risk Management:

The Company is subject to market risk as a result of changes in commodity prices, foreign currency exchange rates, and interest rates. The Company 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.

Physical forward electricity contracts within AEP's traditional economic market area are recorded on a net basis as domestic regulated electric utility operations revenues in the month when the physical contract settles. Physical forward electricity contracts outside AEP's traditional marketing area, and all financial electricity trading transactions where the underlying physical commodity is outside AEP's traditional economic market area are recorded on a net basis in worldwide electric and gas operations revenues.

In the first quarter of 1999 the Company 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 energy trading contracts be marked-to-market. The effect on the Consolidated Statements of Income of marking open trading contracts to market is deferred as regulatory assets or liabilities for the portion of those open electricity trading transactions within the AEP's marketing area that are included in cost of service on a settlement basis for ratemaking purposes in the Company's non-Virginia jurisdictions. A Virginia jurisdiction net mark-to-market pre-tax gain of $5 million for the year ended December 31, 1999 is included in domestic regulated revenues as a result of an agreed prohibition against establishing new regulatory assets in a February 1999 Virginia SCC approved settlement agreement. Open contracts outside of AEP Power Pool's marketing area are marked-to-market in worldwide electric and gas operations revenues. The adoption of the EITF did not have a material effect on results of operations, cash flows or financial condition. All physical and financial instruments for natural gas except for certain qualifying hedges are marked to market and are included on a net basis in worldwide electric and gas operations revenues. The 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 1999 and 1998 for electric and gas trading activities were:

Revenues - Net Gain (Loss)	1999	1998
	(in millions)	
Domestic Regulated Electric Utility Operations	$27	$111
Worldwide Electric and Gas Operations	14	(33)

Electric and gas trading activities were not material in 1997.

Investment in foreign ventures exposes the Company to risk of foreign currency fluctuations. Also, the Company is exposed to changes in interest rates primarily due to short- and long-term borrowings used to fund its business operations. The debt portfolio has both fixed and variable interest rates with terms from one day to forty years and an average duration of four years at December 31, 1999. The Company 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 the Company's best estimate of its fair value.

The book values and fair values of the Company's significant financial instruments at

December 31, 1999 and 1998 are summarized in the following table. The fair values of long-term debt and preferred stock 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 valuation methodology. The estimates presented herein are not necessarily indicative of the amounts that the Company could realize in a current market exchange.

	1999		1998	
Non-Derivatives	Book Value	Fair Value	Book Value	Fair Value
	(in millions)		(in millions)	
Long-term Debt	$7,447	$7,209	$7,006	$7,291
Preferred Stock	119	117	128	134

Derivatives

	1999			1998		
Trading Assets	Notional Amount	Fair Value	Average Fair Value	Notional Amount	Fair Value	Average Fair Value
Electric	GWH	(in millions)		GWH	(in millions)	
Futures and Options-NYMEX (net)	224	$ 2	$ 1	-	$ -	$ -
Physicals	69,509	577	517	58,521	46	41
Options - OTC	6,203	39	62	3,873	32	79
Swaps	177	1	1	276	3	1
Gas	MMMBTU	(in millions)		MMMBTU	(in millions)	
Futures and Options-NYMEX (net)	-	$ -	$ -	55,442	$ 6	$ 2
Physicals	345,830	37	39	212,307	44	30
Options - OTC	192,593	54	40	65,920	18	12
Swaps	2,682,033	410	312	1,081,954	246	143
Trading Liabilities						
Electric	GWH	(in millions)		GWH	(in millions)	
Futures and Options-NYMEX (net)	-	$ -	$ -	705	$ (7)	$ (2)
Physicals	74,764	(536)	(498)	57,652	(51)	(46)
Options - OTC	8,907	(43)	(56)	2,935	(29)	(78)
Swaps	180	(2)	(2)	490	(8)	(2)
Gas	MMMBTU	(in millions)		MMMBTU	(in millions)	
Futures and Options-NYMEX (net)	69,840	$ (8)	$ (5)	-	$ -	$ -
Physicals	301,271	(32)	(26)	180,949	(42)	(29)
Options - OTC	227,225	(55)	(37)	74,770	(23)	(14)
Swaps	2,601,644	(379)	(303)	1,092,660	(231)	(136)

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, 1999 and 1998 was $25 million and $10 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 nonperformance. The Company 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, the Company will require further enhancements to mitigate risk. Since the formation of the trading business in July of 1997, the Company has not experienced a significant loss due to the credit risk; furthermore, the Company does not anticipate any future material effect on its results of operations, cash flow or financial condition as a result of counter party nonperformance.

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value - The trust investments, reported in other assets, are recorded at market value in accordance with SFAS 115 and consist of tax-exempt municipal bonds and other securities. At December 31, 1999 and 1998 the fair values of the trust investments were $708 million and $648 million, respectively, and had a cost basis of $636 million and $584 million, respectively. Accumulated gross unrealized holding gains were $78 million and $65 million at December 31, 1999 and 1998, respectively and accumulated gross unrealized holding losses were $7 million and $1 million at December 31, 1999 and 1998, respectively. The change in market value in 1999, 1998, and 1997 was a net unrealized holding gain of $8 million, $24 million, and $19 million, respectively.

The cost basis of trust investments by security type was:

	December 31,	
	1999	1998
	(in millions)	
Tax-Exempt Bonds	$351	$326
Equity Securities	116	96
Treasury Bonds	73	71
Corporate Bonds	13	11
Cash, Cash Equivalents and Accrued Interest	83	80
Total	$636	$584

Proceeds from sales and maturities of trust securities of $226 million during 1999 resulted in $6 million of realized gains and $5 million of realized losses. Proceeds from sales and maturities of securities of $225 million during 1998 resulted in $8 million of realized gains and $3 million of realized losses. Proceeds from sales and maturities of trust securities of $147 million during 1997 resulted in $4 million of realized gains and $1 million of realized losses. The cost of trust securities for determining realized gains and losses is original acquisition cost including amortized premiums and discounts.

At December 31, 1999, the year of maturity of trust fund investments other than equity securities, was:

	(in millions)
2000	$120
2001 - 2004	174
2005 - 2009	182
After 2009	44
Total	$520

CitiPower entered into several interest rate swap agreements for $788 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, 1999. As of December 31, 1999, CitiPower was a party to interest rate swaps having a aggregate notional amount of $630 million, with $367 million maturing on December 31, 2000, and $263 million maturing on December 31, 2003. The average fixed interest rate payable on the aggregate of the interest rate swaps is 5.32%. The average floating rate for interest rate swaps was 5.93% at December 31, 1999. The estimated fair value of the interest rate swaps, which represents the estimated amount CitiPower would receive to terminate the swaps at December 31, 1999, based on quoted interest rates, is a net receivable of $17 million.

In accordance with the debt covenants included in the financing provisions of this 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, 1999, CitiPower had outstanding energy trading derivatives with a total contracted load of 7,313 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, 1999 is $7 million in excess of net contract value.

15. Income Taxes:

The details of income taxes as reported are as follows:

	Year Ended December 31,		
	1999	1998	1997
	(in millions)		
Federal:			
Current	$139	$247	$330
Deferred	116	16	(32)
Total	255	263	298
State:			
Current	3	18	22
Deferred	-	-	-
Total	3	18	22
International:			
Current	-	-	-
Deferred	2	-	-
Total	2	-	-
Total Income Tax as Reported	$260	$281	$320

The following is a reconciliation 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,		
	1999	1998	1997
	(in millions)		
Income Before Preferred Stock Dividend Requirements of Subsidiaries	$531	$547	$ 638
Extraordinary Loss - UK Windfall Tax (Note 10)	-	-	(109)
Federal Income Taxes	255	263	298
Pre-Tax Book Income	$786	$810	$ 827
Federal Income Tax on Pre-Tax Book Income at Statutory Rate *(35%)*	$275	$283	$289
Increase (Decrease) in Income Tax Resulting from the Following Items:			
Depreciation	62	58	53
Corporate Owned Life Insurance	2	(16)	(18)
Foreign Tax Credits	(35)	(8)	(13)
Investment Tax Credits (net)	(25)	(25)	(25)
Extraordinary Loss - UK Windfall Tax	-	-	38
State	3	18	22
International	2	-	-
Other	(24)	(29)	(26)
Total Income Taxes as Reported	$260	$281	$320
Effective Income Tax Rate	32.9%	33.9%	37.7%

The following tables show the elements of the Company's net deferred tax liability and the significant temporary differences:

	December 31,	
	1999	1998
	(in millions)	
Deferred Tax Assets	$ 930	$ 879
Deferred Tax Liabilities	(3,675)	(3,480)
Net Deferred Tax Liabilities	$(2,745)	$(2,601)
Property Related Temporary Differences	$(2,151)	$(2,170)
Amounts Due From Customers For Future Federal Income Taxes	(376)	(395)
Deferred State Income Taxes	(205)	(194)
All Other (net)	(13)	158
Net Deferred Tax Liabilities	$(2,745)	$(2,601)

The Company 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 1996 are presently being audited by the IRS. With the exception of interest deductions related to AEP's corporate owned life insurance program, which are discussed under the heading, COLI Litigation, in Note 6, 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.

16. Supplementary Information:

	Year Ended December 31,		
	1999	1998	1997
	(in million)		
Purchased Power - Ohio Valley Electric Corporation (44.2% owned by AEP System)	$64	$43	$30
Cash was paid for:			
Interest (net of capitalized amounts)	$513	$413	$390
Income Taxes	$95	$282	$399
Noncash Investing and Financing Activities:			
Acquisitions under Capital Leases	$80	$119	$235
Assumption of Liabilities related to Acquisitions	$ -	$152	$ -

17. 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,		
	1999	1998	1997
	(in millions)		
Lease Payments on Operating Leases	$245	$255	$257
Amortization of Capital Leases	96	91	105
Interest on Capital Leases	34	37	31
Total Lease Rental Costs	$375	$383	$393

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

	December 31,	
	1999	1998
	(in millions)	
PROPERTY, PLANT AND EQUIPMENT UNDER CAPITAL LEASES:		
Production	$ 46	$ 47
Distribution	15	15
Other:		
Nuclear Fuel (net of amortization)	108	104
Mining Assets and Other	612	584
Total Property, Plant and Equipment	781	750
Accumulated Amortization	261	217
Net Property, Plant and Equipment under Capital Leases	$520	$533
Obligations Under Capital Leases:		
Noncurrent Liability	$429	$451
Liability Due Within One Year	91	82
Total Obligations Under Capital Leases	$520	$533

Properties under operating leases and related obligations are not included in the Consolidated Balance Sheets.

Future minimum lease payments consisted of the following at December 31, 1999:

	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2000	$116	$ 234
2001	98	231
2002	74	225
2003	55	224
2004	41	223
Later Years	134	3,226
Total Future Minimum Lease Payments	518 (a)	$4,363
Less Estimated Interest Element	106	
Estimated Present Value of Future Minimum Lease Payments	412	
Unamortized Nuclear Fuel	108	
Total	$520	

(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.

18. Lines of Credit and Commitment Fees:

At December 31, 1999, unused short-term bank lines of credit were available in the amount of $1,056 million. In addition one subsidiary not engaged in providing domestic regulated electric utility services has a line of credit under a revolving credit agreement that expires in December 2002. The amount of credit available under the revolving credit agreement was $20 million at December 31, 1999. The short-term bank lines of credit and the revolving credit agreement require the payment of facility fees and do not require compensating balances.

Outstanding short-term debt consisted of:

	December 31,	
	1999	1998
	(in millions)	
Balance Outstanding:		
Notes Payable	$208	$198
Commercial Paper	680	419
Total	$888	$617

	December 31,	
	1999	1998
Year-End Weighted Average Interest Rate:		
Notes Payable	6.7%	5.8%
Commercial Paper	6.5%	6.2%
Total	6.6%	6.1%

19. Unaudited Quarterly Financial Information:

	Quarterly Periods Ended 1999			
(In Millions - Except Per Share Amounts)	March 31	June 30	Sept. 30	Dec. 31
Operating Revenues	$1,694	$1,643	$1,914	$1,665
Operating Income	381	285	376	263
Net Income	151	88	174	107
Earnings per Share*	0.79	0.46	0.90	0.55

*Amounts for 1999 do not add to $2.69 earnings per share due to rounding.

Fourth quarter 1999 earnings include various favorable adjustments totaling $53 million. These adjustments include $21 million net of tax from the deferral of Cook Plant restart expenses net of amortization under the terms of a Michigan jurisdiction settlement agreement approved on December 16, 1999 (see Note 2 for details); $17 million net of tax from changes in estimates of state and local taxes that resulted from the resolution of property valuation disputes, a net operating loss carry back and adjustments to the prior year tax accrual after filing state tax returns; $8 million net of tax from changes in estimates for pole attachment revenues due to adjustments to the accrual for prior billings for usage of pole attachments by telecommunications companies; and $7 million from a reduction in Australian income tax rates.

	Quarterly Periods Ended 1998			
(In Millions - Except Per Share Amounts)	March 31	June 30	Sept. 30	Dec. 31
Operating Revenues	$1,521	$1,557	$1,858	$1,461
Operating Income	344	294	413	196
Net Income	151	118	195	72
Earnings per Share	0.79	0.62	1.02	0.38

See "Reclassification" in Note 1 regarding reclassification of prior period amounts.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES

	December 31, 1999			
	Call Price per Share (a)	Shares Authorized(b)	Shares Outstanding(g)	Amount (In Millions)
Not Subject to Mandatory Redemption:				
4.08% - 4.56%	$102-$110	932,403	446,764	$ 45
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

	December 31, 1998			
	Call Price per Share (a)	Shares Authorized(b)	Shares Outstanding(g)	Amount (In Millions)
Not Subject to Mandatory Redemption:				
4.08% - 4.56%	$102-$110	932,403	460,016	$ 46
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	(d)	1,950,000	388,100	$ 39
6.02% - 6-7/8% (c)	(e)	1,950,000	637,950	64
7% (f)	(f)	250,000	250,000	25
Total Subject to Mandatory Redemption (c)				$128

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, 1999 the subsidiaries had 7,262,605, 22,200,000 and 7,611,984 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 $5,000,000 million each year for the years 2000, 2001, 2002, $11,600,000 million in 2003 and $7,700,000 in 2004.

(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 98,252 shares in 1999, 7,220 shares in 1998 and 4,258,947 shares in 1997.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

SCHEDULE OF CONSOLIDATED CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES

	December 31, 1999			
	Call Price per Share (a)	Shares Authorized(b)	Shares Outstanding(g)	Amount (In Millions)
Not Subject to Mandatory Redemption:				
4.08% - 4.56%	$102-$110	932,403	446,764	$ 45
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

	December 31, 1998			
	Call Price per Share (a)	Shares Authorized(b)	Shares Outstanding(g)	Amount (In Millions)
Not Subject to Mandatory Redemption:				
4.08% - 4.56%	$102-$110	932,403	460,016	$ 46
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	(d)	1,950,000	388,100	$ 39
6.02% - 6-7/8% (c)	(e)	1,950,000	637,950	64
7% (f)	(f)	250,000	250,000	25
Total Subject to Mandatory Redemption (c)				$128

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, 1999 the subsidiaries had 7,262,605, 22,200,000 and 7,611,984 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 $5,000,000 million each year for the years 2000, 2001, 2002, $11,600,000 million in 2003 and $7,700,000 in 2004.

(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 98,252 shares in 1999, 7,220 shares in 1998 and 4,258,947 shares in 1997.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT OF SUBSIDIARIES

Maturity	Weighted Average Interest Rate December 31, 1999	Interest Rates at December 31, 1999	Interest Rates at December 31, 1998	December 31, 1999	December 31, 1998
				(in millions)	
FIRST MORTGAGE BONDS					
1999-2002	7.19%	6.35%-8.95%	6.35%-8.95%	$ 609	$ 759
2003-2006	6.77%	6%-8%	6%-8%	783	846
2022-2025	7.92%	7.10%-8.80%	7.10%-8.80%	822	1,021
INSTALLMENT PURCHASE CONTRACTS (a)					
1999-2002	5.08%	4.80%-5.55%	4.05%-5.15%	145	145
2007-2026	6.26%	5.00%-7-7/8%	5.00%-7-7/8%	806	776
NOTES PAYABLE (b)					
1999-2008	6.56%	5.8675%-9.60%	5.49%-9.60%	1,594	1,493
SENIOR UNSECURED NOTES					
2000-2004	6.79%	6.50%-7.45%	6-1/2%-6.73%	1,003	448
2005-2009	6.58%	6.24%-6.91%	6.24%-6.91%	488	338
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
OTHER LONG-TERM DEBT (c)				285	269
Unamortized Discount (net)				(48)	(49)
Total Long-term Debt Outstanding (d)				7,447	7,006
Less Portion Due Within One Year				1,111	206
Long-term Portion				$6,336	$6,800

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 6 of the Notes to Consolidated Financial Statements) and financing obligation under sale lease back agreements.

(d) Long-term debt outstanding at December 31, 1999 is payable as follows:

Principal Amount (in millions)	
2000	$1,111
2001	270
2002	391
2003	1,374
2004	601
Later Years	3,748
Total Principal Amount	7,495
Unamortized Discount	(48)
Total	$7,447

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 accompanying consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries as of December 31, 1999 and 1998, 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, 1999. 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 generally accepted auditing standards. 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 American Electric Power Company, Inc. and its subsidiaries as of December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

Deloitte & Touche LLP
Columbus, Ohio
February 22, 2000
(March 3, 2000 as to Note 7)

PRINTED ON RECYCLED PAPER

Columbus Southern Power Company

1999 Annual Report

AEP: America's Energy Partner℠

COLUMBUS SOUTHERN POWER COMPANY
1 Riverside Plaza, Columbus, Ohio 43215

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BACKGROUND

COLUMBUS SOUTHERN POWER COMPANY (the Company), is engaged in the generation, purchase, transmission and distribution of electric power serving approximately 655,000 customers in central and southern Ohio. Approximately 80% of retail revenues are derived from electricity sales in the Columbus metropolitan area which is a governmental, educational, wholesale and retail distribution center with a wide diversity of industries. Principal industries served are chemicals, primary metals, food processing, electronic machinery and fabricated metal products. The Company also sells and transmits power at wholesale to other electric utilities, municipalities and non-utility entities engaged in the wholesale power market.

The Company, which was organized in 1937 under the laws of Ohio, is a subsidiary of American Electric Power Company, Inc., a public utility holding company. The Company does business as American Electric Power (AEP) along with all of the parent's operating subsidiary companies in order to serve its customers more efficiently as one operating organization aligned by distinct business units. The Company has the following wholly-owned subsidiaries: Conesville Coal Preparation Company (CCPC) which provides coal washing services for one of the Company's generating stations; Simco Inc. which is engaged in leasing a coal conveyor system to CCPC; and Colomet, Inc. which is engaged in real estate activities for the Company.

The Company's generating capacity consists of 2,595 megawatts (mw) of coal-fired generation which includes 1,330 mw from facilities jointly owned with two unaffiliated utilities. The generating plants and transmission facilities of the Company and certain other affiliated AEP System utility subsidiaries are operated as an integrated system with their costs and benefits shared through the AEP System Power Pool and AEP Transmission Agreement. Wholesale energy sales made by the Power Pool are allocated to the Pool members. The other AEP System Pool members are: Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company. The Company is interconnected with three other affiliated companies, AEP Generating Company, Kingsport Power Company and Wheeling Power Company that are not members of the Power Pool, and with numerous unaffiliated utilities through the AEP System. In addition the Company is directly interconnected with the following unaffiliated entities: The Cincinnati Gas & Electric Company, The Dayton Power and Light Company and Ohio Edison Company as well as the Ohio Valley Electric Corporation, an affiliate that is not a member of the AEP System.

DIRECTORS

E. Linn Draper, Jr.
Henry W. Fayne
William J. Lhota
James J. Markowsky
Armando A. Pena
Joseph H. Vipperman

OFFICERS

E. Linn Draper, Jr.
Chairman of the Board
and Chief Executive Officer

William J. Lhota
President and Chief
Operating Officer

Henry W. Fayne
Vice President

James J. Markowsky
Vice President

Armando A. Pena
Vice President, Treasurer and
Chief Financial Officer

Marsha P. Ryan
Vice President

Joseph H. Vipperman
Vice President

Leonard V. Assante
Controller and
Chief Accounting Officer

John F. DiLorenzo, Jr.
Secretary

Timothy P. Bowman
Assistant Controller and
Assistant Secretary

William L. Scott
Assistant Controller

Thomas G. Berkemeyer
Assistant Secretary

John B. Shinnock
Assistant Secretary

Bruce M. Barber
Assistant Treasurer

Christopher J. Keklak
Assistant Treasurer

s of January 1, 2000 the current directors and officers of Columbus Southern Power Company were employees of merican Electric Power Service Corporation with one exception: Ms. Ryan, who is an employee of Columbus outhern Power Company.

