UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2006

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to_________

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
0-18135	AEP GENERATING COMPANY (An Ohio Corporation)	31-1033833
0-346	AEP TEXAS CENTRAL COMPANY (A Texas Corporation)	74-0550600
0-340	AEP TEXAS NORTH COMPANY (A Texas Corporation)	75-0646790
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6858	KENTUCKY POWER COMPANY (A Kentucky Corporation)	61-0247775
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215	
	Telephone (614) 716-1000	

Indicate by check mark if the registrants with respect to American Electric Power Company, Inc. and Appalachian Power Company, is each a well-known seasoned issuer, as defined in Rule 405 on the Securities Act. Yes ☒ No. ☐

Indicate by check mark if the registrants with respect to AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are well-known seasoned issuers, as defined in Rule 405 on the Securities Act. Yes ☐ No. ☒

Indicate by check mark if the registrants with respect to American Electric Power Company, Inc., AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No. ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No. ☐

Indicate by check mark if disclosure of delinquent filers with respect to Appalachian Power Company or Ohio Power Company pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements of Appalachian Power Company or Ohio Power Company incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of 'accelerated filer and large accelerated filer' in Rule 12b-2 of the Exchange Act. (Check One)
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, or non-accelerated filers. See definition of 'accelerated filer and large accelerated filer' in Rule 12b-2 of the Exchange Act. (Check One)
Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

Indicate by check mark if the registrants are shell companies, as defined in Rule 12b-2 of the Exchange Act. Yes ☐ No. ☒

AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company and Public Service Company of Oklahoma meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

Securities registered pursuant to Section 12(b) of the Act:

Registrant	**Title of each class**	**Name of each exchange on which registered**
AEP Generating Company	None	
AEP Texas Central Company	None	
AEP Texas North Company	None	
American Electric Power Company, Inc.	Common Stock, $6.50 par value	New York Stock Exchange
Appalachian Power Company	None	
Columbus Southern Power Company	None	
Indiana Michigan Power Company	6% Senior Notes, Series D, Due 2032	New York Stock Exchange
Kentucky Power Company	None	
Ohio Power Company	None	
Public Service Company of Oklahoma	6% Senior Notes, Series B, Due 2032	New York Stock Exchange
Southwestern Electric Power Company	None	

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of each class
AEP Generating Company	None
AEP Texas Central Company	None
AEP Texas North Company	None
American Electric Power Company, Inc.	None
Appalachian Power Company	4.50% Cumulative Preferred Stock, Voting, no par value
Columbus Southern Power Company	None
Indiana Michigan Power Company	None
Kentucky Power Company	None
Ohio Power Company	4.50% Cumulative Preferred Stock, Voting, $100 par value
Public Service Company of Oklahoma	None
Southwestern Electric Power Company	4.28% Cumulative Preferred Stock, Non-Voting, $100 par value
	4.65% Cumulative Preferred Stock, Non-Voting, $100 par value
	5.00% Cumulative Preferred Stock, Non-Voting, $100 par value

	Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2006, the last trading date of the registrants' most recently completed second fiscal quarter	**Number of shares of common stock outstanding of the registrants at December 31, 2006**
AEP Generating Company	None	1,000 ($1,000 par value)
AEP Texas Central Company	None	2,211,678 ($25 par value)
AEP Texas North Company	None	5,488,560 ($25 par value)
American Electric Power Company, Inc.	$13,492,667,933	396,674,736 ($6.50 par value)
Appalachian Power Company	None	13,499,500 (no par value)
Columbus Southern Power Company	None	16,410,426 (no par value)
Indiana Michigan Power Company	None	1,400,000 (no par value)
Kentucky Power Company	None	1,009,000 ($50 par value)
Ohio Power Company	None	27,952,473 (no par value)
Public Service Company of Oklahoma	None	9,013,000 ($15 par value)
Southwestern Electric Power Company	None	7,536,640 ($18 par value)

Note On Market Value Of Common Equity Held By Non-Affiliates

American Electric Power Company, Inc. owns, directly or indirectly, all of the common stock of AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (see Item 12 herein).

Documents Incorporated By Reference

Description	**Part of Form 10-K Into Which Document Is Incorporated**
Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2006: AEP Generating Company AEP Texas Central Company AEP Texas North Company American Electric Power Company, Inc. Appalachian Power Company Columbus Southern Power Company Indiana Michigan Power Company Kentucky Power Company Ohio Power Company Public Service Company of Oklahoma Southwestern Electric Power Company	Part II
Portions of Proxy Statement of American Electric Power Company, Inc. for 2007 Annual Meeting of Shareholders.	Part III
Portions of Information Statements of the following companies for 2007 Annual Meeting of Shareholders: Appalachian Power Company Ohio Power Company	Part III

This combined Form 10-K is separately filed by AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, American Electric Power Company, Inc., Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Except for American Electric Power Company, Inc., each registrant makes no representation as to information relating to the other registrants.

You can access financial and other information at AEP's website, including AEP's Principles of Business Conduct (which also serves as a code of ethics applicable to Item 10 of this Form 10-K), certain committee charters and Principles of Corporate Governance. The address is www.AEP.com. AEP makes available, free of charge on its website, copies of its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC.

TABLE OF CONTENTS

GLOSSARY OF TERMS

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP
AEP or parent	American Electric Power Company, Inc.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo
AEP Power Pool	APCo, CSPCo, I&M, KPCo and OPCo, as parties to the Interconnection Agreement
AEPSC or Service Corporation	American Electric Power Service Corporation, a service company subsidiary of AEP
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries
AEP West companies	PSO, SWEPCo, TCC and TNC
AEP Utilities	AEP Utilities, Inc., a subsidiary of AEP, formerly, Central and South West Corporation
AFUDC	Allowance for funds used during construction (the net cost of borrowed funds, and a reasonable rate of return on other funds, used for construction under regulatory accounting)
ALJ	Administrative law judge
APCo	Appalachian Power Company, a public utility subsidiary of AEP
APSC	Arkansas Public Service Commission
Buckeye	Buckeye Power, Inc., an unaffiliated corporation
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
Cardinal Station	Generating facility co-owned by Buckeye and OPCo
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CG&E	The Cincinnati Gas & Electric Company, an unaffiliated utility company
Cook Plant	The Donald C. Cook Nuclear Plant (2,143 MW), owned by I&M, and located near Bridgman, Michigan
CSPCo	Columbus Southern Power Company, a public utility subsidiary of AEP
CSW	Central and South West Corporation, a public utility holding company that merged with AEP in June 2000.
CSW Operating Agreement	Agreement, dated January 1, 1997, as amended, originally by and among PSO, SWEPCo, TCC and TNC, currently by and between PSO and SWEPCO governing generating capacity allocation. AEPSC acts as the agent for the parties.
DOE	United States Department of Energy
Dow	The Dow Chemical Company, and its affiliates collectively, unaffiliated companies
DP&L	The Dayton Power and Light Company, an unaffiliated utility company
EMF	Electric and Magnetic Fields
EPA	United States Environmental Protection Agency
EPACT	The Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Inc.
FPA	Federal Power Act
I&M	Indiana Michigan Power Company, a public utility subsidiary of AEP
I&M Power Agreement	Unit Power Agreement Between AEGCo and I&M, dated March 31, 1982
Interconnection Agreement	Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants
IURC	Indiana Utility Regulatory Commission
KPCo	Kentucky Power Company, a public utility subsidiary of AEP

Abbreviation or Acronym	Definition
LLWPA	Low-Level Waste Policy Act of 1980
LPSC	Louisiana Public Service Commission
MEMCO	AEP MEMCO LLC
MISO	Midwest Independent Transmission System Operator
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
NOx	Nitrogen oxide
NPC	National Power Cooperatives, Inc., an unaffiliated corporation
NRC	Nuclear Regulatory Commission
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff, filed with FERC
OCC	Corporation Commission of the State of Oklahoma
Ohio Act	Ohio electric restructuring legislation
OPCo	Ohio Power Company, a public utility subsidiary of AEP
OVEC	Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo together own a 43.47% equity interest
PJM	PJM Interconnection, L.L.C., a regional transmission organization
PSO	Public Service Company of Oklahoma, a public utility subsidiary of AEP
PUCO	Public Utilities Commission of Ohio
PUCT	Public Utility Commission of Texas
PUHCA	Public Utility Holding Company Act of 1935, as amended (repealed effective February 8, 2006)
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REP	Texas retail electricity provider
Rockport Plant	A generating plant owned and partly leased by AEGCo and I&M (two 1,300 MW, coal-fired) located near Rockport, Indiana
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
S&P	Standard & Poor's Ratings Service
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
SWEPCo	Southwestern Electric Power Company, a public utility subsidiary of AEP
TCA	Transmission Coordination Agreement dated January 1, 1997 by and among, PSO, SWEPCo, TCC, TNC and AEPSC, which allocated costs and benefits through September 2005 in connection with the operation of the transmission assets of the four public utility subsidiaries
TCC	AEP Texas Central Company, formerly Central Power and Light Company, a public utility subsidiary of AEP
TEA	Transmission Equalization Agreement dated April 1, 1984 by and among APCo, CSPCo, I&M, KPCo and OPCo, which allocates costs and benefits in connection with the operation of transmission assets
Texas Act	Texas electric restructuring legislation
TNC	AEP Texas North Company, formerly West Texas Utilities Company, a public utility subsidiary of AEP
Tractebel	Tractebel Energy Marketing, Inc.
TVA	Tennessee Valley Authority
VSCC	Virginia State Corporation Commission
WPCo	Wheeling Power Company, a public utility subsidiary of AEP
WVPSC	West Virginia Public Service Commission

FORWARD-LOOKING INFORMATION

This report made by AEP and certain of its registrant subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its registrant subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Electric load and customer growth.
- Weather conditions, including storms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters.
- Availability of generating capacity and the performance of our generating plants.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for new investments, transmission service and environmental compliance).
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp. and related matters).
- Our ability to constrain operation and maintenance costs.
- The economic climate and growth in our service territory and changes in market demand and demographic patterns.
- Inflationary and interest rate trends.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas, and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom AEP has contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas, and other energy-related commodities.
- Changes in utility regulation, including the potential for new legislation or regulation in Ohio and or Virginia and membership in and integration into regional transmission organizations.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of our pension and other postretirement benefit plans.
- Prices for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

The registrants expressly disclaim any obligation to update any forward-looking information.

PART I

ITEM 1. BUSINESS

GENERAL

OVERVIEW AND DESCRIPTION OF SUBSIDIARIES

AEP was incorporated under the laws of the State of New York in 1906 and reorganized in 1925. It is a public utility holding company that owns, directly or indirectly, all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries.

The service areas of AEP's public utility subsidiaries cover portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. The generating and transmission facilities of AEP's public utility subsidiaries are interconnected and their operations are coordinated. Transmission networks are interconnected with extensive distribution facilities in the territories served. The public utility subsidiaries of AEP have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. Restructuring legislation in Michigan, Ohio, the ERCOT area of Texas and, as of December 31, 2006, Virginia has caused AEP public utility subsidiaries in those states to unbundle previously integrated regulated rates for their retail customers.

The AEP System is an integrated electric utility system. As a result, the member companies of the AEP System have contractual, financial and other business relationships with the other member companies, such as participation in the AEP System savings and retirement plans and tax returns, sales of electricity and transportation and handling of fuel. The member companies of the AEP System also obtain certain accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost from a common provider, AEPSC.

At December 31, 2006, the subsidiaries of AEP had a total of 20,442 employees. Because it is a holding company rather than an operating company, AEP has no employees. The public utility subsidiaries of AEP are:

APCo (organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 949,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2006, APCo and its wholly owned subsidiaries had 2,461 employees. Among the principal industries served by APCo are coal mining, primary metals, chemicals and textile mill products. In addition to its AEP System interconnections, APCo also is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Energy Corporation and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

CSPCo (organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 742,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. At December 31, 2006, CSPCo had 1,233 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. Among the principal industries served are food processing, chemicals, primary metals, electronic machinery and paper products. In addition to its AEP System interconnections, CSPCo also is interconnected with the following unaffiliated utility companies: CG&E, DP&L and Ohio Edison Company. CSPCo is a member of PJM.

I&M (organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 582,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. At December 31, 2006, I&M had 2,643 employees. Among the principal industries served are primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber and miscellaneous plastic products and chemicals and allied products. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. In addition to its AEP System interconnections, I&M also is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, CG&E, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power & Light Company. I&M is a member of PJM.

KPCo (organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 176,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2006, KPCo had 466 employees. In addition to its AEP System interconnections, KPCo also is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

Kingsport Power Company (organized in Virginia in 1917) provides electric service to approximately 46,000 retail customers in Kingsport and eight neighboring communities in northeastern Tennessee. Kingsport Power Company does not own any generating facilities and is a member of PJM. It purchases electric power from APCo for distribution to its customers. At December 31, 2006, Kingsport Power Company had 60 employees.

OPCo (organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 712,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2006, OPCo had 2,330 employees. Among the principal industries served by OPCo are primary metals, rubber and plastic products, stone, clay, glass and concrete products, petroleum refining and chemicals. In addition to its AEP System interconnections, OPCo also is interconnected with the following unaffiliated utility companies: CG&E, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

PSO (organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 520,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2006, PSO had 1,233 employees. Among the principal industries served by PSO are natural gas and oil production, oil refining, steel processing, aircraft maintenance, paper manufacturing and timber products, glass, chemicals, cement, plastics, aerospace manufacturing, telecommunications, and rubber goods. In addition to its AEP System interconnections, PSO also is interconnected with Ameren Corporation, Empire District Electric Co., Oklahoma Gas & Electric Co., Southwestern Public Service Co. and Westar Energy Inc. PSO is a member of SPP.

SWEPCo (organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 456,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2006, SWEPCo had 1,545 employees. Among the principal industries served by SWEPCo are natural gas and oil production, petroleum refining, manufacturing of pulp and paper, chemicals, food processing, and metal refining. The territory served by SWEPCo also includes several military installations, colleges, and universities. SWEPCO also owns and operates a lignite coal mining operation. In addition to its AEP System interconnections, SWEPCo is also interconnected with CLECO Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

TCC (organized in Texas in 1945) is engaged in the transmission and distribution of electric power to approximately 738,000 retail customers through REPs in southern Texas. Under the Texas Act, TCC has completed the final stage of exiting the generation business and has sold all of its generation assets. At December 31, 2006, TCC had 1,224 employees. Among the principal industries served by TCC are oil and gas extraction, food processing, apparel, metal refining, chemical and petroleum refining, plastics, and machinery equipment. In addition to its AEP System interconnections, TCC is a member of ERCOT.

TNC (organized in Texas in 1927) is engaged in the transmission and distribution of electric power to approximately 189,000 retail customers through REPs in west and central Texas. TNC's remaining generating capacity that is not deactivated has been transferred to an affiliate at TNC's cost pursuant to a 20-year agreement. At December 31, 2006, TNC had 386 employees. Among the principal industries served by TNC are agriculture and the manufacturing or processing of cotton seed products, oil products, precision and consumer metal products, meat products and gypsum products. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

WPCo (organized in West Virginia in 1883 and reincorporated in 1911) provides electric service to approximately 41,000 retail customers in northern West Virginia. WPCo does not own any generating facilities. WPCo is a member of PJM. It purchases electric power from OPCo for distribution to its customers. At December 31, 2006, WPCo had 61 employees.

AEGCo (organized in Ohio in 1982) is an electric generating company. AEGCo sells power at wholesale to I&M and KPCo. AEGCo has no employees.

SERVICE COMPANY SUBSIDIARY

AEP also owns a service company subsidiary, AEPSC. AEPSC provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to the AEP System companies. The executive officers of AEP and certain of its public utility subsidiaries are employees of AEPSC. At December 31, 2006, AEPSC had 5,961 employees.

CLASSES OF SERVICE

The principal classes of service from which the public utility subsidiaries of AEP derive revenues and the amount of such revenues during the year ended December 31, 2006 are as follows:

Description	AEP System(a)	APCo	CSPCo	I&M	KPCo
	(in thousands)				
UTILITY OPERATIONS:					
Retail Sales					
Residential Sales	$ 3,688,000	$ 695,141	$ 632,878	$ 389,185	$ 156,547
Commercial Sales	2,643,000	349,869	569,865	303,540	93,659
Industrial Sales	2,422,000	476,964	193,740	350,282	140,627
Total Other Retail Sales	297,000	78,103	24,171	25,637	8,650
Total Retail	9,050,000	1,600,077	1,420,654	1,068,644	399,483
Wholesale					
Off-System Sales	2,355,000	473,811	260,996	492,182	111,638
Transmission	269,000	28,545	16,949	23,139	6,855
Total Wholesale	2,624,000	502,356	277,945	515,321	118,493
Other Electric Revenues	264,000	43,206	16,943	17,170	8,456
Other Operating Revenues	128,000	9,797	5,467	32,181	1,148
Sales To Affiliates	-	238,592	85,726	343,631	58,287
Total Utility Operating Revenues	12,066,000	2,394,028	1,806,735	1,976,947	585,867
OTHER	556,000	-	-	-	-
TOTAL REVENUES	$ 12,622,000	$ 2,394,028	$ 1,806,735	$ 1,976,947	$ 585,867

Description	OPCo	PSO	SWEPCo	TCC(b)	TNC(b)
	(in thousands)				
UTILITY OPERATIONS:					
Retail Sales					
Residential Sales	$ 542,406	$ 506,360	$ 399,931	$ 242,081	$ 56,821
Commercial Sales	356,768	363,401	335,182	194,696	28,622
Industrial Sales	536,244	333,369	268,554	40,186	8,643
Total Other Retail Sales	33,183	94,123	6,867	9,513	11,613
Total Retail	1,468,601	1,297,253	1,010,534	486,476	105,699
Wholesale					
Off-System Sales	483,888	52,913	257,362	17,226	148,034
Transmission	21,546	16,209	38,044	81,667	36,328
Total Wholesale	505,434	69,122	295,406	98,893	184,362
Other Electric Revenues	32,244	18,174	80,713	38,471	5,869
Other Operating Revenues	16,478	5,242	2,741	34,421	315
Sales to Affiliates	702,118	51,993	42,445	6,403	33,225
Total Utility Operating Revenues	2,724,875	1,441,784	1,431,839	664,664	329,470
OTHER	-	-	-	-	-
TOTAL REVENUES	$ 2,724,875	$ 1,441,784	$ 1,431,839	$ 664,664	$ 329,470

(a) Includes revenues of other subsidiaries not shown. Intercompany transactions have been eliminated, including $309,814,000 of AEGCo's revenues for the year ended December 31, 2006.

(b) TCC and TNC revenues from distribution and transmission services to REPs are reflected in retail classes of customer.

EPACT AND THE REPEAL OF PUHCA

EPACT was signed into law on August 8, 2005. Among other things, EPACT repealed PUHCA, effective February 8, 2006. PUHCA regulated many significant aspects of a registered holding company system, such as the AEP System.

PUHCA limited the operations of a registered holding company system to a single integrated public utility system and such other businesses as were incidental or necessary to the operations of the system. PUHCA also required that transactions between associated companies in a registered holding company system be performed at cost, with limited exceptions. As a result of PUHCA's repeal, utility holding companies, including the AEP system, are no longer limited to a single integrated public utility system. Further, utility holding companies are no longer restricted from acquiring businesses that may not be related to the utility business. Jurisdiction over certain holding company related activities has been transferred to the FERC, including the issuances of securities by public utilities, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both FERC and state regulators will be permitted to review the books and records of any company within a holding company system.

EPACT contains key provisions affecting the electric power industry. These provisions include tax changes for the utility industry, incentives for emissions reductions and federal insurance and incentives to build new nuclear power plants. It gives the FERC "backstop" transmission siting authority as well as increased utility merger oversight. The law also provides incentives and funding for clean coal technologies and initiatives to voluntarily reduce greenhouse gases. FERC has issued regulations implementing EPACT. We do not expect compliance with these regulations to have a material adverse impact on our financial condition and results of operations.

FINANCING

General

Companies within the AEP System generally use short-term debt to finance working capital needs. Short-term debt is also used to finance acquisitions, construction and redemption or repurchase of outstanding securities until such needs can be financed with long-term debt. In recent history, short-term funding needs have been provided for by cash on hand and AEP's commercial paper program. Funds are made available to subsidiaries under the AEP corporate borrowing program. Certain public utility subsidiaries of AEP also sell accounts receivable to provide liquidity.

AEP's revolving credit agreements (which backstop the commercial paper program) include covenants and events of default typical for this type of facility, including a maximum debt/capital test and a $50 million cross-acceleration provision. At December 31, 2006, AEP was in compliance with its debt covenants. With the exception of a voluntary bankruptcy or insolvency, any event of default has either or both a cure period or notice requirement before termination of the agreements. A voluntary bankruptcy or insolvency would be considered an immediate termination event. See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2006 Annual Reports, under the heading entitled *Financial Condition* for additional information with respect to AEP's credit agreements.

AEP's subsidiaries have also utilized, and expect to continue to utilize, additional financing arrangements, such as leasing arrangements, including the leasing of coal transportation equipment and facilities.

Credit Ratings

In September 2005, Moody's upgraded AEP's senior unsecured rating to Baa2 from Baa3 and its commercial paper rating to Prime-2 from Prime-3. There were no changes in the ratings or rating outlook for AEP or AEP's rated subsidiaries by Moody's since that time. S&P did not change the ratings of AEP or its rated subsidiaries during 2006; it did improve our business risk profile rating from six to five. Fitch placed TNC on negative outlook in April 2006 but has made no other changes to the ratings of AEP or its rated subsidiaries during 2006.

See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2006 Annual Reports, under the heading entitled *Financial Condition* for additional information with respect to the credit ratings of the registrants other than AEGCo.

ENVIRONMENTAL AND OTHER MATTERS

General

AEP's subsidiaries are currently subject to regulation by federal, state and local authorities with regard to air and water-quality control and other environmental matters, and are subject to zoning and other regulation by local authorities. The environmental issues that are potentially material to the AEP system include:

- Global climate change and legislative responses to it, including limitations on CO_2 emissions. See *Management's Financial Discussion and Analysis of Results of Operations* under the headings entitled *Environmental Matters – Potential Regulation of* CO_2 *Emissions.*

- The CAA and CAAA and state laws and regulations (including State Implementation Plans) that require compliance, obtaining permits and reporting as to air emissions. See *Management's Financial Discussion and Analysis of Results of Operations* under the headings entitled *Environmental Matters - Clean Air Act Requirements* and *Estimated Air Quality Environmental Investments*.

- Litigation with the federal and certain state governments and certain special interest groups regarding whether modifications to or maintenance of certain coal-fired generating plants required additional permitting or pollution control technology, and/or whether emissions from coal-fired generating plants cause or contribute to global climate changes. See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters - Environmental Litigation* and Note 6 to the consolidated financial statements entitled *Commitments, Guarantees and Contingencies*, included in the 2006 Annual Reports, for further information.

- Rules issued by the EPA and certain states that require substantial reductions in SO_2, mercury and NOx emissions, which have compliance dates that take effect periodically through as late as 2018. AEP is installing (and has installed) emission control technology and is taking other measures to comply with required reductions. See *Management's Financial Discussion and Analysis of Results of Operations* under the headings entitled *Environmental Matters - Clean Air Act Requirements* and *Estimated Air Quality Environmental Investments* included in the 2006 Annual Reports for further information.