SELECTED CONSOLIDATED FINANCIAL DATA

	Year Ended December 31,				
	1999	1998	1997	1996	1995
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	$1,229,994	$1,187,745	$1,094,851	$1,105,683	$1,071,86
Operating Expenses	1,007,204	975,534	899,724	920,136	886,05
Operating Income	222,790	212,211	195,127	185,547	185,80
Nonoperating Income (Loss)	2,709	(1,343)	3,137	(970)	5,20
Income Before Interest Charges	225,499	210,868	198,264	184,577	191,01
Interest Charges (net)	75,229	77,824	78,885	77,469	80,39
Net Income	150,270	133,044	119,379	107,108	110,61
Preferred Stock Dividend Requirements	2,131	2,131	2,442	6,029	11,90
Earnings Applicable to Common Stock	$ 148,139	$ 130,913	$ 116,937	$ 101,079	$ 98,70

	December 31,				
	1999	1998	1997	1996	1995
			(in thousands)		
BALANCE SHEETS DATA:					
Electric Utility Plant	$3,151,619	$3,053,565	$2,976,110	$2,899,893	$2,820,20
Accumulated Depreciation	1,210,994	1,134,348	1,074,588	1,016,909	953,17
Net Electric Utility Plant	$1,940,625	$1,919,217	$1,901,522	$1,882,984	$1,867,03
Total Assets	$2,809,990	$2,681,690	$2,613,860	$2,541,586	$2,594,12
Common Stock and Paid-in Capital	$ 613,899	$ 613,518	$ 613,138	$ 615,735	$ 615,45
Retained Earnings	246,584	186,441	138,172	99,582	74,32
Total Common Shareholder's Equity	$ 860,483	$ 799,959	$ 751,310	$ 715,317	$ 689,77
Cumulative Preferred Stock - Subject to Mandatory Redemption (a)	$ 25,000	$ 25,000	$ 25,000	$ 75,000	$ 82,50
Long-term Debt (a)	$ 924,545	$ 959,786	$ 969,600	$ 897,281	$ 990,79
Obligations Under Capital Leases (a)	$ 40,270	$ 42,362	$ 38,587	$ 36,134	$ 27,81
Total Capitalization and Liabilities	$2,809,990	$2,681,690	$2,613,860	$2,541,586	$2,594,12

(a) Including portion due within one year.

MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

Columbus Southern Power Company is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP Co., Inc.), a public utility holding company. The Company is engaged in the generation, purchase, sale, transmission and distribution of electric power to 655,000 retail customers in central and southern Ohio and does business as American Electric Power (AEP). The Company 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. The Company 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 or receipt of capacity charges and 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 revenues or costs. Since the Company's MLR increased in 1999, the AEP Power Pool is allocating a larger share of certain revenues and expenses to the Company.

Net Income Increases

Net income increased $17.2 million or 13% in 1999 primarily due to increased sales to retail customers reflecting an 8% increase in sales to residential customers and a 6% increase in commercial sales.

Operating Revenues Increase

Operating revenues increased $42.2 million in 1999 as follows:

(dollars in millions)	Increase (Decrease) From Previous Year Amount	%
Retail:		
Residential	$33.0	
Commercial	26.2	
Industrial	2.9	
Other	0.2	
	62.3	6.2
Wholesale	(25.0)	(17.2)
Transmission	0.7	2.5
Other	4.2	29.2
Total	$42.2	3.6

The increase in retail revenues resulted from a 5% increase in retail energy sales primarily due to the increased sales to residential and commercial customers, which reflects colder winter weather in the Company's service territory, and growth in the number of residential and commercial customers.

The 17% decrease in wholesale revenues is attributable to the Company's MLR share of a decline in net revenues from AEP Power Pool trading transactions reflecting a decline in trading margins resulting from a moderation in 1999 of extreme weather in 1998 and capacity shortages experienced in the summer of 1998 in the AEP Power Pool's marketing area. Power trading transactions involve the purchase and sale of substantial amounts of electricity and are conducted by the AEP Power Pool. Revenues from regulated trading activities are allocated to AEP Power Pool members based on MLR and recorded net of purchases.

Operating Expenses Increase

Operating expenses increased $31.7 million or 3% in 1999 due mainly to increased purchased power expense. Changes in the components of operating expenses were as follows:

(dollars in millions)	Increase (Decrease) From Previous Year Amount	%
Fuel	$ (3.5)	(1.9)
Purchased Power	27.8	11.7
Other Operation	(12.1)	(6.0)
Maintenance	3.1	5.0
Depreciation	3.3	3.6
Taxes Other Than Federal Income Taxes	3.6	3.1
Federal Income Taxes	9.5	12.4
Total	$ 31.7	3.2

An increase in purchases of electricity from the AEP Power Pool to support retail demand and increased capacity charges paid to the AEP Power Pool due to the increase in the Company's MLR are the primary reasons for the increase in purchased power expense.

The decrease in other operation expense was primarily attributable to increased gains on the sale of emission allowances and cost containment efforts including staff reductions at the power plants and within the engineering and maintenance group of AEP Service Corporation which bills the Company for operations support services.

Federal income taxes attributable to operations increased primarily due to an increase in pre-tax operating income.

Market Risks

The Company has certain market risks inherent in its business activities from changes in electricity commodity prices and interest rates. The allocation of trading of electricity and related financial derivative instruments through the AEP Power Pool exposes the Company to market risk. Market risk represents the risk of loss that may impact the Company due to adverse changes in electricity 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 three-day holding period. Throughout 1999 and 1998, the highest, lowest and average VaR in the wholesale electricity trading portfolio was less than $2.5 and $2 million, respectively. Based on this VaR analysis, at December 31, 1999 a near term change in electricity commodity prices is not expected to have a material effect on the Company's results of operations, cash flows or financial condition.

The Company is exposed to changes in interest rates primarily due to short-term and long-term borrowings to fund its business operations. The debt portfolio has both fixed and variable interest rates with terms from one day to 28 years and an average duration of seven years at December 31, 1999. The Company 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 the Company's exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $135 million at December 31, 1999 and $75 million at December 31, 1998. The Company 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 the Company.

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	1999	1998	1997
		(in thousands)	
OPERATING REVENUES	$1,229,994	$1,187,745	$1,094,851
OPERATING EXPENSES:			
Fuel	185,511	189,031	180,086
Purchased Power	265,457	237,688	176,311
Other Operation	190,614	202,720	180,663
Maintenance	65,229	62,095	66,956
Depreciation	94,532	91,218	90,723
Amortization of Zimmer Plant Phase-in Costs	-	-	15,746
Taxes Other Than Federal Income Taxes	120,147	116,548	117,519
Federal Income Taxes	85,714	76,234	71,720
TOTAL OPERATING EXPENSES	1,007,204	975,534	899,724
OPERATING INCOME	222,790	212,211	195,127
NONOPERATING INCOME (LOSS)	2,709	(1,343)	3,137
INCOME BEFORE INTEREST CHARGES	225,499	210,868	198,264
INTEREST CHARGES	75,229	77,824	78,885
NET INCOME	150,270	133,044	119,379
PREFERRED STOCK DIVIDEND REQUIREMENTS	2,131	2,131	2,442
EARNINGS APPLICABLE TO COMMON STOCK	$ 148,139	$ 130,913	$ 116,937

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year Ended December 31,		
	1999	1998	1997
		(in thousands)	
Retained Earnings January 1	$186,441	$138,172	$ 99,582
Net Income	150,270	133,044	119,379
	336,711	271,216	218,961
Deductions:			
Cash Dividends Declared:			
Common Stock	87,996	82,644	78,684
Cumulative Preferred Stock - 7% Series	1,750	1,750	1,750
Total Cash Dividends Declared	89,746	84,394	80,434
Capital Stock Expense	381	381	355
Total Deductions	90,127	84,775	80,789
Retained Earnings December 31	$246,584	$186,441	$138,172

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

	December 31, 1999	1998
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$ 1,544,858	$1,526,869
Transmission	350,826	339,934
Distribution	1,032,550	938,283
General	141,137	130,002
Construction Work in Progress	82,248	118,477
Total Electric Utility Plant	3,151,619	3,053,565
Accumulated Depreciation	1,210,994	1,134,348
NET ELECTRIC UTILITY PLANT	1,940,625	1,919,217
OTHER PROPERTY AND INVESTMENTS	101,286	73,088
CURRENT ASSETS:		
Cash and Cash Equivalents	5,107	7,206
Accounts Receivable:		
Customers	77,418	89,522
Affiliated Companies	28,453	17,966
Miscellaneous	8,887	11,989
Allowance for Uncollectible Accounts	(3,045)	(2,598)
Fuel - at average cost	21,484	22,140
Materials and Supplies - at average cost	41,696	33,263
Accrued Utility Revenues	48,117	40,127
Energy Marketing and Trading Contracts	90,103	12,670
Prepayments	37,969	29,084
TOTAL CURRENT ASSETS	356,189	261,369
REGULATORY ASSETS	339,103	353,369
DEFERRED CHARGES	72,787	74,647
TOTAL	$ 2,809,990	$2,681,690

See Notes to Consolidated Financial Statements.

	December 31, 1999	1998
	(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	572,873	572,492
Retained Earnings	246,584	186,441
Total Common Shareholder's Equity	860,483	799,959
Cumulative Preferred Stock - Subject to Mandatory Redemption	25,000	25,000
Long-term Debt	924,545	959,786
TOTAL CAPITALIZATION	1,810,028	1,784,745
OTHER NONCURRENT LIABILITIES	43,056	42,176
CURRENT LIABILITIES:		
Short-term Debt	45,500	52,500
Accounts Payable - General	28,279	34,631
Accounts Payable - Affiliated Companies	52,776	37,132
Taxes Accrued	143,477	141,831
Interest Accrued	13,936	14,355
Energy Marketing and Trading Contracts	87,911	13,682
Other	34,375	37,197
TOTAL CURRENT LIABILITIES	406,254	331,328
DEFERRED INCOME TAXES	447,607	442,100
DEFERRED INVESTMENT TAX CREDITS	44,716	48,710
DEFERRED CREDITS	58,329	32,631
COMMITMENTS AND CONTINGENCIES (Notes 5 and 6)		
TOTAL	$2,809,990	$2,681,690

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	1999	1998	1997
		(in thousands)	
OPERATING ACTIVITIES:			
Net Income	$ 150,270	$ 133,044	$ 119,379
Adjustments for Noncash Items:			
Depreciation	94,962	91,426	90,959
Deferred Federal Income Taxes	10,481	17,101	5,250
Deferred Investment Tax Credits	(3,994)	(4,224)	(4,168)
Deferred Fuel Costs (net)	8,889	(11,311)	(6,115)
Deferred Zimmer Plant Operating Expenses and Carrying Charges	-	-	16,097
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	5,166	(5,910)	(47,966)
Fuel, Materials and Supplies	(7,777)	(8,226)	(4,900)
Accrued Utility Revenues	(7,990)	11,638	(19,939)
Accounts Payable	9,292	476	16,459
Payment of Disputed Tax and Interest Related to COLI	(2,240)	(37,243)	-
Other (net)	(13,426)	29,776	(6,316)
Net Cash Flows From Operating Activities	243,633	216,547	158,740
INVESTING ACTIVITIES:			
Construction Expenditures	(115,321)	(114,979)	(108,931)
Proceeds from Sale and Leaseback Transactions and Other	1,858	2,637	1,722
Net Cash Flows Used For Investing Activities	(113,463)	(112,342)	(107,209)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	-	111,075	86,172
Retirement of Preferred Stock	-	-	(52,953)
Retirement of Long-term Debt	(35,523)	(122,206)	(14,640)
Change in Short-term Debt (net)	(7,000)	(14,100)	14,800
Dividends Paid on Common Stock	(87,996)	(82,644)	(78,684)
Dividends Paid on Cumulative Preferred Stock	(1,750)	(1,750)	(2,734)
Net Cash Flows Used For Financing Activities	(132,269)	(109,625)	(48,039)
Net Increase (Decrease) in Cash and Cash Equivalents	(2,099)	(5,420)	3,492
Cash and Cash Equivalents January 1	7,206	12,626	9,134
Cash and Cash Equivalents December 31	$ 5,107	$ 7,206	$ 12,626

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING POLICIES:

Organization

Columbus Southern Power Company (the Company or CSPCo) is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP Co., Inc.), a public utility holding company. The Company is engaged in the generation, purchase, sale, transmission and distribution of electric power serving 655,000 retail customers in its service territory in central and southern Ohio and does business as American Electric Power (AEP). Under the terms of the AEP System Power Pool (AEP Power Pool) and the AEP System Transmission Equalization Agreement, the Company's generation and transmission facilities are operated in conjunction with the facilities of certain other AEP affiliated utilities as an integrated utility system. The Company as a member of the AEP Power Pool shares in the revenues and costs of AEP Power Pool wholesale sales to neighboring utility systems and power marketers. The Company also sells wholesale power to municipalities.

The Company's three wholly-owned subsidiaries, which are consolidated in these financial statements, are: Conesville Coal Preparation Company (CCPC) which provides coal washing services for one of the Company's generating stations; Simco Inc. which is engaged in leasing a coal conveyor system to CCPC; and Colomet, Inc. which is engaged in real estate activities on behalf of the Company.

Regulation

As a subsidiary of AEP Co., Inc., the Company is subject to the regulation of the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (1935 Act). Retail rates are regulated by the Public Utilities Commission of Ohio (PUCO). The Federal Energy Regulatory Commission (FERC) regulates the Company's wholesale and transmission rates.

Principles of Consolidation

The consolidated financial statements include the revenues, expenses, cash flows, assets, liabilities and equity of CSPCo and its wholly-owned subsidiaries. Significant inter-company items are eliminated in consolidation.

Basis of Accounting

As a cost-based rate-regulated entity, CSPCo's financial statements 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 Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred income) are recorded to reflect the economic effects of regulation and to match expenses with regulated revenues.

Use of Estimates

The preparation of these financial statements in conformity with generally accepted accounting principles requires in certain instances the use of estimates. Actual results could differ from those estimates.

Utility Plant

Electric utility plant is stated at original cost and is generally subject to first mortgage liens. Additions, major replacements and betterments are added to the plant accounts. Retirements of plant are deducted from the electric plant in service account and are deducted from accumulated depreciation together with associated removal costs, net of salvage. The costs of labor, materials and overheads incurred to operate and maintain

utility 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 utility plant. It represents the estimated cost of borrowed and equity funds used to finance construction projects. The amounts of AFUDC for 1999, 1998 and 1997 were not significant.

Depreciation

Depreciation of electric utility plant is provided on a straight-line basis over the estimated useful lives of utility plant and is calculated largely through the use of composite rates by functional class. The annual composite depreciation rates for 1999, 1998 and 1997 are as follows:

Functional Class of Property	Annual Composite Depreciation Rates		
	1999	1998	1997
Production	3.2%	3.2%	3.2%
Transmission	2.3%	2.3%	2.3%
Distribution	3.7%	3.7%	3.7%
General	3.3%	3.6%	3.4%

Expenditures for the demolition and removal of plant are charged to the accumulated provision for depreciation and recovered through depreciation charges included in rates.

Cash and Cash Equivalents

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

Operating Revenues and Fuel Costs

Revenues include billed revenues as well as an accrual of electricity consumed but unbilled at month-end. Changes in retail jurisdictional fuel costs are deferred until reflected in revenues in later months through a fuel cost recovery mechanism. The deferral is amortized to fuel expense commensurate with its recovery in rates. Wholesale jurisdictional fuel cost changes are expensed and billed as incurred.

Energy Marketing and Trading Transactions

The AEP Power Pool implements and administers power marketing and trading transactions (trading activities) in which the Company shares. Trading activities involve the sale of electricity under physical forward contracts at fixed and variable prices and the trading of electricity contracts including exchange traded futures and options, over-the-counter options and swaps. The majority of these transactions represent physical forward electricity contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. The net revenues from these regulated transactions in AEP Power Pool's traditional marketing area are included in operating revenues for ratemaking, accounting and financial and regulatory reporting purposes.

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. The Company's share of these non-regulated trading activities are included in nonoperating income.

In the first quarter of 1999 the Company adopted the Financial Accounting Standards Board's Emerging Issues Task Force Consensus (EITF) 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." The EITF requires that all energy trading contracts be marked-to-market. The effect on the Consolidated Statements of Income of marking open trading contracts to market is deferred as regulatory assets or liabilities for those open trading transactions within the AEP Power Pool's marketing area that are included in cost of service on a settlement basis for rate-making purposes. The Company's share of non-regulated open trading contracts are accounted for on a mark-to-market basis in nonoperating income. Unrealized mark-to-market gains and losses from trading activities are reported as assets

and liabilities, respectively. The adoption of the EITF did not have a material effect on results of operations, cash flows or financial condition.

The Company enters 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 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, 1999 or 1998.

See Note 11 - Financial Instruments, Credit and Risk Management for further discussion.

Reclassification

Certain prior year amounts have been reclassified to conform to current year presentation. Such reclassifications had no impact on previously reported net income.

Income Taxes

The Company 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 rates (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.

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 regulated plant investment.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt are deferred as regulatory assets and amortized over the remaining term of the reacquired debt in accordance with rate-making treatment. If debt is refinanced, reacquisition costs are deferred and amortized over the term of the replacement debt commensurate with their recovery in rates.

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

Redemption premiums paid to reacquire preferred stock are included in paid-in capital and amortized to reduce retained earnings commensurate with their recovery in rates. The excess of par value over the cost of preferred stock reacquired is credited to paid-in capital and amortized to retained earnings.

Other Property and Investments

Other property and investments are stated at cost.

Comprehensive Income

There were no material differences between net income and comprehensive income.

2. RATE MATTERS:

The Federal Energy Regulatory Commission (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, by requiring them to use 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.

In July 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 which would reduce AEP's rates for the affected customers below the settlement rate. AEP and certain of the affected customers have sought rehearing of the Commission's Order. The Company made a provision in September 1999 for its share of the refund including interest.

On December 10, 1999, the AEP System filed a settlement agreement with the FERC resolving the issues on rehearing of the July 30, 1999 order. Under terms of the settlement, the AEP System will make refunds retroactive to September 7, 1993 to certain customers affected by the July 30, 1999 FERC order. The refunds will be made in two payments. The first payment was made February 2, 2000 pursuant to a FERC order granting AEP's request to make interim refunds. The remainder will be paid after the FERC issues a final order and approves a compliance filing that the AEP System will make pursuant to the final order. In addition, a new rate was made effective January 1, 2000, subject to FERC approval, for all transmission service customers and a future rate was established to take effect upon the consummation of the AEP and Central and South West Corporation merger unless a superseding rate is made effective prior to the merger.

3. EFFECTS OF REGULATION:

In accordance with SFAS 71 the consolidated financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred income) 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 Company's regulated rates be cost-based and the recovery of regulatory assets must be probable. Management has reviewed all the evidence currently available and concluded that the Company continues to meet the requirements to apply SFAS 71. In the event a portion of the Company's business no longer met those requirements, net regulatory assets would have to be written off for that portion of the business and assets attributable to that portion of the business would have to be tested for possible impairment and, if required, an impairment loss recorded unless the net regulatory assets and impairment losses are recoverable as a stranded cost. (See Note 4 "Ohio Restructuring Legislation.")

Recognized regulatory assets and liabilities are comprised of the following:

	December 31, 1999	1998
	(in thousands)	
Regulatory Assets:		
Amounts Due From Customers For Future Income Taxes	$243,031	$248,115
Deferred Zimmer Plant Carrying Charges	42,826	42,841
Unamortized Loss On Reacquired Debt	23,307	26,537
Other	29,939	35,876
Total Regulatory Assets	$339,103	$353,369
Regulatory Liabilities:		
Deferred Investment Tax Credits	$44,716	$48,710
Other*	37,621	26,052
Total Regulatory Liabilities	$82,337	$74,762

* Included in Deferred Credits on the Consolidated Balance Sheets.

4. OHIO RESTRUCTURING LEGISLATION:

The Ohio Electric Restructuring Act of 1999 (the Act) became law in October 1999. The Act provides for customer choice of electricity supplier, a residential rate reduction of 5% for the generation portion of rates and a freezing of generation rates including fuel rates beginning on January 1, 2001. The Act also provides for a five-year transition period to move from cost-based rates to market pricing for generation services. It authorizes the PUCO to address certain major transition issues including unbundling of rates and the recovery of transition costs. Under the Act, transition costs can include regulatory assets, generating asset impairments and other stranded costs, employee severance and re-training costs, consumer education costs and other costs. Stranded generation costs are those costs of generation above the market price for electricity that potentially would not be recoverable in a competitive market.

Retail electric services that will be competitive are defined in the Act as electric generation service, aggregation service and power marketing and brokering. Under the legislation the PUCO is granted broad oversight responsibility and is required by the Act to promulgate rules for competitive retail electric generation service and transition plan filings. The Act also gives the PUCO authority to approve a transition plan for each electric utility company and sets a deadline of no later than October 31, 2000 for those approvals.

The Act provides that electric utilities in Ohio with an opportunity to recover PUCO approved allowable transition costs through generation rates paid through December 31, 2005 by customers who do not switch generation suppliers and through a transition charge for customers who switch generation suppliers. Recovery of the regulatory asset portion of transition costs can, under certain circumstances, extend beyond the five-year transition period but cannot continue beyond December 31, 2010.

The Act also provides for a reduction in property tax assessments, the imposition of franchise and income taxes, and the replacement of a gross receipts tax with a kilowatt hour (kwh) based excise tax. The property tax assessment percentage on generation property will be lowered from 100% to 25% of value effective January 1, 2001 and electric utilities will become subject to the Ohio Corporate Franchise Tax and municipal income taxes on January 1, 2002. The last year for which 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, deferred 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. The change in the tax law to impose an excise tax based on kwh sold to Ohio customers commencing before the expiration of the gross receipts tax privilege period will result in a 12 month period when the Company is recording as an expense both the gross receipts tax and the excise tax. In the Company's Ohio transition plan filing, recovery of $40 million was sought

for this overlap of the gross receipts and excise taxes.

The Company filed its transition plan with the PUCO on December 30, 1999. The filing included the following elements:

- a rate unbundling plan including tariff terms and conditions necessary for restructuring,
- a corporate separation plan,
- an application for transition revenues,
- a plan for independent operation of transmission facilities and
- other components for the implementation of restructuring.

Under the rate unbundling plan in the transition plan filing, the Company will offer two transition period tariffs beginning January 1, 2001, the standard tariff and the open access distribution tariff. The proposed standard tariff applies to customers who do not choose an alternative energy supplier. This tariff schedule includes detailed charges for generation, transmission and distribution and riders to fund universal service, to promote energy efficiency and to recover regulatory assets and taxes. Taxes include charges for municipal income, excise and franchise taxes and tax credits for gross receipts and property taxes. For customers who choose an alternative electric supplier, the proposed open access distribution tariff will apply. This tariff includes charges for transmission and distribution and riders to fund universal service, to promote energy efficiency and to recover regulatory assets and taxes. These riders are the same as those in the standard tariff except there is no property tax credit.

The corporate separation plan contains proposals for the Company to establish separate subsidiaries to own and operate the transmission and distribution assets. The Company will retain generation related assets. The separation plan will be implemented in a manner that recognizes the current overlap of financing arrangements. This would permit an orderly and economically efficient separation of generation from transmission and distribution so that additional transition costs can be minimized from premature unwinding of existing financial instruments. Prior to the actual legal separation, the Company will functionally separate generation from transmission and distribution.

An application to receive transition revenues was included in the Company's transition plan filing. It requests recovery of stranded generation costs over a five year period and recovery of generation-related regulatory assets of $363 million over a 10-year period. The amount requested for recovery of regulatory assets includes current and new regulatory assets including those arising from compliance with the Act.

Included in the transition plan is a proposal to implement independent operation of the transmission system. The Company proposes to join a regional transmission organization whose approval is currently pending before the FERC. A project timeline for activities to implement operational support systems and other technical implementation issues to arrive at and support a competitive electricity market are included in the transition plan.

The Company plans to provide severance, retraining, early retirement, retention, outplacement and other assistance for displaced employees. At this time no employees are identified as affected by electric utility restructuring. Consequently, recovery of such costs was not requested in transition revenues as filed with the transition plan.

The transition plan includes a consumer education plan which will be implemented in conjunction with other electric utilities and the PUCO staff. The transition plan also has terms and conditions for changing suppliers and the commitment of time a customer must accept in a service contract which are two features necessary to accommodate restructuring.

A proposed shopping incentive in the transition plan represents the lower of the market price or the unbundled generation rate in current tariff schedules.

As discussed in Note 3, "Effects of Regulation," the Company defers as regulatory assets and liabilities certain expenses and revenues consistent with the regulatory process in accordance with SFAS 71. Management has concluded that as of December 31, 1999 the requirements to apply SFAS 71 continue to be met since the Company's rates for generation will continue to be cost-based regulated until the PUCO takes action on the transition plan and the proposed tariff schedules contained in it as provided in the Act. The establishment of rates and charges under the transition plan should enable the Company to determine its ability to recover regulatory assets, transition costs and other stranded costs, a requirement to discontinue application of SFAS 71.

When the transition plan and tariff schedules are approved, the application of SFAS 71 will be discontinued for the Ohio retail jurisdictional portion of the generation business. At that time the Company will have to write-off its Ohio jurisdictional generation-related regulatory assets to the extent that they cannot be recovered under the tariff schedules in the transition plan approved by the PUCO and record any asset impairments in accordance with SFAS 121, "Accounting for the Impairment of Long-lived Assets and for Long-lived Assets to Be Disposed Of." An impairment loss would be recorded to the extent that the cost of generation assets cannot be recovered through generation-related revenues during the transition period and future market prices. Until the PUCO completes its regulatory process and issues an order related to the Company's transition plan, it is not possible for management to determine if any of the Company's generating assets are impaired in accordance with SFAS 121. The amount of regulatory assets recorded on the books at December 31, 1999 applicable to the Ohio retail jurisdictional generating business is $305 million before related tax effects. Recovery of these regulatory assets and an estimated asset impairment are being sought as a part of the Company's Ohio transition plan filing.

A determination of whether the Company will experience any asset impairment loss regarding its Ohio retail jurisdictional generating assets and any loss from a possible inability to recover Ohio generation-related regulatory assets and other transition costs cannot be made until the PUCO takes action on the Company's transition plan. Management is seeking full recovery of generation-related regulatory assets, stranded costs and other transition costs in its transition plan filing. The PUCO is required to complete its regulatory process including review of the Company's transition plan filing and issue a transition order no later than October 31, 2000. Should the PUCO fail to fully approve the Company's transition plan and its tariff schedules which include recovery of the Company's generation-related regulatory assets, stranded costs and other transition costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

5. COMMITMENTS AND CONTINGENCIES:

Construction and Other Commitments

Substantial construction commitments have been made to support the Company's utility operations and are estimated to be $395 million for 2000-2002.

Long-term fuel supply contracts contain clauses that provide for periodic price adjustments. The PUCO has a fuel clause mechanism that provides for deferral and subsequent recovery or refund of changes in the cost of fuel with commission review and approval. The fuel supply contracts are for various terms, the longest of which extends to 2007, and contain various clauses that would release the Company from its obligation under certain force majeure conditions.

Federal EPA Complaint and Notice of Violation

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.

On November 3, 1999 the Department of Justice, at the request of the United States (U.S.) Environmental Protection Agency (Federal EPA), filed a complaint in the U.S. District Court for the Southern District of Ohio that alleges the Company and certain other affiliated utilities made modifications to generating units at certain of their coal-fired generating plants over the course of the past 25 years that extend unit operating lives or increase unit generating capacity without a preconstruction permit in violation of the Clean Air Act. Federal EPA also issued Notices of Violation to other AEP companies alleging similar violations at certain AEP plants. A number of unaffiliated utilities also received Notices of Violation, complaints or administrative orders.

The states of New Jersey, New York and Connecticut were subsequently granted leave to intervene in the Federal EPA's action against the Company under the Clean Air Act. On November 18, 1999 a number of environmental groups filed a lawsuit against power plants owned by the Company alleging similar violations to those in the Federal EPA complaint and Notices of Violation. This action 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.

Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act and intends to vigorously pursue its defense of this matter.

In the event the Company does 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, transition charges and/or reflected in the future market prices of electricity.

Litigation

The Internal Revenue Service (IRS) agents auditing the AEP System's consolidated federal income tax returns requested a ruling from their National Office that certain interest deductions claimed by the Company relating to AEP's corporate owned life insurance (COLI) program should not be allowed. As a result of a suit filed in U.S. District Court (discussed below) this request for ruling was withdrawn by the IRS agents. Adjustments have been or will be proposed by the IRS disallowing COLI interest deductions for taxable years 1991-96. A disallowance of the COLI interest deductions through December 31, 1999 would reduce earnings by approximately $43 million (including interest).

The Company made payments of taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of any additional above market rate interest on the contested amount. The payments to the IRS are included on the consolidated balance sheet in other property and investments pending the resolution of this matter. The Company is seeking refund through litigation of all amounts paid plus interest.

In order to resolve this issue, the Company filed suit against the United States

in the U.S. District Court for the Southern District of Ohio in March 1998. In 1999 a U.S. Tax Court judge decided in the Winn-Dixie Stores v. Commissioner case that a corporate taxpayer's COLI interest deduction should be disallowed. Notwithstanding the Tax Court's decision in Winn-Dixie, management has made no provision for any possible adverse earnings impact from this matter because it believes, and has been advised by outside counsel, that it has a meritorious position and will vigorously pursue its lawsuit. In the event the resolution of this matter is unfavorable, it will have a material adverse impact on results of operations, cash flows and possibly financial condition.

The Company is involved in a number of other legal proceedings and claims. While management is unable to predict the ultimate outcome of litigation, it is not expected that the resolution of these matters will have a material adverse effect on the results of operations, cash flows or financial condition.

6. SUBSEQUENT EVENT - NOx REDUCTIONS (March 3, 2000):

On March 3, 2000, the U.S. Court of Appeals for the District of Columbia Circuit (Appeals Court) issued a decision generally upholding Federal EPA's final rule (the NOx rule) that requires substantial reductions in nitrogen oxide (NOx) emissions in 22 eastern states, including Ohio where the Company's generating plants are located. A number of utilities, including the Company, had filed petitions seeking a review of the final rule in the Appeals Court. On May 25, 1999, the Appeals Court had indefinitely stayed the requirement that states develop revised air quality programs to impose the NOx reductions but did not, however, stay the final compliance date of May 1, 2003.

On April 30, 1999, Federal EPA took final action with respect to petitions filed by eight northeastern states pursuant to the Clean Air Act (Section 126 Rule). The rule approved portions of the states' petitions and imposed NOx reduction requirements on AEP System generating units which are approximately equivalent to the reductions contemplated by the NOx Rule. The AEP System companies with generating plants, as well as other utility companies, filed a petition in the Appeals Court seeking review of Federal EPA's approval of the northeastern states' petitions. In 1999, three additional northeastern states and the District of Columbia filed petitions with Federal EPA similar to those originally filed by the eight northeastern states. Since the petitions relied in part on compliance with an 8-hour ozone standard remanded by the Appeals Court in May 1999, Federal EPA indicated its intent to decouple compliance with the 8-hour standard and issue a revised rule.

On December 17, 1999, Federal EPA issued a revised Section 126 Rule not based on the 8-hour standard and ordered 392 industrial facilities, including certain coal-fired generating plants owned by the Company, to reduce their NOx emissions by May 1, 2003. This rule approves portions of the petitions filed by four northeastern states which contend that their failure to meet Federal EPA smog standards is due to emissions from upwind states' industrial and coal-fired generating facilities.

Preliminary estimates indicate that compliance with the NOx rule upheld by the Appeal Court could result in required capital expenditures of approximately $136 million for the Company. Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the Company's preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless such costs are recovered from customers through regulated rates, transition charges and/or reflected in the future market price of electricity, they will have an adverse effect on future results of operations and cash flows and possibly financial condition.

7. RELATED PARTY TRANSACTIONS:

Benefits and costs of the AEP System's generating plants are shared by members of the AEP Power Pool of which the Company is a member. Under the terms of the System Interconnection Agreement, capacity charges and credits are designed to allocate the cost of the System's capacity among the AEP Power Pool members based on their relative peak demands and generating reserves. 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.

Operating revenues include $15.1 million in 1999, $20.1 million in 1998 and $18.6 million in 1997 for energy supplied to the AEP Power Pool.

Since the Company's internal peak demand exceeds its generating capacity, charges for AEP Power Pool capacity reservation, which is a charge for the right to receive power even if the power is not taken, and charges for energy received from the AEP Power Pool were included in purchased power expense as follows:

	Year Ended December 31,		
	1999	1998	1997
	(in thousands)		
Capacity Charges	$114,794	$ 98,042	$ 82,536
Energy Charges	84,780	69,577	74,416
Total	$199,574	$167,619	$156,952

The AEP Power Pool allocated operating revenues, purchased power expense and nonoperating income to the Company. Power marketing and trading operations, which are described in Note 1, are conducted by the AEP Power Pool and shared with the Company. Net trading transactions are included in operating revenues if the trading transactions are within the AEP Power Pool's traditional marketing area and are recorded in nonoperating income if the net trading transactions are outside of the AEP Power Pool's traditional marketing area. The total amounts allocated by the AEP Power Pool, which includes amounts for power marketing and trading transactions, are as follow:

	Year Ended December 31,		
	1999	1998	1997
	(in thousands)		
Operating Revenues	$103,962	$109,963	$63,635
Purchased Power Expense	60,926	62,728	13,209
Nonoperating Income (Loss)	1,914	(6,335)	(44)

Purchased power expense includes $6.0 million in 1999, $5.9 million in 1998 and $6.1 million in 1997 for energy bought from the Ohio Valley Electric Corporation, an affiliated company that is not a member of the AEP Power Pool.

The Company participates in the AEP Transmission Equalization Agreement along with other AEP System electric operating utility companies. This agreement combines certain AEP System companies' investments in transmission facilities and shares the costs of ownership in proportion to the System companies' respective peak demands. Pursuant to the terms of the agreement, since the Company's relative investment in transmission facilities is less than its relative peak demand, other operation expense includes equalization charges of $39.0 million, $35.6 million and $29.9 million in 1999, 1998 and 1997, respectively.

American Electric Power Service Corporation (AEPSC) provides certain managerial and professional services to AEP System companies including the Company. The costs of the services are billed by AEPSC to its affiliated companies 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.

8. STAFF REDUCTIONS:

During 1998 an internal evaluation of the power generation organization was conducted with a goal of developing a better organizational structure for a competitive generation market. The study was completed in October 1998. In addition, a review of energy delivery staffing levels was conducted in 1998. As a result approximately 70 power generation and energy delivery positions were identified for elimination.

Severance accruals totaling $3.4 million were recorded by the Company in December 1998 for reductions in power generation and energy delivery staffs and were charged to other operation expense in the Consolidated Statements of Income. In the first quarter of 1999 the power generation and energy delivery staff reductions were made. The amount of severance benefits paid was not significantly different from the amount accrued.

9. BENEFIT PLANS:

The Company and its subsidiaries participate in the AEP System qualified pension plan, a defined benefit plan which covers all employees. Net pension credits for the years ended December 31, 1999 and 1998 were $4.9 million and $1.4 million, respectively. Pension costs were not significant in 1997.

Postretirement benefits other than pensions are provided for retired employees for medical and death benefits under an AEP System plan. The annual accrued costs were $8.6 million in 1999 and $7.5 million in 1998 and 1997.

A defined contribution employee savings plan required that the Company make contributions to the plan totaling $1.7 million in 1999, $1.8 million in 1998 and $1.9 million in 1997.

10. SEGMENT INFORMATION:

Effective December 31, 1998 the Company adopted SFAS 131, "Disclosures about Segments of an Enterprise and Related Information". The Company has one reportable segment, a regulated vertically integrated electricity generation and energy delivery business. All other activities are insignificant. The Company's operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on business processes, cost structures and operating results. Included in the regulated electric utility segment is the power marketing and trading activities that are discussed in Note 1. For the years ended December 31, 1999, 1998 and 1997, all of the Company's revenues are derived from the generation, sale and delivery of electricity in the U.S.

11. FINANCIAL INSTRUMENTS, CREDIT AND RISK MANAGEMENT:

The Company is subject to market risk as a result of changes in electricity commodity prices and interest rates. The Company through its membership in the AEP Power Pool participates in a power marketing and trading operation that manages the exposure to electricity 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. Physical forward electricity contracts within the AEP System's traditional marketing area are recorded on a net basis as operating revenues in the month when the physical contract settles. The Company's share of the net gains from these regulated transactions for the years ended December 31, 1999 and 1998 are $4 million and $19 million, respectively. These activities were not material in 1997.

Non-regulated physical forward electricity contracts outside AEP's traditional marketing area, and all financial electricity trading transactions where the underlying physical commodity is outside AEP's traditional marketing area are marked to market and recorded in nonoperating income. These non-regulated open trading contracts are accounted for on a mark-to-market basis in non-operating income. The Company's share of the net gains (losses) from these non-regulated trading transactions for the year ended December 31, 1999 and 1998 are $2 million and $(6) million, respectively.

In the first quarter of 1999 the Company adopted EITF 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." The EITF requires that all energy trading contracts be marked-to-market. The effect on the Consolidated Statements of Income of marking open regulated trading contracts to market is deferred as regulatory assets or liabilities for those open trading transactions within the AEP Power Pool's marketing area that are included in the cost of service on a settlement basis for rate-making purposes. The unrealized mark-to-market gains and losses from trading of financial instruments are reported as assets and liabilities, respectively. These activities were not material in prior periods.

The Company is exposed to risk from changes in interest rates primarily due to short-term and long-term borrowings used to fund its business operations. The debt portfolio has both fixed and variable interest rates with terms from one day to 28 years and an average duration of seven years at December 31, 1999. A near term change in interest rates should not materially affect results of operations or financial position since the Company would not expect to liquidate its entire debt portfolio in a one year holding period.

Market Valuation

The book value 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 amounts and fair values of the Company's significant financial instruments at December 31, 1999 and 1998 are summarized in the following table. The fair values of long-term debt and preferred stock 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 valuation methodology. The estimates presented herein are not necessarily indicative of the amounts that the Company could realize in a current market exchange.

	1999		1998	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)		(in thousands)	
Non-Derivatives				
Long-term Debt	$925,000	$889,000	$959,800	$1,011,600
Preferred Stock	25,000	25,438	25,000	25,900

Derivatives

	1999			1998		
	Notional Amount	Fair Value	Average Fair Value	Notional Amount	Fair Value	Average Fair Value
			(Dollars in thousands)			
Trading Assets	GWH			GWH		
Electric						
NYMEX Futures and Options	40	$ 312	$ 159			
Physicals	12,503	103,794	91,570	10,161	$7,900	$ 7,100
Options	1,116	7,369	11,140	673	5,500	13,500
Swaps	32	70	56	48	600	200
Trading Liabilities						
	GWH			GWH		
Electric						
NYMEX Futures and Options	-	-	-	122	(1,200)	(300)
Physicals	13,449	96,748	88,194	10,010	(8,600)	(8,000)
Options	1,602	7,717	10,114	509	(4,900)	(12,600)
Swaps	32	64	53	85	(1,300)	(300)

Credit and Risk Management

In addition to market risk associated with electricity price movements, the Company through the AEP Power Pool 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 nonperformance. The AEP Power Pool has established and enforced credit policies that minimize this risk. The AEP Power Pool 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, the AEP Power Pool requires further credit enhancements to mitigate risk. Since the formation of the power marketing and trading business in July of 1997, the Company has experienced no significant losses due to the credit risk associated with risk management activities; furthermore, the Company does not anticipate any future material effect on its results of operations, cash flow or financial condition as a result of counter party nonperformance.

12. COMMON OWNERSHIP OF GENERATING AND TRANSMISSION FACILITIES:

The Company jointly owns, as tenants in common, four generating units and transmission facilities with two 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. The Company's proportionate share of the operating costs associated with such facilities is included in the Consolidated Statements of Income and the investments are reflected in the accompanying Consolidated Balance Sheets under utility plant as follows:

		Company's Share December 31,			
		1999		1998	
	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Utility Plant in Service	Construction Work in Progress
		(in thousands)			
Production:					
W.C. Beckjord Generating Station (Unit No. 6)	12.5	$ 13,919	$ 390	$ 13,869	$ 211
Conesville Generating Station (Unit No. 4)	43.5	80,433	80	80,029	1,616
J.M. Stuart Generating Station	26.0	184,168	3,620	182,564	2,532
Wm. H. Zimmer Generating Station	25.4	701,054	6,030	699,704	3,978
		$979,574	$10,120	$976,166	$8,337
Transmission	(a)	$60,333	$1,210	$59,668	$1,151

(a) Varying percentages of ownership.

At December 31, 1999 and 1998, the accumulated depreciation with respect to the Company's share of jointly owned facilities amounted to $361.1 million and $331.9 million, respectively.

13. FEDERAL INCOME TAXES:

The details of federal income taxes as reported are as follows:

	Year Ended December 31,		
	1999	1998	1997
		(in thousands)	
Charged (Credited) to Operating Expenses (net):			
Current	$79,409	$62,120	$ 69,619
Deferred	9,737	17,612	5,678
Deferred Investment Tax Credits	(3,432)	(3,498)	(3,577)
Total	85,714	76,234	71,720
Charged (Credited) to Nonoperating Income (net):			
Current	(3,210)	(3,795)	(941)
Deferred	744	(511)	(428)
Deferred Investment Tax Credits	(562)	(726)	(591)
Total	(3,028)	(5,032)	(1,960)
Total Federal Income Taxes as Reported	$82,686	$71,202	$ 69,760

The following is a reconciliation 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 federal income taxes reported.

	Year Ended December 31,		
	1999	1998	1997
		(in thousands)	
Net Income	$150,270	$133,044	$119,379
Federal Income Taxes	82,686	71,202	69,760
Pre-tax Book Income	$232,956	$204,246	$189,139
Federal Income Taxes on Pre-tax Book Income at Statutory Rate (35%)	$81,535	$71,486	$66,199
Increase (Decrease) in Federal Income Taxes Resulting From the Following Items:			
Depreciation	8,846	8,604	8,651
Investment Tax Credits (net)	(3,994)	(4,224)	(4,168)
Other	(3,701)	(4,664)	(922)
Total Federal Income Taxes as Reported	$82,686	$71,202	$69,760
Effective Federal Income Tax Rate	35.5%	34.9%	36.9%

The following tables show the elements of the net deferred tax liability and the significant temporary differences giving rise to such deferrals:

	December 31,	
	1999	1998
	(in thousands)	
Deferred Tax Assets	$ 79,510	$ 79,374
Deferred Tax Liabilities	(527,117)	(521,474)
Net Deferred Tax Liabilities	$(447,607)	$(442,100)
Property Related Temporary Differences	$(352,805)	$(346,483)
Amounts Due From Customers For Future Federal Income Taxes	(85,078)	(86,822)
All Other (net)	(9,724)	(8,795)
Net Deferred Tax Liabilities	$(447,607)	$(442,100)

The Company and its subsidiaries join in the filing of a consolidated federal income tax return with their affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

The AEP System has settled with the IRS all issues from the audits of the consolidated federal income tax returns for the years prior to 1991. Returns for the years 1991 through 1996 are presently being audited by the IRS. With the exception of interest deductions related to AEP's corporate owned life insurance program, which is discussed under the heading "Litigation" in Note 5, 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.

14. COMMON SHAREHOLDER'S EQUITY:

In 1999, 1998 and 1997 net changes to paid-in capital of $381,000, $380,000 and $(2,597,000), respectively, represented gains and expenses associated with cumulative preferred stock transactions. There were no other material transactions affecting the common stock and paid-in capital accounts in 1999, 1998 and 1997.

15. CUMULATIVE PREFERRED STOCK:

At December 31, 1999, authorized shares of cumulative preferred stock were as follows:

Par Value	Shares Authorized
$100	2,500,000
25	7,000,000

The cumulative preferred stock outstanding is subject to mandatory redemption and has an involuntary liquidation preference of par value. The Company redeemed 500,000 shares of the 7-7/8% Series Cumulative Preferred Stock in 1997.

Series	Call Price December 31, 1999	Par Value	Shares Outstanding December 31, 1999	Amount December 31, 1999	Amount December 31, 1998
				(In thousands)	
7%	(a)	$100	250,000	$25,000	$25,000

(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. Redemption of this series is prohibited prior to August 1, 2000. The sinking fund provisions of the 7% series aggregate $5,000,000, in 2000, 2001, 2002, 2003 and 2004.