- CERCLA, which imposes costs for environmental remediation upon owners and previous owners of sites, as well as transporters and generators of hazardous material disposed of at such sites. AEP does not, however, anticipate that any of its currently identified CERCLA-related issues will result in material costs or penalties to the AEP System. See Note 6 to the consolidated financial statements entitled *Commitments, Guarantees and Contingencies*, included in the 2006 Annual Reports, under the heading entitled *The Comprehensive Environmental Response Compensation and Liability Act* (*Superfund) and State Remediation* for further information.

- The Federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits. In July 2004, the EPA adopted a new Clean Water Act rule to reduce the number of fish and other aquatic organisms killed at once-through cooled power plants. See *Management's*

Financial Discussion and Analysis of Results of Operations, included in the 2006 Annual Reports, under the heading entitled *Environmental Matters - Clean Water Act Regulations* for additional information.

- Solid and hazardous waste laws and regulations, which govern the management and disposal of certain wastes. The majority of solid waste created from the combustion of coal and fossil fuels is fly ash and other coal combustion byproducts, which the EPA has determined are not hazardous waste subject to RCRA.

In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters*, included in the 2006 Annual Reports, for further information with respect to environmental issues.

If our expenditures for pollution control technologies, replacement generation and associated operating costs are not recoverable from customers through regulated rates (in regulated jurisdictions) or market prices (in deregulated jurisdictions), those costs could adversely affect future results of operations and cash flows, and possibly financial condition.

The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the AEP System.

See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters* and Note 6 to the consolidated financial statements entitled *Commitments, Guarantees and Contingencies,* included in the 2006 Annual Reports, for further information with respect to environmental matters.

Environmental Investments

Investments related to improving AEP System plants' environmental performance and compliance with air and water quality standards during 2004, 2005 and 2006 and the current estimates for 2007, 2008 and 2009 are shown below, in each case excluding AFUDC or capitalized interest. Substantial investments in addition to the amounts set forth below are expected by the System in future years in connection with the modification and addition of facilities at generating plants for environmental quality controls in order to comply with air and water quality standards which have been or may be adopted. Future investments could be significantly greater if litigation regarding whether AEP properly installed emission control equipment on its plants is resolved against any AEP subsidiaries or emissions reduction requirements are accelerated or otherwise become more onerous or if CO_2 becomes regulated. See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters* and Note 6 to the consolidated financial statements, entitled *Commitments, Guarantees and Contingencies*, included in the 2006 Annual Reports, for more information regarding this litigation and environmental expenditures in general.

Historical and Projected Environmental Investments

	2004 Actual	2005 Actual	2006 Actual	2007 Estimate	2008 Estimate	2009 Estimate
			(in thousands)			
AEGCo	$6,500	$1,400	$1,400	$1,400	$900	$1,300
APCo	159,100	231,200	532,800	305,200	215,100	164,200
CSPCo	23,200	32,200	138,900	112,000	133,400	36,200
I&M	11,800	62,900	23,200	4,800	18,900	16,100
KPCo	2,700	13,100	(12,400)	2,600	14,600	14,800
OPCo	133,000	458,600	660,800	498,800	104,500	30,300
PSO	100	200	500	2,500	12,000	18,300
SWEPCo	4,000	11,900	21,000	7,100	17,300	16,600
TCC	0	0	0	0	0	0
TNC	0	(100)	0	700	4,600	2,800
AEP System	$340,400	$811,400	$1,366,200	$935,100	$521,300	$300,600

Figures set forth in parentheses reflect amounts invested and later expensed as a result of project cancellation or significant delay.

Electric and Magnetic Fields

EMF are found everywhere there is electricity. Electric fields are created by the presence of electric charges. Magnetic fields are produced by the flow of those charges. This means that EMF are created by electricity flowing in transmission and distribution lines, electrical equipment, household wiring, and appliances.

A number of studies in the past several years have examined the possibility of adverse health effects from EMF. While some of the epidemiological studies have indicated some association between exposure to EMF and health effects, none has produced any conclusive evidence that EMF does or does not cause adverse health effects.

Management cannot predict the ultimate impact of the question of EMF exposure and adverse health effects. If further research shows that EMF exposure contributes to increased risk of cancer or other health problems, or if the courts conclude that EMF exposure harms individuals and that utilities are liable for damages, or if states limit the strength of magnetic fields to such a level that the current electricity delivery system must be significantly changed, then the results of operations and financial condition of AEP and its operating subsidiaries could be materially adversely affected unless these costs can be recovered from customers.

UTILITY OPERATIONS

GENERAL

Utility operations constitute most of AEP’s business operations. Utility operations include (i) the generation, transmission and distribution of electric power to retail customers and (ii) the supplying and marketing of electric power at wholesale (through the electric generation function) to other electric utility companies, municipalities and other market participants. AEPSC, as agent for AEP’s public utility subsidiaries, performs marketing, generation dispatch, fuel procurement and power-related risk management and trading activities.

ELECTRIC GENERATION

Facilities

AEP's public utility subsidiaries own or lease approximately 35,000 MW of domestic generation. See *Item 2 — Properties* for more information regarding AEP's generation capacity.

AEP Power Pool and CSW Operating Agreement

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio." The Interconnection Agreement has been approved by the FERC.

The member-load-ratio is calculated monthly by dividing such company's highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all AEP East companies. As of December 31, 2006, the member-load-ratios were as follows:

	Peak Demand (MW)	**Member-Load Ratio (%)**
APCo	6,943	30.2
CSPCo	4,425	19.3
I&M	4,650	20.3
KPCo	1,665	7.3
OPCo	5,260	22.9

The Ohio Act was enacted in 2001. To comply with that law CSPCo and OPCo functionally separated their generation business from their remaining operations. They plan to remain functionally separated through at least December 31, 2008 as authorized by their rate stabilization plans approved by the PUCO. CSPCo and OPCo have been involved in discussions with various stakeholders in Ohio about potential legislation to address the period following the expiration of the rate stabilization plans. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2006 Annual Reports, for more information.

Since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement (Allowance Agreement), which provides, among other things, for the transfer of emission allowances associated with transactions under the Interconnection Agreement.

The following table shows the net (credits) or charges allocated among the parties under the Interconnection Agreement during the years ended December 31, 2004, 2005 and 2006:

	2004	**2005**	**2006**
		(in thousands)	
APCo	$239,400	$288,000	$319,500
CSPCo	284,900	285,600	281,700
I&M	(141,500)	(197,400)	(146,100)
KPCo	31,600	42,200	38,800
OPCo	(414,400)	(418,400)	(493,900)

PSO, SWEPCo, and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which has been approved by the FERC. The CSW Operating Agreement requires these public utility subsidiaries to maintain adequate annual planning reserve margins and requires the subsidiaries that have capacity in excess of the required margins to make such capacity available for sale to other public utility subsidiary parties as capacity commitments. Parties are compensated for energy delivered to the recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales in their region are generally shared based on the amount of energy each west zone public utility subsidiary contributes that is sold to third parties. The separation of the generation business undertaken by TCC and TNC to comply with the Texas Act has made the business operations of TCC and TNC incompatible with the CSW Operating Agreement. As a result, with FERC approval, these companies are no longer parties to, and no longer supply generating capacity under, the CSW Operating Agreement.

The following table shows the net (credits) or charges allocated among the parties under the CSW Operating Agreement during the years ended December 31, 2004, 2005 and 2006:

	2004	**2005**	**2006**
		(in thousands)	
PSO	$55,000	$27,600	$(15,300)
SWEPCo	(59,800)	(27,500)	9,900
TCC	1,100	0	0
TNC	3,700	(100)	5,400

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any public utility subsidiary is primarily sold to customers by such public utility subsidiary at rates approved by the public utility commission in the jurisdiction of sale. In Ohio and Virginia, such rates are based on a statutory formula as those jurisdictions continue to transition to the use of market rates for generation. See *Regulation — Rates* under *Item 1, Utility Operations*.

Under both the Interconnection Agreement and CSW Operating Agreement, power that is not needed to serve the native load of our public utility subsidiaries is sold in the wholesale market by AEPSC on behalf of those subsidiaries. See *Risk Management and Trading*, below, for a discussion of the trading and marketing of such power.

AEP's System Integration Agreement, which has been approved by the FERC, provides for the integration and coordination of AEP's East companies, PSO and SWEPCO. This includes joint dispatch of generation within the AEP System and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). It is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits for activities within each zone. The separation of the generation business undertaken by TCC and TNC to comply with the Texas Act has also made the business operations of TCC and TNC incompatible with the System Integration Agreement. As a result, with FERC approval, these two companies have been removed from this agreement.

Risk Management and Trading

As agent for AEP's public utility subsidiaries, AEPSC sells excess power into the market and engages in power, natural gas, coal and emissions allowances risk management and trading activities focused in regions in which AEP traditionally operates. These activities primarily involve the purchase and sale of electricity (and to a lesser extent, natural gas, coal and emissions allowances) under physical forward contracts at fixed and variable prices. These contracts include physical transactions, over-the-counter swaps and exchange-traded futures and options. The majority of physical forward contracts are typically settled by entering into offsetting contracts. These transactions are executed with numerous counterparties or on exchanges. Counterparties and exchanges may require cash or cash related instruments to be deposited on these transactions as margin against open positions. As of December 31, 2006, counterparties and exchanges have posted approximately $156 million in cash, cash equivalents or letters of credit with AEPSC for the benefit of AEP's public utility subsidiaries (while, as of that date, AEP's public utility subsidiaries had posted approximately $110 million with counterparties and exchanges). Since open trading contracts are valued based on changes in market power prices, exposures change daily.

Fuel Supply

The following table shows the sources of power generated by the AEP System:

	2004	2005	2006
Coal and Lignite	83%	83%	85%
Natural Gas	5%	6%	6%
Nuclear	12%	10%	9%
Hydroelectric and other	1%	1%	<1%

Variations in the generation of nuclear power are primarily related to refueling and maintenance outages in addition to the sale of TCC's share of a nuclear generating unit in May 2005. Variations in the generation of natural gas power are primarily related to the availability of cheaper alternatives to fulfill certain power requirements and the deactivation or sale of certain gas-fired plants owned by TCC and TNC. Price increases in one or more fuel sources relative to other fuels generally result in increased use of other fuels.

Coal and Lignite: AEP's public utility subsidiaries procure coal and lignite under a combination of purchasing arrangements including long-term contracts, affiliate operations, short-term, and spot agreements with various producers and coal trading firms. The price for most solid fuels generally has been increasing. Management has responded to increases in the price of coal by rebalancing the coal used in its generating facilities with products from different coal regions and sources that have different heat and sulfur contents. This rebalancing is an ongoing process that is expected to continue, primarily enabled by the installation of scrubbers at many of our generating facilities. Management believes, but cannot provide assurances, that AEP's public utility subsidiaries will be able to secure and transport coal and lignite of adequate quality and in adequate quantities to operate their coal and lignite-fired units. Through subsidiaries, AEP owns or leases more than 7,000 railcars, 600 barges, 15 towboats and a coal handling terminal with 20 million tons of annual capacity to move and store coal for use in its generating facilities. See MEMCO Operations for a discussion of AEP's for-profit coal and other dry-bulk commodity transportation operations that are not part of AEP's Utility Operations segment.

The following table shows the amount of coal and lignite delivered to the AEP System during the past three years and the average delivered price of spot coal purchased by System companies:

	2004	2005	2006
Total coal delivered to AEP operated plants (thousands of tons)	71,778	75,063	77,897
Average price per ton of purchased coal	$28.96	$32.67	$35.37

The coal supplies at AEP System plants vary from time to time depending on various factors, including customers' usage of electric power, space limitations, the rate of consumption at particular plants, labor issues and weather conditions which may interrupt deliveries. At December 31, 2006, the System's coal inventory was approximately 44 days of normal usage. This estimate assumes that the total supply would be utilized through the operation of plants that use coal most efficiently.

In cases of emergency or shortage, system companies have developed programs to conserve coal supplies at their plants. Such programs have been filed and reviewed with officials of federal and state agencies and, in some cases, the relevant state regulatory agency has prescribed actions to be taken under specified circumstances by System companies, subject to the jurisdiction of such agency.

The FERC has adopted regulations relating, among other things, to the circumstances under which, in the event of fuel emergencies or shortages, it might order electric utilities to generate and transmit electric power to other regions or systems experiencing fuel shortages, and to ratemaking principles by which such electric utilities would be compensated. In addition, the federal government is authorized, under prescribed conditions, to reallocate coal and to require the transportation thereof, for the use at power plants or major fuel-burning installations experiencing fuel shortages.

***Natural Gas**:* Through its public utility subsidiaries, AEP consumed over 104 billion cubic feet of natural gas during 2006 for generating power. A majority of the natural gas-fired power plants are connected to at least two pipelines, which allows greater access to competitive supplies and improves delivery reliability. A portfolio of long-term, monthly, seasonal firm and daily peaking purchase and transportation agreements (that are entered into on a competitive basis and based on market prices) supplies natural gas requirements for each plant.

Nuclear: I&M has made commitments to meet the current nuclear fuel requirements of the Cook Plant. I&M has made and will make purchases of uranium in various forms in the spot, short-term, and mid-term markets until it decides that deliveries under long-term supply contracts are warranted.

For purposes of the storage of high-level radioactive waste in the form of spent nuclear fuel, I&M completed modifications to its spent nuclear fuel storage pool more than 10 years ago. I&M anticipates that the Cook Plant has sufficient storage capacity for its spent nuclear fuel to permit normal operations through 2013. I&M has initiated a project to study the use of dry cask storage.

Nuclear Waste and Decommissioning

As the owner of the Cook Plant, I&M has a significant future financial commitment to dispose of spent nuclear fuel and decommission and decontaminate the plant safely. The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. The estimated cost of decommissioning and disposal of low-level radioactive waste for the Cook Plant ranges from $733 million to $1.3 billion in 2006 nondiscounted dollars. At December 31, 2006, the total decommissioning trust fund balance for the Cook Plant was $974 million. The ultimate cost of retiring the Cook Plant may be materially different from estimates and funding targets as a result of the:

- Type of decommissioning plan selected;
- Escalation of various cost elements (including, but not limited to, general inflation and the cost of energy);
- Further development of regulatory requirements governing decommissioning;
- Limited availability to date of significant experience in decommissioning such facilities;
- Technology available at the time of decommissioning differing significantly from that assumed in studies;
- Availability of nuclear waste disposal facilities; and

- Availability of a DOE facility for permanent storage of spent nuclear fuel.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant will not be significantly different than current projections.

See Note 10 to the consolidated financial statements, entitled *Nuclear*, included in the 2006 Annual Reports, for information with respect to nuclear waste and decommissioning.

Low-Level Radioactive Waste: The LLWPA mandates that the responsibility for the disposal of low-level radioactive waste rests with the individual states. Low-level radioactive waste consists largely of ordinary refuse and other items that have come in contact with radioactive materials. Michigan does not currently have a disposal site for such waste available. I&M cannot predict when such a site may be available, but South Carolina and Utah operate low-level radioactive waste disposal sites and currently accept low-level radioactive waste from Michigan. I&M's access to the South Carolina facility is currently allowed through the end of fiscal year 2008. There is currently no set date limiting I&M's access to the Utah facility.

Structured Arrangements Involving Capacity, Energy, and Ancillary Services

In January 2000, OPCo and NPC, an affiliate of Buckeye, entered into an agreement relating to the construction and operation of a 510 MW gas-fired electric generating peaking facility to be owned by NPC and called the Mone Plant. OPCo is entitled to 100% of the power generated by the Mone Plant, and is responsible for the fuel and other costs of the facility through May 2007, as extended. Following that, NPC and OPCo will be entitled to 80% and 20%, respectively, of the power of the Mone Plant, and both parties will generally be responsible for their allocable portion of the fuel and other costs of the facility.

Certain Power Agreements

AEGCo: Since its formation in 1982, AEGCo's business has consisted of the ownership and financing of its 50% interest in Unit 1 of the Rockport Plant and, since 1989, its 50% leasehold interest in Unit 2 of the Rockport Plant. Substantially all of the operating revenues of AEGCo are derived from the sale of capacity and energy associated with its interest in the Rockport Plant to I&M and KPCo pursuant to unit power agreements, which have been approved by the FERC.

The I&M Power Agreement provides for the sale by AEGCo to I&M of all the capacity (and the energy associated therewith) available to AEGCo at the Rockport Plant. Whether or not power is available from AEGCo, I&M is obligated to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M). When added to amounts received by AEGCo from any other sources, such amounts will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by FERC, currently 12.16%. The I&M Power Agreement will continue in effect until the last of the lease terms of Unit 2 of the Rockport Plant has expired (currently December 2022) unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the capacity (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo the amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo unit power agreement expires in December 2022.

AEGCo and AEP have entered into a capital funds agreement pursuant to which, among other things, AEP has unconditionally agreed to make cash capital contributions, or in certain circumstances subordinated loans, to AEGCo to the extent necessary to enable AEGCo to (i) maintain such an equity component of capitalization as required by governmental regulatory authorities; (ii) provide its proportionate share of the funds required to permit commercial operation of the Rockport Plant; (iii) enable AEGCo to perform all of its obligations, covenants and agreements under, among other things, all loan agreements, leases and related documents to which AEGCo is or becomes a party (AEGCo Agreements); and (iv) pay all indebtedness, obligations and liabilities of AEGCo (AEGCo Obligations) under the AEGCo Agreements, other than indebtedness, obligations or liabilities owing to AEP. The capital funds agreement will terminate after all AEGCo obligations have been paid in full.

OVEC: AEP and several unaffiliated utility companies jointly own OVEC. The aggregate equity participation of AEP in OVEC is 43.47%. Until September 1, 2001, OVEC supplied from its generating capacity the power requirements of a uranium enrichment plant near Portsmouth, Ohio owned by the DOE. The sponsoring companies are now entitled to receive and obligated to pay for all OVEC capacity (approximately 2,200 MW) in proportion to their respective power participation ratios. The aggregate power participation ratio of APCo, CSPCo, I&M and OPCo is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and to provide a return on its equity capital. The Amended and Restated Inter-Company Power Agreement, which defines the rights of the owners and sets the power participation ratio of each, will expire by its terms on March 12, 2026. AEP and the other owners have been evaluating the need for environmental investments related to their ownership interests, which are material. In December 2006, OVEC's Board of Directors authorized interim capital expenditures totaling $366 million in order to complete detailed engineering and begin construction of flue gas desulfurization (sulfur dioxide scrubber) projects and the associated scrubber waste disposal landfills. If approved, the estimated total cost to complete the projects would be slightly in excess of $1 billion, which OVEC would expect to finance through issuing debt.

Buckeye: On October 1, 2004, AEP joined PJM, and the Buckeye transmission service over the AEP System was transferred under the PJM Open Access Transmission Tariff (OATT). The Cardinal Station Agreement between OPCO and Buckeye contains a provision that expired in May 2006. Under that provision, Buckeye was entitled to receive, and was obligated to pay for, the excess of its maximum one-hour coincident peak demand plus a 15% reserve margin over the 1,226,500 kilowatts of capacity of the generating units which Buckeye currently owns in the Cardinal Station. Such demand, which occurred on July 25, 2005, was recorded at 1,434,807 kilowatts. With the expiration of that provision, Buckeye is entitled to receive and must pay for power in amounts equal to its proportionate share of the station.

ELECTRIC TRANSMISSION AND DISTRIBUTION

General

AEP's public utility subsidiaries (other than AEGCo) own and operate transmission and distribution lines and other facilities to deliver electric power. See *Item 2—Properties* for more information regarding the transmission and distribution lines. Most of the transmission and distribution services are sold, in combination with electric power, to retail customers of AEP's public utility subsidiaries in their service territories. These sales are made at rates established and approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC. See *Regulation—Rates*. The FERC regulates and approves the rates for wholesale transmission transactions. See *Item 1 – Business/Utility Operations - Regulation—FERC*. As discussed below, some transmission services also are separately sold to non-affiliated companies.

AEP's public utility subsidiaries (other than AEGCo) hold franchises or other rights to provide electric service in various municipalities and regions in their service areas. In some cases, these franchises provide the utility with the exclusive right to provide electric service. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business. For a discussion of competition in the sale of power, see *Item 1 – Business/Utility Operations - Competition*.

AEP Transmission Pool

Transmission Equalization Agreement: APCo, CSPCo, I&M, KPCo and OPCo operate their transmission lines as a single interconnected and coordinated system and are parties to the TEA, defining how they share the costs and benefits associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345kV and above) and certain facilities operated at lower voltages (138kV up to 345kV). The TEA has been approved by the FERC. Sharing under the TEA is based upon each company's "member-load-ratio." The member-load-ratio is calculated monthly by dividing such company's highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all east zone operating companies. The respective peak demands and member-load-ratios as of December 31, 2006 are set forth above in the section titled *ELECTRIC GENERATION* – AEP Power Pool and CSW Operating Agreement.

The following table shows the net (credits) or charges allocated among the parties to the TEA during the years ended December 31, 2004, 2005 and 2006:

	2004	**2005**	**2006**
		(in thousands)	
APCo	$(500)	$8,900	$(16,000)
CSPCo	37,700	34,600	46,000
I&M	(40,800)	(47,000)	(37,000)
KPCo	(6,100)	(3,500)	(2,000)
OPCo	9,700	7,000	9,000

Transmission Coordination Agreement: PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with the responsibility of (i) overseeing the coordinated planning of the transmission facilities of the AEP West companies, including the performance of transmission planning studies, (ii) the interaction of such subsidiaries with independent system operators and other regional bodies interested in transmission planning and (iii) compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the AEP West companies have delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the AEP OATT on their behalf. Prior to September 2005, the TCA also provided for the allocation among the AEP West companies of revenues collected for transmission and ancillary services provided under the AEP OATT. Since then, these allocations have been determined by the FERC-approved OATT for the SPP (with respect to PSO and SWEPCo) and PUCT-approved protocols for ERCOT (with respect to TCC and TNC).

The following table shows the net (credits) or charges allocated among the parties to the TCA prior to September 2005, and pursuant to the SPP OATT and ERCOT protocols as described above during the years ended December 31, 2004, 2005 and 2006:

	2004	**2005**	**2006**
		(in thousands)	
PSO	$8,100	$3,500	$1,800
SWEPCo	13,800	5,200	(1,900)
TCC	(12,200)	(3,800)	1,100
TNC	(9,700)	(4,900)	(1,000)

Transmission Services for Non-Affiliates: In addition to providing transmission services in connection with their own power sales, AEP's public utility subsidiaries through RTOs also provide transmission services for non-affiliated companies. See *Item 1 – Business/Utility operations - Regional Transmission Organizations*, below. Transmission of electric power by AEP's public utility subsidiaries is regulated by the FERC.

Coordination of East and West Zone Transmission: AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP East and AEP West companies. The System Transmission Integration Agreement functions as an umbrella agreement in addition to the TEA and the TCA. The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues and

- The allocation of third-party transmission costs and revenues and System dispatch costs.

The System Transmission Integration Agreement contemplates that additional service schedules may be added as circumstances warrant.

Regional Transmission Organizations

On April 24, 1996, the FERC issued orders 888 and 889. These orders require 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 tariffs in making off-system and third-party sales. As part of the orders, the FERC issued a *pro-forma* tariff that reflects the Commission's views on the minimum non-price terms and conditions for non-discriminatory transmission service. In addition, the orders require all transmitting utilities to establish an OASIS, which electronically posts transmission information such as available capacity and prices, and require utilities to comply with Standards of Conduct that prohibit utilities' system operators from providing non-public transmission information to the utility's merchant energy employees. The orders also allow a utility to seek recovery of certain prudently incurred stranded costs that result from unbundled transmission service.

In December 1999, FERC issued Order 2000, which provides for the voluntary formation of RTOs, entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals. As a condition of FERC's approval in 2000 of AEP's merger with CSW, AEP was required to transfer functional control of its transmission facilities to one or more RTOs. The AEP East Companies integrated into PJM (a FERC-approved RTO) on October 1, 2004.

SWEPCo and PSO are members of the SPP. In February 2004, the FERC conditionally approved SPP as an RTO. In October 2004, the FERC issued an order granting RTO status to SPP subject to certain filings. The APSC and LPSC have ordered the utilities in those states, including our utilities, to analyze and submit to them the costs and benefits of RTO options available to the utilities. Certain states in the region have undertaken and released a study investigating the costs and benefits of SPP developing into a RTO that administers energy and associated markets. On August 10, 2006, the APSC issued an order approving, among other things, SWEPCo's participation in SPP, subject to certain reporting and continuing oversight conditions.

The remaining AEP West companies (TCC and TNC) are members of ERCOT.

See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2006 Annual Reports under the heading entitled *RTO Formation/Integration Costs* and *Transmission Rate Proceedings at the FERC* for a discussion of public utility subsidiary participation in RTOs.

REGULATION

General

Except for retail generation sales in Ohio, Virginia and the ERCOT area of Texas, AEP's public utility subsidiaries' retail rates and certain other matters are subject to traditional regulation by the state utility commissions. While still regulated, retail sales in Michigan are now made at unbundled rates. See *Item 1 – Utility Operations - Electric Restructuring and Customer Choice Legislation* and *Rates*, below. AEP's subsidiaries are also subject to regulation by the FERC under the FPA. I&M is subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant. AEP and its public utility subsidiaries are also subject to the regulatory provisions of EPACT, much of which is administered by the FERC. EPACT contains key provisions affecting the electric power industry such as giving the FERC "backstop" transmission siting authority as well as increased utility merger oversight. The law also provides incentives and funding for clean coal technologies and initiatives to voluntarily reduce greenhouse gases.

Rates

Historically, state utility commissions have established electric service rates on a cost-of-service basis, which is designed to allow a utility an opportunity to recover its cost of providing service and to earn a reasonable return on its investment used in providing that service. A utility's cost of service generally reflects its operating expenses, including operation and maintenance expense, depreciation expense and taxes. State utility commissions periodically adjust rates pursuant to a review of (i) a utility's revenues and expenses during a defined test period and (ii) such utility's level of investment. Absent a legal limitation, such as a law limiting the frequency of rate changes or capping rates for a period of time as part of a transition to customer choice of generation suppliers, a state utility commission can review and change rates on its own initiative. Some states may initiate reviews at the request of a utility, customer, governmental or other representative of a group of customers. Such parties may, however, agree with one another not to request reviews of or changes to rates for a specified period of time.

In many jurisdictions, the rates of AEP's public utility subsidiaries are generally based on the cost of providing traditional bundled electric service (i.e., generation, transmission and distribution service). In the ERCOT area of Texas, our utilities have exited the generation business and they currently charge unbundled cost-based rates for transmission and distribution service. In Ohio, rates are transitioning from bundled cost-based rates for electric service to unbundled cost-based rates for transmission and distribution service on the one hand, and market pricing for and/or customer choice of generation on the other. Historically, the state regulatory frameworks in the service area of the AEP System reflected specified fuel costs as part of bundled (or, more recently, unbundled) rates or incorporated fuel adjustment clauses in a utility's rates and tariffs. Fuel adjustment clauses permit periodic adjustments to fuel cost recovery from customers and therefore provide protection against exposure to fuel cost changes. While the historical framework remains in a portion of AEP's service territory, recovery of increased fuel costs through a fuel adjustment clause is no longer provided for in Ohio.

The following state-by-state analysis summarizes the regulatory environment of certain major jurisdictions in which AEP operates. Several public utility subsidiaries operate in more than one jurisdiction.

Indiana: I&M provides retail electric service in Indiana at bundled rates approved by the IURC. While rates are set on a cost-of-service basis, I&M's base rates are capped through June 30, 2007. Its fuel recovery rate is capped through that time period at a level that automatically increased in January 2006 and January 2007. I&M expects, however, that its actual fuel costs will exceed the capped fuel rates permitted through June 30, 2007.

Ohio*:* CSPCo and OPCo each operated as a functionally separated utility and provided "default" retail electric service to customers at unbundled rates pursuant to the Ohio Act through December 31, 2006. The PUCO approved the rate stabilization plans filed by CSPCo and OPCo (which, among other things, address default retail generation service rates from January 1, 2006 through December 31, 2008). The Ohio Supreme Court vacated and remanded the PUCO's approval of the rate stabilization plans. In response, the PUCO issued an order requiring CSPCo and OPCo to make additional filings and holding that their rate stabilization plans remained in effect. CSPCo and OPCo have submitted proposals with the PUCO addressing the matters identified by the PUCO. Retail generation rates will be determined consistent with the rate stabilization plan until December 31, 2008. CSPCo and OPCo are providing and will continue to provide distribution services to retail customers at rates approved by the PUCO. These rates will be frozen (with certain exceptions, including automatic annual increases in generation rates of 3% and 7% for CSPCo and OPCo, respectively) from their levels as of December 31, 2005 through December 31, 2008. Transmission services will continue to be provided at rates established by the FERC. CSPCo and OPCo have been involved in discussions with various stakeholders in Ohio about potential legislation to address the period following the expiration of the rate stabilization plans. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2006 Annual Reports, for more information.

Oklahoma*:* PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above the amount included in base rates are recovered by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is generally adjusted annually and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers when new annual factors are established. In November 2006, PSO filed a request with the OCC seeking an increase in base rates and other rate relief. The OCC has not yet ruled on this filing. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2006 Annual Reports, for information regarding current rate proceedings.

Texas: TCC has sold all of its generation assets and TNC has transferred its active generation capacity to a non-utility affiliate pursuant to a 20-year agreement. TCC and TNC serve most of their retail customers in the ERCOT area of Texas through non-affiliated REPs. TCC and TNC provide retail transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. In November 2006, TCC and TNC filed requests with the PUCT seeking increases in the rates charged to REPs for delivering electricity over their transmission and distribution lines. The PUCT has not ruled on the filings. See Note 4 to the consolidated financial statements, entitled *Rate Matters* included in the 2006 Annual Reports, for information on current rate proceedings. In August 2006, the PUCT delayed competition in the SPP area of Texas until at least January 1, 2011. As such, SWEPCo's Texas operations continue to operate and to be regulated as a traditional bundled utility with both base and fuel rates.

Virginia: APCo provides retail electric service in Virginia at unbundled rates. In February 2007, the Virginia legislature adopted amendments to its previously-enacted electric restructuring law. The amendments would cut two years off of the transition period (from 2010 to 2008) after which rates for retail generation supply would return to a form of cost-based regulation. The Governor of Virginia has not yet signed this legislation. APCo's unbundled generation, transmission (which reflect FERC-approved transmission rates) and distribution rates, as well as its functional separation plan, were approved by the VSCC in December 2001. APCO's base rates are capped at their mid-1999 levels until the end of the transition period (now December 31, 2010), or sooner if the VSCC finds that a competitive market for generation exists in Virginia, but APCo is permitted to seek two changes to its capped rates through December 31, 2010. In addition, APCo is entitled to annual rate changes to recover the incremental costs it incurs for transmission and distribution reliability and compliance with state or federal environmental laws or regulations. In May 2006, APCo filed a request with the VSCC seeking an increase in base rates. Hearings on this request were held in December 2006. APCo expects a ruling in 2007. APCo is entitled to adjustments to fuel rates through 2010 to recover its actual fuel costs, the fuel component of its purchased power costs and certain capacity charges. APCo recovers its generation capacity charges through capped base rates. In November 2006, the VSCC approved APCo's previous request to recover additional environmental and reliability-related costs. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2006 Annual Reports, for additional information on these matters.

West Virginia: APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC. West Virginia generally allows for timely recovery of fuel costs. In July 2006, the WVPSC approved an increase in the retail rates of APCo and WPCo and the reactivation of their suspended operative fuel clause and other recovery mechanisms. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2006 Annual Reports, for additional information on current rate proceedings.

Other Jurisdictions: The public utility subsidiaries of AEP also provide service at regulated bundled rates in Arkansas, Kentucky, Louisiana and Tennessee and regulated unbundled rates in Michigan.

The following table illustrates the current rate regulation status of the states in which the public utility subsidiaries of AEP operate:

	Status of Base Rates for		**Fuel Clause Rates(6)**		
Jurisdiction	**Power Supply**	**Energy Delivery**	**Status**	**Off-System Sales Profits Shared with Ratepayers**	**Percentage of AEP System Retail Revenues(1)**
Ohio	See footnote 2	Distribution frozen through 2008(2)	None	Not applicable	32%
Oklahoma	Not capped or frozen	Not capped or frozen	Active	Yes	14%
Texas ERCOT	Not applicable (3)	Not capped or frozen	Not applicable	Not applicable	7%
Texas SPP	Not capped or frozen	Not capped or frozen	Active	Yes	5%
Indiana	Capped until 6/30/07	Capped until 6/30/07	Capped until 6/30/07 (4)	No	10%
Virginia	Capped until as late as 12/31/10(5)	Capped until as late as 12/31/10(5)	Active	No	9%
West Virginia	Not capped or frozen	Not capped or frozen	Active	No	9%
Louisiana	Not capped or frozen	Not capped or frozen	Active	Yes, above base levels	4%
Kentucky	Not capped or frozen	Not capped or frozen	Active	Yes, above and below base levels	4%
Arkansas	Not capped or frozen	Not capped or frozen	Active	Yes, above base levels	3%
Michigan	Not capped or frozen	Not capped or frozen	Active	Yes, in some areas	2%
Tennessee	Not capped or frozen	Not capped or frozen	Active	No	1%

(1) Represents the percentage of revenues from sales to retail customers from AEP utility companies operating in each state to the total AEP System revenues from sales to retail customers for the year ended December 31, 2006.

(2) The PUCO has approved the rate stabilization plan filed by CSPCo and OPCo that began after the market development period and extends through December 31, 2008 during which OPCo's retail generation rates will increase 7% annually and CSPCo's retail generation rates will increase 3% annually. Distribution rates are frozen, with certain exceptions, through December 31, 2008. The rate stabilization plans have been the subject of litigation. At the PUCO's request, CSPCo and OPCo have submitted proposals addressing those matters identified by the commission. See Note 4 to the Consolidated Financial Statements, entitled *Rate Matters.*

(3) TCC and TNC are no longer in the retail generation supply business. Retail electric service in the ERCOT area of Texas is provided to most customers through unaffiliated REPs with TCC and TNC providing only regulated delivery services. SWEPCo and an affiliated REP provide retail electric service in the SPP area of Texas. All customers of the affiliated REP were transferred to SWEPCo with the first billing cycle in February 2007.

(4) Fuel rates capped through June 2007 billing month subject to certain events at the Cook Plant.

(5) Legislation passed in 2004 capped base rates until December 31, 2010 and expanded the rate change opportunities to one full rate case (including generation, transmission and distribution) between July 1, 2004 and June 30, 2007 (which has been filed) and one additional full rate case between July 1, 2007 and December 31, 2010. The law also permits APCo to recover, on a timely basis, incremental costs incurred on and after July 1, 2004 for transmission and distribution reliability purposes and to comply with state and federal environmental laws and regulations. In February 2007, the Virginia legislature adopted amendments to its previously-enacted electric restructuring law. The amendments would cut two years off of the transition period (from 2010 to 2008) after which rates for retail generation supply would return to a form of cost-based regulation. The Governor of Virginia has not yet signed this legislation.

(6) Includes, where applicable, fuel and fuel portion of purchased power.

FERC

Under the FPA, FERC regulates rates for interstate sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. FERC regulations require AEP to provide open access transmission service at FERC-approved rates. FERC also regulates unbundled transmission service to retail customers. FERC also regulates the sale of power for resale in interstate commerce by (i) approving contracts for wholesale sales to municipal and cooperative utilities and (ii) granting authority to public utilities to sell power at wholesale at market-based rates upon a showing that the seller lacks the ability to improperly influence market prices. Except for wholesale power that AEP delivers within its control area of the SPP, AEP has market-rate authority from FERC, under which much of its wholesale marketing activity takes place.

The FERC has jurisdiction over the issuances of securities of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both FERC and state regulators are permitted to review the books and records of any company within a holding company system. EPACT gives the FERC "backstop" transmission siting authority as well as increased utility merger oversight.

ELECTRIC RESTRUCTURING AND CUSTOMER CHOICE LEGISLATION

Certain states in AEP's service area have adopted restructuring or customer choice legislation. In general, this legislation provides for a transition from bundled cost-based rate regulated electric service to unbundled cost-based rates for transmission and distribution service and market pricing for the supply of electricity with customer choice of supplier. At a minimum, this legislation allows retail customers to select alternative generation suppliers. Electric restructuring and/or customer choice began on January 1, 2001 in Ohio and on January 1, 2002 in Michigan, Virginia and the ERCOT area of Texas. Electric restructuring in the SPP area of Texas has been delayed by the PUCT until at least 2011. AEP's public utility subsidiaries operate in both the ERCOT and SPP areas of Texas. See Note 4 to the consolidated financial statements entitled *Rate Matters* for additional information.

Ohio Restructuring

The Ohio Act requires vertically integrated electric utility companies that are in the business of providing competitive retail electric service in Ohio to separate their generating functions from their transmission and distribution functions. Following the market development period (which ended December 31, 2005), retail customers receive distribution and, where applicable, transmission service from the incumbent utility whose distribution rates are approved by the PUCO and whose transmission rates are based on rates established by the FERC. The PUCO approved CSPCo's and OPCo's rate stabilization plans that, among other things, addressed default generation service rates from January 1, 2006 through December 31, 2008. See *Item 1 – Utility Operations - Regulation—FERC* for a discussion of FERC regulation of transmission rates, *Regulation—Rates—Ohio* and Note 4 to the consolidated financial statements entitled *Rate Matters*, included in the 2006 Annual Reports, for a discussion of the impact of restructuring on distribution rates. The PUCO authorized CSPCo and OPCo to remain functionally separated through the end of that three-year period. The Supreme Court of Ohio vacated and remanded the PUCO's order authorizing the rate stabilization plans. In response, the PUCO issued an order in August 2006 requiring CSPCo and OPCo to make additional filings and holding that the rate stabilization plans remained in effect. CSPCo and OPCo have submitted proposals with the PUCO addressing the matters identified by the PUCO. CSPCo and OPCo have been involved in discussions with various stakeholders in Ohio about potential legislation to address the period following the expiration of the rate stabilization plans.

Texas Restructuring

Signed into law in June of 1999, the Texas Act substantially amended the regulatory structure governing electric utilities in Texas in order to allow retail electric competition for customers. Among other things, the Texas Act:

- gave Texas customers the opportunity to choose their REP beginning January 1, 2002 (delayed until at least 2011 in the SPP portion of Texas),
- required each utility to legally separate into a REP, a power generation company, and a transmission and distribution utility, and
- required that REPs provide electricity at generally unregulated rates, except that until January 1, 2007 the prices that may be charged to residential and small commercial customers by REPs affiliated with a utility within the affiliated utility's service area are set by the PUCT, until certain conditions in the Texas Act are met.

The Texas Act provides each affected utility an opportunity to recover its generation related regulatory assets and stranded costs resulting from the legal separation of the transmission and distribution utility from the generation facilities and the related introduction of retail electric competition. Regulatory assets consist of the Texas jurisdictional amount of generation-related regulatory assets and liabilities in the audited financial statements as of December 31, 1998. Stranded costs consist of the positive excess of the net regulated book value of generation assets (as of December 31, 2001) over the market value of those assets, taking specified factors into account, as ultimately determined in a PUCT true-up proceeding.

In May 2005, TCC filed its stranded cost quantification application, or true-up proceeding, with the PUCT seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items. A final order was issued in April 2006. In the final order, the PUCT determined TCC's net stranded generation costs and other recoverable true-up items to be approximately $1.475 billion. Other parties have appealed the PUCT's final order as unwarranted or too large; TCC has appealed seeking additional recovery consistent with the Texas Act and related rules. In a preliminary ruling filed in February 2007, the Texas state district court adjudicating the appeal of the final order in the true-up proceeding found that the PUCT erred in several respects, including the method used to determine stranded costs and the awarding of certain carrying costs. Following the preliminary ruling, the court granted a rehearing of the issue regarding the method to determine stranded costs. That rehearing is scheduled for late March 2007. TCC intends to appeal any final adverse rulings regarding the PUCT's order in the true-up proceedings.

After PUCT approval, in October 2006 TCC issued $1.74 billion of securitization bonds, including additional issuance and carrying costs through the date of issuance. The PUCT authorized negative competition transition charges in the amount of $356 million in October 2006. TCC is required to refund this amount to its ratepayers. For a discussion of (i) regulatory assets and stranded costs subject to recovery by TCC and (ii) rate adjustments made after implementation of restructuring to allow recovery of certain costs by or with respect to TCC and TNC, see Note 4 to the consolidated financial statements entitled *Rate Matters* included in the 2006 Annual Reports.

Michigan Customer Choice

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Rates for retail electric service for I&M's Michigan customers were unbundled (though they continue to be regulated) to allow customers the ability to evaluate the cost of generation service for comparison with other suppliers. At December 31, 2006, none of I&M's Michigan customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory.

Virginia Restructuring

In April 2004, the Governor of Virginia signed legislation that extends the transition period for electricity restructuring, including capped rates, through December 31, 2010. The legislation provides specified cost recovery opportunities during the capped rate period, including two optional general base rate changes and an opportunity for timely recovery, through a separate rate mechanism, of certain incremental environmental and reliability costs incurred on and after July 1, 2004. In February 2007, the Virginia legislature adopted amendments to its previously-enacted electric restructuring law. The amendments would cut two years off of the transition period (from 2010 to 2008) after which rates for retail generation supply would return to a form of cost-based regulation. The Governor of Virginia has not yet signed this legislation.

COMPETITION

The public utility subsidiaries of AEP, like the electric industry generally, face competition in the sale of available power on a wholesale basis, primarily to other public utilities and power marketers. The Energy Policy Act of 1992 was designed, among other things, to foster competition in the wholesale market by creating a generation market with fewer barriers to entry and mandating that all generators have equal access to transmission services. As a result, there are more generators able to participate in this market. The principal factors in competing for wholesale sales are price (including fuel costs), availability of capacity and power and reliability of service.

AEP's public utility subsidiaries also compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil and coal, within their service areas. The primary factors in such competition are price, reliability of service and the capability of customers to utilize sources of energy other than electric power. With respect to competing generators and self-generation, the public utility subsidiaries of AEP believe that they generally maintain a favorable competitive position. With respect to alternative sources of energy, the public utility subsidiaries of AEP believe that the reliability of their service and the limited ability of customers to substitute other cost-effective sources for electric power place them in a favorable competitive position, even though their prices may be higher than the costs of some other sources of energy.

Significant changes in the global economy in recent years have led to increased price competition for industrial customers in the United States, including those served by the AEP System. Some of these industrial customers have requested price reductions from their suppliers of electric power. In addition, industrial customers that are downsizing or reorganizing often close a facility based upon its costs, which may include, among other things, the cost of electric power. The public utility subsidiaries of AEP cooperate with such customers to meet their business needs through, for example, providing various off-peak or interruptible supply options pursuant to tariffs filed with the various state commissions. Occasionally, these rates are first negotiated, and then filed with the state commissions. The public utility subsidiaries of AEP believe that they are unlikely to be materially adversely affected by this competition.

SEASONALITY

The sale of electric power is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of AEP's facilities and the terms of power sale contracts into which AEP enters. In addition, AEP has historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish AEP's results of operations and may impact its financial condition. Conversely, unusually extreme weather conditions could increase AEP's results of operations.

MEMCO OPERATIONS

Our MEMCO business segment transports coal and dry bulk commodities primarily on the Ohio, Illinois, and Lower Mississippi rivers. Almost all of our customers are nonaffiliated third parties who obtain the transport coal and dry bulk commodities for various uses. We charge these customers market rates for the purpose of making a profit. Depending on market conditions and other factors, including barge availability, we have also served AEP utility subsidiary affiliates. Our affiliated utility customers procure the transport of coal for use as fuel in their respective generating plants. We charge affiliated customers rates that reflect our costs. The MEMCO operations include approximately 2,038 barges, 37 towboats and 10 harbor boats that we own or lease.

Competition within the barging industry for major commodity contracts is intense, with a number of companies offering transportation services in the waterways we serve. We compete with other carriers primarily on the basis of commodity shipping rates, but also with respect to customer service, available routes, value-added services (including scheduling convenience and flexibility), information timeliness and equipment. Since 1980, the industry has experienced consolidation. The resulting companies increasingly offer the widespread geographic reach necessary to support major national customers. Demand for barging services can be seasonal, particularly with respect to the movement of harvested agricultural commodities (beginning in the late summer and extending through the fall.) Cold winter weather may also limit our operations when certain of the waterways we serve are closed.

Our transportation operations are subject to regulation by the U.S. Coast Guard, federal laws, state laws and certain international conventions. Legislation has been proposed that could make our towboats subject to inspection by the U.S. Coast Guard.

GENERATION AND MARKETING

Our generation and marketing business segment consists of non-utility generating assets and as of January 2007, a competitive power supply and energy trading business. We enter into short and long-term transactions to buy or sell capacity, energy, and ancillary services primarily in the ERCOT market. The assets utilized in this segment include approximately 791 MW of domestic wind power and gas-fired generation facilities (of which AEP ownership is approximately 551 MW) and, since January 2007, 377 MW of coal-fired capacity obtained from TNC's interest in the Oklaunion power station. TNC has entered into a 20-year power agreement transferring this generating capacity to a non-utility affiliate that we operate in order to comply with the separation requirements of the Texas Act. The power obtained from the Oklaunion power station is to be marketed and sold in ERCOT. We are regulated by the PUCT for transactions inside ERCOT and by the FERC for transactions outside of ERCOT. While peak load in ERCOT typically occurs in the summer, we do not necessarily expect seasonal variation in our operations.

OTHER

Gas Operations

In January 2005, we sold a 98% controlling interest in HPL and related assets with the remaining 2% interest being sold to the buyer in November 2005. See Note 8 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments, and Assets Held for Sale*, included in the 2006 Annual Reports for more information. As a result, management anticipates that our gas marketing operations will be limited to managing our obligations with respect to the gas transactions entered into before these sales.

Plaquemine Cogeneration Facility

Pursuant to an agreement with Dow, AEP constructed an 880 MW cogeneration facility ("Facility") at Dow's chemical facility in Plaquemine, Louisiana that achieved commercial operation status in 2004. Dow used a portion of the energy produced by the Facility and sold the excess power to us. We agreed to sell up to all of the excess 800 MW to Tractebel. That power agreement is currently being litigated. See Note 6 to the consolidated financial statements entitled *Commitments, Guarantees and Contingencies*. In November 2006, we sold our interest in the Facility to Dow. Negotiations for the sale resulted in an after-tax impairment of approximately $136 million. See Note 8 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments and Assets Held for Sale.*

For information regarding other non-core investments, see Note 8 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments and Assets Held for Sale,* included in the 2006 Annual Reports.