16. LONG-TERM DEBT AND LINES OF CREDIT:

Long-term debt by major category was outstanding as follows:

	December 31, 1999	December 31, 1998
	(in thousands)	
First Mortgage Bonds	$562,327	$597,847
Installment Purchase Contracts	91,112	91,058
Senior Unsecured Notes	159,212	159,105
Junior Debentures	111,894	111,776
Total	$924,545	$959,786

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 1999	December 31, 1998
		(in thousands)	
7.25	2002 - October 1	$ 75,000	$ 75,000
7.15	2002 - November 1	20,000	20,000
6.80	2003 - May 1	50,000	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	15,000	15,000
7.90	2023 - May 1	50,000	50,000
7.75	2023 - August 1	33,000	40,000
7.45	2024 - March 1	30,000	50,000
7.60	2024 - May 1	41,000	50,000
Unamortized Discount		(2,173)	(2,653)
Total		$562,327	$597,847

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 as follows:

% Rate	Due	December 31, 1999	December 31, 1998
		(in thousands)	
6-3/8	2020 - December 1	$48,550	$48,550
6-1/4	2020 - December 1	43,695	43,695
Unamortized Discount		(1,133)	(1,187)
Total		$91,112	$91,058

Under the terms of the installment purchase contracts, the Company is required to pay amounts sufficient to enable the payment of interest on and the principal of related pollution control revenue bonds issued to finance the Company's share of construction of pollution control facilities at the Zimmer Plant.

Senior Unsecured Notes are composed of the following:

		December 31, 1999	December 31, 1998
		(in thousands)	
% Rate	Due		
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		(788)	(895)
Total		$159,212	$159,105

Junior debentures are composed of the following:

		December 31, 1999	December 31, 1998
		(in thousands)	
% Rate	Due		
8-3/8	2025 - September 30	$ 75,000	$ 75,000
7.92	2027 - March 31	40,000	40,000
Unamortized Discount		(3,106)	(3,224)
Total		$111,894	$111,776

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, 1999 future annual long-term debt payments are as follows:

	Amount (in thousands)
2000	$ -
2001	-
2002	95,000
2003	110,000
2004	100,000
Later Years	626,745
Total Principal Amount	931,745
Unamortized Discount	(7,200)
Total	$924,545

Short-term debt borrowings are limited by provisions of the 1935 Act to $350 million. Lines of credit are shared with AEP System companies and at December 31, 1999 and 1998 were available in the amounts of $1,056 million and $763 million, respectively. The short-term bank lines of credit require the payment of facility fees and do not require compensating balances. Outstanding short-term debt consisted of:

	Balance Outstanding (in thousands)	Year-end Weighted Average Interest Rate
December 31, 1999:		
Commercial Paper	$45,500	6.5%
December 31, 1998:		
Commercial Paper	$52,500	6.4%

17. SUPPLEMENTARY INFORMATION:

	Year Ended December 31, 1999	1998	1997
		(in thousands)	
Cash was paid for:			
Interest (net of capitalized amounts)	$72,007	$73,917	$74,248
Income Taxes	71,809	53,410	70,870
Noncash Acquisitions under Capital Leases	6,855	11,107	8,568

18. LEASES:

Leases of property, plant and equipment are for periods of up to 31 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, 1999	1998	1997
		(in thousands)	
Operating Leases	$ 5,687	$ 8,107	$ 6,279
Amortization of Capital Leases	7,427	6,530	6,675
Interest on Capital Leases	2,720	2,626	2,022
Total Rental Costs	$15,834	$17,263	$14,976

Properties under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

	December 31, 1999	December 31, 1998
	(in thousands)	
Electric Utility Plant Under Capital Leases	$60,469	$59,687
Other Property Under Capital Leases	2,917	2,699
Total Properties Under Capital Leases	63,386	62,386
Accumulated Amortization	23,116	20,024
Net Properties Under Capital Leases	$40,270	$42,362
Obligations Under Capital Leases*:		
Noncurrent Liability	$33,031	$35,335
Liability Due Within One Year	7,239	7,027
Total Capital Lease Obligations	$40,270	$42,362

* Represents the present value of future minimum lease payments.

Capital lease obligations are included in other noncurrent liabilities and other current liabilities on the Consolidated Balance Sheets. Properties under operating leases and related obligations are not included in the Consolidated Balance Sheets.

Future minimum lease payments consisted of the following at December 31, 1999:

	Capital Leases	Non-cancelable Operating Leases
	(in thousands)	
2000	$ 9,777	$ 4,575
2001	8,771	4,318
2002	7,589	774
2003	5,976	735
2004	4,723	735
Later Years	14,419	3,555
Total Future Minimum Lease Payments	51,255	$14,692
Less Estimated Interest Element	10,985	
Estimated Present Value of Future Minimum Lease Payments	$40,270	

19. UNAUDITED QUARTERLY FINANCIAL INFORMATION:

Quarterly Periods Ended	Operating Revenues	Operating Income	Net Income
		(in thousands)	
1999			
March 31	$279,067	$46,047	$27,418
June 30	301,419	54,473	34,559
September 30	368,946	83,478	63,719
December 31	280,562	38,792	24,574
1998			
March 31	$266,399	$45,229	$25,645
June 30	298,263	57,151	38,742
September 30	361,405	74,263	52,291
December 31	261,678	35,568	16,366

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of Columbus Southern Power Company and its subsidiaries as of December 31, 1999 and 1998, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1999. 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 generally accepted auditing standards. 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, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 22, 2000
(March 3, 2000 as to Note 6)

OPERATING STATISTICS

	1999	1998	1997	1996	1995
OPERATING REVENUES (in thousands):					
Retail:					
Residential:					
Without Electric Heating	$ 359,319	$ 335,270	$ 317,341	$ 325,351	$ 329,881
With Electric Heating	113,881	104,905	110,385	115,339	115,386
Total Residential	473,200	440,175	427,726	440,690	445,267
Commercial	420,612	394,363	381,368	383,621	371,461
Industrial	151,353	148,463	147,367	147,543	143,162
Miscellaneous	17,289	17,115	16,170	16,043	16,041
Total Retail	1,062,454	1,000,116	972,631	987,897	975,931
Wholesale (sales for resale)	120,374	145,376	97,016	93,496	75,466
Total Revenues from Energy Sales	1,182,828	1,145,492	1,069,647	1,081,393	1,051,397
Other	47,166	42,253	25,204	24,290	20,465
Total Operating Revenues	$1,229,994	$1,187,745	$1,094,851	$1,105,683	$1,071,862
SOURCES AND USES OF ENERGY (in millions of kilowatthours):					
Sources:					
Net Generated - Steam	13,718	14,867	14,163	13,679	12,825
Purchases - Unaffiliated and Power Pool	7,966	6,748	7,807	7,338	6,031
Total Sources	21,684	21,615	21,970	21,017	18,856
Less: Losses, Company Use, Etc.	1,144	1,394	1,153	1,170	1,120
Net Sources	20,540	20,221	20,817	19,847	17,736
USES:					
Retail Sales:					
Residential:					
Without Electric Heating	4,405	4,132	3,894	3,864	3,913
With Electric Heating	1,708	1,543	1,701	1,762	1,735
Total Residential	6,113	5,675	5,595	5,626	5,648
Commercial	6,683	6,289	6,079	5,938	5,792
Industrial	3,198	3,191	3,208	3,068	2,989
Miscellaneous	441	429	412	412	404
Total Retail Sales	16,435	15,584	15,294	15,044	14,833
Wholesale Sales (sales for resale)	4,105	4,637	5,523	4,803	2,903
Total USES	20,540	20,221	20,817	19,847	17,736

OPERATING STATISTICS (Concluded)

	1999	1998	1997	1996	1995
AVERAGE COST OF FUEL CONSUMED (in cents): (a)					
Per Million Btu	129	136	138	136	142
Per Kilowatthour Generated	1.30	1.37	1.40	1.37	1.42
RESIDENTIAL SERVICE - AVERAGES:					
Annual Kwh Use per Customer:					
With Electric Heating	16,606	15,186	17,071	18,082	18,196
Total	10,556	10,027	10,103	10,333	10,547
Annual Electric Bill:					
With Electric Heating	$1,106.95	$1,032.28	$1,107.78	$1,183.45	$1,210.13
Total	$817.14	$777.64	$772.29	$809.39	$831.39
Price per Kwh (in cents):					
With Electric Heating	6.67	6.80	6.49	6.54	6.65
Total	7.74	7.76	7.64	7.83	7.88
NUMBER OF CUSTOMERS:					
Year-End:					
Retail:					
Residential:					
Without Electric Heating	483,189	471,403	458,329	450,239	443,817
With Electric Heating	104,035	102,564	100,766	98,570	96,427
Total Residential	587,224	573,967	559,095	548,809	540,244
Commercial	64,613	62,652	58,807	57,030	55,118
Industrial	2,876	2,824	2,865	2,932	2,938
Miscellaneous	301	295	331	323	314
Total Retail	655,014	639,738	621,098	609,094	598,614
Wholesale (sales for resale)	118	124	57	56	34
Total Electric Customers	655,132	639,862	621,155	609,150	598,648

(a) Excludes effect of deferred collection of fuel costs.

DIVIDENDS AND PRICE RANGES OF CUMULATIVE PREFERRED STOCK
By Quarters (1999 and 1998)

	1999 - Quarters				1998 - Quarters			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
CUMULATIVE PREFERRED STOCK								
($100 Par Value)								
7% Series								
Dividends Paid Per Share	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75	$1.75
Market Price - $ Per Share (OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-

OTC - Over-the-Counter
Dash indicates quotation not available.

INVESTOR INQUIRIES
Investors should direct inquiries to Investor Relations Using the toll free number, 1-800-237-2667 or by writing to:

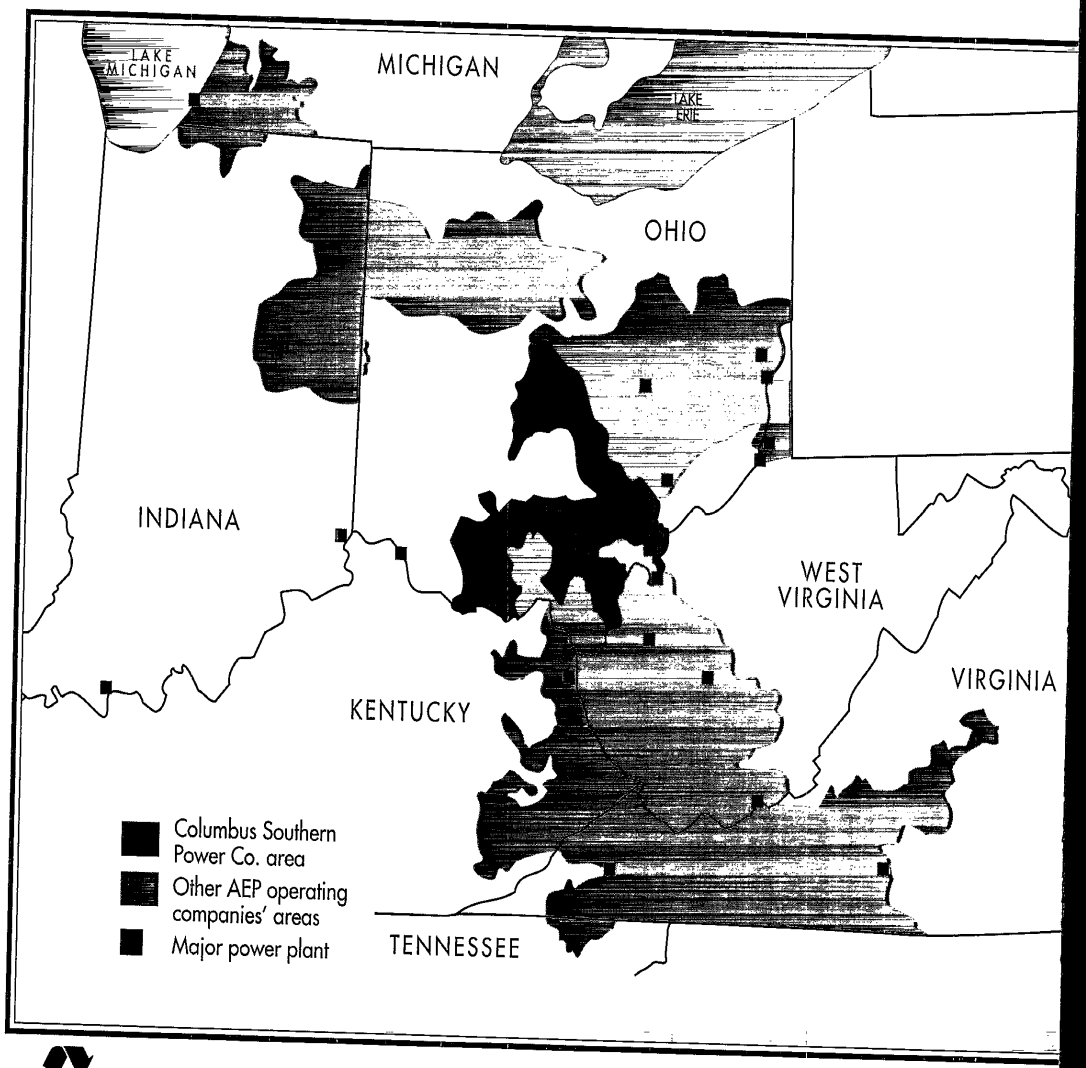
Bette Jo Rozsa
Managing Director of Investor Relations
American Electric Power Service Corporation
28th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

FORM 10-K ANNUAL REPORT
The Annual Report (Form 10-K) to the Securities and Exchange Commission will be available in April 2000 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

Columbus Southern Power Service Area and the American Electric Power System



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Ohio Power Company

1999 Annual Report

AEP: America's Energy Partner℠

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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

OHIO POWER COMPANY
301 Cleveland Avenue, S. W., Canton, Ohio 44701

BACKGROUND

OHIO POWER COMPANY (the Company), is engaged in the generation, sale, purchase, transmission and distribution of electric power. The Company serves approximately 679,000 retail customers in northwestern, east central, eastern and southern sections of Ohio. Principal industries served are primary metals, rubber and plastic products, stone, clay, glass and concrete products and petroleum refining. The Company also sells and transmits power at wholesale to other electric utilities, municipalities and non-utility entities engaged in the wholesale power market.

The Company, which was organized in 1907 under the laws of Ohio, is a subsidiary of American Electric Power Company, Inc., a public utility holding company. The Company does business as American Electric Power (AEP) along with all of the parent's operating subsidiary companies in order to serve its customers more efficiently as one operating organization aligned by distinct business units. The Company's three wholly-owned subsidiaries, Central Ohio Coal Company, Southern Ohio Coal Company and Windsor Coal Company, have interests in coal reserves and mine coal that is purchased by the Company.

The Company's generating capacity consists of 8,464 megawatts (mw) of coal-fired generation and 48 mw of hydroelectric generation. The generating plants and transmission facilities of the Company and certain other affiliated AEP System utility subsidiaries are operated as an integrated system with their costs and benefits shared through the AEP System Power Pool and AEP Transmission Agreement. Wholesale energy sales made by the Power Pool are allocated to the Company and the other Pool members. The other AEP System Pool members are: Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company and Kentucky Power Company. The Company is also directly interconnected with Wheeling Power Company, an affiliated distribution company that purchases all of its energy from the Company, and with the following unaffiliated entities: The Cincinnati Gas & Electric Company, The Cleveland Electric Illuminating Company, The Dayton Power and Light Company, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company as well as the Ohio Valley Electric Corporation, an affiliate that is not a member of the AEP System. In addition, the Company is interconnected with two other affiliated companies, AEP Generating Company and Kingsport Power Company, that are not members of the Power Pool, and with numerous unaffiliated utilities through the AEP System.

DIRECTORS

E. Linn Draper, Jr.

Henry W. Fayne

William J. Lhota

James J. Markowsky

Armando A. Pena

Joseph H. Vipperman

OFFICERS

E. Linn Draper, Jr.
Chairman of the Board and Chief Executive Officer

William J. Lhota
President and Chief Operating Officer

Henry W. Fayne
Vice President

James J. Markowsky
Vice President

Armando A. Pena
Vice President, Treasurer and
Chief Financial Officer

Marsha P. Ryan
Vice President

Joseph H. Vipperman
Vice President

Leonard V. Assante
Controller and Chief Accounting Officer

John F. DiLorenzo, Jr.
Secretary

Timothy P. Bowman
Assistant Controller and Assistant
Secretary

William L. Scott
Assistant Controller

Thomas G. Berkemeyer
Assistant Secretary

G.F. Clifton
Assistant Secretary

John B. Shinnock
Assistant Secretary

Bruce M. Barber
Assistant Treasurer

Christopher J. Keklak
Assistant Treasurer

As of January 1, 2000 the current directors and officers of Ohio Power Company were employees of American Electric Power Service Corporation with one exception: Ms. Ryan, who was an employee of Columbus Southern Power Company, an affiliated company.

ELECTED CONSOLIDATED FINANCIAL DATA

	Year Ended December 31,				
	1999	1998	1997	1996	1995
			(in thousands)		
NCOME STATEMENTS DATA:					
Operating Revenues	$2,039,263	$2,105,547	$1,892,110	$1,911,708	$1,822,997
Operating Expenses	1,750,434	1,816,175	1,615,717	1,614,547	1,550,837
Operating Income	288,829	289,372	276,393	297,161	272,160
Nonoperating Income	7,000	588	14,822	6,374	11,240
Income Before Interest Charges	295,829	289,960	291,215	303,535	283,400
Interest Charges	83,672	80,035	82,526	85,880	93,953
Net Income	212,157	209,925	208,689	217,655	189,447
Preferred Stock Dividend Requirements	1,417	1,474	2,647	8,778	14,668
Earnings Applicable to Common Stock	$ 210,740	$ 208,451	$ 206,042	$ 208,877	$ 174,779

	December 31,				
	1999	1998	1997	1996	1995
			(in thousands)		
ALANCE SHEETS DATA:					
Electric Utility Plant	$5,400,917	$5,257,841	$5,155,797	$4,996,621	$4,915,222
Accumulated Depreciation and Amortization	2,621,711	2,461,376	2,349,995	2,216,534	2,091,148
Net Electric Utility Plant	$2,779,206	$2,796,465	$2,805,802	$2,780,087	$2,824,074
Total Assets	$4,677,209	$4,344,680	$4,163,202	$4,092,166	$4,156,564
Common Stock and Paid-in Capital	$ 783,577	$ 783,536	$ 783,497	$ 781,863	$ 780,675
Retained Earnings	587,424	587,500	590,151	584,015	518,029
Total Common Shareholder's Equity	$1,371,001	$1,371,036	$1,373,648	$1,365,878	$1,298,704
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$ 16,937	$ 17,370	$ 17,542	$ 38,532	$ 41,240
Subject to Mandatory Redemption (a)	8,850	11,850	11,850	109,900	115,000
Total Cumulative Preferred Stock	$ 25,787	$ 29,220	$ 29,392	$ 148,432	$ 156,240
Long-term Debt (a)	$1,151,511	$1,084,928	$1,095,226	$1,069,729	$1,227,632
Obligations Under Capital Leases (a)	$ 136,543	$ 142,635	$ 157,487	$ 131,285	$ 131,926
Total Capitalization and Liabilities	$4,677,209	$4,344,680	$4,163,202	$4,092,166	$4,156,564

a) Including portion due within one year.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

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 that could cause actual results to differ materially from forward looking statements are: electric load and customer growth; abnormal weather conditions; available sources and costs of fuels; availability of generating capacity; the ability to recover generation-related regulatory assets and other transition costs including stranded costs as the generation portion of the retail business moves from cost-based rates to market prices beginning January 1, 2001; new legislation and government regulations; the ability of the Company to successfully control its costs; the economic climate and growth in our service territory; the outcome of litigation with the Internal Revenue Service (IRS) related to certain interest deductions for a corporate owned life insurance program; the ability of the Company to successfully challenge new environmental regulations and to successfully litigate claims that the Company violated the Clean Air Act; inflationary trends; changes in electricity market prices; interest rates; and other risks and unforeseen events.

Ohio Power Company (the Company) is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP Co., Inc.), a public utility holding company. The Company is engaged in the generation, purchase, sale, transmission and distribution of electric power and provides electric power to 691,000 retail customers in northwestern, east central, eastern and southern sections of Ohio and does business as American Electric Power (AEP). The Company supplies electric power to the AEP System Power Pool (AEP Power Pool) and shares the revenues and costs of the AEP Power Pool's wholesale sales to neighboring utility systems and power marketers. The Company 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 or receipt of capacity charges and 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 revenues or costs. Since the Company's MLR decreased during 1999 and increased during 1998, the AEP Power Pool is allocating a smaller share and a larger share, respectively, of wholesale revenues and expenses to the Company.

Results of Operations

Net income increased $2 million or 1% in 1999 and $1 million or less than 1% in 1998. The increase in net income in 1999 was primarily due to a decline in operation and maintenance costs reflecting cost containment efforts. The increase in 1998 was mainly due to increased retail, wholesale, and transmission revenues.

Operating Revenues and Energy Sales

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. The 11% increase in operating revenues in 1998 was primarily due to increased retail, wholesale and transmission service revenues. The changes in the components of revenues were as follows:

(dollars in millions)	Increase (Decrease) From Previous Year 1999 Amount	%	1998 Amount	%
Retail:				
Residential	$ 7.5		$ 4.1	
Commercial	0.4		12.9	
Industrial	(5.0)		52.2	
Other	-		0.1	
	2.9	0.2	69.3	5.3
Wholesale	(71.9)	(11.2)	120.6	23.0
Transmission	(5.0)	(7.8)	19.3	43.0
Miscellaneous	7.7	48.0	4.2	35.6
Total	$(66.3)	(3.1)	$213.4	11.3

Although retail revenues were unchanged in 1999, wholesale revenues declined due to decreased sales to the AEP Power Pool and reduced margins on the Company's MLR share of power marketing sales and net energy trading transactions. The decrease in sales to the AEP Power Pool reflects a reduction in demand by the AEP System's wholesale customers. The margins on power marketing sales and energy trading transactions declined as a result of the moderation in 1999 of extreme weather in 1998 and unaffiliated capacity shortages experienced in the summer of 1998 in AEP Power Pool's marketing area.