ITEM 1A. RISK FACTORS

General Risks of Our Regulated Operations

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions. *(Applies to each registrant.)*

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits, construction and/or acquisition of additional generation units and transmission facilities, modernizing existing infrastructure as well as other initiatives. Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates we charge, we would not be able to recover the costs associated with our planned extensive investment. This would cause our financial results to be diminished. While we may seek to limit the impact of any denied recovery by attempting to reduce the scope of our capital investment, there can be no assurance as to the effectiveness of any such mitigation efforts, particularly with respect to previously incurred costs and commitments.

Our planned capital investment program coincides with a material increase in the price of the fuels used to generate electricity. Many of our jurisdictions have fuel clauses that permit us to recover these increased fuel costs through rates without a general rate case. While prudent capital investment and variable fuel costs each generally warrant recovery, in practical terms our regulators could limit the amount or timing of increased costs that we would recover through higher rates. Any such limitation could cause our financial results to be diminished.

Our request for rate recovery of additional costs may not be approved in Virginia. *(Applies to AEP and APCo.)*

APCo filed a request with the VSCC in May 2006 seeking a net increase in base rates of $198 million to recover increasing costs, including a return on equity of 11.5%. APCo also requested to apply its off-system sales margins (currently credited to customers through base rates) to the fuel factor where they can be adjusted annually. APCo also requested to retain a portion of the off-system sales margins. In May 2006, the VSCC issued an order placing the net requested base rate increase into effect as of October 2, 2006, subject to refund. In October 2006, the VSCC staff filed direct testimony recommending a base rate increase of $13 million with a return on equity of 9.9% and no off-system sales margin sharing. Other intervenors have recommended base rate increases ranging from $42 million to $112 million. APCo has filed rebuttal testimony and hearings were held in December 2006. If the VSCC denies the requested rate recovery, it could adversely impact future results of operations and cash flows.

Our request for rate recovery of additional costs may not be approved in Texas. *(Applies to AEP, TCC and TNC.)*

TCC and TNC have filed requests with the PUCT to increase their transmission and distribution rates. The rate requests include the amounts charged for the delivery of electricity over TCC´s and TNC´s transmission and distribution lines. TCC is seeking approval of an $81 million increase, which includes the expiration of $20 million in billing credits that the PUCT required in approving the merger of CSW into AEP. The credits have been in place since 2000. TNC is seeking approval of a $25 million increase, which includes the expiration of $6.2 million in billing credits. TCC and TNC are requesting a return on equity of 11.25% with a capital structure of approximately 60% debt/40% equity. If the PUCT denies the requested rate recovery, it could adversely impact future results of operations and cash flows.

Our request for rate recovery of additional costs may not be approved in Oklahoma. *(Applies to AEP and PSO.)*

PSO filed a request with the OCC in November, 2006 seeking approval of a $50 million overall increase in base rates, an annually adjusted rate mechanism to recover the expected significant investment PSO will be making in new facilities, several new and restructured tariffs to allow PSO to begin to reduce the relationship between its revenues and its sales volumes, and to implement some demand side management tariffs. PSO´s planned investments over the next five years include new generation facilities ($1.12 billion), new and refurbished transmission substations and lines ($302 million) and new distribution lines and equipment ($582 million). If the OCC denies the requested rate recovery, it could adversely impact future results of operations and cash flows.

We may not be able to recover all of our fuel costs in Indiana. *(Applies to AEP and I&M.)*

I&M entered into a settlement agreement which the IURC approved in 2005. The approved settlement caps fuel rates through June 2007 at increasing rates during agreed-upon intervals. I&M has experienced a cumulative under-recovery of fuel costs through December 2006. If future fuel costs through June 30, 2007 continue to exceed the agreed-upon caps, future results of operations and cash flows would be adversely affected.

The rates that SWEPCo may charge its customers may be reduced. *(Applies to SWEPCo.)*

At the time of the CSW merger, SWEPCO agreed to file with the LPSC detailed financial information typically utilized in a revenue requirement filing on a periodic basis in order to demonstrate the lack of adverse impact from the merger. The first such filing was in October 2002 and the second was in April 2004. Both filings indicated SWEPCo's rates should not be reduced. In April 2006, the LPSC and SWEPCo agreed to update the financial information based on a 2005 test year. SWEPCo filed financial review schedules in May 2006 showing a return on equity of 9.44% compared to the previously authorized return on equity of 11.1%. In July 2006, consultants to the LPSC staff filed direct testimony recommending a base rate reduction in the range of $12 million to $20 million for SWEPCo's Louisiana jurisdiction customers, which included a 10% return on equity. The recommended reduction range is subject to SWEPCo validating certain on-going operations and maintenance expense levels and the recommended base rate reduction does not include the impact of a proposed consolidated federal income tax adjustment, which would increase the proposed rate reduction. SWEPCo filed rebuttal testimony in October 2006 refuting the consultants' recommendations. In December 2006, the LPSC staff's consultants filed reply testimony asserting that SWEPCo's Louisiana base rates are excessive by $17 million which includes a proposed return on equity of 9.8%. SWEPCo filed testimony in the first quarter of 2007. Hearings are expected to occur in early 2007. A decision is expected in mid-to-late 2007. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction were ultimately ordered, it would adversely impact future results of operations and cash flows.

The amount that PSO seeks to recover for fuel costs is currently being reviewed. *(Applies to PSO.)*

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO filed with the OCC offering to collect the under-recovery over 18 months. An intervenor, the staff of the OCC and the Attorney General of Oklahoma have made filings indicating that recovery should be reduced substantially or disallowed altogether. These filings disputed the allocation of AEP System off-system sales margins pursuant to an agreement approved by FERC. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices. The allocation issue was referred to an ALJ. The ALJ recommended that the OCC lacks authority to examine whether PSO deviated from the FERC allocation methodology and that any such complaints should be addressed at the FERC. The OCC conducted a hearing on the jurisdictional matter in January 2005 but has not issued a decision. If the OCC determines, as a result of the review, that a portion of PSO's fuel and purchased power costs should not be recovered, there could be an adverse effect on PSO's results of operations, cash flows and possibly financial condition.

The internal allocation of AEP System off-system sales margins has been challenged. *(Applies to APCo, CSPCo, I&M, KPCo and OPCo.)*

Off-system sales margins are allocated among the AEP System companies pursuant to a FERC-approved agreement among those companies entered into at the time of the merger with CSW. In November 2005, we filed with the FERC a proposed allocation methodology to be used in 2006 and beyond. The original allocations have been challenged in different forums, including PSO's fuel clause recovery proceeding before the OCC. In general, the challenges assert that AEP West companies, acquired in the merger with CSW, are being allocated a disproportionately small amount of the off-system sales margins. An ALJ in the OCC proceeding and, separately, a federal district court in Texas have each held that the FERC is the only appropriate adjudicator of such challenges. This holding has been affirmed by a federal appellate court. No proceeding questioning the allocation of our off-system sales is currently before the FERC; the OCC, however, has yet to rule on whether it has jurisdiction over this issue. If the FERC or another entity of competent authority were to retroactively allocate additional off-system sales margins to the AEP West companies, the AEP East companies may be required to pay money to the AEP West companies. Any such payments could have an adverse effect on the results of operations, cash flows and possibly financial condition of the AEP East companies.

The base rates that certain of our utilities charge are currently capped or frozen. *(Applies to AEP, CSPCo, I&M and OPCo.)*

Base rates charged to customers in Michigan and Ohio are currently either frozen or capped. To the extent our costs in these states exceed the applicable cap or frozen rate, those costs are not recoverable from customers.

Certain of our revenues and results of operations are subject to risks that are beyond our control. *(Applies to each registrant.)*

Unless mitigated by timely and adequate regulatory recovery, the cost of repairing damage to our utility facilities due to storms, natural disasters, wars, terrorist acts and other catastrophic events, in excess of insurance coverage, when applicable, may adversely impact our revenues, operating and capital expenses and results of operations. Such events may also create additional risks related to the supply and/or cost of equipment and materials.

We are exposed to nuclear generation risk. *(Applies to AEP and I&M.)*

Through I&M, we own the Cook Plant. It consists of two nuclear generating units for a rated capacity of 2,143 MW, or 6% of our generation capacity. We are, therefore, subject to the risks of nuclear generation, which include the following:

- the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials such as spent nuclear fuel;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations;
- uncertainties with respect to contingencies and assessment amounts if insurance coverage is inadequate (federal law requires owners of nuclear units to purchase the maximum available amount of nuclear liability insurance and potentially contribute to the losses of others); and,
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

There can be no assurance that I&M's preparations or risk mitigation measures will be adequate if and when these risks are triggered.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants such as ours. In addition, although we have no reason to anticipate a serious nuclear incident at our plants, if an incident did occur, it could harm our results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Moreover, a major incident at a nuclear facility in the U.S. could require us to make material contributory payments.

The different regional power markets in which we compete or will compete in the future have changing transmission regulatory structures, which could affect our performance in these regions. *(Applies to each registrant.)*

Our results are likely to be affected by differences in the market and transmission regulatory structures in various regional power markets. Problems or delays that may arise in the operation of new regional transmission organization (RTO) power markets, may restrict our ability to sell power produced by our generating capacity to certain markets if there is insufficient transmission capacity available to fully support market operation. The rules governing the various regional power markets may also change from time to time which could affect our costs or revenues. Because it remains unclear which companies will be participating in the various regional power markets, or the manner in which RTOs will evolve or the regions they will cover, we are unable to assess fully the impact that these power markets may have on our business.

AEP East companies joined PJM on October 1, 2004. SWEPCo and PSO are members of SPP. In February 2004, FERC granted RTO status to SPP, subject to fulfilling specified requirements. In October 2004, the FERC issued an order granting final RTO status to SPP subject to certain filings.

The LPSC has ordered the utilities subject to its jurisdiction, including SWEPCo, to analyze and submit to them the costs and benefits of RTO options available to the utilities. Certain states in the region have undertaken and released a study investigating the costs and benefits of SPP developing into a RTO that administers energy and associated markets.

To the extent we are faced with conflicting state and Federal requirements as to our participation in RTOs, it could adversely affect our ability to operate and recover transmission costs from retail customers. Management is unable to predict the outcome of these transmission regulatory actions and proceedings or their impact on the timing and operation of RTOs, our transmission operations or future results of operations and cash flows.

The amount we charged third parties for using our transmission facilities has been reduced, is subject to refund and may not be completely restored in the future. *(Applies to AEP and AEP East companies.)*

In July 2003, the FERC issued an order directing PJM and the MISO to make compliance filings for their respective tariffs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within those RTOs. The elimination of the T&O rates reduces the transmission service revenues collected by the RTOs and thereby reduces the revenues received by transmission owners under the RTOs' revenue distribution protocols. To mitigate the impact of lost T&O revenues, the FERC approved temporary replacement seams elimination cost allocation (SECA) transition rates beginning in December 2004 and extending through March 2006. Intervenors objected to this decision; therefore the SECA fees we collected ($220 million) are subject to refund.

Approximately $19 million of the SECA revenues that we billed were never collected. The AEP East zone public utilities filed a motion with the FERC to force payment of these SECA billings.

A hearing was held in May 2006 to determine whether any of the SECA revenues should be refunded. In August 2006, the ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates were not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory, and that new compliance filings and refunds should be made. The ALJ also found that unpaid SECA rates must be paid in the recommended reduced amount. The FERC has not ruled on the matter. If the FERC upholds the decision of the ALJ, up to $126 million of collected SECA rates could be refunded by the AEP East zone public utilities. We have recorded provisions in the aggregate amount of $37 million related to the potential refund of SECA rates pending settlement negotiations with various intervenors.

SECA transition rates expired at the end of March 2006 and did not fully compensate AEP for ongoing lost T&O revenues. As a result of rate relief in certain jurisdictions, however, approximately 85% of the ongoing lost T&O revenues are now being recovered from native load customers of AEP East companies in those jurisdictions. The portion attributable to Virginia is being collected subject to refund.

In addition to seeking retail rate recovery from native load customers in the applicable states, AEP and another member of PJM have filed an application with the FERC seeking compensation from other unaffiliated members of PJM for the costs associated with those members' use of our respective transmission assets. A majority of PJM members have filed in opposition to the proposal. Hearings were held in April 2006. An ALJ recommended a rate design that would result in greater recovery for AEP than the proposal AEP had submitted. The ALJ also recommended, however, that the design be phased-in, which could limit the amount of recovery for AEP. The FERC has not yet ruled on this matter. Management cannot at this time estimate the outcome of these proceedings.

Rate regulation may delay or deny full recovery of costs. *(Applies to each registrant.)*

Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. These rates are generally regulated based on an analysis of the applicable utility's expenses incurred in a test year. Thus, the rates a utility is allowed to charge may or may not match its expenses at any given time. Additionally, there may also be a delay between the timing of when these costs are incurred and when these costs are recovered. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs in a timely manner.

We operate in a non-uniform and fluid regulatory environment. *(Applies to each registrant.)*

In addition to the multiple levels of state regulation at the states in which we operate, our business is subject to extensive federal regulation. There can be no assurance that (1) the federal legislative and regulatory initiatives (which have occurred over the past few years and which have generally facilitated competition in the energy sector) will continue or will not be reversed or (2) state regulation will not become significantly more restrictive. Further alteration of the regulatory landscape in which we operate will impact the effectiveness of our business plan and may, because of the continued uncertainty, harm our financial condition and results of operations.

At times, demand for power could exceed our supply capacity. *(Applies to each registrant other than TCC and TNC.)*

We are currently obligated to supply power in parts of eleven states. From time to time, because of unforeseen circumstances, the demand for power required to meet these obligations could exceed our available generation capacity.

If this occurs, we would have to buy power from the market. We may not always have the ability to pass these costs on to our customers because some of the states we operate in do not allow us to increase our rates in response to increased fuel cost charges. Since these situations most often occur during periods of peak demand, it is possible that the market price for power at that time would be very high. Even if a supply shortage were brief, we could suffer substantial losses that could reduce our results of operations.

Risks Related to Market, Economic or Financial Volatility

Downgrades in our credit ratings could negatively affect our ability to access capital and/or to operate our power trading businesses. *(Applies to each registrant other than AEGCo.)*

Following the bankruptcy of Enron, the credit ratings agencies initiated a thorough review of the capital structure and the quality and stability of earnings of energy companies, including us. The agencies revised ratings at that time. Further negative ratings actions could constrain the capital available to our industry and could limit our access to funding for our operations. Our business is capital intensive, and we are dependent upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition could be harmed and future results of operations could be adversely affected.

If Moody's or S&P were to downgrade the long-term rating of any of the registrants**,** particularly below investment grade, the borrowing costs of that registrant would increase, which would diminish its financial results. In addition, the registrant's potential pool of investors and funding sources could decrease.

Our power trading business relies on the investment grade ratings of our individual public utility subsidiaries' senior unsecured long-term debt. Most of our counterparties require the creditworthiness of an investment grade entity to stand behind transactions. If those ratings were to decline below investment grade, our ability to operate our power trading business profitably would be diminished because we would likely have to deposit cash or cash-related instruments which would reduce our profits.

AEP has no income or cash flow apart from dividends paid or other obligations due it from its subsidiaries. *(Applies to AEP.)*

AEP is a holding company and has no operations of its own. Its ability to meet its financial obligations associated with its indebtedness and to pay dividends on its common stock is primarily dependent on the earnings and cash flows of its operating subsidiaries, primarily its regulated utilities, and the ability of its subsidiaries to pay dividends to, or repay loans from, AEP. Its subsidiaries are separate and distinct legal entities that have no obligation (apart from loans from AEP) to provide AEP with funds for its payment obligations, whether by dividends, distributions or other payments. Payments to AEP by its subsidiaries are also contingent upon their earnings and business considerations. In addition, any payment of dividends, distributions or advances by the utility subsidiaries to AEP would be subject to regulatory or contractual restrictions.

Our operating results may fluctuate on a seasonal and quarterly basis. *(Applies to each registrant.)*

Electric power generation is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. The pattern of this fluctuation may change depending on the terms of power sale contracts that we enter into. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish our results of operations and harm our financial condition. Conversely, unusually extreme weather conditions could increase AEP's results of operations in a manner that would not likely be sustainable.

Parties we have engaged to provide construction materials or services may fail to perform their obligations, which could harm our results of operations. *(Applies to each registrant.)*

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades, construction of additional generation units and transmission facilities as well as other initiatives. We are exposed to the risk of substantial price increases in the costs of materials used in construction. We have engaged numerous contractors and entered into a large number of agreements to acquire the necessary materials and/or obtain the required construction related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and almost certainly cause delays in that and related projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. This would cause our financial results to be diminished, and we might incur losses or delays in completing construction.

Changes in commodity prices may increase our cost of producing power or decrease the amount we receive from selling power, harming our financial performance. *(Applies to each registrant.)*

We are heavily exposed to changes in the price and availability of coal because most of our generating capacity is coal-fired. We have contracts of varying durations for the supply of coal for most of our existing generation capacity, but as these contracts end or otherwise are not honored, we may not be able to purchase coal on terms as favorable as the current contracts. Similarly, we are heavily exposed to changes in the price and availability of emission allowances. We use emission allowances based on the amount of coal we use as fuel and the reductions achieved through emission controls and other measures. According to our estimates we have procured sufficient emission allowances to cover our projected needs for the next two years and for much of the projected needs for periods beyond that. At some point, however, we may have to obtain additional allowances and those purchases may not be on as favorable terms as those currently obtained.

We also own natural gas-fired facilities, which increases our exposure to market prices of natural gas. Natural gas prices tend to be more volatile than prices for other fuel sources.

The price trends for coal, natural gas and emission allowances have shown material increases in the recent past. Changes in the cost of coal, emission allowances or natural gas and changes in the relationship between such costs and the market prices of power will affect our financial results. Since the prices we obtain for power may not change at the same rate as the change in coal, emission allowances or natural gas costs, we may be unable to pass on the changes in costs to our customers. In addition, the prices we can charge our retail customers in some jurisdictions are capped.

In addition, actual power prices and fuel costs will differ from those assumed in financial projections used to value our trading and marketing transactions, and those differences may be material. As a result, our financial results may be diminished in the future as those transactions are marked to market.

In certain jurisdictions, we have limited ability to pass on our fuel costs to our customers. *(Applies to AEP, CSPCo, I&M and OPCo.)*

We are exposed to risk from changes in the market prices of coal, natural gas, and emissions allowances used to generate power where generation is no longer regulated or where existing fuel clauses are suspended or frozen. The prices of coal, natural gas and emissions allowances have increased materially in the recent past. The protection afforded by retail fuel clause recovery mechanisms has been eliminated by the implementation of customer choice in Ohio, which represents approximately 20% of our fuel costs. Because the risk of generating costs cannot be passed through to customers as a matter of right in Ohio, we retain these risks. We also have a fuel cap in Indiana that may not allow us to fully recover our fuel costs there. If we cannot recover an amount sufficient to cover our actual fuel costs, our results of operations and cash flows would be adversely affected.

We are exposed to losses resulting from the bankruptcy of Enron Corp. *(Applies to AEP.)*

On June 1, 2001, we purchased Houston Pipe Line Company ("HPL") from Enron Corp. ("Enron"). Later that year, Enron and its subsidiaries filed bankruptcy proceedings in the U.S. Bankruptcy Court for the Southern District of New York. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. In connection with the 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 65 BCF of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, Bank of America ("BOA") and certain other banks (together with BOA, "BOA Syndicate") and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Additionally, Enron and the BOA Syndicate released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. We purchased 10 BCF of gas from Enron and are currently litigating the rights to the remaining 55 BCF of cushion gas.

In February 2004, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements. In 2005 we sold HPL, including the Bammel gas storage facility. We indemnified the purchaser for damages, if any, arising from the litigation with BOA. The case in federal court in Texas is set for trial beginning April 2007. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Risks Relating To State Restructuring

In Ohio, our costs may not be recovered and rates may be reduced. *(Applies to AEP, OPCo and CSPCo)*

In January 2005, the PUCO approved rate stabilization plans ("RSPs") for CSPCo and OPCo. The RSPs provide, among other things, for CSPCo and OPCo to raise their generation rates on an annual basis through 2008 by 3% and 7%, respectively. The RSPs also provide for possible additional annual generation rate increases of up to an average of 4% per year for specified costs. The RSPs also provide that CSPCo and OPCo can recover certain environmental carrying costs, PJM-related administrative costs and certain congestion costs. In 2006, CSPCo and OPCo collected an additional estimated $244 million in gross margin as a result of the RSPs. This amount is expected to increase in 2007 and 2008.

In 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court that challenged the validity of the RSPs under Ohio's electricity restructuring law. In July 2006, the Ohio Supreme Court vacated the PUCO's RSP orders for CSPCo and OPCo and remanded the case to the PUCO for further proceedings.

In August 2006, the PUCO directed CSPCo and OPCo to file a plan providing an option for customer participation in the electric market through competitive bids or other reasonable means. The PUCO also held that the RSPs shall remain effective. Accordingly, the Ohio companies continued collecting RSP revenues. In September 2006, CSPCo and OPCo submitted their proposals to provide additional options for customer participation in the electric market. If the PUCO were to reverse or limit the RSPs, our results of operations and cash flows could be adversely affected.

Some laws and regulations governing restructuring in Virginia have not yet been interpreted or adopted and could harm our business, operating results and financial condition. *(Applies to AEP and APCo.)*

Virginia restructuring legislation was enacted in 1999 providing for retail choice of generation suppliers to be phased in over two years beginning January 1, 2002. It required jurisdictional utilities to unbundle their power supply and energy delivery rates and to file functional separation plans by January 1, 2002. APCo filed its plan with the VSCC and, following VSCC approval of a settlement agreement, now operates in Virginia as a functionally separated electric utility charging unbundled rates for its retail sales of electricity. The settlement agreement addressed functional separation, leaving decisions related to legal separation for later VSCC consideration. While the electric restructuring law in Virginia established the general framework governing the retail electric market, it required the VSCC to issue rules and determinations implementing the law. Some of the regulations governing the retail electric market have not yet been adopted by the VSCC. When the regulations are developed and adopted, compliance with them may harm our business, results of operations and financial condition. In February 2007, the Virginia legislature adopted amendments to its electric restructuring law. The amendments would cut two years off of the transition period (from 2010 to 2008) after which rates for retail generation supply would return to a form of cost-based regulation. The Governor of Virginia has not yet signed this legislation.

There is uncertainty as to our recovery of stranded costs resulting from industry restructuring in Texas. *(Applies to AEP and TCC.)*

Restructuring legislation in Texas required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. We elected to use the sale of assets method to determine the market value of the generation assets of TCC for stranded cost purposes. In general terms, the amount of stranded costs under this market valuation methodology is the amount by which the book value of generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets, as measured by the net proceeds from the sale of the assets. In May 2005, TCC filed its stranded cost quantification application with the PUCT seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items. A final order was issued in April 2006. In the final order, the PUCT determined TCC's net stranded generation costs and other recoverable true-up items to be approximately $1.475 billion. We have appealed the PUCT's final order seeking additional recovery consistent with the Texas Act and related rules, other parties have appealed the PUCT's final order as unwarranted or too large. In a preliminary ruling filed in February 2007, the Texas state district court adjudicating the appeal of the final order in the true-up proceeding found that the PUCT erred in several respects, including the method used to determine stranded costs and the awarding of certain carrying costs. Following the preliminary ruling, the court granted a rehearing of the issue regarding the method to determine stranded costs. That rehearing is scheduled for late March 2007. TCC intends to appeal any final adverse rulings regarding the PUCT's order in the true-up proceeding. If the district court judge's preliminary determination that TCC used an improper method to value its stranded costs is ultimately upheld on appeal, it could substantially reduce TCC's stranded costs. We cannot estimate the amount of any potential impact at this time, but it could exceed TCC's common shareholder's equity at December 31, 2006. Any reduction of the recovery authorized in the PUCT's order could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Collection of our revenues in Texas is concentrated in a limited number of REPs. *(Applies to AEP, TCC and TNC.)*

Our revenues from the distribution of electricity in the ERCOT area of Texas are collected from REPs that supply the electricity we distribute to their customers. Currently, we do business with approximately sixty REPs. The two largest customers of TCC accounted for 29% of its operating revenues in 2006; the three largest customers of TNC accounted for 50% of its operating revenues in 2006. Adverse economic conditions, structural problems in the new Texas market or financial difficulties of one or more REPs could impair the ability of these REPs to pay for our services or could cause them to delay such payments. We depend on these REPs for timely remittance of payments. Any delay or default in payment could adversely affect the timing and receipt of our cash flows and thereby have an adverse effect on our liquidity.

Risks Related to Owning and Operating Generation Assets and Selling Power

Our costs of compliance with environmental laws are significant, and the cost of compliance with future environmental laws could harm our cash flow and profitability. *(Applies to each registrant other than TCC and TNC.)*

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities. These expenditures have been significant in the past, and we expect that they will increase in the future. Costs of compliance with environmental regulations could adversely affect our results of operations and financial position, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increase. All of our estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including timing of implementation, required levels of reductions, allocation requirements of the new rules, and our selected compliance alternatives. As a result, we cannot estimate our compliance costs with certainty. The actual costs to comply could differ significantly from the estimates. All of the costs are incremental to our current investment base and operating cost structure.

If Federal and/or State requirements are imposed on electric utility companies mandating further emission reductions, including limitations on CO_2 emissions, such requirements could make some of our electric generating units uneconomical to maintain or operate. *(Applies to each registrant other than TCC and TNC.)*

Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generating plants are potentially subject to increased regulations, controls and mitigation expenses. Environmental advocacy groups, other organizations and some agencies in the United States are focusing considerable attention on carbon dioxide emissions from power generation facilities and their potential role in climate change. Although several bills have been introduced in Congress that would compel CO_2 emission reductions, none have advanced through the legislature. Future changes in environmental regulations governing these pollutants could make some of our electric generating units uneconomical to maintain or operate. In addition, any legal obligation that would require us to substantially reduce our emissions beyond present levels could require extensive mitigation efforts and, in the case of CO_2 legislation, would raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. While mandatory requirements for further emission reductions from our fossil fleet do not appear to be imminent, we continue to monitor regulatory and legislative developments in this area.

Governmental authorities may assess penalties on us if it is determined that we have not complied with environmental laws and regulations. *(Applies to each registrant other than TCC and TNC.)*

If we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines against us. Recent lawsuits by the EPA and various states filed against us highlight the environmental risks faced by generating facilities, in general, and coal-fired generating facilities, in particular.

Since 1999, we have been involved in litigation regarding generating plant emissions under the CAA. The EPA and a number of states alleged that we and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the CAA. The EPA filed complaints against certain AEP subsidiaries in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the EPA case. The alleged modification of the generating units occurred over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has concluded, but the court is holding the case in abeyance until the U.S. Supreme Court rules on a similar case. No decision has been issued. Additionally, in July 2004 attorneys general of eight states and others sued AEP and other utilities alleging that carbon dioxide emissions from power generating facilities constitute a public nuisance under federal common law. The trial court dismissed the suits and plaintiffs have appealed the dismissal. While we believe the claims are without merit, the costs associated with reducing carbon dioxide emissions could harm our business and our results of operations and financial position.

If these or other future actions are resolved against us, substantial modifications of our existing coal-fired power plants could be required. In addition, we could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay penalties and/or halt operations. Moreover, our results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

Our revenues and results of operations from selling power are subject to market risks that are beyond our control. *(Applies to each registrant other than TCC and TNC.)*

We sell power from our generation facilities into the spot market or other competitive power markets or on a contractual basis. We also enter into contracts to purchase and sell electricity, natural gas, emission allowances and coal as part of our power marketing and energy trading operations. With respect to such transactions, we are generally not guaranteed any rate of return on our capital investments through mandated rates, and our revenues and results of operations are likely to depend, in large part, upon prevailing market prices for power in our regional markets and other competitive markets. These market prices may fluctuate substantially over relatively short periods of time. Trading margins may erode as markets mature and there may be diminished opportunities for gain should volatility decline. In addition, FERC, which has jurisdiction over wholesale power rates, as well as RTOs that oversee some of these markets, may impose price limitations, bidding rules and other mechanisms to address some of the volatility in these markets. Power supply and other similar agreements entered into during extreme market conditions may subsequently be held to be unenforceable by a reviewing court or FERC. Fuel and emissions prices may also be volatile, and the price we can obtain for power sales may not change at the same rate as changes in fuel and/or emissions costs. These factors could reduce our margins and therefore diminish our revenues and results of operations.

Volatility in market prices for fuel and power may result from:

- weather conditions;
- seasonality;
- power usage;
- illiquid markets;
- transmission or transportation constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- demand for energy commodities;
- natural gas, crude oil and refined products, and coal production levels;
- natural disasters, wars, embargoes and other catastrophic events; and
- federal, state and foreign energy and environmental regulation and legislation.

Our power trading (including coal, gas and emission allowances trading and power marketing) and risk management policies cannot eliminate the risk associated with these activities. *(Applies to each registrant other than AEG, TCC and TNC.)*

Our power trading (including coal, gas and emission allowances trading and power marketing) activities expose us to risks of commodity price movements. We attempt to manage our exposure by establishing and enforcing of risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate the risks associated with these activities. As a result, we cannot predict the impact that our energy trading and risk management decisions may have on our business, operating results or financial position.

We routinely have open trading positions in the market, within guidelines we set, resulting from the management of our trading portfolio. To the extent open trading positions exist, fluctuating commodity prices can improve or diminish our financial results and financial position.

Our power trading and risk management activities, including our power sales agreements with counterparties, rely on projections that depend heavily on judgments and assumptions by management of factors such as the future market prices and demand for power and other energy-related commodities. These factors become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. Even when our policies and procedures are followed and decisions are made based on these estimates, results of operations may be diminished if the judgments and assumptions underlying those calculations prove to be inaccurate.

Our financial performance may be adversely affected if we are unable to operate our pooled electric generating facilities successfully. *(Applies to each registrant other than TCC and TNC.)*

Our performance is highly dependent on the successful operation of our electric generating facilities. Operating electric generating facilities involves many risks, including:

- operator error and breakdown or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- fuel supply interruptions caused by transportation constraints, adverse weather, non-performance by our suppliers and other factors; and
- catastrophic events such as fires, earthquakes, explosions, hurricanes, terrorism, floods or other similar occurrences.

A decrease or elimination of revenues from power produced by our electric generating facilities or an increase in the cost of operating the facilities would adversely affect our results of operations.

Parties with whom we have contracts may fail to perform their obligations, which could harm our results of operations. *(Applies to each registrant.)*

We are exposed to the risk that counterparties that owe us money or power could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative hedging arrangements or honor underlying commitments at then-current market prices that may exceed our contractual prices, which would cause our financial results to be diminished and we might incur losses. Although our estimates take into account the expected probability of default by a counterparty, our actual exposure to a default by a counterparty may be greater than the estimates predict.

We rely on electric transmission facilities that we do not own or control. If these facilities do not provide us with adequate transmission capacity, we may not be able to deliver our wholesale electric power to the purchasers of our power. *(Applies to each registrant other than TCC and TNC.)*

We depend on transmission facilities owned and operated by other unaffiliated power companies to deliver the power we sell at wholesale. This dependence exposes us to a variety of risks. If transmission is disrupted, or transmission capacity is inadequate, we may not be able to sell and deliver our wholesale power. If a region's power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

The FERC has issued electric transmission initiatives that require electric transmission services to be offered unbundled from commodity sales. Although these initiatives are designed to encourage wholesale market transactions for electricity and gas, access to transmission systems may in fact not be available if transmission capacity is insufficient because of physical constraints or because it is contractually unavailable. We also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

We do not fully hedge against price changes in commodities. *(Applies to each registrant other than AEG, TCC and TNC.)*

We routinely enter into contracts to purchase and sell electricity, natural gas, coal and emission allowances as part of our power marketing and energy and emission allowances trading operations. In connection with these trading activities, we routinely enter into financial contracts, including futures and options, over-the counter options, financially-settled swaps and other derivative contracts. These activities expose us to risks from price movements. If the values of the financial contracts change in a manner we do not anticipate, it could harm our financial position or reduce the financial contribution of our trading operations.

We manage our exposure by establishing risk limits and entering into contracts to offset some of our positions (i.e., to hedge our exposure to demand, market effects of weather and other changes in commodity prices). However, we do not always hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility, our results of operations and financial position may be improved or diminished based upon our success in the market.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

GENERATION FACILITIES

GENERAL

At December 31, 2006, the AEP System owned (or leased where indicated) generating plants with net power capabilities (winter rating) shown in the following table:

Company	Stations		Coal MW	Natural Gas MW		Hydro MW	Nuclear MW	Lignite MW	Oil MW		Total MW
AEGCo	1	(a)	1,300								1,300
APCo	17	(b)(c)	5,073	528		681					6,282
CSPCo	6	(d)	2,345	857							3,202
I&M	9	(a)	2,295			15	2,143				4,453
KPCo	1		1,060								1,060
OPCo	8	(b)(c)(e)	8,472			26					8,498
PSO	8	(f)	1,018	3,238					25		4,281
SWEPCo	9	(g)	1,848	1,821				842			4,511
TCC	1	(f)(h)	54								54
TNC	11	(f)	377	1,014	(i)				10	(j)	1,401
Totals:	66		23,842	7,458		722	2,143	842	35		35,042
System Percentage			68.0%	21.3%		2.1%	6.1%	2.4%	0.1%		

(a) Unit 1 of the Rockport Plant is owned one-half by AEGCo and one-half by I&M. Unit 2 of the Rockport Plant is leased one-half by AEGCo and one-half by I&M. The leases terminate in 2022 unless extended. In December 2006, AEGCo agreed to buy Lawrenceburg Generating Station, a 1,096 MW gas-fired unit in Indiana from Public Service Electric and Gas Company. Assuming receipt of regulatory approvals, the acquisition is expected to close in the second quarter of 2007.

(b) Unit 3 of the John E. Amos Plant is owned one-third by APCo and two-thirds by OPCo.

(c) APCo owns Units 1 and 3 and OPCo owns Units 2, 4 and 5 of Philip Sporn Plant, respectively.

(d) CSPCo owns generating units in common with CG&E and DP&L. Its percentage ownership interest is reflected in this table. In November 2006, CSPCo agreed to buy Darby Electric Generating Station, a 480 MW gas-fired unit in Ohio from DP&L. Assuming receipt of regulatory approvals, the acquisition is expected to close in the first half of 2007.

(e) The scrubber facilities at the General James M. Gavin Plant are leased. OPCo is permitted to terminate the lease as early as 2010.

(f) As of December 31, 2006, PSO, TCC and TNC, along with Oklahoma Municipal Power Authority and The Public Utilities Board of the City of Brownsville, Texas, jointly owned the Oklaunion power station. Their respective ownership interests are reflected in this table. In February 2007, TCC sold its interest in Oklaunion to The Public Utilities Board of the City of Brownsville, Texas. In order to comply with the separation requirements of the Texas Act, in January 2007, TNC entered into a 20-year power agreement transferring its generating capacity in the Oklaunion power station to a non-utility affiliate.

(g) SWEPCo owns generating units in common with unaffiliated parties. Only its ownership interest is reflected in this table.

(h) Under the Texas Act, TCC has exited the generation business. As a result, in February 2007 TCC sold the last of its generation facilities.

(i) TNC's gas fired generation is deactivated.

(j) TNC's oil fired generation is deactivated.

COOK NUCLEAR PLANT

The following table provides operating information relating to the Cook Plant.

	Cook Plant	
	Unit 1	**Unit 2**
Year Placed in Operation	1975	1978
Year of Expiration of NRC License	2034	2037
Nominal Net Electrical Rating in Kilowatts	1,036,000	1,107,000
Net Capacity Factors (a)		
2006	80.4%	86.5%
2005	88.8%	97.1%
2004	97.0%	81.6%
2003 (b)	73.5%	74.5%

(a) Net Capacity Factor values since 2004 reflect Nominal Net Electrical Rating in Kilowatts of 1,036,000 (Unit 1) and 1,107,000 (Unit 2). Net Capacity Factor values for 2003 and earlier, however, reflect previous Nominal Net Electrical Rating in Kilowatts of 1,020,000 (Unit 1) and 1,090,000 (Unit 2).

(b) The capacity factors for both units of the Cook Plant were reduced in 2003 due to an unplanned maintenance outage to implement upgrades to the traveling water screens system following a fish intrusion.

Costs associated with the operation (excluding fuel), maintenance and retirement of nuclear plants continue to be more significant and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the operation of nuclear facilities. I&M may also incur costs and experience reduced output at Cook Plant, because of the design criteria prevailing at the time of construction and the age of the plant's systems and equipment. Nuclear industry-wide and Cook Plant initiatives have contributed to slowing the growth of operating and maintenance costs at these plants. However, the ability of I&M to obtain adequate and timely recovery of costs associated with the Cook Plant is not assured. Such costs may include replacement power, any unamortized investment at the end of the useful life of the Cook Plant (whether scheduled or premature), the carrying costs of that investment and retirement costs.

In addition to the generating facilities described above, AEP has ownership interests in other electrical generating facilities. Information concerning these facilities at December 31, 2006 is listed below.

Facility	Fuel	Location	Capacity Total MW	Owner-ship Interest	Status
Desert Sky Wind Farm	Wind	Texas	161	100%	Exempt Wholesale Generator(a)
Sweeny	Natural gas	Texas	480	50%	Qualifying Facility(b)
Trent Wind Farm	Wind	Texas	150	100%	Exempt Wholesale Generator(a)
Total			791		

(a) As defined under rules issued pursuant to EPACT.
(b) As defined under the Public Utility Regulatory Policies Act of 1978.

See Note 8 to the consolidated financial statements entitled *Acquisitions, Dispositions, Discontinued Operations, Impairments and Assets Held for Sale*, included in the 2006 Annual Reports, for a discussion of AEP's disposition of independent power producer and foreign generation assets.

TRANSMISSION AND DISTRIBUTION FACILITIES

The following table sets forth the total overhead circuit miles of transmission and distribution lines of the AEP System and its operating companies and that portion of the total representing 765kV lines:

	Total Overhead Circuit Miles of Transmission and Distribution Lines	Circuit Miles of 765kV Lines
AEP System (a)	223,076 (b)	2,116
APCo	51,579	734
CSPCo (a)	15,443	—
I&M	21,985	615
Kingsport Power Company	1,356	—
KPCo	10,897	258
OPCo	30,723	509
PSO	21,149	—
SWEPCo	20,693	—
TCC	29,432	—
TNC	18,120	—
WPCo	1,699	—

(a) Includes 766 miles of 345,000-volt jointly owned lines.
(b) Includes 73 miles of overhead transmission lines not identified with an operating company.

TITLES

The AEP System's generating facilities are generally located on lands owned in fee simple. The greater portion of the transmission and distribution lines of the System has been constructed over lands of private owners pursuant to easements or along public highways and streets pursuant to appropriate statutory authority. The rights of AEP's public utility subsidiaries in the realty on which their facilities are located are considered adequate for use in the conduct of their business. Minor defects and irregularities customarily found in title to properties of like size and character may exist, but such defects and irregularities do not materially impair the use of the properties affected thereby. AEP's public utility subsidiaries generally have the right of eminent domain which permits them, if necessary, to acquire, perfect or secure titles to or easements on privately held lands used or to be used in their utility operations. Recent legislation in Ohio and Virginia has restricted the right of eminent domain previously granted for power generation purposes.

Substantially all the fixed physical properties and franchises of SWEPCo, except for limited exceptions, are subject to the lien of its mortgage and deed of trust securing its first mortgage bonds.

SYSTEM TRANSMISSION LINES AND FACILITY SITING

Laws in the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Texas, Tennessee, Virginia, and West Virginia require prior approval of sites of generating facilities and/or routes of high-voltage transmission lines. We have experienced delays and additional costs in constructing facilities as a result of proceedings conducted pursuant to such statutes, and in proceedings in which our operating companies have sought to acquire rights-of-way through condemnation. These proceedings may result in additional delays and costs in future years.

CONSTRUCTION PROGRAM

GENERAL

With input from its state utility commissions, the AEP System continuously assesses the adequacy of its generation, transmission, distribution and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment process, assumptions are continually being reviewed as new information becomes available, and assessments and plans are modified, as appropriate. AEP forecasts $3.5 billion, $3.0 billion and $3.0 billion of construction expenditures for 2007, 2008 and 2009, respectively. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

PROPOSED TRANSMISSION FACILITIES

PJM Project

AEP has filed a proposal with the FERC and the PJM to build a new 765kV transmission line stretching from West Virginia to New Jersey. The proposed transmission corridor will span approximately 550 miles and is designed to reduce PJM congestion costs through enhancing transfer capability and also to reduce transmission line losses. It also is expected to improve reliability in the eastern transmission grid. AEP´s proposed transmission line, called the AEP Interstate Project, would originate at AEP´s Amos transmission station in Putnam County, WV, connect through Doubs Station in Frederick County, MD and terminate at the Deans Station in Middlesex County, NJ. The proposed route follows a corridor conceptually identified by PJM as a transmission route needed to address transmission congestion within the PJM footprint. Exact routing of the line would be determined after PJM approves the project. AEP will work with PJM, other affected transmission owners and stakeholders throughout the siting process. It is expected that a new AEP subsidiary, AEP Transmission Co., LLC, will own the line and undertake construction of the project. The projected costs are approximately $3 billion, which may be shared with other stakeholders. The anticipated in-service date is 2015 assuming three years to site and acquire rights-of-way and five years to build the line. This projected in-service date also assumes approval by PJM in mid-2007 followed by approval by FERC on initial rates by the end of 2007.

AEP also has filed with the DOE in its efforts to designate National Interest Electric Transmission Corridors (NIETC). EPACT provides for NIETC designation for areas that are experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers. In August 2006, the DOE issued the "National Interest Electric Transmission Congestion Study". In this study, DOE indicated that the mid-Atlantic Coastal area, which the AEP project is designed to reinforce, is one of the two most critical congestion areas in the nation. This finding should help AEP to obtain early NIETC designation as promulgated by EPACT. In October 2006, we filed comments with the DOE encouraging corridor designation that is consistent with the proposed line.

In July 2006, pursuant to a request by AEP, the FERC clarified that the project qualifies for incentive rate treatment, provided that the new line is included in PJM's formal Regional Transmission Expansion Plan to be finalized in 2007. The approved incentives include, (a) a return on equity set at the high end of the "zone of reasonableness"; (b) the option to timely recover the cost of capital associated with construction work in progress; and (c) the ability to defer expense and recover costs incurred during the pre-construction and pre-operating period. Since the FERC has clarified that the project qualifies for these rate incentives, we expect to propose rates that will capture the incentives in future FERC rate filings.

ERCOT Joint Venture

In November 2006 AEP announced a memorandum of understanding with MidAmerican Energy Holdings Co. (MidAmerican) to form a joint venture company to build and own new electric transmission assets in ERCOT. In January 2007, we signed a participation agreement with MidAmerican to form a joint venture company, Electric Transmission Texas LLC (ETT), to fund, own and operate electric transmission assets in ERCOT. ETT filed with the PUCT in January 2007 requesting regulatory approval to operate as an electric transmission utility in Texas, to transfer from TCC to ETT approximately $76 million of transmission assets currently under construction, to sell or transfer ownership of ETT as discussed below, and to establish a wholesale transmission tariff for ETT. ETT also requested approval of initial rates based on an 11.25% return on equity.

Upon receipt of all required regulatory approvals, respective subsidiaries of AEP and of MidAmerican each will acquire a 50% equity ownership in ETT. The anticipated utility capitalization structure of ETT is approximately 40% equity and 60% debt. AEP and MidAmerican expect ETT to invest in additional transmission projects in ERCOT. The companies anticipate in excess of $1 billion in projects could be included in the new company during the next several years. TCC also made a regulatory filing at the FERC in February 2007 regarding the transfer of transmission assets from TCC to ETT. In February 2007, ETT filed a proposal with the PUCT that addresses the Competitive Renewable Energy Zone initiative of the Texas legislature. The proposal outlines the opportunities for additional significant investment in transmission assets in Texas. The joint venture is anticipated to begin operations in the second half of 2007, subject to regulatory approval from the PUCT and the FERC.

Completed Project

APCo has completed construction of the Wyoming-Jacksons Ferry 765kV transmission line that was placed in -service on June 20, 2006.

PROPOSED GENERATION FACILITIES

IGCC Projects

In conjunction with an environmental impact study issued in August 2004, we announced plans to construct a synthesis-gas-fired plant or plants of approximately 1,200 MW of capacity in the next five to six years utilizing integrated gasification combined cycle (IGCC) technology. We originally estimated construction and other direct costs would equal approximately $1.2 billion for each nominal 629 MW facility. We currently expect these estimates to be exceeded in amounts that are not yet determinable and that may be material. We are currently completing front-end engineering and design on the facilities pursuant to an agreement with General Electric and Bechtel Power Corporation and are working with state regulators and legislators to establish a framework for expedient recovery of this significant investment in new clean coal technology.

The plans are contingent upon receiving adequate cost recovery through rates approved by the applicable commission prior to beginning construction. In January 2006, APCo filed a petition with the WVPSC requesting its approval of a Certificate of Public Convenience and Necessity to construct a 600 MW IGCC plant adjacent to APCo's existing Mountaineer generating station in Mason County, WV. In January 2007, the WVPSC issued an order setting a deadline of December 3, 2007 for it to rule on APCo's filing.

In March 2005, OPCo and CSPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a new 600 MW IGCC power plant using clean-coal technology. The application proposed for cost recovery associated with the IGCC plant in three phases. In April 2006, the PUCO issued an order authorizing OPCo and CSPCo to implement Phase 1 of their cost recovery proposal. In June 2006, the PUCO issued another order approving a tariff to recover Phase 1 pre-construction costs. In its June order, the PUCO indicated that if the Ohio companies have not commenced continuous construction of the IGCC plant within five years of the order, all charges collected for pre-construction costs must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on Phases 2 and 3 cost recovery until further hearings are held. No date for a further hearing has been set.