Revenues from retail customers increased in 1998 reflecting a 5% increase in commercial sales and a 3% rise in industrial sales. The rise in commercial sales resulted from growth in the number of commercial customers. The increase in industrial sales was primarily due to a return to work following a labor dispute which idled a major industrial customer's manufacturing facilities from October 1996 through most of the third quarter of 1997.

The increase in revenues from wholesale customers of 23% in 1998 was primarily due to increased sales to the AEP Power Pool and the Company's share of increased AEP Power Pool power marketing sales and net trading transactions. The increase in power marketing and trading reflects the growth in the AEP Power Pool's power trading business. The increase in the Company's sales to the AEP Power Pool were required to replace the energy of an affiliate's nuclear plant which has been on an extended outage since September 1997.

The increase in transmission revenues in 1998 was primarily due to a substantial rise in the volume of energy transmitted for unaffiliated entities. The Federal Energy Regulatory Commission's (FERC) issuance of open access transmission rules facilitated the growth in the demand for transmission services. The Company received its MLR share of the increase in transmission revenues.

Operating Expenses

Operating expenses decreased 4% in 1999 after increasing 12% in 1998. The operating expense decline in 1999 reflects cost containment efforts and lower fuel costs due mainly to a decrease in generation reflecting lower demand for wholesale energy. The increase in 1998 was attributable to increased fuel, purchased power and other operation expenses mainly due to the increased demand for power and costs associated with growth of the power marketing and trading operation. Changes in the components of operating expenses were as follows:

(dollars in millions)	Increase (Decrease) From Previous Year 1999 Amount	%	1998 Amount	%
Fuel	$(50.8)	(6.9)	$ 96.4	15.0
Purchased Power	12.4	8.2	78.6	108.9
Other Operation	(26.1)	(7.4)	31.1	9.7
Maintenance	(18.3)	(13.1)	(4.2)	(2.9)
Depreciation and Amortization	4.6	3.2	3.7	2.6
Taxes Other Than Federal Income Taxes	(3.5)	(2.0)	0.9	0.5
Federal Income Taxes	16.0	13.3	(6.0)	(4.7)
Total Operating Expenses	$(65.7)	(3.6)	$200.5	12.4

Fuel expense decreased in 1999 due to a 6% decrease in generation reflecting the decline in wholesale sales. The increase in fuel expense in 1998 was due to an increase in generation to meet the increased demand for energy to replace the energy of an affiliate's unavailable nuclear units and an increase in the average cost of fuel consumed.

Purchased power expense increased significantly in 1998 primarily due to the Company's share of increased purchases of power by the AEP Power Pool to meet the demand for wholesale power marketing sales.

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 the Company for operations support services.

Other operation expense increased in 1998 primarily due to increased costs under the AEP System Transmission Equalization Agreement, reflecting an increase in the Company's MLR, severance accruals for reductions in power generation and energy delivery staff, increased expenses for emission allowances used as a result of the increased generation to meet demand for power and increased costs related to management's decision to grow the new power marketing and trading business. The AEP System Transmission Equalization Agreement combines certain AEP System companies' investments in transmission facilities and shares the costs of ownership in proportion to the System companies' respective peak demands.

The decline in maintenance expense in 1999 reflects cost containment efforts discussed above.

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

Nonoperating income declined in 1998 primarily due to net losses from non-regulated power trading transactions outside of the AEP Power Pool's traditional marketing area which are marked-to-market.

Business Outlook

The most significant factors affecting the Company's future earnings are its ability to recover regulatory assets, transition and other stranded costs under The Ohio Electric Restructuring Act of 1999; weather in the service territories served by the Company and its wholesale customers; generating unit availability; the outcome of litigation with the IRS related to certain interest deductions for a corporate owned life insurance program; and the outcome of ongoing environmental litigation and proposed air quality standards. In 1999 significant progress was made related to many of these major challenges.

Ohio Restructuring and The Transition To Market Pricing For Generation

The Ohio Electric Restructuring Act of 1999 (the Act) became law in October 1999. The Act provides for customer choice of electricity supplier, a residential rate reduction of 5% for the generation portion of rates and a freezing of the unbundled generation rates

including fuel rates beginning on January 1, 2001. The Act also provides for a five-year transition period to move from cost-based rates to market pricing for generation services. It authorizes the Public Utilities Commission of Ohio (PUCO) to address certain major transition issues including unbundling of rates and the recovery of transition costs including stranded costs. Transition costs include generation-related regulatory assets, (which include, among other expense deferrals, unrecovered deferred fuel costs, deferred tax benefits that were flowed through to reduce past rates and deferred affiliated mine shutdown costs), impaired tangible generating asset values, and future contract costs. Stranded costs are those costs of generation above market that would not be recoverable in a competitive market. Transition costs also include customer choice education costs, development costs of new customer choice billing and metering systems, costs of filing a transition plan, employee severance and retraining costs and other costs.

Retail electric services that will be competitive are defined in the Act as electric generation service, aggregation service, and power marketing and brokering. Under the Act the PUCO is granted broad oversight responsibility and is required to approve by October 31, 2000 a transition plan for each electric utility company. Electric utility companies in Ohio were required to file their transition plans by January 3, 2000. The Company filed its plan in December 1999.

The Act provides Ohio electric utilities with an opportunity to recover PUCO approved allowable transition costs through the generation portion of transition rates paid through December 31, 2005 by customers who do not switch generation suppliers and through a transition charge for customers who switch generation suppliers. Under the Act recovery of the regulatory asset portion of transition costs can, under certain circumstances with PUCO approval, extend beyond the five-year transition period but cannot continue beyond December 31, 2010.

The Act also provides for a reduction in property tax assessments; exemption of electric utilities from the gross receipts tax; and the imposition of a franchise tax, income taxes, and a new kilowatthour (kwh) excise tax. The property tax assessment percentage on electric generation property will be lowered from 100% to 25% of value effective January 1, 2001 and electric utilities will become subject to the Ohio Corporate Franchise Tax and municipal income taxes on January 1, 2002. The last year for which electric utilities will pay a 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, which will terminate for electric utilities, is paid by the Company at the beginning of the tax year, deferred 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. The change in the tax law to impose an excise tax based on kwh sold to Ohio customers commencing before the expiration of the gross receipts tax privilege period will result in a 12 month period (May 1, 2001 to April 30, 2002) when the Company is recording as an expense both the gross receipts tax and the kwh excise tax. In the Company's Ohio transition plan filing, recovery of $50 million was sought for this overlap of the gross receipts and excise taxes.

The PUCO is required to issue a transition order no later than October 31, 2000 regarding the Company's transition filings which included the following elements:

- a rate unbundling plan including tariff terms and conditions necessary for restructuring,
- a corporate separation plan,
- an application for transition revenues,
- a plan for independent operation of transmission facilities and
- other components for the implementation of restructuring.

The rate unbundling portion of the Company's transition plan filing provides for two transition period tariffs beginning January 1, 2001, the standard tariff and the open access distribution tariff. The Company's proposed standard tariff applies to customers who do not choose an alternative energy supplier. This tariff schedule includes detailed charges for generation, transmission and distribution and riders to fund universal service, to promote energy efficiency and to recover regulatory assets and taxes. Taxes include charges for municipal income, excise and franchise taxes and tax credits for gross receipts and property taxes. For customers who choose an alternative electric supplier, the proposed open access distribution tariff will apply. This tariff includes charges for distribution and riders to fund universal service, to promote energy efficiency and to recover regulatory assets and taxes. These riders are the same as those in the standard tariff except there is no property tax credit.

The Company's corporate separation plan proposal requires the establishment of separate subsidiaries to own and operate its transmission and distribution assets. The Company will retain its generation assets. The separation plan will be implemented in a manner that recognizes the current overlap of financing arrangements. This would permit an orderly and economically efficient separation so that additional transition costs from prematurely retiring of financial instruments can be minimized. Prior to the actual legal separation, the Company will functionally separate generation from transmission and distribution.

The transition plan filing requests recovery of stranded generation costs over a five year period and recovery of generation-related regulatory assets and other transition costs of $611 million over a 10-year period through transition revenues. The amount requested for recovery of regulatory assets includes current and new regulatory assets including those arising from compliance with the electric restructuring law. Also included in the requested recovery amount were deferred fuel and affiliated mine closure costs.

In the Ohio jurisdiction the Company is subject to certain limitations on the current recovery of affiliated coal costs under PUCO approved agreements, which are discussed in Note 2 of the Notes to Consolidated Financial Statements. Under the terms of the agreements full recovery of the Ohio jurisdictional portion of deferred unrecovered costs of affiliated mining operations including future mine closure costs was expected to occur before the expiration of the PUCO approved agreements in 2009. Management closed the Muskingum mine in 1999 and plans to close the Windsor mine in 2000 and the Meigs mine in 2001. Provisions for Muskingum and Windsor mine shutdown costs totaling $45 million and $48 million were recorded in 1998 and 1999, respectively. These provisions were deferred in the Ohio jurisdiction under the PUCO approved agreements because management believed that these mine shutdown cost deferrals are probable of future recovery through the agreements. However, since the Act will supersede the agreements effective January 1, 2001, the Company has filed under the provisions of the Act for recovery of all of its stranded regulatory assets including the affiliated coal and mine closure costs deferred under the agreements of $196 million at December 31, 1999 plus the projected amount that will be deferred by the beginning of the transition period, January 1, 2001, which includes the accrual for the closure costs of the Meigs mine.

Included in the transition plan is a proposal to implement independent operation of the transmission system. The Company proposes to join a regional transmission organization whose approval is currently pending before the FERC.

See Note 4 of the Notes to Consolidated Financial Statements for further discussion of the Ohio restructuring plan.

Regulatory/Restructuring Accounting

Under the provisions of Statement of Financial Accounting Standards (SFAS) 71 "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) are included in the consolidated balance sheets of cost-based regulated utilities in accordance with regulatory actions in order to match expenses and revenues. In order to maintain net regulatory assets on the balance sheet, SFAS 71 requires that rates charged to customers be cost based and provide for the probable recovery of the regulatory assets over future accounting periods. Management has concluded that as of December 31, 1999 the requirements to apply SFAS 71 continue to be met. However, the Ohio Electric Restructuring Act will result in the discontinuance of SFAS 71 regulatory accounting for the generation portion of the Ohio jurisdiction.

In the event a portion of the Company's business no longer meets the requirements of SFAS 71, SFAS 101 "Accounting for the Discontinuance of Application of Statement 71" requires that net regulatory assets be written off for that portion of the business. The provisions of SFAS 71 and SFAS 101 did not anticipate or provide accounting guidance for an extended transition period and for recovery of stranded costs during and after a transition period through a wires charge or regulated distribution rates. In 1997 the Financial Accounting Standards Board's (FASB) Emerging Issues Task Force (EITF) addressed such a situation with the consensus reached on issue 97-4 that requires that the application of SFAS 71 to a segment of a regulated electric utility cease when that segment is subject to a legislatively approved plan for competitive market pricing from cost-based regulated rates and/or a rate order is issued containing sufficient detail for the utility to reasonably determine what the restructuring plan would entail and how it will affect the utility's financial statements. The EITF indicated that the cessation of application of SFAS 71 regulatory accounting would require that regulatory assets and impaired stranded plant cost applicable to the portion of the business that was no longer cost-based regulated, be written off unless they are recoverable in the future through transition rates and/or post-transition cost based regulated rates.

Potential For A Write Off In Ohio

The Company's accounting for generation will continue to be in accordance with SFAS 71 in the Ohio jurisdiction and will continue to be considered to be cost-based regulated for accounting purposes until the amount of transition rates and stranded cost wires charges are determined and known. The establishment of transition rates and wire charges should enable management to determine the Company's ability to recover stranded costs including regulatory assets and transition costs, a requirement under EITF 97-4 to discontinue application of SFAS 71. When the amount of unbundled frozen generation transition rates and distribution stranded cost wires charges are known for the Ohio jurisdiction, the application of SFAS 71 will be discontinued for the Ohio retail jurisdictional portion of the Company's generation business. Management expects this to occur when the PUCO issues its order to approve a transition plan for the Company's Ohio jurisdiction. The Act requires that the PUCO issue its order no later than October 31, 2000.

Upon the discontinuance of SFAS 71 the Company will have to write off its Ohio

jurisdictional generation-related regulatory assets to the extent that they cannot be recovered under the frozen transition rates and stranded costs distribution wires charges and record any asset accounting impairments. An impairment loss would be recorded (on a discounted basis) to the extent that the cost of generation assets cannot be recovered through non-discounted generation-related revenues during the transition period and future market prices. Absent the determination in the regulatory process of transition rates, any wires charge and other pertinent information, it is not possible at this time for management to determine if any of the Company's generating assets are impaired for accounting purposes on an undiscounted cash flow basis.

The amount of regulatory assets recorded on the books at December 31, 1999 applicable to the Ohio retail jurisdictional generation business before related tax effects is estimated to be $361 million. Due to the planned closing of the Company's affiliated mines, including the Meigs mine, projected generation-related regulatory assets as of December 31, 2000 (the date that recoverable generation related regulatory assets are measured under the Act) allocable to the Ohio retail jurisdiction are estimated to exceed $520 million, before income tax effects. Recovery of these Ohio generation related regulatory assets was sought as a part of the Company's Ohio transition plan filing. Based on current projections of future market prices, the Company does not anticipate that it will experience material tangible asset accounting impairment write-offs. Whether the Company will experience material regulatory asset write-offs will depend on whether the PUCO approves the Company's request for their recovery.

Determination of whether the Company will experience any asset impairment loss regarding its Ohio retail jurisdictional generating assets and any loss from the possible inability to recover Ohio generation related regulatory assets and other transition costs cannot be made until such time as the transition rates and the wires charges are determined through the regulatory process. Should the PUCO fail to approve transition rates and wires charges that are sufficient to provide for recovery of the Company's generation-related regulatory assets, any other stranded costs and transition costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Environmental Concerns and Issues

We take great pride in our efforts to economically produce and deliver electricity while minimizing the impact on the environment. Over the years the Company has spent hundreds of millions of dollars to equip our facilities with the latest cost effective clean air and water technologies and to research new technologies. We are also proud of our award winning efforts to reclaim our mining properties. We intend to continue in a leadership role fostering economically prudent efforts to protect and preserve the environment while providing a vital commodity, electricity, to our customers at a fair price.

Air Quality

In 1998 the United States (U.S.) Environmental Protection Agency (Federal EPA) issued a final rule which requires substantial reductions in nitrogen oxide (NOx) emissions in 22 eastern states, including the states in which the Company's generating plants are located. A number of utilities, including the Company, filed petitions seeking a review of the final rule in the U.S. Court of Appeals for the District of Columbia Circuit (Appeals Court). On March 3, 2000, the Appeals Court issued a decision generally upholding Federal EPA's final rule on NOx emission reductions.

On April 30, 1999, Federal EPA took final action with respect to petitions filed by eight northeastern states pursuant to the Clean Air Act (Section 126 Rule). The Rule approved portions of the states' petitions and imposed NOx reduction requirements on AEP System generating units which are

approximately equivalent to the reductions contemplated by the NOx emission reduction final rule. The AEP System companies with coal-fired generating plants, as well as other utility companies, filed a petition in the Appeals Court seeking review of the Section 126 Rule. In 1999, three additional northeastern states and the District of Columbia filed petitions with Federal EPA similar to those originally filed by the eight northeastern states. Since the petitions relied in part on compliance with an 8-hour ozone standard remanded by the Appeals Court, Federal EPA indicated its intent to decouple compliance with the 8-hour standard and issue a revised rule.

On December 17, 1999, Federal EPA issued a revised Section 126 Rule requiring 392 industrial plants, including certain generating plants owned by the Company, to reduce their NOx emissions by May 1, 2003. This rule approves petitions of four northeastern states which contend that their failure to meet Federal EPA smog standards is due to coal-fired generating plants in upwind states, including many of the Company's plants, and not their automobiles and other local sources.

Preliminary estimates indicate that compliance with the Federal EPA's final rule on NOx emission reductions that was upheld by the Appeals Court could result in required capital expenditures of approximately $624 million for the Company. It should be noted, however, that compliance costs cannot be estimated with certainty since actual costs incurred to comply could be significantly different from this preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless compliance costs are recovered from customers through regulated rates, unbundled generation transition rates, wires charges and the future market price of electricity, such compliance costs will have an adverse effect on future results of operations, cash flows and possibly financial condition.

Federal EPA Complaint and Notice of Violation

Under the Clean Air Act, if a plant undergoes a major modification that results in a significant 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.

On November 3, 1999, the Department of Justice, at the request of Federal EPA, filed a complaint in the U.S. District Court for the Southern District of Ohio that alleges the Company and certain other affiliated utilities made modifications to certain of their coal-fired generating plants over the course of the past 25 years that extend their operating lives or increase their generating capacity in violation of the Clean Air Act. Federal EPA also issued Notices of Violation to the Company and certain other affiliated utilities alleging violations of certain provisions of the Clean Air Act at certain plants including the Company's plants. A number of unaffiliated utilities also received Notices of Violation complaints or administration orders.

The states of New Jersey, New York and Connecticut were subsequently allowed to join Federal EPA's action against the Company under the Clean Air Act. On November 18, 1999, a number of environmental groups filed a lawsuit against power plants owned by the Company alleging similar violations to those in the Federal EPA complaint and Notices of Violation. This action was consolidated with the Federal EPA action. The complaints and Notices of Violation named all of the Company's seven coal-fired generating plants. Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act provisions and intends to vigorously pursue its defense of this matter.

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 all of Federal EPA's contentions, could be substantial. In the event the Company does 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, approved unbundled transition generation rates, wires charges and future market prices for electricity.

Financial Condition

The Company issued $225 million principal amount of long-term obligations in 1999 at interest rates ranging from 5.15% to 7%. The principal amount of long-term debt retirements, including maturities, totaled $140 million with interest rates ranging from 6.55% to 7.85%. The Company's senior secured debt/first mortgage bond ratings are: Moody's, A3; Standard & Poor's, A-; Fitch, A-; and Duff & Phelps, A.

Gross plant and property additions were $223 million in 1999 and $215 million in 1998. Management estimates construction expenditures for the next three years to be $783 million. The funds for construction of new facilities and improvement of existing facilities can come from a combination of internally generated funds, short-term and long-term borrowings, preferred stock issuances and investments in common equity by the Company's parent. However, all of the construction expenditures for the next three years are expected to be financed with internally generated funds.

When necessary the Company generally issues short-term debt to provide for interim financing of capital expenditures that exceed internally generated funds. At December 31, 1999, $1,056 million of unused short-term lines of credit shared with other AEP System companies were available. Short-term debt borrowings are limited by provisions of the Public Utility Holding Company Act of 1935 to $450 million. Generally periodic reductions of outstanding short-term debt are made through issuances of long-term debt and through additional capital contributions by the parent company.

The Company's earnings coverage presently exceeds all minimum coverage requirements for the issuance of mortgage bonds and preferred stock. The minimum coverage ratios are 2.0 for mortgage bonds and 1.5 for preferred stock. At December 31, 1999, the mortgage bonds and preferred stock coverage ratios were 11.78 and 3.17, respectively.

Market Risks

The Company has certain market risks inherent in its business activities from changes in electricity commodity prices and interest rates. The allocation of trading of electricity and related financial derivative instruments through the AEP Power Pool exposes the Company to market risk. Market risk represents the risk of loss that may impact the Company due to adverse changes in electricity 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 three-day holding period. Throughout 1999 and 1998, the Company's share of the highest, lowest and average VaR in the wholesale trading portfolio was less than $3.9 million and $3 million, respectively. Based on this VaR analysis, at December 31, 1999 a near term change in commodity prices is not expected to have a material effect on the Company's results of operations, cash flows or financial condition.

The Company is exposed to changes in interest rates primarily due to short-term and long-term borrowings to fund its business operations. The debt portfolio has variable and fixed interest rates with terms from one day to 39 years and an average duration of six years at December 31, 1999. The Company 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 the Company's exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $157 million at December 31, 1999 and $144 million at December 31, 1998. The Company 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 the Company.

Inflation affects the Company's cost of replacing utility plant and the cost of operating and maintaining its plant. The rate-making process limits our 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.

Litigation

Corporate Owned Life Insurance

The Internal Revenue Service (IRS) agents auditing the AEP System's consolidated federal income tax returns requested a ruling from their National Office that certain interest deductions claimed by the Company relating to a corporate owned life insurance (COLI) program should not be allowed. As a result of a suit filed in U.S. District Court (discussed below) this request for ruling was withdrawn by the IRS agents. Adjustments have been or will be proposed by the IRS disallowing COLI interest deductions for taxable years 1991-96. A disallowance of the COLI interest deductions through December 31, 1999 would reduce earnings by approximately $118 million inclusive of interest.

The Company made payments of taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of any additional above market rate interest on the contested amount. The payments to the IRS are included on the consolidated balance sheets in other property and investments pending the resolution of this matter. The Company is seeking refund through litigation of all amounts paid plus interest.

In order to resolve this issue, the Company filed suit against the U.S. in the U.S. District Court for the Southern District of Ohio in March 1998. In 1999 a U.S. Tax Court judge decided in the Winn-Dixie Stores v. Commissioner case that a corporate taxpayer's COLI deduction should be disallowed. Notwithstanding the decision in Winn-Dixie management has made no provision for any possible adverse earnings impact from this matter because it believes, and has been advised by outside counsel, that it has a meritorious position and will vigorously pursue its lawsuit. In the event the resolution of this matter is unfavorable, it will have a material adverse impact on results of operations, cash flows and possibly financial condition.

The Company is 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.