SWEPCo Projects

In December 2005, SWEPCo sought proposals for new peaking, intermediate and base load generation to be online between 2008 and 2011. In May 2006, SWEPCo announced plans to construct new generation. SWEPCo will build up to 480 MW of simple-cycle natural gas combustion turbine peaking generation in Tontitown, Arkansas. SWEPCo also will build a 480 MW combined-cycle natural gas fired plant at its existing Arsenal Hill Power Plant in Shreveport, Louisiana. SWEPCo also plans to build a new 600 MW base load coal plant, of which its investment will be 73%, in Hempstead County, Arkansas by 2011. Preliminary cost estimates for the new facilities are approximately $1.4 billion. These new facilities are subject to regulatory approvals from SWEPCo's three state commissions—APSC, LPSC and the PUCT. The peaking generation facility in Tontitown, Arkansas has been approved by all three state commissions. Construction of all of these units is expected to begin in 2007.

PSO Projects

In September 2005, PSO sought proposals for new peaking generation to be online in 2008. In December 2005, PSO sought proposals for base load generation to be online in 2011. PSO received and evaluated proposals with oversight from a neutral third party. In March 2006, PSO announced plans to add 170 MW of peaking generation to its Riverside Station plant in Jenks, Oklahoma. PSO will construct and operate two 85 MW simple-cycle natural gas combustion turbines at the Jenks facility. In March 2006, PSO announced plans to add 170 MW of peaking generation to its Southwestern Station plant in Anadarko, Oklahoma. PSO will construct and operate two 85 MW simple-cycle natural gas combustion turbines at that facility. Combined preliminary cost estimates for these additions are approximately $120 million. In July 2006, PSO announced plans to enter a joint venture with Oklahoma Gas and Electric Company ("OG&E") and Oklahoma Municipal Power Authority. OG&E will construct and operate a new 950 MW coal-fueled electricity generating unit near Red Rock, Oklahoma. PSO will own 50% of the new unit. Preliminary cost estimates for 100% of the new facility are approximately $1.8 billion. The unit is expected to be online no later than the first half of 2012. These new facilities are subject to regulatory approval from the OCC. Construction of all of these units is expected to begin in 2007.

Other

Our significant planned environmental investments in emission control installations at existing coal-fired plants and our commitment to IGCC technology reinforce our belief that coal will be a lower-emission domestic energy source of the future and further signals our commitment to invest in clean, environmentally safe technology. For additional information regarding anticipated environmental expenditures, see *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Environmental Matters*.

CONSTRUCTION EXPENDITURES

The following table shows construction expenditures (including environmental expenditures) during 2004, 2005 and 2006 and current estimates of 2007, 2008 and 2009 construction expenditures, in each case excluding AFUDC, capitalized interest and assets acquired under leases.

	2004 Actual	**2005 Actual**	**2006 Actual**	**2007 Estimate**	**2008 Estimate**	**2009 Estimate**
			(in thousands)			
AEP Systems (a)	$1,536,400 (b)	$2,501,600 (c)	$3,522,100 (d)	$3,440,300 (e)	$3,026,300	$2,974,100
AEGCo	15,700	15,200	10,000	18,000	28,300	34,100
APCo	435,900	634,000	922,700	663,600	531,200	460,900
CSPCo	148,200	171,600	315,100	337,200	354,300	232,600
I&M	173,400	317,100	306,900	252,000	264,300	293,800
KPCo	38,000	60,300	57,400	70,500	114,500	100,100
OPCo	339,200	733,400	968,700	832,000	367,800	389,200
PSO	90,800	139,700	245,200	318,600	329,600	465,900
SWEPCo	95,300	151,200	330,300	537,300	605,200	539,700
TCC	109,400	186,300	273,200	240,600	213,700	273,100
TNC	35,700	64,800	67,900	142,600	187,900	148,900

(a) Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies. Excludes discontinued operations.
(b) Excludes Cash Flow Statement Adjustments (Statement of Cash Flow Including AFUDC Debt Equals $1,636,200)
(c) Excludes $293 million for the purchase of two generating plants and Cash Flow Statement Adjustments (Statement of Cash Flow Including AFUDC Debt Equals $2,403,800)
(d) Excludes Cash Flow Statement Adjustments (Statement of Cash Flow Including AFUDC Debt Equals $3,528,000)
(e) Excludes $427 million for the purchase of two generating plants.

The System construction program is reviewed continuously and is revised from time to time in response to changes in estimates of customer demand, business and economic conditions, the cost and availability of capital, environmental requirements and other factors. Changes in construction schedules and costs, and in estimates and projections of needs for additional facilities, as well as variations from currently anticipated levels of net earnings, Federal income and other taxes, and other factors affecting cash requirements, may increase or decrease the estimated capital requirements for the System's construction program.

POTENTIAL UNINSURED LOSSES

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including liabilities relating to damage to our generating plants and costs of replacement power. Unless allowed to be recovered through rates, future losses or liabilities which are not completely insured could have a material adverse effect on results of operations and the financial condition of AEP and other AEP System companies. For risks related to owning a nuclear generating unit, see Note 10 to the consolidated financial statements entitled *Nuclear* for information with respect to nuclear incident liability insurance.

ITEM 3. LEGAL PROCEEDINGS

For a discussion of material legal proceedings, see Note 6 to the consolidated financial statements, entitled *Commitments*, *Guarantees and Contingencies*, incorporated by reference in Item 8.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

AEP, APCo, OPCo and SWEPCo . None.

AEGCo, CSPCo, I&M, KPCo, PSO, TCC and TNC. Omitted pursuant to Instruction I(2)(c).

EXECUTIVE OFFICERS OF THE REGISTRANTS

AEP. The following persons are, or may be deemed, executive officers of AEP. Their ages are given as of February 1, 2007.

Name	Age	Office (a)
Michael G. Morris	60	Chairman of the Board, President and Chief Executive Officer of AEP and of AEPSC
Nicholas K. Akins	46	Executive Vice President of AEP and Executive Vice President-Generation of AEPSC
Carl L. English	60	President-AEP Utilities of AEP and of AEPSC
Thomas M. Hagan	62	Executive Vice President of AEP and Executive Vice President-AEP Utilities-West of AEPSC
John B. Keane	60	Senior Vice President, General Counsel, Chief Compliance Officer and Secretary of AEP and Senior Vice President and General Counsel of AEPSC
Holly K. Koeppel	48	Executive Vice President and Chief Financial Officer of AEP and of AEPSC
Robert P. Powers	52	Executive Vice President of AEP and Executive Vice President-AEP Utilities-East of AEPSC
Susan Tomasky	53	Executive Vice President of AEP and Executive Vice President-Shared Services of AEPSC

(a) Before joining AEPSC in his current position in January 2004, Mr. Morris was Chairman of the Board, President and Chief Executive Officer of Northeast Utilities (1997-2003). Messrs. Akins, Hagan, and Powers and Ms. Tomasky and Ms. Koeppel have been employed by AEPSC or System companies in various capacities (AEP, as such, has no employees) for the past five years. Messrs. Hagan and Powers, Ms. Koeppel and Ms. Tomasky became executive officers of AEP effective with their promotions to Executive Vice President on September 9, 2002, October 24, 2001, November 18, 2002 and January 26, 2000, respectively. As a result of AEP's realignment of its executive management team in July 2004, Mr. Keane became an executive officer of AEP. Before joining AEPSC in his current position in July 2004, Mr. Keane was President of Bainbridge Crossing Advisors. Before that, he was Vice President-Administration for Northeast Utilities (1998-2002). Mr. English joined AEP as President-Utility Group and became an executive officer of AEP on August 1, 2004. Before joining AEPSC in his current position in August 2004, Mr. English was President and Chief Executive Officer of Consumers Energy gas division (1999-2004). As a result of AEP's realignment of management in August 2006, Mr. Akins became an executive officer of AEP. All of the above officers are appointed annually for a one-year term by the board of directors of AEP, the board of directors of AEPSC, or both, as the case may be.

APCo, OPCo and SWEPCo . The names of the executive officers of APCo, OPCo and SWEPCo, the positions they hold with these companies, their ages as of February 1, 2007, and a brief account of their business experience during the past five years appear below. The directors and executive officers of APCo, OPCo and SWEPCo are elected annually to serve a one-year term.

Name	Age	Position	Period
Michael G. Morris (a)(b)	60	Chairman of the Board, President, Chief Executive Officer and Director of AEP and AEPSC	2004-Present
		Chairman of the Board, Chief Executive Officer and Director of APCo, OPCo and SWEPCo	2004-Present
		Chairman of the Board, President and Chief Executive Officer of Northeast Utilities	1997-2003
Nicholas K. Akins (a)	46	Executive Vice President of AEP	2006-Present
		Executive Vice President-Generation and Director of AEPSC	2006-Present
		Vice President and Director of APCo and OPCo	2006-Present
		Director of SWEPCo	2006-Present
		President and Chief Operating Officer of SWEPCo	2004-2006
		Vice President-Energy Market Services of AEPSC	2002-2004
		Vice President-Energy Delivery Business Development of AEPSC	2001-2002
Carl L. English (c)	60	President-AEP Utilities of AEP	2004-Present
		President-AEP Utilities and Director of AEPSC	2004-Present
		Director and Vice President of APCo, OPCo and SWEPCo	2004-Present
		President and Chief Executive Officer of Consumers Energy gas division	1999-2004
Thomas M. Hagan (d)	62	Executive Vice President of AEP	2006-Present
		Executive Vice President-AEP Utilities-West	2004-Present
		Director of AEPSC	2002-Present
		Vice Chairman of the Board of SWEPCo	2004-Present
		Vice President and Director of SWEPCo	2002-Present
		Vice President and Director of APCo and OPCo	2002-2004
		Executive Vice President of AEP	2004
		Executive Vice President-Shared Services of AEPSC	2002-2004
		Senior Vice President-Governmental Affairs of AEPSC	2000-2002

Name	Age	Position	Period
John B. Keane (e)	60	Senior Vice President, General Counsel, Chief Compliance Officer and Secretary of AEP	2004-Present
		Senior Vice President, General Counsel and Director of AEPSC	2004-Present
		Director of APCo, OPCo and SWEPCo	2004-Present
		President of Bainbridge Crossing Advisors	2003-2004
		Vice President-Administration-Northeast Utilities	1998-2002
Holly K. Koeppel (a)	48	Executive Vice President and Chief Financial Officer of AEP and AEPSC	2006-Present
		Director of AEPSC	2003-Present
		Executive Vice President-AEP Utilities-East of AEPSC	2004-Present
		Vice President of APCo and OPCo	2003-Present
		Director of APCo and OPCo	2004-Present
		Chief Financial Officer of APCo, OPCo and SWEPCo	2006-Present
		Vice President and Director of SWEPCO	2006-Present
		Executive Vice President of AEP	2004
		Executive Vice President-Commercial Operations of AEPSC	2002-2004
		Senior Vice President-Corporate Development of AEPSC	2002
Robert P. Powers (f)	52	Executive Vice President of AEP	2004-Present
		Executive Vice President-AEP Utilities East of AEPSC	2006-Present
		Director of AEPSC	2001-Present
		Executive Vice President-Generation of AEPSC	2003-2006
		Director and Vice President of APCo and OPCo	2001-Present
		Director and Vice President of SWEPCo	2001-2006
		Executive Vice President-Nuclear Generation and Technical Services of AEPSC	2001-2003
Susan Tomasky (c)	53	Executive Vice President of AEP	2004-Present
		Executive Vice President-Shared Services of AEPSC	2006-Present
		Chief Financial Officer and Vice President of AEP	2001-2006
		Executive Vice President-Chief Financial Officer of AEPSC	2004-2006
		Director of AEPSC	1998-Present
		Vice President and Director of APCo, OPCo and SWEPCo	2000-Present
		Executive Vice President-Policy, Finance and Strategic Planning of AEPSC	2001-2004

(a) Messrs. Morris and Akins and Ms. Koeppel are directors of AEGCo, CSPCo, I&M, KPCo, PSO, TCC and TNC.
(b) Mr. Morris is a director of Cincinnati Bell, Inc. and The Hartford Financial Services Group, Inc.
(c) Mr. English and Ms. Tomasky are directors of CSPCo, I&M, KPCo, PSO, TCC and TNC.
(d) Mr. Hagan is a director of PSO, TCC and TNC.
(e) Mr. Keane is a director of AEGCo, CSPCo, KPCo, PSO, TCC and TNC.
(f) Mr. Powers is a director of AEGCo, CSPCo, I&M, KPCo, PSO, TCC and TNC.

APCo:

Name	Age	Position	Period
Dana E. Waldo	55	President and Chief Operating Officer of APCo and Kingsport Power Company	2004-Present
		President of Wheeling Power Company	2005-Present
		President and Chief Executive Officer of West Virginia Roundtable	1999-2004

OPCo:

Name	Age	Position	Period
Kevin E. Walker	43	President and Chief Operating Officer of CSPCo and OPCo	2004-Present
		President of WPCo	2004-2005
		Vice President of Consolidated Edison (New York)	2001-2004

SWEPCo:

Name	Age	Position	Period
Venita McCellon-Allen	47	President and Chief Operating Officer of SWEPCo	2006-Present
		Director and Senior Vice President-Shared Services of AEPSC	2004-2006
		Director of APCo, I&M, OPCo, SWEPCo and TCC	2004-2006
		Senior Vice President-Human Resources for Baylor Health Care Systems	2000-2004

PART II

ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

AEP. The information required by this item is incorporated herein by reference to the material under AEP *Common Stock and Dividend Information* in the 2006 Annual Report.

AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. The common stock of these companies is held solely by AEP. The amounts of cash dividends on common stock paid by these companies to AEP during 2006, 2005 and 2004 are incorporated by reference to the material under *Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss)* in the 2006 Annual Reports.

The following table provides information about purchases by AEP (or its publicly-traded subsidiaries) during the quarter ended December 31, 2006 of equity securities that are registered by AEP (or its publicly-traded subsidiaries) pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number Of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
10/01/06 – 10/31/06(a)(b)	177	$ 68.08	-	$ -
11/01/06 – 11/30/06(c)	17	83.50	-	-
12/01/06 – 12/31/06	-	-	-	-
Total	194	$ 69.43	-	$ -

(a) OPCo repurchased 2 shares of its 4.50% cumulative preferred stock, in privately-negotiated transactions outside of an announced program

(b) TCC repurchased 175 shares of its 4.20% cumulative preferred stock, in privately-negotiated transactions outside of an announced program.

(c) SWEPCo repurchased 17 shares of its 5.00% cumulative preferred stock, in privately-negotiated transactions outside of an announced program.

ITEM 6. SELECTED FINANCIAL DATA

AEGCo, **CSPCo, I&M, KPCo, PSO, TCC and TNC.** Omitted pursuant to Instruction I(2)(a).

AEP, APCo, OPCo and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Selected Consolidated Financial Data* in the 2006 Annual Reports.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

AEGCo, CSPCo, I&M, KPCo, PSO, TCC and TNC. Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under *Management's Financial Discussion and Analysis of Results of Operations* in the 2006 Annual Reports.

AEP, APCo, OPCo and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Management's Financial Discussion and Analysis of Results of Operations* in the 2006 Annual Reports.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. The information required by this item is incorporated herein by reference to the material under *Management's Financial Discussion and Analysis of Results of Operations* in the 2006 Annual Reports.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. The information required by this item is incorporated herein by reference to the financial statements and financial statement schedules described under Item 15 herein.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC. None.

ITEM 9A. CONTROLS AND PROCEDURES

During 2006, management, including the principal executive officer and principal financial officer of each of American Electric Power Company, Inc. (“AEP”), AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (each, together with AEP, a “Registrant” and collectively, together with AEP, the “Registrants”) evaluated each respective Registrant’s disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the Commission’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to each Registrant’s management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of December 31, 2006, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There have been no changes in the Registrants’ internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter of 2006 that materially affected, or are reasonably likely to materially affect, the Registrants’ internal controls over financial reporting.

Additional information required by this item of AEP, as a large accelerated filer, is incorporated by reference to *Management’s Report on Internal Control over Financial Reporting*, included in the 2006 Annual Report.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

AEGCo, **CSPCo, I&M, KPCo, PSO, TCC and TNC.** Omitted pursuant to Instruction I(2)(c).

AEP:

Directors, Director Nomination Process and Audit Committee. The information required by this item concerning directors and nominees for election as directors at AEP's annual meeting of shareholders (Item 401 of Regulation S-K), the director nomination process (Item 407(c)(3)) and the audit committee (Item 407(d)(4) and (d)(5)) is incorporated herein by reference to information contained in the definitive proxy statement of AEP for the 2007 annual meeting of shareholders.

Executive Officers. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I, Item 4 of this report.

Code of Ethics. AEP's Principles of Business Conduct is the code of ethics that applies to AEP's Chief Executive Officer, Chief Financial Officer and principal accounting officer. The Principles of Business Conduct is available on AEP's website at *www.aep.com*. The Principles of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Investor Relations, American Electric Power Company, Inc., 1 Riverside Plaza, Columbus, Ohio 43215.

If any substantive amendments to the Principles of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Principles of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or principal accounting officer, AEP will disclose the nature of such amendment or waiver on AEP's website, *www.aep.com*, or in a report on Form 8-K.

Beneficial Ownership Reporting Compliance. The information required by this item is incorporated herein by reference to information contained in the definitive proxy statement of AEP for the 2007 annual meeting of shareholders.

APCo and OPCo:

Directors and Executive Officers. The information required by this item is incorporated herein by reference to the information in the definitive information statement of each company for the 2007 annual meeting of stockholders. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I, Item 4 of this report.

Audit Committee. Each of APCo and OPCo is a controlled subsidiary of AEP and does not have a separate audit committee.

Code of Ethics. AEP's Principles of Business Conduct is the code of ethics that applies to the Chief Executive Officer, Chief Financial Officer and principal accounting officer of APCo and OPCo. The discussion of AEP's Principles of Business Conduct above is incorporated herein by reference. If any substantive amendments to the Principles of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Principles of Business Conduct, to the Chief Executive Officer, Chief Financial Officer or principal accounting officer of APCo or

OPCo, as applicable, that company will disclose the nature of such amendment or waiver on AEP's website, *www.aep.com*, or in a report on Form 8-K.

SWEPCo:

Directors and Executive Officers. The names of the directors and executive officers of SWEPCo, the positions they hold with SWEPCo, their ages as of February 1, 2007, and a brief account of their business experience during the past five years appear below or under the caption *Executive Officers of the Registrants* in Part I, Item 4 of this report.

Name	Age	Position	Period
Stephen P. Smith (a)	45	Senior Vice President and Treasurer of AEP	2004-Present
		Vice President and Director of APCo, OPCo and SWEPCo	2004-Present
		Director of AEPSC	2004-Present
		Senior Vice President and Treasurer of AEPSC	2003-Present
		Treasurer of AEPSC, APCo, OPCo and SWEPCo	2003-Present
		President and Chief Operating Officer-Corporate Services for NiSource	1999-2003
Dennis E. Welch (b)	55	Senior Vice President of AEP	2005-Present
		Director of APCo, OPCo and SWEPCo	2005-Present
		Senior Vice President-Environment and Safety and Director of AEPSC	2005-Present
		President of Yankee Gas Services Company	2001-2005

(a) Mr. Smith is a director of AEGCo, CSPCo, KPCo, PSO, TCC and TNC.
(b) Mr. Welch is a director of CSPCo, KPCo, PSO, TCC and TNC.

Audit Committee. SWEPCo is a controlled subsidiary of AEP and does not have a separate audit committee.

Code of Ethics. AEP's Principles of Business Conduct is the code of ethics that applies to the Chief Executive Officer, Chief Financial Officer and principal accounting officer of SWEPCo. The discussion of AEP's Principles of Business Conduct above is incorporated herein by reference. If any substantive amendments to the Principles of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Principles of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or principal accounting officer, SWEPCo will disclose the nature of such amendment or waiver on AEP's website, *www.aep.com*, or in a report on Form 8-K.

ITEM 11. EXECUTIVE COMPENSATION

AEGCo, **CSPCo, I&M, KPCo, PSO, TCC and TNC.** Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under *Directors Compensation and Stock Ownership, Executive Compensation* and the performance graph of the definitive proxy statement of AEP for the 2007 annual meeting of shareholders.

APCo and OPCo. The information required by this item is incorporated herein by reference to the material under *Executive Compensation* of the definitive information statement of each company for the 2007 annual meeting of stockholders.

SWEPCo. The information required by this item is incorporated herein by reference to the material under *Executive Compensation* of the definitive proxy statement of AEP for the 2007 annual meeting of shareholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

AEGCo, **CSPCo, I&M, KPCo, PSO, TCC and TNC.** Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the material under *Share Ownership of Directors and Executive Officers* of the definitive proxy statement of AEP for the 2007 annual meeting of shareholders.

APCo and OPCo. The information required by this item is incorporated herein by reference to the material under *Share Ownership of Directors and Executive Officers* in the definitive information statement of each company for the 2007 annual meeting of stockholders.

SWEPCo. All 7,536,640 outstanding shares of Common Stock, $18 par value, of SWEPCo are directly and beneficially held by AEP. Holders of the Cumulative Preferred Stock of SWEPCo generally have no voting rights, except with respect to certain corporate actions and in the event of certain defaults in the payment of dividends on such shares.

The table below shows the number of shares of AEP Common Stock and stock-based units that were beneficially owned, directly or indirectly, as of January 1, 2006, by each director and nominee of SWEPCo and each of the executive officers of SWEPCo named in the summary compensation table, and by all directors and executive officers of SWEPCo as a group. It is based on information provided to SWEPCo by such persons. No such person owns any shares of any series of the Cumulative Preferred Stock of SWEPCo. Unless otherwise noted, each person has sole voting power and investment power over the number of shares of AEP Common Stock and stock-based units set forth opposite his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	**Shares (a)**		**Stock Units (b)**	**Total**
Nicholas K. Akins	15,900		1,574	17,474
Carl L. English	13,610		12,351	25,961
Thomas M. Hagan	166,708		28,971	195,679
John B. Keane	6,804		6,174	12,978
Holly K. Koeppel	36,967		33,617	70,584
Venita McCellon-Allen	4,536		4,066	8,602
Michael G. Morris	438,498	(c)	161,008	599,506
Stephen P. Smith	19,000		9,814	28,814
Susan Tomasky	208,572		41,144	249,716
Dennis E. Welch	3,333		10,398	13,731
All Directors and Executive Officers	913,928	(d)	309,117	1,223,045

Name	AEP Retirement Savings Plan (Share Equivalents)
Nicholas K. Akins	—
Carl L. English	—
Thomas M. Hagan	5,715
John B. Keane	—
Holly K. Koeppel	267
Venita McCellon-Allen	—
Michael G. Morris	—
Stephen P. Smith	—
Susan Tomasky	4,238
Dennis E. Welch	—
All Directors and Executive Officers	10,220

With respect to the share equivalents held in the AEP Retirement Savings Plan, such persons have sole voting power, but the investment/disposition power is subject to the terms of the Plan. Also, includes the following numbers of shares attributable to options exercisable within 60 days: Mr. Akins, 15,900; Mr. Hagan, 150,500; Ms. Koeppel, 36,700; Mr. Morris, 149,000; Mr. Smith, 16,500; Ms. Tomasky, 204,334; and Mr. Welch, 3,333.

(a) Includes share equivalents held in the AEP Retirement Savings Plan in the amounts listed.
(b) This column includes amounts deferred in stock units and held under AEP's various director and officer benefit plans.
(c) Represents less than 1% of the total number of shares outstanding.
(d) Includes restricted shares with different vesting schedules and accrued dividends.

EQUITY COMPENSATION PLAN INFORMATION

Information regarding the equity compensation plan is incorporated by reference from the definitive proxy statement of AEP for the 2007 annual meeting of shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

AEGCo, **CSPCo, I&M, KPCo, PSO, TCC and TNC.** Omitted pursuant to Instruction I(2)(c).

AEP. The information required by this item is incorporated herein by reference to the definitive proxy statement of AEP for the 2007 annual meeting of shareholders.

APCo, **OPCo and SWEPCo:** **Certain Relationships and Related Transactions.** None.
Director Independence. None of the directors of APCo, OPCo or SWEPCo is independent because each director is either (i) an officer of the company in which each serves as director, or (ii) an officer of AEP.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

AEP. The following table presents fees for professional audit services rendered by Deloitte & Touche LLP for the audit of AEP's annual financial statements for the years ended December 31, 2006 and December 31, 2005, and fees billed for other services rendered by Deloitte & Touche LLP during those periods.

	2006	**2005**
Audit Fees (1)		
Financial Statements	$8,564,000	$8,469,000
Internal Control over financial reporting	4,080,000	4,210,000
Total Audit Fees	12,644,000	12,679,000
Audit-Related Fees (2)	822,000	581,000
Tax Fees (3)	703,000	1,116,000
TOTAL	$14,169,000	$14,376,000

(1) Audit fees in 2005 and 2006 consisted primarily of fees related to the audit of the Company's annual consolidated financial statements, including each registrant subsidiary. Audit fees also included auditing procedures performed in accordance with Sarbanes-Oxley Act Section 404 and the related Public Company Accounting Oversight Board Auditing Standard Number 2 regarding the Company's internal control over financial reporting. This category also included work generally only the independent registered public accounting firm can reasonably be expected to provide.

(2) Audit related fees consisted principally of regulatory and statutory audits and audit-related work in connection with acquisitions and dispositions.

(3) Tax fees consisted principally of tax compliance services. Tax compliance services are services rendered based upon facts already in existence or transactions that have already occurred to document, compute, and obtain government approval for amounts to be included in tax filings.

APCo and OPCo. The information required by this item is incorporated herein by reference to the definitive information statement of each company for the 2007 annual meeting of stockholders.

AEGCo, **CSPCo, I&M, KPCo, PSO, SWEPCo, TCC and TNC.**

Each of the above is a wholly-owned subsidiary of AEP and does not have a separate audit committee. A description of the AEP Audit Committee pre-approval policies, which apply to these companies, is contained in the definitive proxy statement of AEP for the 2007 annual meeting of shareholders. The following table presents directly billed fees for professional services rendered by Deloitte & Touche LLP for the audit of these companies' annual financial statements for the years ended December 31, 2005 and 2006, and fees directly billed for other services rendered by Deloitte & Touche LLP during those periods. Deloitte & Touche LLP also provides additional professional and other services to the AEP System, the cost of which may ultimately be allocated to these companies though not billed directly to them. For a description of these fees and services, see the definitive proxy statement of AEP for the 2007 annual meeting of shareholders.

	AEGCo		CSPCo		I&M	
	2006	2005	2006	2005	2006	2005
Audit Fees						
Financial Statement Audits	$162,474	$165,550	$786,264	$672,646	$ 841,07	$755,644
Sarbanes-Oxley 404	97,512	100,619	451,248	465,626	426,768	440,366
Audit Fees – Other	57,739	29,628	179,792	145,287	276,523	139,603
Audit Fees Subtotal	317,725	295,797	1,417,304	1,283,559	1,544,365	1,335,613
Audit-Related Fees	5,513	0	31,755	55,500	248,233	5,500
Tax Fees	1,350	2,250	22,913	23,100	26,216	30,350
TOTAL	$324,588	$298,047	$1,471,972	$1,362,159	$1,818,814	$1,371,463

	KPCo		PSO		SWEPCo	
	2006	2005	2006	2005	2006	2005
Audit Fees						
Financial Statement Audits	$488,070	$446,615	$293,625	$416,418	$336,039	$483,761
Sarbanes-Oxley 404	247,656	255,547	238,272	245,864	276,216	285,438
Audit Fees – Other	107,136	71,972	111,144	89,098	133,580	99,190
Audit Fees Subtotal	842,862	774,134	643,041	751,380	745,835	868,389
Audit-Related Fees	15,638	0	16,772	5,500	87,657	5,500
Tax Fees	8,945	10,550	18,804	21,400	22,134	20,400
TOTAL	$867,445	$784,684	$678,617	$778,280	$855,626	$894,289

	TCC		TNC	
	2006	2005	2006	2005
Audit Fees				
Financial Statement Audits	$332,124	$512,496	$122,019	$175,723
Sarbanes-Oxley 404	310,896	320,802	163,608	168,821
Audit Fees – Other	242,977	170,027	42,018	48,337
Audit Fees Subtotal	885,997	1,003,325	327,645	392,881
Audit-Related Fees	60,113	0	6,029	0
Tax Fees	23,079	28,900	9,795	15,250
TOTAL	$969,189	$1,032,225	$343,469	$408,131

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

The following documents are filed as a part of this report:

	Page
1. FINANCIAL STATEMENTS:	
The following financial statements have been incorporated herein by reference pursuant to Item 8.	
AEGCo:	
Statements of Income for the years ended December 31, 2006, 2005 and 2004; Statements of Retained Earnings for the years ended December 31, 2006, 2005 and 2004; Balance Sheets as of December 31, 2006 and 2005; Statements of Cash Flows for the years ended December 31, 2006, 2005 and 2004; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
AEP and Subsidiary Companies:	
Reports of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Operations for the years ended December 31, 2006, 2005 and 2004; Consolidated Balance Sheets as of December 31, 2006 and 2005; Consolidated Statements of Cash Flows for the years ended December 31, 2006, 2005 and 2004; Consolidated Statements of Changes in Common Shareholders' Equity and Comprehensive Income (Loss) for the years ended December 31, 2006, 2005 and 2004; Notes to Consolidated Financial Statements.	
APCo, CSPCo, I&M, OPCo, SWEPCo, TNC and TCC:	
Consolidated Statements of Income (or Statements of Operations) for the years ended December 31, 2006, 2005 and 2004; Consolidated Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss) for the years ended December 31, 2006, 2005 and 2004; Consolidated Balance Sheets as of December 31, 2006 and 2005; Consolidated Statements of Cash Flows for the years ended December 31, 2006, 2005 and 2004; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
KPCo and PSO:	
Statements of Income for the years ended December 31, 2006, 2005 and 2004; Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss) for the years ended December 31, 2006, 2005 and 2004; Balance Sheets as of December 31, 2006 and 2005; Statements of Cash Flows for the years ended December 31, 2006, 2005 and 2004; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
2. FINANCIAL STATEMENT SCHEDULES:	
Financial Statement Schedules are listed in the Index to Financial Statement Schedules (Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable). Report of Independent Registered Public Accounting Firm	S-1
3. EXHIBITS:	
Exhibits for AEGCo, AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC are listed in the Exhibit Index beginning on page E-1 and are incorporated herein by reference	E-1

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ HOLLY K. KOEPPEL
(Holly K. Koeppel, Executive Vice President and Chief Financial Officer)

Date: February 28, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ MICHAEL G. MORRIS **(Michael G. Morris)**	Chairman of the Board, President, Chief Executive Officer And Director	February 28, 2007
(ii) Principal Financial Officer:		
/s/ HOLLY K. KOEPPEL **(Holly K. Koeppel)**	Executive Vice President and Chief Financial Officer	February 28, 2007
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Senior Vice President, Controller and Chief Accounting Officer	February 28, 2007
(iv) A Majority of the Directors:		
*E. R. BROOKS *DONALD M. CARLTON *RALPH D. CROSBY, JR. *JOHN P. DESBARRES *ROBERT W. FRI *LINDA A. GOODSPEED *WILLIAM R. HOWELL *LESTER A. HUDSON, JR. *LIONEL L. NOWELL, III *RICHARD L. SANDOR *DONALD G. SMITH *KATHRYN D. SULLIVAN		
*By: /s/ HOLLY K. KOEPPEL **(Holly K. Koeppel, Attorney-in-Fact)**		February 28, 2007

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AEP GENERATING COMPANY

By: /s/ HOLLY K. KOEPPEL
(Holly K. Koeppel, Vice President and Chief Financial Officer)

Date: February 28, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ MICHAEL G. MORRIS **(Michael G. Morris)**	Chairman of the Board, Chief Executive Officer and Director	February 28, 2007
(ii) Principal Financial Officer:		
/s/ HOLLY K. KOEPPEL **(Holly K. Koeppel)**	Vice President, Chief Financial Officer and Director	February 28, 2007
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 28, 2007
(iv) A Majority of the Directors:		
* NICHOLAS K. AKINS * JOHN B. KEANE * ROBERT P. POWERS * STEPHEN P. SMITH		
*By: /s/ HOLLY K. KOEPPEL **(Holly K. Koeppel, Attorney-in-Fact)**		February 28, 2007

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AEP TEXAS CENTRAL COMPANY
AEP TEXAS NORTH COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ HOLLY K. KOEPPEL
(Holly K. Koeppel, Vice President and Chief Financial Officer)

Date: February 28, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ MICHAEL G. MORRIS **(Michael G. Morris)**	Chairman of the Board, Chief Executive Officer and Director	February 28, 2007
(ii) Principal Financial Officer:		
/s/ HOLLY K. KOEPPEL **(Holly K. Koeppel)**	Vice President, Chief Financial Officer and Director	February 28, 2007
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 28, 2007
(iv) A Majority of the Directors:		
*NICHOLAS K. AKINS *CARL L. ENGLISH *THOMAS M. HAGAN *JOHN B. KEANE *STEPHEN P. SMITH *SUSAN TOMASKY *DENNIS E. WELCH		
*By: /s/ HOLLY K. KOEPPEL **(Holly K. Koeppel, Attorney-in-Fact)**		February 28, 2007

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

APPALACHIAN POWER COMPANY
COLUMBUS SOUTHERN POWER COMPANY
KENTUCKY POWER COMPANY
OHIO POWER COMPANY

By: /s/ HOLLY K. KOEPPEL
(Holly K. Koeppel, Vice President and Chief Financial Officer)

Date: February 28, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ MICHAEL G. MORRIS **(Michael G. Morris)**	Chairman of the Board, Chief Executive Officer and Director	February 28, 2007
(ii) Principal Financial Officer:		
/s/ HOLLY K. KOEPPEL **(Holly K. Koeppel)**	Vice President, Chief Financial Officer and Director	February 28, 2007
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 28, 2007
(iv) A Majority of the Directors:		
*NICHOLAS K. AKINS *CARL L. ENGLISH *JOHN B. KEANE *ROBERT P. POWERS *STEPHEN P. SMITH *SUSAN TOMASKY *DENNIS E. WELCH		
*By: /s/ HOLLY K. KOEPPEL **(Holly K. Koeppel, Attorney-in-Fact)**		February 28, 2007

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

INDIANA MICHIGAN POWER COMPANY

By: /s/ HOLLY K. KOEPPEL
(**Holly K. Koeppel Vice President and Chief Financial Officer)**

Date: February 28, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	**Title**	**Date**
(i) Principal Executive Officer:		
/s/ MICHAEL G. MORRIS **(Michael G. Morris)**	Chairman of the Board, Chief Executive Officer and Director	February 28, 2007
(ii) Principal Financial Officer:		
/s/ HOLLY K. KOEPPEL **(Holly K. Koeppel)**	Vice President, Chief Financial Officer and Director	February 28, 2007
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 28, 2007
(iv) A Majority of the Directors:		
*NICHOLAS K. AKINS *K. G. BOYD *CARL L. ENGLISH *ALLEN R. GLASSBURN *JOANN M. GREVENOW *PATRICK C. HALE *MARC E. LEWIS *HELEN J. MURRAY *ROBERT P. POWERS *SUSANNE M. MOORMAN ROWE *SUSAN TOMASKY		
*By: /s/ HOLLY K. KOEPPEL **(Holly K. Koeppel, Attorney-in-Fact)**		February 28, 2007

INDEX TO FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited the consolidated financial statements of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, and the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, and have issued our reports thereon dated February 28, 2007 (which reports express unqualified opinions and, with respect to the report on the consolidated financial statements, includes an explanatory paragraph concerning the adoption of new accounting pronouncements in 2004, 2005 and 2006); such consolidated financial statements and reports are included in your 2006 Annual Report and are incorporated herein by reference. Our audits also included the consolidated financial statement schedule of the Company listed in Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited the financial statements of AEP Texas Central Company and subsidiaries, AEP Texas North Company and subsidiary, Appalachian Power Company and subsidiaries, Columbus Southern Power Company and subsidiaries, Indiana Michigan Power Company and subsidiaries, Kentucky Power Company, Ohio Power Company Consolidated, Public Service Company of Oklahoma and Southwestern Electric Power Company Consolidated (collectively the "Companies") as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, and have issued our reports thereon dated February 28, 2007 (which reports express unqualified opinions and include an explanatory paragraph concerning the adoption of new accounting pronouncements in 2004, 2005 and 2006 where applicable); such financial statements and reports are included in the Companies 2006 Annual Reports and are incorporated herein by reference. Our audits also included the financial statement schedules of the Companies listed in Item 15. These financial statement schedules are the responsibility of the Companies' management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2007

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2006	$ 30,553	$ 29,831	$ 1,001	$ 31,557	$ 29,828
Year Ended December 31, 2005	77,175	27,384	24	74,030	30,553
Year Ended December 31, 2004	123,685	39,766	7,989	94,265	77,175

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2006	$ 143	$ (29) (c)	$ -	$ 65	$ 49
Year Ended December 31, 2005	3,493	29	-	3,379	143
Year Ended December 31, 2004	1,710	3,493	-	1,710	3,493

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.
(c) Includes a credit of $29 thousand from a true-up adjustment as a result of changes to the System Integration Agreement and the CSW Operating Agreement.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2006	$ 18	$ (9) (c)	$ -	$ -	$ 9
Year Ended December 31, 2005	787	14	-	783	18
Year Ended December 31, 2004	175	787	-	175	787

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.
(c) Includes a credit of $14 thousand from a true-up adjustment as a result of changes to the System Integration Agreement and the CSW Operating Agreement.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2006	$ 1,805	$ 4,012	$ 999	$ 2,482	$ 4,334
Year Ended December 31, 2005	5,561	3,304	21	7,081	1,805
Year Ended December 31, 2004	2,085	3,059	4,201	3,784	5,561

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2006	$ 1,082	$ 189	$ -	$ 725	$ 546
Year Ended December 31, 2005	674	408	-	-	1,082
Year Ended December 31, 2004	531	577	187	621	674

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2006	$ 898	$ 208	$ -	$ 505	$ 601
Year Ended December 31, 2005	187	819	-	108	898
Year Ended December 31, 2004	531	195	90	629	187

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

KENTUCKY POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
		(in thousands)			
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2006	$ 147	$ 80	$ -	$ -	$ 227
Year Ended December 31, 2005	34	146	-	33	147
Year Ended December 31, 2004	736	43	27	772	34

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

OHIO POWER COMPANY CONSOLIDATED
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
		(in thousands)			
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2006	$ 1,517	$ 243	$ -	$ 936	$ 824
Year Ended December 31, 2005	93	1,425	-	1	1,517
Year Ended December 31, 2004	789	122	89	907	93

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

PUBLIC SERVICE COMPANY OF OKLAHOMA
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
		(in thousands)			
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2006	$ 240	$ (81) (c)	$ -	$ 154	$ 5
Year Ended December 31, 2005	76	164	-	-	240
Year Ended December 31, 2004	37	21	55	37	76

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.
(c) Includes a credit of $81 thousand from a true-up adjustment as a result of changes to the System Integration Agreement and the CSW Operating Agreement.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2006	$ 548	$ (37) (c)	$ -	$ 381	$ 130
Year Ended December 31, 2005	45	534	-	31	548
Year Ended December 31, 2004	2,093	(2,079)	134	103	45

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.
(c) Includes a credit of $95 thousand from a true-up adjustment as a result of changes to the System Integration Agreement and the CSW Operating Agreement.

EXHIBIT INDEX

The documents listed below are being filed or have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof. Exhibits ("Ex") not identified as previously filed are filed herewith. Exhibits, designated with a dagger (†), are management contracts or compensatory plans or arrangements required to be filed as an Exhibit to this Form pursuant to Item 14(c) of this report.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
REGISTRANT: AEGCo File No. 0-18135		
3(a)	Articles of Incorporation of AEGCo.	Registration Statement on Form 10 for the Common Shares of AEGCo, Ex 3(a).
3(b)	Copy of the Code of Regulations of AEGCo, amended as of June 15, 2000.	2000 Form 10-K, Ex 3(b).
10(a)	Capital Funds Agreement dated as of December 30, 1988 between AEGCo and AEP.	Registration Statement No. 33-32752, Ex 28(a).
10(b)(1)	Unit Power Agreement dated as of March 31, 1982 between AEGCo and I&M, as amended.	Registration Statement No. 33-32752, Ex 28(b)(1)(A)(B).
10(b)(2)	Unit Power Agreement, dated as of August 1, 1984, among AEGCo, I&M and KPCo.	Registration Statement No. 33-32752, Ex 28(b)(2).
10(c)	Lease Agreements, dated as of December 1, 1989, between AEGCo and Wilmington Trust Company, as amended.	Registration Statement No. 33-32752, Ex 28(c)(1-6)(C); 1993 Form 10-K, Ex 10(c)(1-6)(B).
*13	Copy of those portions of the AEGCo 2006 Annual Report, which are incorporated by reference in this filing.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: AEP‡ File No. 1-3525		
3(a)	Composite of the Restated Certificate of Incorporation of AEP, dated January 13, 1999.	1998 Form 10-K, Ex 3(c).
3(b)	By-Laws of AEP, as amended through December 15, 2003	2003 Form 10-K, Ex 3(d).
4(a)	Indenture (for unsecured debt securities), dated as of May 1, 2001, between AEP and The Bank of New York, as Trustee.	Registration Statement No. 333-86050, Ex 4(a)(b)(c); Registration Statement No. 333-105532, Ex 4(d)(e)(f).
4(b)	Purchase Agreement dated as of March 8, 2005, between AEP and Merrill Lynch International	Form 10-Q, Ex. 4(a), March 31, 2005
10(a)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); 1990 Form 10-K, Ex 10(a)(3).
10(b)	Restated and Amended Operating Agreement, among PSO, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006,.	2002 Form 10-K; Ex 10(b) Form 10-Q, Ex 10(b), March 31, 2006.
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	1985 Form 10-K; Ex 10(b) 1988 Form 10-K, Ex 10(b)(2).
10(d)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(d).

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
10(e)(1)		Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.		2004 Form 10-K, Ex 10(e)(1)
10(e)(2)		PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.		2004 Form 10-K, Ex 10(e)(2)
10(e)(3)		Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.		2004 Form 10-K, Ex 10(e)(3)
10(f)		Lease Agreements, dated as of December 1, 1989, between AEGCo or I&M and Wilmington Trust Company, as amended.		Registration Statement No. 33-32752, Ex 28(c)(1-6)(C); Registration Statement No. 33-32753, Ex 28(a)(1-6)(C); AEGCO 1993 Form 10-K, Ex 10(c)(1-6)(B); I&M 1993 Form 10-K, Ex 10(e)(1-6)(B).
10(g)		Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested)		OPCo 1994 Form 10-K, Ex 10(l)(2).
10(h)		Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.		1996 Form 10-K, Ex 10(l)
†10(i)		AEP Accident Coverage Insurance Plan for directors.		1985 Form 10-K, Ex 10(g)
*†10(j)(1)		AEP Retainer Deferral Plan for Non-Employee Directors, effective January 1, 2005, as amended February 9, 2007.		Form 10-Q, Ex. 10(b), March 31, 2005
†10(j)(2)		AEP Stock Unit Accumulation Plan for Non-Employee Directors, as amended.		2003 Form 10-K, Ex 10(k)(2).
*†10(j)(2)(A)		First Amendment to AEP Stock Unit Accumulation Plan for Non-Employee Directors dated as of February 9, 2007		
†10(k)(1)(A)		AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001.		2000 Form 10-K, Ex 10(j)(1)(A)
†10(k)(1)(B)		Guaranty by AEP of AEPSC Excess Benefits Plan.		1990 Form 10-K, Ex 10(h)(1)(B)
†10(k)(1)(C)		First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003.		2002 Form 10-K; Ex 10(1)(1)(c)
*†10(k)(2)		AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2005 (Non-Qualified), as amended December 28, 2006.		
†10(k)(3)		Service Corporation Umbrella Trust for Executives.		1993 Form 10-K, Ex 10(g)(3).
†10(l)(1)		Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.		2003 Form 10-K, Ex 10(m)(1).
†10(l)(2)		Memorandum of agreement between Susan Tomasky and AEPSC dated January 3, 2001.		2000 Form 10-K, Ex 10(s)
†10(l)(3)		Letter Agreement dated June 23, 2000 between AEPSC and Holly K. Koeppel.		2002 Form 10-K; Ex 10(m)(3)(A)
†10(l)(4)		Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.		2002 Form 10-K; Ex 10(m)(4)
†10(l)(5)		Letter Agreements dated June 4, 2004 and June 9, 2004 between AEPSC and Carl English		Form 10-Q, Ex 10(b), September 30, 2004
*†10(l)(6)		Letter Agreements dated June 14, 2004 and June 17, 2004 between AEPSC and John B. Keane		
†10(m)		AEP System Senior Officer Annual Incentive Compensation Plan.		1996 Form 10-K, Ex 10(i)(1)
†10(n)(1)		AEP System Survivor Benefit Plan, effective January 27, 1998.		Form 10-Q, Ex 10, September 30, 1998
†10(n)(2)		First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.		2002 Form 10-K; Ex 10(o)(2)
*†10(o)		AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2005, as amended		

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
		December 28, 2006.		
†10(p)		AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.		2002 Form 10-K, Ex 10(r)
†10(q)		Nuclear Key Contributor Retention Plan dated May 1, 2000.		2002 Form 10-K; Ex 10(s)
†10(r)		AEP Change In Control Agreement, effective January 1, 2006.		Form 8-K, Ex 1, dated January 3, 2006
†10(s)(1)		Amended and Restated AEP System Long-Term Incentive Plan		Form 8-K, Item 1.01, dated April 26, 2005.
†10(s)(2)		Form of Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended		Form 10-Q, Ex. 10(c), September 30, 2004
†10(s)(3)		Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.		Form 10-Q, Ex 10(a), March 31, 2005
*†10(s)(4)		AEP System Stock Ownership Requirement Plan, (as Amended and Restated Effective January 1, 2005), as amended December 28, 2006		
†10(t)(1)		Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997.		CSW 1998 Form 10-K, Ex 18, File No. 1-1443
†10(t)(2)		Certified Board Resolutions of AEP Utilities, Inc. (formerly CSW) of July 16, 1996.		2003 Form 10-K, Ex 10(v)(3).
†10(t)(3)		Central and South West Corporation Executive Deferred Savings Plan as amended and restated effective as of January 1, 1997.		CSW 1998 Form 10-K, Ex 24, File No. 1-1443.
*12		Statement re: Computation of Ratios.		
*13		Copy of those portions of the AEP 2006 Annual Report (for the fiscal year ended December 31, 2006) which are incorporated by reference in this filing.		
*21		List of subsidiaries of AEP.		
*23		Consent of Deloitte & Touche LLP.		
*24		Power of Attorney.		
*31(a)		Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
*31(b)		Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
*32(a)		Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.		
*32(b)		Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.		
REGISTRANT: APCo‡ File No. 1-3457				
3(a)		Composite of the Restated Articles of Incorporation of APCo, amended as of March 7, 1997.		1996 Form 10-K, Ex 3(d).
3(b)		By-Laws of APCo, amended as of October 24, 2001.		2001 Form 10-K, Ex 3(e).
4(a)		Indenture (for unsecured debt securities), dated as of January 1, 1998, between APCo and The Bank of New York, As Trustee.		Registration Statement No. 333-45927, Ex 4(a)(b); Registration Statement No. 333-49071, Ex 4(b); Registration Statement No. 333-84061, Ex 4(b)(c); Registration Statement No. 333-100451, Ex 4(b)(c)(d); Registration Statement No. 333-116284, Ex 4(b)(c); Registration Statement No. 333-123348, Ex 4(b)(c). Registration Statement No. 333-136432, Ex 4(b)(c)(d)
10(a)(1)		Power Agreement, dated October 15, 1952, between		Registration Statement No. 2-60015, Ex 5(a);