Other Matters

Superfund

By-products from the generation of electricity include materials such as ash, slag, and sludge. 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, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. The Company is currently incurring costs to safely dispose of such substances. Additional costs could be incurred to comply with new laws and regulations if enacted.

The Comprehensive Environmental Response, Compensation and Liability Act (Superfund) addresses clean-up of hazardous substances at disposal sites and authorizes Federal EPA to administer the clean-up programs. As of year-end 1999, the Company is involved in litigation with respect to two sites overseen by the Federal EPA. There is one additional site for which the Company has received an information request which could lead to a potentially responsible party (PRP) designation. The Company has also been named a PRP at one site under state law. The Company's liability has been resolved for a number of sites with no significant effect on results of operations and present estimates do not anticipate material cleanup costs for identified sites. However, if for reasons not currently identified significant costs are incurred for cleanup, future results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be recovered from customers.

The Clean Air Act Amendments (CAAA) required Federal EPA to issue rules to implement the law. In 1996 Federal EPA issued final rules governing NOx emissions that must be met after January 1, 2000 (Phase II of the CAAA). The final rules required substantial reductions in NOx emissions from certain types of boilers including those in the power plants of the Company and its affiliates in the AEP System. To comply with Phase II of CAAA, the Company installed NOx emission control equipment on certain units and switched fuel at other units. The Company is operating under the Phase II rules which require reporting at the end of each year. The Company does not anticipate any material problems complying with the rules.

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, President Clinton indicated that he will not submit the treaty to the Senate for consideration until it contains 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 been negotiated. At the Fourth Conference of the Parties, held in Buenos Aires, Argentina, 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. We 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, the costs to comply with the 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 or implemented in the U.S. in its current form.

Year 2000 Readiness Disclosure

On or about midnight on December 31, 1999, digital computing systems could have produced erroneous results or failed, unless these systems had been modified or replaced, because such systems may have been programmed incorrectly and interpreted the date of January 1, 2000 as being January 1st of the year 1900 or another incorrect date. In addition, certain systems may fail to detect that the year 2000 is a leap year or otherwise incorrectly interpret a year 2000 date.

The Company has not experienced any material failures of generation and delivery of electric energy due to Year 2000 because of the AEP System's preparations. Such preparations included the modification or replacement of certain computer hardware and software to minimize Year 2000-related failures and repair. This includes both information technology systems (IT), which are mainframe and client server applications, and embedded logic systems (non-IT), such as process controls for energy production and delivery. Externally, the problem was addressed with entities that interact with the Company, including suppliers, customers, creditors, financial service organizations and other parties essential to the Company's operations. In the course of the external evaluation, the Company sought written assurances from third parties regarding their state of Year 2000 readiness. Another issue addressed was the impact of electric power grid problems that may have occurred outside of our transmission system.

Through December 31, 1999, the Company's share of the AEP System's expenditures on the Year 2000 project was $14 million. Most Year 2000 costs were for IT contractors and consultants and for salaries of internal IT professionals and were expensed; however, in certain cases the Company acquired hardware and new software that was capitalized.

New Accounting Standards

The FASB issued SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" in June 1998. SFAS 133 establishes accounting and reporting standards for derivative instruments. It requires that all derivatives be recognized as either an asset or a liability and measured at fair value in the financial statements. If certain conditions are met, a derivative may be designated as a hedge of possible changes in fair value of an asset, liability or firm commitment; variable cash flows of forecasted transactions; or foreign currency exposure. The accounting/reporting for changes in a derivative's fair value (gains and losses) depend on the intended use and resulting designation of the derivative. Management is currently studying the provisions of SFAS 133 and reviewing the Company's contracts and transactions to determine the impact on the Company's results of operations, cash flows and financial condition when SFAS 133 is adopted on January 1, 2001.

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	1999	1998	1997
		(in thousands)	
OPERATING REVENUES	$2,039,263	$2,105,547	$1,892,110
OPERATING EXPENSES:			
Fuel	687,672	738,522	642,135
Purchased Power	163,143	150,733	72,153
Other Operation	327,132	353,194	322,088
Maintenance	121,299	139,611	143,831
Depreciation and Amortization	149,055	144,493	140,807
Taxes Other Than Federal Income Taxes	165,891	169,353	168,480
Federal Income Taxes	136,242	120,269	126,223
Total Operating Expenses	1,750,434	1,816,175	1,615,717
OPERATING INCOME	288,829	289,372	276,393
NONOPERATING INCOME	7,000	588	14,822
INCOME BEFORE INTEREST CHARGES	295,829	289,960	291,215
INTEREST CHARGES	83,672	80,035	82,526
NET INCOME	212,157	209,925	208,689
PREFERRED STOCK DIVIDEND REQUIREMENTS	1,417	1,474	2,647
EARNINGS APPLICABLE TO COMMON STOCK	$ 210,740	$ 208,451	$ 206,042

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	1999	1998	1997
		(in thousands)	
OPERATING ACTIVITIES:			
Net Income	$ 212,157	$ 209,925	$ 208,689
Adjustments for Noncash Items:			
Depreciation, Depletion and Amortization	193,780	172,085	172,186
Deferred Federal Income Taxes	3,666	3,042	7,627
Deferred Investment Tax Credits	(3,458)	(3,525)	(3,487)
Deferred Fuel Costs (net)	(76,978)	(44,694)	(34,548)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(49,309)	(12,376)	(62,371)
Fuel, Materials and Supplies	(60,500)	18,612	(11,127)
Accrued Utility Revenues	(2,074)	(5,915)	1,266
Accounts Payable	9,195	51,040	95,348
Payment of Disputed Tax and Interest Related to COLI	(6,272)	(104,222)	-
Change in Operating Reserves	66,573	77,811	30,294
Other (net)	48,718	42,981	38,141
Net Cash Flows From Operating Activities	335,498	404,764	442,018
INVESTING ACTIVITIES:			
Construction Expenditures	(193,870)	(185,036)	(172,477)
Proceeds from Sales of Property and Other	5,900	5,910	8,954
Net Cash Flows Used For Investing Activities	(187,970)	(179,126)	(163,523)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	222,308	186,126	146,590
Retirement of Cumulative Preferred Stock	(3,392)	(133)	(117,624)
Retirement of Long-term Debt	(158,638)	(197,911)	(122,127)
Change in Short-term Debt (net)	71,913	44,305	37,398
Dividends Paid on Common Stock	(210,813)	(211,101)	(199,333)
Dividends Paid on Cumulative Preferred Stock	(1,420)	(1,475)	(3,199)
Net Cash Flows Used For Financing Activities	(80,042)	(180,189)	(258,295)
Net Increase in Cash and Cash Equivalents	67,486	45,449	20,200
Cash and Cash Equivalents January 1	89,652	44,203	24,003
Cash and Cash Equivalents December 31	$ 157,138	$ 89,652	$ 44,203

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

	December 31, 1999	December 31, 1998
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,713,421	$2,646,597
Transmission	857,420	842,318
Distribution	999,679	949,224
General (including mining assets)	713,882	689,815
Construction Work in Progress	116,515	129,887
Total Electric Utility Plant	5,400,917	5,257,841
Accumulated Depreciation and Amortization	2,621,711	2,461,376
NET ELECTRIC UTILITY PLANT	2,779,206	2,796,465
OTHER PROPERTY AND INVESTMENTS	253,668	218,311
CURRENT ASSETS:		
Cash and Cash Equivalents	157,138	89,652
Accounts Receivable:		
Customers	246,310	215,665
Affiliated Companies	89,215	63,922
Miscellaneous	22,055	28,139
Allowance for Uncollectible Accounts	(2,223)	(1,678)
Fuel - at average cost	146,317	94,914
Materials and Supplies - at average cost	95,967	86,870
Accrued Utility Revenues	45,575	43,501
Energy Marketing and Trading Contracts	134,567	19,790
Prepayments and Other	38,472	34,523
TOTAL CURRENT ASSETS	973,393	675,298
REGULATORY ASSETS	577,090	551,776
DEFERRED CHARGES	93,852	102,830
TOTAL	$4,677,209	$4,344,680

See Notes to Consolidated Financial Statements.

	December 31, 1999	December 31, 1998
	(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	462 376	462,335
Retained Earnings	587,424	587,500
Total Common Shareholder's Equity	1,371,001	1,371,036
Cumulative Preferred Stock:		
Not Subject to Mandatory Redemption	16,937	17,370
Subject to Mandatory Redemption	8,850	11,850
Long-term Debt	1,139,834	1,073,456
TOTAL CAPITALIZATION	2,536,622	2,473,712
OTHER NONCURRENT LIABILITIES	414,837	360,330
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	11,677	11,472
Short-term Debt	194,918	123,005
Accounts Payable - General	180,383	173,369
Accounts Payable - Affiliated Companies	64,599	62,418
Taxes Accrued	179,112	161,406
Interest Accrued	16,863	14,187
Obligations Under Capital Leases	34,284	28,310
Energy Marketing and Trading Contracts	131,844	22,480
Other	96,445	97,916
TOTAL CURRENT LIABILITIES	910,125	694,563
DEFERRED INCOME TAXES	676,460	711,913
DEFERRED INVESTMENT TAX CREDITS	35,838	39,296
DEFERRED CREDITS	103,327	64,866
COMMITMENTS AND CONTINGENCIES (Notes 5 and 6)		
TOTAL	$4,677,209	$4,344,680

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year Ended December 31,		
	1999	1998	1997
		(in thousands)	
Retained Earnings January 1	$587,500	$590,151	$584,015
Net Income	212,157	209,925	208,689
	799,657	800,076	792,704
Deductions:			
Cash Dividends Declared:			
Common Stock	210,813	211,101	199,333
Cumulative Preferred Stock:			
4.08% Series	61	63	91
4.20% Series	97	97	127
4.40% Series	142	143	204
4-1/2% Series	460	467	581
5.90% Series	472	487	961
6.02% Series	156	186	735
6.35% Series	32	32	500
Total Dividends	212,233	212,576	202,532
Capital Stock Expense	-	-	21
Total Deductions	212,233	212,576	202,553
Retained Earnings December 31	$587,424	$587,500	$590,151

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING POLICIES:

Organization

Ohio Power Company (the Company or OPCo) is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP Co., Inc.), a public utility holding company. The Company is engaged in the generation, purchase, sale, transmission and distribution of electric power to 691,000 retail customers in northwestern, east central, eastern and southern sections of Ohio and does business as American Electric Power (AEP). Under terms of the AEP System Power Pool (AEP Power Pool) and AEP System Transmission Equalization Agreement, the Company's generation and transmission facilities are operated in conjunction with the facilities of certain other AEP affiliated utilities as an integrated utility system. The Company as a member of the AEP Power Pool shares in the revenues and costs of AEP Power Pool wholesale sales to neighboring utility systems and power marketers. The Company also sells wholesale power to municipalities and cooperatives.

The Company has three wholly-owned coal-mining subsidiaries: Central Ohio Coal Company (COCCo), Southern Ohio Coal Company (SOCCo) and Windsor Coal Company (WCCo). Coal produced by SOCCo's Meigs mine is sold to the Company at cost including a Securities and Exchange Commission (SEC) approved return on investment. COCCo closed the Muskingum mine in October 1999 and WCCo is scheduled to close April 30, 2000. See Footnote 2, "Rate Matters" for further discussion of fuel cost recovery.

Regulation

As a subsidiary of AEP Co., Inc., the Company is subject to regulation by the SEC under the Public Utility Holding Company Act of 1935 (1935 Act). Retail rates are regulated by the Public Utilities Commission of Ohio (PUCO). The Federal Energy Regulatory Commission(FERC) regulates the Company's wholesale and transmission rates.

Principles of Consolidation

The consolidated financial statements include the revenues, expenses, cash flows, assets, liabilities and equity of OPCo and its wholly-owned subsidiaries. Significant intercompany items are eliminated in consolidation.

Basis of Accounting

As a cost-based rate-regulated entity, the Company's consolidated financial statements 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 Statement of Financial Accounting Standards (SFAS) 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred income) are recorded to reflect the economic effects of regulation and to match expenses with regulated revenues.

Use of Estimates

The preparation of these financial statements in conformity with generally accepted accounting principles requires in certain instances the use of estimates. Actual results could differ from those estimates.

Utility Plant

Electric utility plant is stated at original cost and is generally subject to first mortgage liens. Additions, major replacements and betterments are added to the plant accounts. Retirements of plant are deducted from the electric utility plant in service account and deducted from accumulated depreciation together with associated removal costs, net of salvage. The costs of labor, materials and overheads incurred to operate and maintain utility 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 utility plant. It represents the estimated cost of borrowed and equity funds used to finance construction projects. The amounts of AFUDC for 1999, 1998 and 1997 were not significant.

Depreciation, Depletion and Amortization

Depreciation of electric utility plant 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		
	1999	1998	1997
Production:			
Steam-Fossil-Fired	3.4%	3.4%	3.4%
Hydroelectric-Conventional	2.7%	2.7%	2.7%
Transmission	2.3%	2.3%	2.3%
Distribution	4.0%	4.0%	4.0%
General	2.7%	2.5%	2.5%

Amounts for demolition and removal of plant are recovered through depreciation charges included in rates. Depreciation, depletion and amortization of 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 $2.32 per ton in 1999, $1.85 per ton in 1998 and $1.91 per ton in 1997. These costs are included in the cost of coal charged to fuel expense.

Cash and Cash Equivalents

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

Operating Revenues and Fuel Costs

Revenues include billed revenues as well as an accrual of electricity consumed but unbilled at month-end. Changes in retail fuel cost are deferred until reflected in revenues through a PUCO fuel cost recovery mechanism. See Note 2 regarding limitations on recovery of retail jurisdictional fuel costs. Wholesale jurisdictional fuel cost changes are expensed and billed as incurred.

Energy Marketing and Trading Transactions

The AEP Power Pool administers and implements power marketing and trading transactions (trading activities) in which the Company shares. Trading activities involve the sale of electricity under physical forward contracts at fixed and variable prices and the trading of electricity contracts including exchange traded futures and options, over-the-counter options and swaps. The majority of these transactions represent physical forward electric contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. The net revenues from these regulated

transactions in AEP System's traditional marketing area are included in operating revenues for ratemaking, accounting and financial and regulatory reporting purposes.

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. The Company's share of these non-regulated trading activities are included in nonoperating income.

In the first quarter of 1999 the Company adopted the Financial Accounting Standards Board's Emerging Issues Task Force Consensus (EITF) 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities". The EITF requires that all energy trading contracts be marked-to-market. The effect on the Consolidated Statements of Income of marking open trading contracts to market is deferred as regulatory assets or liabilities for those open trading transactions within the AEP System Power Pool's marketing area that are included in cost of service on a settlement basis for ratemaking purposes. The Company's share of non-regulated open trading contracts are accounted for on a mark-to-market basis in non-operating income. The unrealized mark-to-market gains and losses from trading activities are reported as assets and liabilities, respectively. The adoption of the EITF did not have a material effect on results of operations, cash flows or financial condition.

The Company enters 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 on the anticipation debt instruments 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, 1999 or 1998.

See Note 11 - Financial Instruments, Credit and Risk Management for further discussion.

Reclassification

Certain prior year amounts have been reclassified to conform to current year presentation. Such reclassifications had no impact on previously reported net income.

Income Taxes

The Company 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 rates (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.

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

Gains and losses from the reacquisition of debt are deferred and amortized over the remaining term of the reacquired debt in accordance with rate-making treatment. If the debt is refinanced the reacquisition costs are deferred and amortized over the term of the replacement debt commensurate with their recovery in rates.

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

Redemption premiums paid to reacquire preferred stock 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.

Other Property and Investments

Other property and investments are stated at cost.

Comprehensive Income

There were no material differences between net income and comprehensive income.

2. RATE MATTERS:

Recovery of Fuel Costs

Under the terms of a 1992 stipulation agreement the cost of coal burned at the Gavin Plant is subject to a 15-year predetermined price of $1.575 per million Btu's with quarterly escalation adjustments through November 2009. A 1995 Settlement Agreement set the fuel component of the electric fuel component (EFC) factor at 1.465 cents per Kwh for the period June 1, 1995 through November 30, 1998. The 1995 Settlement Agreement requires for the two year period from December 1, 1998 through November 30, 2000 that coal from Central Ohio Coal Company's Muskingum mine and Windsor Coal Company's mine be priced at the market price for comparable quality coal. The Company is allowed to defer the difference for future recovery. Effective December 1, 1998 the 1992 stipulation continued to control the recovery of fuel costs at the Gavin Plant and the ability of OPCo to recover the costs to shut down its affiliated mines. To the extent the actual cost of coal burned at the Gavin Plant is below the predetermined prices, the stipulation agreement provides the Company with the opportunity to recover over its term the Ohio jurisdictional share of the Company's investment in and the liabilities and future shutdown costs of its affiliated mines as well as any fuel costs incurred above the predetermined rate and deferred for future recovery under the agreements. These agreements will be superseded effective January 1, 2001 by the Ohio Electric Restructuring Act of 1999 (see Note 4).

The Muskingum coal mine which supplied all of its output to OPCo was closed in October 1999. During 1999 efforts began to reclaim the properties, sell or scrap all mining equipment, terminate both capital and operating leases and perform other activities necessary to shut down the mine. Mine reclamation activities should be completed by December 31 2002; postremediation monitoring is anticipated to continue for five years after completion of reclamation.

In 1999 the Company announced that the affiliated Windsor coal mine would close April 30, 2000. After the mine closes, efforts will begin to reclaim the property, sell or scrap all mining equipment and perform other activities necessary to shut down the mine. Reclamation activities should be completed within two to three years after shutdown.

The Company recorded mine closing costs of $45 million in 1998 for the Muskingum mine and $48 million in 1999 for

the Windsor mine. Pursuant to terms of the 1992 and 1995 agreements, the Company deferred accrued mine closure costs of $19 million in 1998 for the Muskingum mine and $25 million in 1999 for the Windsor mine. Fuel expense included $23 million and $26 million in 1999 and 1998, respectively, of mine closure costs. At December 31, 1999, the accrued liabilities for reclamation, mine closing costs and post shutdown costs were $119 million for the Muskingum mine and $84 million for the Windsor mine.

Revenues and net income for the Muskingum mining operation in 1999 up to the shutdown date were $64 million and $1,000, respectively. For the years ended December 31, 1998 and 1997 revenues and net income from the Muskingum mining operation were $110 million and $1,000 and $66 million and zero, respectively. For the years ended December 31, 1999, 1998 and 1997 revenues and net income from the Windsor mining operation were $123 million and $18,000, $65 million and $123,000, and $69 million and $1 million, respectively.

Management believes the Ohio jurisdictional portion of the cost of the mine shutdowns can be deferred for future recovery through the Ohio fuel clause mechanism under terms of the Ohio fuel clause predetermined price agreements. At December 31, 1999 the Company has deferred $196 million under the terms of the Ohio fuel clause predetermined price agreements. However, since the Ohio Electric Restructuring Act of 1999 (the Act) supersedes the agreements, the Company has filed under the provisions of the Act for recovery of all of its generation related regulatory assets which includes the fuel deferral at December 31, 1999 plus the projected balance that will be deferred for the accrual of the Meigs mine closure costs by the beginning of the transition period, January 1, 2001. Under the provisions of the Act the Company is seeking a total of $360 million for the regulatory assets deferred under the above agreements through transition rates and a post generation deregulation five year wires charge. Unless the cost of the remaining coal production and deferred mine shutdowns are recovered through the remaining Ohio fuel clause rates and Ohio restructuring transition rates and/or a post deregulation wires charge, future results of operations and cash flows will be adversely affected.

Management intends to continue to recover from non-Ohio jurisdictional ratepayers the non-Ohio jurisdictional portion of the investment in and the liabilities and closing costs of the Meigs, Muskingum and Windsor mines. The non-Ohio jurisdictional portion of shutdown costs for these mines which includes the investment in the mines, leased asset buy-outs, reclamation costs and employee benefits is estimated to be approximately $62 million after tax at December 31, 1999.

Open Access Transmission Tariff

The Federal Energy Regulatory Commission (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, by requiring them to use 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.

In July 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 which would reduce AEP's rates for the affected customers below the settlement rate. AEP and certain of the affected customers have sought rehearing of the Commission's Order. The Company made a provision in September 1999 for its share of the refund including interest.

On December 10, 1999, the AEP System filed a settlement agreement with the FERC resolving the issues on rehearing of the July 30, 1999 order. Under terms of the settlement, the AEP System will make refunds retroactive to September 7, 1993 to certain customers affected by the July 30, 1999 FERC order. The refunds will be made in two payments. The first payment was made on February 2, 2000 pursuant to a FERC order granting AEP's request to make interim refunds. The remainder will be paid after the FERC issues a final order and approves a compliance filing that the AEP System will make pursuant to the final order. In addition, a new rate was made effective January 1, 2000, subject to FERC approval, for all transmission service customers and a future rate was established to take effect upon the consummation of the AEP and Central and South West Corporation merger unless a superseding rate is made effective prior to the merger.

3. EFFECTS OF REGULATION:

In accordance with SFAS 71 the consolidated financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred income) 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 Company's regulated rates be cost-based and the recovery of regulatory assets must be probable. Management has reviewed all the evidence currently available and concluded that the Company continues to meet the requirements to apply SFAS 71. In the event a portion of the Company's business no longer met those requirements, net regulatory assets would have to be written off for that portion of the business and assets attributable to that portion of the business would have to be tested for possible impairment and, if required, an impairment loss recorded unless the net regulatory assets and impairment losses are recoverable as a stranded cost. See Note 4 "Ohio Restructuring Legislation" for a discussion of deregulation of generation under an Ohio electric restructuring law.

Recognized regulatory assets and liabilities are comprised of the following:

	December 31,	
	1999	1998
	(In Thousands)	
Regulatory Assets:		
Amounts Due From Customers For Future Income Taxes	$331,164	$370,468
Deferred Fuel Costs	180,336	110,602
Unamortized Loss On Reacquired Debt	15,666	14,996
Other	49,924	55,710
Total Regulatory Assets	$577,090	$551,776
Regulatory Liabilities:		
Deferred Investment Tax Credits	$ 35,838	$39,296
Deferred Gains From Emission Allowance Sales*	53,738	40,000
Other*	13,043	8,170
Total Regulatory Liabilities	$102,619	$87,466

*Included in Deferred Credits on Consolidated Balance Sheets.

4. OHIO RESTRUCTURING LEGISLATION:

The Ohio Electric Restructuring Act of 1999 (the Act) became law in October 1999. The Act provides for customer choice of electricity supplier, a residential rate reduction of 5% for the generation portion of rates and a freezing of generation rates including fuel rates beginning on January 1, 2001. The Act also provides for a five-year transition period to move from cost based rates to market pricing for generation services. It authorizes the PUCO to address certain major transition issues including unbundling of rates and the recovery of transition costs. Under the Act, transition costs can include regulatory assets, impairments of generating assets and other stranded costs, employee severance and re-training costs, consumer education costs and other costs. Stranded generation costs are those costs of generation above the market price for electricity that potentially would not be recoverable in a competitive market.

Retail electric services that will be competitive are defined in the Act as electric generation service, aggregation service and power marketing and brokering. Under the legislation the PUCO is granted broad oversight responsibility and is required by the Act to promulgate rules for competitive retail electric generation service and transition plan filings. The Act also gives the PUCO authority to approve a transition plan for each electric utility company and sets a deadline of no later than October 31, 2000 for those approvals.

The Act provides that electric utilities in Ohio with an opportunity to recover PUCO approved allowable transition costs through generation rates paid through December 31, 2005 by customers who do not switch generation suppliers and through a transition charge for customers who switch generation suppliers. Recovery of the regulatory asset portion of transition costs can, under certain circumstances, extend beyond the five-year transition period but cannot continue beyond December 31, 2010.

The Act also provides for a reduction in property tax assessments, the imposition of franchise and income taxes, and the replacement of a gross receipts tax with a kilowatt-hour (kwh) based excise tax. The property tax assessment percentage on generation property will be lowered from 100% to 25% of value effective January 1, 2001 and electric utilities will become subject to the Ohio Corporate Franchise Tax and municipal income taxes on January 1, 2002. The last year for which 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, deferred 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. The change in the tax law to impose an excise tax based on kwh sold to Ohio customers commencing before the expiration of the gross receipts tax privilege period will result in a 12 month period when the Company is recording as an expense both the gross receipts tax and the excise tax. In the Company's Ohio transition plan filing, recovery of $50 million was sought for this overlap of the gross receipts and excise taxes.

The Company filed its transition plan with the PUCO on December 30, 1999. The filing included the following elements:

- a rate unbundling plan including tariff terms and conditions necessary for restructuring,
- a corporate separation plan,
- an application for transition revenues,
- a plan for independent operation of transmission facilities and

- other components for the implementation of restructuring.

Under the rate unbundling plan in the transition plan filing, the Company will offer two transition period tariffs beginning January 1, 2001, the standard tariff and the open access distribution tariff. The proposed standard tariff applies to customers who do not choose an alternative energy supplier. This tariff schedule includes detailed charges for generation, transmission and distribution and riders to fund universal service, to promote energy efficiency and to recover regulatory assets and taxes. Taxes include charges for municipal income, excise and franchise taxes and tax credits for gross receipts and property taxes. For customers who choose an alternative electric supplier, the proposed open access distribution tariff will apply. This tariff includes charges for transmission and distribution and riders to fund universal service, to promote energy efficiency and to recover regulatory assets and taxes. These riders are the same as those in the standard tariff except there is no property tax credit.

The Company's corporate separation plan proposal requires establishment of separate subsidiaries to own and operate the transmission and distribution assets. The Company will retain generation related assets. The separation plan will be implemented in a manner that recognizes the current overlap of financing arrangements. This would permit an orderly and economically efficient separation of generation from transmission and distribution so that additional transition costs can be minimized from premature unwinding of existing financial instruments. Prior to the actual legal separation, the Company will functionally separate generation from transmission and distribution.

An application to receive transition revenues was included in the Company's transition plan filing. It requests recovery of stranded generation costs over a five year period and recovery of generation-related regulatory assets of $611 million over a 10-year period. The amount requested for recovery of regulatory assets includes current and new regulatory assets including those arising from compliance with the Act and closure of the affiliated mines.

Included in the transition plan is a proposal to implement independent operation of the transmission system. The Company proposes to join a regional transmission organization whose approval is currently pending before the FERC. A project timeline for activities to implement operational support systems and other technical implementation issues to arrive at and support a competitive electricity market are included in the transition plan.

The Company plans to provide severance, retraining, early retirement, retention, outplacement and other assistance for displaced employees. At this time no employees are identified as affected by electric utility restructuring. Consequently, recovery of such costs was not requested in transition revenues as filed with the transition plan.

The transition plan includes a consumer education plan which will be implemented in conjunction with other electric utilities and the PUCO staff. The transition plan also has terms and conditions for changing suppliers and the commitment of time a customer must accept in a service contract which are two features necessary to accommodate restructuring.

A proposed shopping incentive in the transition plan represents the lower of the market price or the unbundled generation rate in current tariff schedules.

As discussed in Note 3, "Effects of Regulation," the Company defers as regulatory assets and liabilities certain expenses and revenues consistent with the regulatory process in accordance with SFAS 71. Management has concluded that as of December 31, 1999 the requirements to apply SFAS 71 continue to be met since the

Company's rates for generation will continue to be cost-based regulated until the PUCO takes action on the transition plan and the proposed tariff schedules contained in it as provided in the Act. The establishment, on or before the October 31, 2000 deadline, of rates and charges under the transition plan should enable the Company to determine its ability to recover regulatory assets, transition costs and other stranded costs, a requirement to discontinue application of SFAS 71.

When the transition plan and tariff schedules are approved, the application of SFAS 71 will be discontinued for the Ohio retail jurisdictional portion of the generation business. At that time the Company will have to write-off its Ohio jurisdictional generation-related regulatory assets to the extent that they cannot be recovered under the tariff schedules in the transition plan approved by the PUCO and record any asset impairments in accordance with SFAS 121, "Accounting for the Impairment of Long-lived Assets and for Long-lived Assets to Be Disposed Of." An impairment loss would be recorded to the extent that the cost of generating assets cannot be recovered through generation-related revenues during the transition period and future market prices. Until the PUCO completes its regulatory process and issues an order related to the Company's transition plan, it is not possible for management to determine if any of the Company's generating assets are impaired in accordance with SFAS 121. The amount of regulatory assets recorded on the books at December 31, 1999 applicable to the Ohio retail jurisdictional generating business is $361 million before related tax effects. Due to the planned closing of affiliated mines and other anticipated events, generation-related regulatory assets as of December 31, 2000 allocable to the Ohio retail jurisdiction are estimated to exceed $520 million, before income tax effects. Recovery of these regulatory assets and an estimated asset impairment are being sought as a part of the Company's Ohio transition plan filing.

A determination of whether the Company will experience any asset impairment loss regarding its Ohio retail jurisdictional generating assets and any loss from a possible inability to recover Ohio generation-related regulatory assets and other transition costs cannot be made until the PUCO takes action on the Company's transition plan. Management is seeking full recovery of generation-related regulatory assets, stranded costs and other transition costs in its transition plan filing. The PUCO is required to complete its regulatory process including review of the Company's transition plan filing and issue a transition order no later than October 31, 2000. Should the PUCO fail to fully approve the Company's transition plan and its tariff schedules which include recovery of the Company's generation-related regulatory assets, stranded costs and other transition costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

5. COMMITMENTS AND CONTINGENCIES:

Construction and Other Commitments

Substantial construction commitments have been made to support the Company's utility operations and are estimated to be $783 million for 2000-2002.

In addition to fuel acquired from coal-mining subsidiaries and spot-markets, the Company has long-term fuel supply contracts with unaffiliated companies. The contracts generally contain clauses that provide for periodic price adjustments. The Company's retail jurisdictional fuel clause mechanism provides, with the PUCO's review and approval, for deferral and subsequent

recovery or refund of changes in the cost of fuel. However, effective with restructuring in Ohio, which is effective on January 1, 2001, the fuel clause will be frozen and will eventually terminate on December 31, 2005 with the end of the transition period. As such the Company will be subject to market risk in the price of fuel after January 1, 2001. The unaffiliated fuel supply contracts are for various terms, the longest of which extends to 2012, and contain clauses that would release the Company from its obligation under certain force majeure conditions.

Federal EPA Complaint and Notice of Violation

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.

On November 3, 1999 the Department of Justice, at the request of Federal EPA, filed a complaint in the U.S. District Court for the Southern District of Ohio that alleges the Company made modifications to generating units at certain of its coal-fired generating plants over the course of the past 25 years that extend unit operating lives or increase unit generating capacity without a preconstruction permit in violation of the Clean Air Act. Federal EPA also issued Notices of Violation to other AEP companies alleging similar violations at certain AEP plants. A number of unaffiliated utilities also received Notices of Violation, complaints or administrative orders.

The states of New Jersey, New York and Connecticut were subsequently granted leave to intervene in the Federal EPA's action against the Company under the Clean Air Act. On November 18, 1999 a number of environmental groups filed a lawsuit against power plants owned by the Company alleging similar violations to those in the Federal EPA complaint and Notices of Violation. This action 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.

Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act and intends to vigorously pursue its defense of this matter.

In the event the Company does 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 as generation is deregulated, future market prices for electricity.

Litigation

The Internal Revenue Service (IRS) agents auditing the AEP System's consolidated federal income tax returns requested a ruling from their National Office that certain interest deductions claimed by the Company relating to AEP's corporate owned life insurance (COLI) program should not be allowed. As a result of a suit filed in U.S. District Court (discussed below) this request for ruling was withdrawn by the IRS agents. Adjustments have been or will be proposed by the IRS disallowing COLI interest deductions for taxable years 1991-96. A disallowance of COLI interest deductions through December 31, 1999 would reduce earnings by approximately $118 million (including interest).

The Company made payments of taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of any additional above market rate interest on the contested amount. The payments to the IRS are included on the consolidated balance sheets in other property and investments pending the resolution of this matter. The Company is seeking refund through litigation of all amounts paid plus interest.

In order to resolve this issue, the Company filed suit against the United States in the U.S. District Court for the Southern District of Ohio in March 1998. In 1999 a U.S. Tax Court judge decided in the Winn-Dixie Stores v. Commissioner case that a corporate taxpayer's COLI interest deduction should be disallowed. Notwithstanding the Tax Court's decision in Winn-Dixie, management has made no provision for any possible adverse earnings impact from this matter because it believes, and has been advised by outside counsel, that it has a meritorious position and will vigorously pursue its lawsuit. In the event the resolution of this matter is unfavorable, it will have a material adverse impact on results of operations, cash flows and possibly financial condition.

Other

The Company is 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 the results of operations, cash flows or financial condition.

6. SUBSEQUENT EVENT - NOx REDUCTIONS (March 3, 2000):

On March 3, 2000, the U.S. Court of Appeals for the District of Columbia Circuit (Appeals Court) issued a decision generally upholding Federal EPA's final rule (the NOx rule) that requires substantial reductions in nitrogen oxide (NOx) emissions in 22 eastern states, including the states in which the Company's generating plants are located. A number of utilities, including the Company, had filed petitions seeking a review of the final rule in the Appeals Court. On May 25, 1999, the Appeals Court had indefinitely stayed the requirement that states develop revised air quality programs to impose the NOx reductions but did not, however, stay the final compliance date of May 1, 2003.

On April 30, 1999, Federal EPA took final action with respect to petitions filed by eight northeastern states pursuant to the Clean Air Act (Section 126 Rule). The rule approved portions of the states' petitions and imposed NOx reduction requirements on AEP System generating units which are approximately equivalent to the reductions contemplated by the NOx Rule. The AEP System companies with generating plants, as well as other utility companies, filed a petition in the Appeals Court seeking review of Federal EPA's approval of the northeastern states' petitions. In 1999, three additional northeastern states and the District of Columbia filed petitions with Federal EPA similar to those originally filed by the eight northeastern states. Since the petitions relied in part on compliance with an 8-hour ozone standard remanded by the Appeals Court in May 1999, Federal EPA indicated its intent to decouple compliance with the 8-hour standard and issue a revised rule.

On December 17, 1999, Federal EPA issued a revised Section 126 Rule not based on the 8-hour standard and ordered 392 industrial facilities, including certain coal-fired generating plants owned by the Company, to reduce their NOx emissions by May 1, 2003. This rule approves portions of the petitions filed by four northeastern states which contend that their failure to meet Federal EPA smog standards is due to emissions from

upwind states' industrial and coal-fired generating facilities.

Preliminary estimates indicate that compliance with the NOx rule upheld by the Appeals Court could result in required capital expenditures of approximately $624 million for the Company. Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the Company's preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless such costs are recovered from customers through regulated rates and/or reflected in the future market price of electricity if generation is deregulated, they will have an adverse effect on future results of operations, cash flows and possibly financial condition.

7. RELATED PARTY TRANSACTIONS:

Benefits and costs of the AEP System's generating plants are shared by members of the AEP Power Pool of which the Company is a member. Under the terms of the System Interconnection Agreement, capacity charges and credits are designed to allocate the cost of the System's capacity among the AEP Power Pool members based on their relative peak demands and generating reserves. 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 Company is a net supplier to the pool and, therefore, receives capacity credits from the AEP Power Pool.

Operating revenues include revenues for capacity and energy supplied to the AEP Power Pool as follows:

	Year Ended December 31,		
	1999	1998	1997
	(In Thousands)		
Capacity Revenues	$148,876	$150,378	$165,604
Energy Revenues	183,619	212,965	149,436
Total	$332,495	$363,343	$315,040

Purchased power expense includes charges of $20.9 million in 1999, $18.2 million in 1998 and $26.4 million in 1997 for energy received from the Power Pool.

The AEP Power Pool allocates operating revenues, purchased power expense and nonoperating income to the Company. Power marketing and trading operations, which are described in Note 1, are conducted by the AEP Power Pool and shared with the Company. Net trading transactions are included in operating revenues if the trading transactions are within the AEP Power Pool's traditional marketing area and are recorded in nonoperating income if the net trading transactions are outside of the AEP Power Pool's traditional marketing area. The total amounts allocated by the AEP Power Pool which includes amounts for power marketing and trading transactions, are as follows:

	Year Ended December 31,		
	1999	1998	1997
	(in thousands)		
Operating Revenues	$138,709	$176,710	$105,377
Purchased Power Expense	94,296	101,255	21,839
Nonoperating Income (Loss)	4,776	(10,136)	(72)

Purchased power expense includes $25.6 million in 1999, $12 million in 1998 and $6.2 million in 1997 for energy bought from the Ohio Valley Electric Corporation, an affiliated company that is not a member of the AEP Power Pool.

Operating revenues include energy sold directly to Wheeling Power Company (WPCo) in the amounts of $55.6 million in 1999, $55.2 million in 1998 and $55.0 million in 1997. WPCo is an affiliated distribution utility that is not a member of the AEP Power Pool.

The Company participates in the AEP Transmission Equalization Agreement along with other AEP System electric operating utility companies. This agreement combines certain AEP System companies' investments in transmission facilities and shares the costs

of ownership in proportion to the System companies' respective peak demands. Pursuant to the terms of the agreement, since the Company's relative investment in transmission facilities is less than its relative peak demand, other operation expense includes equalization charges of $17.5 million, $16.9 million and $10.5 million in 1999, 1998 and 1997, respectively.

Coal-transportation costs paid to affiliated companies aggregate approximately $9.1 million, $7.6 million and $8.5 million in 1999, 1998 and 1997, respectively. These charges are included in fuel expense. The prices charged by the affiliates for coal transportation services are computed in accordance with orders issued by the SEC.

The Company and an affiliate, Appalachian Power Company, jointly own two power plants. The costs of operating these facilities are apportioned between the owners based on ownership interests. The Company's share of these costs is included in the appropriate expense accounts on the Consolidated Statements of Income and the investment is included in electric utility plant on the Consolidated Balance Sheets.

American Electric Power Service Corporation (AEPSC) provides certain managerial and professional services to AEP System companies including the Company. The costs of the services are billed by AEPSC to its affiliated companies 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.

8. STAFF REDUCTIONS:

During 1998 an internal evaluation of the power generation organization was conducted with a goal of developing a better organizational structure for a competitive generation market. The study was completed in October 1998. In addition, a review of energy delivery staffing levels was conducted in 1998. As a result approximately 150 power generation and energy delivery positions were identified for elimination.

Severance accruals totaling $8.6 million were recorded in December 1998 for reductions in power generation and energy delivery staffs and were charged to other operation expense in the Consolidated Statements of Income. In the first quarter of 1999 the power generation and energy delivery staff reductions were made. The amount of severance benefits paid was not significantly different from the amount accrued.

9. BENEFIT PLANS:

The Company and its subsidiaries participate in the AEP System qualified pension plan, a defined benefit plan which covers all employees, except participants in the United Mine Workers of America (UMWA) pension plans. Net pension costs (credits) for the AEP System pension plan for the years ended December 31, 1999 and 1997 were $(5.0) million and $1.4 million, respectively. There were no pension costs in 1998.

Postretirement benefits other than pensions are provided for retired employees for medical and death benefits under an AEP System plan. Postretirement medical benefits for UMWA employees who have or will retire after January 1, 1976 are the liabilities of the Company's coal-mining subsidiaries. The

annual accrued costs for postretirement medical and death benefits were $52.5 million in 1999, $54.6 million in 1998 and $30.1 million in 1997.

A defined contribution employee savings plan required that the Company make contributions to the plan of $3.7 million in 1999 and $4 million each year in 1998 and 1997.

Other UMWA Benefits

The Company provides 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 based on hours worked are expensed as paid as part of the cost of active mining operations and were not material in 1999, 1998 and 1997. Based upon the UMWA actuarial estimate, the Company's share of the unfunded pension liability was $16.5 million at June 30, 1999. In the event the Company should significantly reduce or cease mining operations or contributions to the UMWA trust funds, a withdrawal obligation will be triggered for the pension that equals the unfunded pension liability. If the Meigs mining operations had been closed on December 31, 1999 the estimated annual liability for the UMWA health and welfare plans would have been approximately $1 million.

10. SEGMENT INFORMATION:

Effective December 31, 1998 the Company adopted SFAS 131, "Disclosures about Segments of an Enterprise and Related Information". The Company has one reportable segment, a regulated vertically integrated electricity generation and energy delivery business. All other activities are insignificant. The Company's operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on business processes, cost structures and operating results. Included in the regulated electric utility segment is the power marketing and trading activities that are discussed in Note 1 and the Company's coal mining activities. For the years ended December 31, 1999, 1998 and 1997, all of the Company's revenues are derived from the generation, sale and delivery of electricity in the United States.

11. FINANCIAL INSTRUMENTS, CREDIT AND RISK MANAGEMENT:

The Company is subject to market risk as a result of changes in electricity commodity prices and interest rates. The Company through its membership in the AEP Power Pool participates in a power marketing and trading operation that manages the exposure to electricity 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. Physical forward electricity contracts within the AEP System's traditional marketing area are recorded on a net basis as operating revenues in the month when the physical contract settles. The Company's share of the net gains from these regulated transactions for the year ended December 31, 1999 and 1998 was $6 million and $31 million, respectively. These activities were not material in 1997.

Non-regulated physical forward electricity contracts outside AEP's traditional marketing area and all financial electricity trading transactions where the underlying physical commodity is outside AEP's traditional marketing area are recorded in non-operating income. Non-regulated open trading contracts are accounted for on a mark-to-market basis in nonoperating income.

The Company's share of the net gains (losses) from these non-regulated trading transactions for the year ended December 31, 1999 and 1998 was $5 million and $(10) million, respectively.

In the first quarter of 1999 the Company adopted EITF 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." The EITF requires that all energy trading contracts be marked-to-market. The effect on the Consolidated Statements of Income of marking open trading contracts to market is deferred as regulatory assets or liabilities for those open trading transactions within the AEP Power Pool's marketing area that are included in the cost of service on a settlement basis for rate-making purposes. The unrealized mark-to-market gains and losses from trading of financial instruments are reported as assets and liabilities, respectively. These activities were not material in prior periods.

The Company is exposed to risk from changes in interest rates primarily due to short-term and long-term borrowings used to fund its business operations. The debt portfolio has both fixed and variable interest rates with terms from one day to 39 years and an average duration of six years at December 31, 1999. A near term change in interest rates should not materially affect results of operations or financial position since the Company would not expect to liquidate its entire debt portfolio in a one year holding period.

Market Valuation

The book value amounts 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 amounts and fair values of the Company's significant financial instruments at December 31, 1999 and 1998 are summarized in the following table. The fair values of long-term debt and preferred stock 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 valuation methodology. The estimates presented herein are not necessarily indicative of the amounts that the Company could realize in a current market exchange.

	1999		1998	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)		(in thousands)	
Non-Derivatives				
Long-term Debt	$1,151,511	$1,027,000	$1,084,928	$1,140,000
Preferred Stock	8,850	8,500	11,850	12,200

Derivatives

	1999			1998		
	Notional Amount	Fair Value	Average Fair Value	Notional Amount	Fair Value	Average Fair Value
			(Dollars in thousands)			
Trading Assets						
Electric	GWH			GWH		
NyMex Future and Options	61	$ 583	$ 286	-	$ -	$ -
Physicals	18,753	155,507	146,395	15,990	12,800	11,100
Options	1,673	9,672	9,936	1,058	8,200	21,000
Swaps	48	987	967	76	900	300
Trading Liabilities						
Electric	GWH			GWH		
NyMex Future and Options	-	$ -	$ -	193	$ (2,100)	$ (500)
Physicals	20,171	(143,440)	(135,015)	15,753	(14,700)	(12,700)
Options	2,403	(11,506)	(7,084)	802	(7,300)	(21,400)
Swaps	49	(1,846)	(1,829)	133	(2,100)	(500)

Credit and Risk Management

In addition to market risk associated with electricity price movements, the Company through the AEP Power Pool 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 nonperformance. The AEP Power Pool has established and enforced credit policies that minimize this risk. The AEP Power Pool 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, the AEP Power Pool requires further credit enhancements to mitigate risk. Since the formation of the power marketing and trading business in July of 1997, the Company has experienced no significant losses due to the credit risk associated with risk management activities; furthermore, the Company does not anticipate any future material effect on its results of operations, cash flow or financial condition as a result of counter party nonperformance.

12. FEDERAL INCOME TAXES:

The details of federal income taxes as reported are as follows:

	Year Ended December 31,		
	1999	1998	1997
		(in thousands)	
Charged (Credited) to Operating Expenses (net):			
Current	$133,862	$118,189	$116,795
Deferred	4,205	3,907	11,257
Deferred Investment Tax Credits	(1,825)	(1,827)	(1,829)
Total	136,242	120,269	126,223
Charged (Credited) to Nonoperating Income (net):			
Current	(3,256)	(5,619)	624
Deferred	(539)	(865)	(3,630)
Deferred Investment Tax Credits	(1,633)	(1,698)	(1,658)
Total	(5,428)	(8,182)	(4,664)
Total Federal Income Taxes as Reported	$130,814	$112,087	$121,559

The following is a reconciliation 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 federal income taxes reported.

	Year Ended December 31,		
	1999	1998	1997
		(in thousands)	
Net Income	$212,157	$209,925	$208,689
Federal Income Taxes	130,814	112,087	121,559
Pre-tax Book Income	$342,971	$322,012	$330,248
Federal Income Taxes on Pre-tax Book Income at Statutory Rate (35%)	$120,040	$112,704	$115,587
Increase (Decrease) in Federal Income Taxes Resulting From the Following Items:			
Depreciation	17,517	16,693	15,961
Corporate Owned Life Insurance	198	(5,238)	(7,179)
Investment Tax Credits (net)	(3,458)	(3,525)	(3,487)
Other	(3,483)	(8,547)	677
Total Federal Income Taxes as Reported	$130,814	$112,087	$121,559
Effective Federal Income Tax Rate	38.1%	34.8%	36.8%

The following tables show the elements of the net deferred tax liability and the significant temporary difference giving rise to such deferrals:

	December 31,	
	1999	1998
	(in thousands)	
Deferred Tax Assets	$ 234,826	$ 197,552
Deferred Tax Liabilities	(911,286)	(909,465)
Net Deferred Tax Liabilities	$(676,460)	$(711,913)
Property Related Temporary Differences	$(599,863)	$(621,562)
Amounts Due From Customers For Future Federal Income Taxes	(108,185)	(122,583)
Deferred Fuel	(62,832)	(34,475)
Post Retirement Benefits	44,483	29,667
Deferred State Income Taxes	(22,124)	(20,107)
All Other (net)	72,061	57,147
Net Deferred Tax Liabilities	$(676,460)	$(711,913)

The Company and its subsidiaries join in the filing of a consolidated federal income tax return with their affiliated companies in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

The AEP System has settled with the IRS all issues from the audits of the consolidated federal income tax returns for the years prior to 1991. Returns for the years 1991 through 1996 are presently being audited by the IRS. With the exception of interest deductions related to AEP's corporate owned life insurance program, which are discussed under the heading "Litigation" in Note 5, 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.

13. COMMON SHAREHOLDER'S EQUITY:

In 1999, 1998 and 1997 net changes to paid-in capital of $41,000, $39,000 and $1.6 million, respectively, represented gains and expenses associated with cumulative preferred stock transactions. At December 31, 1999, there were no dividend restrictions on retained earnings. Regulatory approval is required to pay dividends out of paid-in capital.

14. CUMULATIVE PREFERRED STOCK:

At December 31, 1999, authorized shares of cumulative preferred stock were as follows:

Par Value	Shares Authorized
$100	3,762,403
25	4,000,000

Unissued shares of the cumulative preferred stock may or may not possess mandatory redemption characteristics upon issuance. The cumulative preferred stock is callable at the price indicated plus accrued dividends. The involuntary liquidation preference is par value.

A. Cumulative Preferred Stock Not Subject to Mandatory Redemption:

Series	Call Price December 31, 1999	Par Value	Number of Shares Redeemed Year Ended December 31, 1999	1998	1997	Shares Outstanding December 31, 1999	Amount December 31, 1999	1998
							(in thousands)	
4.08%	$103	$100	373	425	27,182	14,595	$ 1,460	$ 1,497
4.20%	103.20	100	-	-	28,875	23,100	2,310	2,310
4.40%	104	100	330	200	55,889	31,944	3,194	3,227
4-1/2%	110	100	3,631	1,096	97,949	99,727	9,973	10,336
							$16,937	$17,370

B. Cumulative Preferred Stock Subject to Mandatory Redemption:

Series (a)	Par Value	Number of Shares Redeemed Year Ended December 31, 1999	1998	1997	Shares Outstanding December 31, 1999	Amount December 31, 1999	1998
						(in thousands)	
5.90% (b)	$100	10,000	-	321,500	72,500	$7,250	$ 8,250
6.02% (c)	100	20,000	-	364,000	11,000	1,100	3,100
6.35% (c)	100	-	-	295,000	5,000	500	500
						$8,850	$11,850

(a) Not callable until after 2002. The sinking fund provisions of each series have been met by the 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.

15. LONG-TERM DEBT AND LINES OF CREDIT:

Long-term debt by major category was outstanding as follows:

	December 31, 1999	December 31, 1998
	(in thousands)	
First Mortgage Bonds	$ 323,772	$ 413,113
Installment Purchase Contracts	233,025	232,722
Senior Unsecured Notes	408,671	234,266
Notes Payable	30,000	30,000
Junior Debentures	131,860	131,740
Other	24,183	43,087
	1,151,511	1,084,928
Less Portion Due Within One Year	11,677	11,472
Total	$1,139,834	$1,073,456

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 1999	December 31, 1998
		(in thousands)	
6.75	2003 - April 1	$ 40,000	$ 40,000
6.875	2003 - June 1	-	40,000
6.55	2003 - October 1	32,135	40,000
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
7.85	2023 - June 1	-	40,000
7.375	2023 - October 1	40,000	40,000
7.10	2023 - November 1	23,000	25,000
7.30	2024 - April 1	25,000	25,000
Unamortized Discount (net)		(1,363)	(1,887)
Total		$323,772	$413,113

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:

	December 31, 1999	December 31, 1998
	(in thousands)	
Ohio Air Quality Development 7.4% Series B due 2009 - August 1	$ -	$ 50,000
5.15% Series C due 2026 - May 1	50,000	-
Mason County, West Virginia: 5.45% Series B due 2016 - December 1	50,000	50,000
Marshall County, West Virginia: 5.45% Series B due 2014 - July 1	50,000	50,000
5.90% Series D due 2022 - April 1	35,000	35,000
6.85% Series C due 2022 - June 1	50,000	50,000
Unamortized Discount	(1,975)	(2,278)
Total	$233,025	$232,722

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

Senior unsecured notes are as follows:

% Rate	Due	December 31, 1999	December 31, 1998
		(in thousands)	
6.75%	2004 - July 1	$100,000	$ -
7.00%	2004 - July 1	75,000	-
6.73	2004 - November 1	48,000	48,000
6.24	2008 - December 4	50,000	50,000
7-3/8	2038 - June 30	140,000	140,000
Unamortized Discount		(4,329)	(3,734)
Total		$408,671	$234,266

Notes payable outstanding are as follows:

% Rate	Due	December 31, 1999	December 31, 1998
		(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:

	December 31, 1999	1998
	(in thousands)	
8.16% Series A due 2025 - September 30	$ 85,000	$ 85,000
7.92% Series B due 2027 - March 31	50,000	50,000
Unamortized Discount	(3,140)	(3,260)
Total	$131,860	$131,740

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 contains a bargain purchase option at expiration of the agreement. At December 31, 1999 the interest rate was 6.98%.

At December 31, 1999, future annual long-term debt payments are as follows:

	Amount (in thousands)
2000	$ 11,677
2001	42,506
2002	-
2003	147,135
2004	223,000
Later Years	738,000
Total Principal Amount	1,162,318
Unamortized Discount	(10,807)
Total	$1,151,511

Short-term debt borrowings are limited by provisions of the 1935 Act to $450 million. Lines of credit are shared with other AEP System companies and at December 31, 1999 and 1998 were available in the amounts of $1,056 million and $763 million, respectively. The short-term bank lines of credit require payment of facility fees and do not require compensating balances. Outstanding short-term debt consisted of:

	Balance Outstanding (in thousands)	Year-end Weighted Average Interest Rate
December 31, 1999:		
Notes Payable	$ 5,400	7.2%
Commercial Paper	189,518	6.6%
Total	$194,918	6.6%
December 31, 1998:		
Commercial Paper	$123,005	6.0%

16. SUPPLEMENTARY INFORMATION:

	Year Ended December 31, 1999	1998	1997
	(in thousands)		
Cash was paid for:			
Interest (net of capitalized amounts)	$78,739	$ 79,667	$ 81,594
Income Taxes	94,606	118,548	127,719
Noncash Acquisitions Under Capital Leases	28,561	29,938	53,389

17. LEASES:

Leases of property, plant and equipment are for periods of up to 30 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, 1999	1998	1997
	(in thousands)		
Lease Payments on Operating Leases	$ 60,026	$ 59,141	$62,260
Amortization of Capital Leases	35,622	36,585	25,275
Interest on Capital Leases	9,552	14,309	9,445
Total Lease Rental Costs	$105,200	$110,035	$96,980

Properties under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

	December 31, 1999	1998
	(in thousands)	
Electric Utility Plant Under Capital Leases:		
Production Plant	$ 24,428	$ 23,833
General Plant (including mining assets)	194,172	187,925
Total Electric Utility Plant Under Capital Leases	218,600	211,758
Accumulated Amortization	90,154	77,131
Net Electric Utility Plant Under Capital leases	128,446	134,627
Net Other Property Under Capital Leases	8,097	8,008
Net Property Under Capital Leases	$136,543	$142,635
Obligations Under Capital Leases*:		
Noncurrent Liability	$102,259	$114,325
Liability Due Within One Year	34,284	28,310
Total Capital Lease Obligations	$136,543	$142,635

* Represents the present value of future minimum lease payments.

Noncurrent capital lease obligations are included in other noncurrent liabilities on the Consolidated Balance Sheets. Properties under operating leases and related obligations are not included in the Consolidated Balance Sheets.

Future minimum lease payments consisted of the following at December 31, 1999:

	Capital Leases	Non-Cancelable Operating Leases
	(in thousands)	
2000	$ 42,743	$ 51,597
2001	36,158	51,202
2002	18,679	50,903
2003	16,984	50,587
2004	13,401	50,672
Later Years	42,879	353,240
Total Future Minimum Lease Payments	170,844	$608,201
Less Estimated Interest Element	34,301	
Estimated Present Value of Future Minimum Lease Payments	$136,543	

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION:

Quarterly Periods Ended	Operating Revenues	Operating Income	Net Income
	(in thousands)		
1999			
March 31	$518,221	$78,956	$60,821
June 30	498,587	73,328	51,865
September 30	544,451	72,858	56,233
December 31	478,004	63,687	43,238
1998			
March 31	$515,672	$79,069	$60,436
June 30	523,671	69,865	53,059
September 30	597,812	88,838	65,961
December 31	468,392	51,600	30,469

Fourth quarter 1998 net income declined primarily as a result of unseasonably mild weather and severance accruals for staff reductions.

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of Ohio Power Company and its subsidiaries as of December 31, 1999 and 1998, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1999. 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 generally accepted auditing standards. 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 Ohio Power Company and its subsidiaries as of December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 22, 2000
(March 3, 2000 as to Note 6)

OPERATING STATISTICS

	1999	1998	1997	1996	1995
OPERATING REVENUES (in thousands):					
Retail:					
Residential:					
Without Electric Heating	$ 289,705	$ 287,219	$ 274,680	$ 280,640	$ 277,780
With Electric Heating	144,034	139,053	147,503	155,081	145,688
Total Residential	433,739	426,272	422,183	435,721	423,468
Commercial	276,539	276,135	263,212	265,886	257,300
Industrial	665,751	670,756	618,547	635,404	639,177
Miscellaneous	8,222	8,230	8,109	8,065	8,065
Total Retail	1,384,251	1,381,393	1,312,051	1,345,076	1,328,010
Wholesale (sales for resale)	572,136	644,058	523,426	526,702	457,758
Total Revenues from Energy Sales	1,956,387	2,025,451	1,835,477	1,871,778	1,785,768
Other	82,876	80,096	56,633	39,930	37,229
Total Operating Revenues	$ 2,039,263	$2,105,547	$1,892,110	$1,911,708	$1,822,997
SOURCES AND USES OF ENERGY (in millions of kilowatthours):					
SOURCES:					
Net Generated:					
Steam	46,771	50,412	50,216	50,116	44,040
Hydroelectric	163	175	221	176	227
PFBC (a)	-	-	-	-	52
Purchases - Unaffiliated and Power Pool	6,445	5,468	4,972	4,611	3,644
Total Sources	53,379	56,055	55,409	54,903	47,963
Less: Losses, Company Use, Etc.	2,769	2,755	2,472	2,358	2,293
Net Sources	50,610	53,300	52,937	52,545	45,670
USES:					
Retail Sales:					
Residential:					
Without Electric Heating	4,255	4,200	4,016	4,079	4,119
With Electric Heating	2,291	2,199	2,363	2,480	2,418
Total Residential	6,546	6,399	6,379	6,559	6,537
Commercial	5,051	5,015	4,787	4,803	4,712
Industrial	20,060	20,389	19,875	20,007	20,068
Miscellaneous	83	84	83	83	83
Total Retail	31,740	31,887	31,124	31,452	31,400
Wholesale Sales (sales for resale)	18,870	21,413	21,813	21,093	14,270
Total Uses	50,610	53,300	52,937	52,545	45,670

(a) Pressurized Fluidized Bed Combustion - Demonstration Plant.

OPERATING STATISTICS (Concluded)

	1999	1998	1997	1996	1995
AVERAGE COST OF FUEL CONSUMED (in cents): (a)					
Per Million Btu	171	167	157	152	158
Per Kilowatthour Generated	1.67	1.62	1.55	1.49	1.54
RESIDENTIAL SERVICE - AVERAGES:					
Annual Kwh Use per Customer:					
With Electric Heating	16,492	15,927	17,370	18,516	18,348
Total	11,042	10,846	10,892	11,274	11,308
Annual Electric Bill:					
With Electric Heating	$1,037.06	$1,007.20	$1,084.21	$1,157.60	$1,105.46
Total	$731.65	$722.50	$720.87	$748.87	$732.48
Price per Kwh (in cents):					
With Electric Heating	6.29	6.32	6.24	6.25	6.02
Total	6.63	6.66	6.62	6.64	6.48
NUMBER OF CUSTOMERS:					
Year-End:					
Retail:					
Residential:					
Without Electric Heating	456,791	453,908	450,873	449,130	447,641
With Electric Heating	140,021	139,021	137,222	135,091	133,088
Total Residential	596,812	592,929	588,095	584,221	580,729
Commercial	83,292	81,476	79,896	78,258	77,110
Industrial	7,848	7,882	7,974	8,034	8,061
Miscellaneous	2,604	2,592	2,553	2,553	2,557
Total Retail	690,556	684,879	678,518	673,066	668,457
Wholesale (sales for resale)	123	149	111	81	58
Total Electric Customers	690,679	685,028	678,629	673,147	668,515

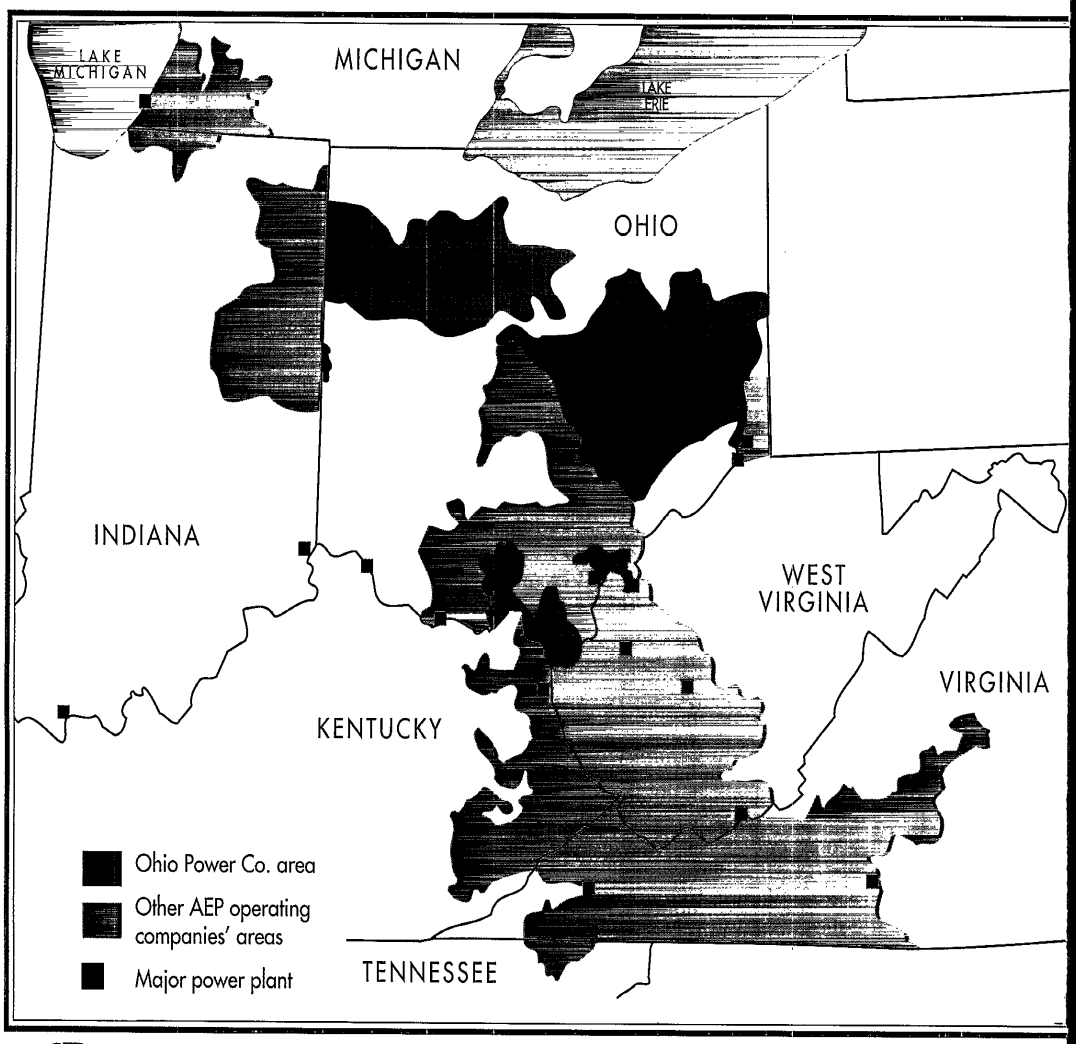
(a) Excludes effect of deferred collection of fuel costs.

DIVIDENDS AND PRICE RANGES OF CUMULATIVE PREFERRED STOCK
By Quarters (1999 and 1998)

	1999 - Quarters				1998 - Quarters			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
CUMULATIVE PREFERRED STOCK								
($100 Par Value)								
4.08% Series								
Dividends Paid Per Share	$1.020	$1.020	$1.020	$1.020	$1.02	$1.02	$1.02	$1.02
Market Price - $ Per Share (OTC)								
Ask - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
Bid - High	67	68-1/4	68-1/4	60-1/8	57	61-5/8	63-1/2	66-1/4
- Low	66-1/4	67	60	60	56-1/2	57	61-5/8	63-1/2
4.20% Series								
Dividends Paid Per Share	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05
Market Price - $ Per Share (OTC)								
Ask - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
Bid - High	70-1/4	70-1/4	70-1/4	61-1/8	64-5/8	68-1/8	68-3/4	70-1/4
- Low	70-1/4	70-1/4	61	58-1/2	62-1/4	64-3/4	68-1/8	68-3/4
4.40% Series								
Dividends Paid Per Share	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10
Market Price - $ Per Share (OTC)								
Ask - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
Bid - High	73	73	73	64	64-1/4	69	71-1/8	72-1/2
- Low	72-1/2	73	64	62	63-1/2	64-1/4	69	71-1/8
4-1/2% Series								
Dividends Paid Per Share	$1.125	$1.125	$1.125	$1.125	$1.125	$1.125	$1.125	$1.125
Market Price - $ Per Share (OTC)								
Ask - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
Bid - High	75-3/8	75-3/4	75-1/2	64-1/2	66-3/4	72-3/4	73-1/8	75-3/8
- Low	75-3/8	75-3/8	64	61-1/4	64-7/8	66-3/4	72-3/4	73-1/8
5.90% Series								
Dividends Paid Per Share	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475
Market Price - $ Per Share (OTC)								
Ask - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
Bid - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
6.02% Series								
Dividends Paid Per Share	$1.505	$1.505	$1.505	$1.505	$1.505	$1.505	$1.505	$1.505
Market Price - $ Per Share (OTC)								
Ask - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
Bid - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
6.35% Series								
Dividends Paid Per Share	$1.5875	$1.5875	$1.5875	$1.5875	$1.5875	$1.5875	$1.5875	$1.5875
Market Price - $ Per Share (OTC)								
Ask - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
Bid - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-

OTC - Over-the-Counter
Note - The above bid and asked quotations represent prices between dealers and do not represent actual transactions.
Market quotations provided by National Quotation Bureau, Inc.
Dash indicates quotes not available.

Ohio Power Service Area and the American Electric Power System



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