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
		OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.		Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(D); 1989 Form 10-K, Ex 10(a)(1)(F); 1992 Form 10-K, Ex 10(a)(1)(B)].
10(a)(2)		Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended March 13, 2006.		Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); 1992 Form 10-K, Ex 10(a)(2)(B); 2005 Form 10-K, Ex 10(a)(2).
10(a)(3)		Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.		Registration Statement No. 2-60015, Ex 5(e).
10(b)		Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended.		Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); AEP 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525.
10(c)		Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.		AEP 1985 Form 10-K, Ex 10(b); AEP 1988 Form 10-K, Ex 10(b)(2).
10(d)(1)		Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.		2004 Form 10-K, Ex 10(d)(1)
10(d)(2)		PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.		2004 Form 10-K, Ex 10(d)(2)
10(d)(3)		Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.		2004 Form 10-K, Ex 10(d)(3)
10(e)		Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.		AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525.
†10(f)		AEP System Senior Officer Annual Incentive Compensation Plan		AEP 1996 Form 10-K, Ex 10(i)(1), File No. 1-3525.
†10(g)(1)(A)		AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001.		AEP 2000 Form 10-K, Ex 10(j)(1)(A), File No. 1-3525.
†10(g)(1)(B)		First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003.		2002 Form 10-K; Ex 10(h)(1)(B).
*†10(g)(2)		AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2005 (Non-Qualified), as amended December 28, 2006.		2005 Form 10-K; Ex 10(g)(2)
†10(g)(3)		Umbrella Trust for Executives.		AEP 1993 Form 10-K, Ex 10(g)(3), File No. 1-3525.
†10(h)(1)		Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.		2003 Form 10-K, Ex 10(i)(1).
†10(hi)(2)		Memorandum of Agreement between Susan Tomasky and AEPSC dated January 3, 2001.		AEP 2000 Form 10-K, Ex 10(s), File No. 1-3525.
†10(hi)(3)		Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.		2002 Form 10-K; Ex 10(i)(3).
†10(h)(4)		Letter Agreements dated June 4, 2004 and June 9, 2004 between AEPSC and Carl English		AEP Form 10-Q, Ex 10(b), September 30, 2004
*†10(h)(5)		Letter Agreements dated June 14, 2004 and June 17, 2004 between AEPSC and John B. Keane		
†10(i)(1)		AEP System Survivor Benefit Plan, effective January 27, 1998.		AEP Form 10-Q, Ex 10, September 30, 1998, File No. 1-3525.
†10(i)(2)		First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.		2002 Form 10-K; Ex 10(j)(2).
†10(j)		AEP Change In Control Agreement, effective January 1, 2006.		Form 8-K, Ex 1 dated January 3, 2006,

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(k)(1)	Amended and Restated AEP System Long-Term Incentive Plan.	Form 8-K, Ex 10.1, dated April 26, 2005.
†10(k)(2)	Form of Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended	AEP Form 10-Q, Ex. 10(c), dated November 5, 2004.
†10(k)(3)	Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	AEP Form 10-Q, Ex 10(a), March 31, 2005
*†10(k)(4)	AEP System Stock Ownership Requirement Plan, (as Amended and Restated Effective January 1, 2005), as amended December 28, 2006	
†10(l)(1)	Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997.	CSW 1998 Form 10-K, Ex 18, File No. 1-1443.
†10(l)(2)	Certified Board Resolutions of AEP Utilities, Inc. (formerly CSW) of July 16, 1996.	2003 Form 10-K, Ex 10(n)(3).
*†10(m)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2005, as amended December 28, 2006.	2003 Form 10-K, Ex 10(o)(1); Form 10-Q, Ex 10(b), June 30, 2005.
†10(n)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K; Ex 10(p).
†10(o)	Nuclear Key Contributor Retention Plan dated May 1, 2000.	2002 Form 10-K; Ex 10(q).
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the APCo 2006 Annual Report (for the fiscal year ended December 31, 2006) which are incorporated by reference in this filing.	
21	List of subsidiaries of APCo	AEP 2006 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: CSPCo‡ File No. 1-2680		
3(a)	Composite of Amended Articles of Incorporation of CSPCo, dated May 19, 1994.	1994 Form 10-K, Ex 3(c).
3(b)	Code of Regulations and By-Laws of CSPCo.	1987 Form 10-K, Ex 3(d).
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo and Bankers Trust Company, as Trustee.	Registration Statement No. 333-54025, Ex 4(a)(b)(c)(d); Registration Statement No. 333-128174, Ex 4(b)(c)(d).
4(c)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between CSPCo and Bank One, N.A., as Trustee.	Registration Statement No. 333-128174, Ex 4(e)(f)(g)
4(b)	Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated October 14, 2005, establishing terms of 5.85% senior Notes, Series F, due 2035.	Form 8-K, Ex 4(a), dated October 14, 2005.
10(a)(1)	Power Agreement, dated October 15, 1952, between	Registration Statement No. 2-60015, Ex 5(a);

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
		OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.		Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No. 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(B); APCo 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457; APCo 1992 Form 10-K, Ex 10(a)(1)(B), File No.1-3457.
10(a)(2)		Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended March 13, 2006.		Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); 1992 Form 10-K, Ex 10(a)(2); 2005 Form 10-K, Ex 10(a)(2).
10(a)(3)		Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.		Registration Statement No. 2-60015, Ex 5(e).
10(b)		Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and AEPSC, as amended.		Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); AEP 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525.
10(c)		Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo, and with AEPSC as agent, as amended.		AEP 1985 Form 10-K, Ex 10(b), File No. 1-3525; AEP 1988 Form 10-K, Ex 10(b)(2) File No. 1-3525.
10(d)(1)		Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.		2004 Form 10-K, Ex 10(d)(1)
10(d)(2)		PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.		2004 Form 10-K, Ex 10(d)(2)
10(d)(3)		Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.		2004 Form 10-K, Ex 10(d)(3)
10(e)		Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.		AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525.
*12		Statement re: Computation of Ratios.		
*13		Copy of those portions of the CSPCo 2006 Annual Report (for the fiscal year ended December 31, 2006) which are incorporated by reference in this filing.		
21		List of subsidiaries of CSPCo		AEP 2006 Form 10-K, Ex 21, File No. 1-3525.
*23		Consent of Deloitte & Touche LLP.		
*24		Power of Attorney.		
*31(a)		Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
*31(b)		Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
*32(a)		Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.		
*32(b)		Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.		
REGISTRANT: I&M‡File No. 1-3570				
3(a)		Composite of the Amended Articles of Acceptance of I&M, dated of March 7, 1997		1996 Form 10-K, Ex 3(c).
3(b)		By-Laws of I&M, amended as of November 28, 2001.		2001 Form 10-K, Ex 3(d).
4(a)		Indenture (for unsecured debt securities), dated as of October 1, 1998, between I&M and The Bank of New York, as Trustee.		Registration Statement No. 333-88523, Ex 4(a)(b)(c); Registration Statement No. 333-58656, Ex 4(b)(c); Registration Statement No. 333-108975, Ex 4(b)(c)(d); Registration Statement No. 333-136538, Ex. 4(b)(c).

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(b)	Company Order and Officer's Certificate to The Bank of New York, dated November 14, 2006, establishing terms of 6.05% Senior Notes, Series H, due 2037.	Form 8-K, Ex. 4(a), dated November 14, 2006
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a); Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No. 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(D); APCo 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457; APCo 1992 Form 10-K, Ex 10(a)(1)(B), File No. 1-3457.
10(a)(2)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended, March 13, 2006.	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); 1992 Form 10-K, Ex 10(a)(2); 2005 Form 10-K, Ex 10(a)(2).
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended	Registration Statement No. 2-60015, Ex 5(e).
10(a)(4)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended.	Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); APCo 1992 Form 10-K, Ex 10(a)(2)(B), File No. 1-3457.
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M, and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); AEP 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525.
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	AEP 1985 Form 10-KEx 10(b), File No. 1-3525; AEP 1988 Form 10-K, File No. 1-3525, Ex 10(b)(2).
10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(d)(1)
10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(d)(3)
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525.
10(f)	Lease Agreements, dated as of December 1, 1989, between I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32753, Ex 28(a)(1-6)(C); 1993 Form 10-K, Ex 10(e)(1-6)(B).
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the I&M 2006 Annual Report (for the fiscal year ended December 31, 2006) which are incorporated by reference in this filing.	
21	List of subsidiaries of I&M.	AEP 2006 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United	

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
		States Code.		
REGISTRANT: KPCo‡ File No. 1-6858				
3(a)		Restated Articles of Incorporation of KPCo.		1991 Form 10-K, Ex 3(a).
3(b)		By-Laws of KPCo, amended as of June 15, 2000.		2000 Form 10-K, Ex 3(b).
4(a)		Indenture (for unsecured debt securities), dated as of September 1, 1997, between KPCo and Bankers Trust Company, as Trustee.		Registration Statement No. 333-75785, Ex 4(a)(b)(c)(d); Registration Statement No. 333-87216, Ex 4(e)(f); 2002 Form 10-K, Ex 4(c)(d)(e) 2003 Form 10-K, Ex4(b).
10(a)		Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M and OPCo and with AEPSC, as amended.		Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); AEP 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525.
10(b)		Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.		AEP 1985 Form 10-K, Ex 10(b), File No. 1-3525. AEP 1988 Form 10-K, Ex 10(b)(2), File No. 1-3525.
10(c)(1)		Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.		2004 Form 10-K, Ex 10(c)(1)
10(c)(2)		PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.		2004 Form 10-K, Ex 10(c)(2)
10(c)(3)		Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.		2004 Form 10-K, Ex 10(c)(3)
10(d)		Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.		AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525,.
*12		Statement re: Computation of Ratios.		
*13		Copy of those portions of the KPCo 2006 Annual Report (for the fiscal year ended December 31, 2006) which are incorporated by reference in this filing.		
*23		Consent of Deloitte & Touche LLP		
*24		Power of Attorney.		
*31(a)		Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
*31(b)		Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
*32(a)		Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.		
*32(b)		Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.		
REGISTRANT: OPCo‡ File No.1-6543				
3(a)		Composite of the Amended Articles of Incorporation of OPCo, dated June 3, 2002.		Form 10-Q, Ex 3(e), June 30, 2002.
3(b)		Code of Regulations of OPCo.		1990 Form 10-K, Ex 3(d).
4(a)		Indenture (for unsecured debt securities), dated as of September 1, 1997, between OPCo and Bankers Trust Company (now Deutsche Bank Trust Company Americas), as Trustee.		Registration Statement No. 333-49595, Ex 4(a)(b)(c); Registration Statement No. 333-106242, Ex 4(b)(c)(d); Registration Statement No. 333-75783, Ex 4(b)(c) Registration Statement No. 333-127913, Ex 4(b)(c) Registration Statement No. 333-139802, Ex 4(a)(b)(c).
4(b)		Indenture (for unsecured debt securities), dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee.		Registration Statement No. 333-127913, Ex 4(d)(e)(f).

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
10(a)(1)		Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.		Registration Statement No. 2-60015, Ex 5(a); Registration Statement No. 2-63234, Ex 5(a)(1)(B); Registration Statement No. 2-66301, Ex 5(a)(1)(C); Registration Statement No. 2-67728, Ex 5(a)(1)(D); APCo Form 10-K, Ex 10(a)(1)(F), File No. 1-3457; APCo Form 10-K, Ex 10(a)(1)(B), File No. 1-3457.
10(a)(2)		Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended, March 13, 2006.		Registration Statement No. 2-60015, Ex 5(c); Registration Statement No. 2-67728, Ex 5(a)(3)(B); Form 10-K, Ex 10(a)(2); Form 10-K, Ex 10(a)(2).
10(a)(3)		Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.		Registration Statement No. 2-60015, Ex 5(e).
10(b)		Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M and OPCo and with AEPSC, as amended.		Registration Statement No. 2-52910, Ex 5(a); Registration Statement No. 2-61009, Ex 5(b); AEP 1990 Form 10-K, Ex 10(a)(3), File 1-3525.
10(c)		Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent.		AEP 1985 Form 10-K, Ex 10(b), File No. 1-3525, AEP 1988 Form 10-K, Ex 10(b)(2), File No. 1-3525.
10(d)(1)		Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.		2004 Form 10-K, Ex 10(d)(1)
10(d)(2)		PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.		2004 Form 10-K, Ex 10(d)(2)
10(d)(3)		Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.		2004 Form 10-K, Ex 10(d)(3)
10(e)		Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.		AEP 1996 Form 10-K, Ex 10(l), File No. 1-3525.
10(f)(1)		Amendment No. 1, dated October 1, 1973, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto.		1993 Form 10-K, Ex 10(f). 2003 Form 10-K, Ex 10(e)
10(f)(2)		Amendment No. 9, dated July 1, 2003, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto.		Form 10-Q, Ex 10(a), September 30, 2004.
10(g)		Lease Agreement dated January 20, 1995 between OPCo and JMG Funding, Limited Partnership, and amendment thereto (confidential treatment requested).		1994 Form 10-K, Ex 10(l)(2).
†10(h)		AEP System Senior Officer Annual Incentive Compensation Plan.		AEP 1996 Form 10-K, Ex 10(i)(1), File No. 1-3525.
†10(i)(1)(A)		AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2001.		AEP 2000 Form 10-K, Ex 10(j)(1)(A), File No. 1-3525.
†10(i)(1)(B)		First Amendment to AEP System Excess Benefit Plan, dated as of March 5, 2003.		2002 Form 10-K; Ex 10(i)(1)(B)
*†10(i)(2)		AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2005 (Non-Qualified), as amended December 28, 2006.		2005 Form 10-K, Ex. 10(i)(2)
†10(i)(3)		Umbrella Trust for Executives.		AEP 1993 Form 10-K, Ex 10(g)(3), File No. 1-3525.
†10(j)(1)		Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.		2003 Form 10-K, Ex 10(j)(1).
†10(j)(2)		Memorandum of agreement between Susan Tomasky and AEPSC dated January 3, 2001.		AEP 2000 Form 10-K, Ex 10(s), File No. 1-3525.

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
†10(j)(3)		Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.		2002 Form 10-K, Ex 10(j)(3).
†10(j)(4)		Letter Agreements dated June 4, 2004 and June 9, 2004 between AEPSC and Carl English		AEP Form 10-Q, Ex 10(b), September 30, 2004, File No. 1-3525,
*†10(j)(5)		Letter Agreements dated June 14, 2004 and June 17, 2004 between AEPSC and John B. Keane		
†10(k)(1)		AEP System Survivor Benefit Plan, effective January 27, 1998.		AEP Form 10-Q, Ex 10, September 30, 1998, File No. 1-3525.
†10(k)(2)		First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.		2002 Form 10-K; Ex 10(k)(2).
†10(l)		AEP Change In Control Agreement, effective January 1, 2006.		Form 8-K, Ex 1, dated January 3, 2006.
†10(m)(1)		Amended and Restated AEP System Long-Term Incentive Plan.		Form 8-K, Ex. 10.1, dated April 26, 2005..
†10(m)(2)		Form of Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended		AEP Form 10-Q, Ex. 10(c), dated November 5, 2004, File No. 1-3525.
†10(m)(3)		Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.		Form 10-Q, Ex 10(a), March 31, 2005
*†10(m)(4)		AEP System Stock Ownership Requirement Plan, (as Amended and Restated Effective January 1, 2005), as amended December 28, 2006		
†10(n)(1)		Central and South West System Special Executive Retirement Plan as amended and restated effective July 1, 1997.		CSW 1998 Form 10-K, Ex 18, File No. 1-1443.
†10(n)(2)		Certified Board Resolutions of AEP Utilities, Inc. (formerly CSW) of July 16, 1996.		2003 Form 10-K, Ex 10(o)(3).
*†10(o)		AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2005, as amended December 28, 2006.		2003 Form 10-K, Ex 10(p)(1); Form 10-Q, Ex. 10(b), June 30, 2005.
†10(p)		AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.		2002 Form 10-K, Ex 10(q).
†10(q)		Nuclear Key Contributor Retention Plan dated May 1, 2000.		2002 Form 10-K, Ex 10(r).
*12		Statement re: Computation of Ratios.		
*13		Copy of those portions of the OPCo 2006 Annual Report (for the fiscal year ended December 31, 2006) which are incorporated by reference in this filing.		
21		List of subsidiaries of OPCo.		AEP 2006 Form 10-K, Ex 21, File No. 1-3525.
*23		Consent of Deloitte & Touche LLP.		
*24		Power of Attorney.		
*31(a)		Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
*31(b)		Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
*32(a)		Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.		
*32(b)		Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.		
REGISTRANT: PSO‡ File No. 0-343				
3(a)		Restated Certificate of Incorporation of PSO.		CSW 1996 Form U5S, Ex B-3.1, File No. 1-1443.
3(b)		By-Laws of PSO (amended as of June 28, 2000).		2002 Form 10-K, Ex 3(b).

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(a)	Indenture (for unsecured debt securities), dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee.	Registration Statement No. 333-100623, Exs 4(a)(b); Registration Statement No. 333-114665, Ex 4(b)(c); Registration Statement No. 333-133548, Ex 4(b)(c).
4(b)	Sixth Supplemental Indenture, dated as of August 10, 2006 between PSO and The Bank of New York, as Trustee, establishing terms of the 6.15% Senior Notes, Series F, due 2016	Form 8-K, Ex 4(a), dated August 11, 2006
10(a)	Restated and Amended Operating Agreement, among PSO, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006..	2002 Form 10-K, Ex 10(a) Form 10-Q, Ex 10(a), March 31, 2006.
10(b)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K, Ex 10(b).
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the PSO 2006 Annual Report (for the fiscal year ended December 31, 2006) which are incorporated by reference in this filing.	
21	List of subsidiaries of PSO.	AEP 2006 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: SWEPCo‡ File No. 1-3146		
3(a)	Restated Certificate of Incorporation, as amended through May 6, 1997, including Certificate of Amendment of Restated Certificate of Incorporation.	Form 10-Q, Ex 3.4, March 31, 1997.
3(b)	By-Laws of SWEPCo (amended as of April 27, 2000).	Form 10-Q, Ex 3.3, March 31, 2000.
4(a)	Indenture, dated February 1, 1940, between SWEPCo and Continental Bank, National Association and M. J. Kruger, as Trustees, as amended and supplemented.	Registration Statement No. 2-60712, Ex 5.04; Registration Statement No. 2-61943, Ex 2.02; Registration Statement No. 2-66033, Ex 2.02; Registration Statement No. 2-71126, Ex 2.02; Registration Statement No. 2-77165, Ex 2.02; Form U-1 No. 70-7121, Ex 4; Form U-1 No. 70-7233, Ex 3; Form U-1 No. 70-7676, Ex 3; Form U-1 No. 70-7934, Ex 10; Form U-1 No. 72-8041, Ex 10(b); Form U-1 No. 70-8041, Ex 10(c); Form U-1 No. 70-8239, Ex 10(a).
4(b)	SWEPCO-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely Junior Subordinated Debentures of SWEPCo: (1) Subordinated Indenture, dated as of September 1, 2003, between SWEPCo and the Bank of New York, as Trustee. (2) Amended and Restated Trust Agreement of SWEPCo Capital Trust I, dated as of September 1, 2003, among SWEPCo, as Depositor, the Bank of New York, as Property Trustee, The Bank of New York (Delaware), as	2003 Form 10-K, Ex 4(b).

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
		Delaware Trustee, and the Administrative Trustees. (3) Guarantee Agreement, dated as of September 1, 2003, delivered by SWEPCo for the benefit of the holders of SWEPCo Capital Trust I's Preferred Securities. (4) First Supplemental Indenture dated as of October 1, 2003, providing for the issuance of Series B Junior Subordinated Debentures between SWEPCo, as Issuer and the Bank of New York, as Trustee (5) Agreement as to Expenses and Liabilities, dated as of October 1, 2003 between SWEPCo and SWEPCo Capital Trust I (included in Item (4) above as Ex 4(f)(i)(A).		
4(c)		Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCo and The Bank of New York, as Trustee.		Registration Statement No. 333-96213; Registration Statement No. 333-87834, Ex 4(a)(b); Registration Statement No. 333-100632, Ex 4(b); Registration Statement No. 333-108045, Ex 4(b).
4(e)		Fourth Supplemental Indenture, dated as of June 28, 2005 between SWEPCo and The Bank of New York, as Trustee, establishing terms of 4.90% Senior Notes, Series D, due 2015.		Form 8-K, Ex 4(a), dated June 30, 2005
4(f)		Fifth Supplemental Indenture, dated as of January 11, 2007 between SWEPCo and The Bank of New York, as Trustee, establishing terms of 5.55% Senior Notes, Series E, due 2017.		Form 8-K, Ex 4(a), dated January 11, 2007
10(a)		Restated and Amended Operating Agreement, among PSO, TCC, TNC, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006..		2002 Form 10-K; Ex 10(a) Form 10-Q, Ex 10(a), March 31, 2006.
10(b)		Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.		2002 Form 10-K; Ex 10(b).
*12		Statement re: Computation of Ratios.		
*13		Copy of those portions of the SWEPCo 2006 Annual Report (for the fiscal year ended December 31, 2006) which are incorporated by reference in this filing.		
21		List of subsidiaries of SWEPCo.		AEP 2006 Form 10-K, Ex 21, File No. 1-3525.
*23		Consent of Deloitte & Touche LLP.		
*24		Power of Attorney.		
*31(a)		Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
*31(b)		Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.		
*32(a)		Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.		
*32(b)		Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.		
REGISTRANT: TCC‡File No. 0-346				
3(a)		Restated Articles of Incorporation Without Amendment, Articles of Correction to Restated Articles of Incorporation Without Amendment, Articles of Amendment to Restated Articles of Incorporation, Statements of Registered Office and/or Agent, and Articles of Amendment to the Articles of Incorporation.		Form 10-Q, Ex 3.1, March 31, 1997.
3(b)		Articles of Amendment to Restated Articles of Incorporation of TCC dated December 18, 2002.		2002 Form 10-K; Ex 3(b).
3(c)		By-Laws of TCC (amended as of April 19, 2000).		2000 Form 10-K, Ex 3(b).

Exhibit Designation	**Nature of Exhibit**	**Previously Filed as Exhibit to:**
4(a)	Indenture (for unsecured debt securities), dated as of November 15, 1999, between TCC and The Bank of New York, as Trustee, as amended and supplemented.	2000 Form 10-K, Ex 4(c)(d)(e).
4(b)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee.	2003 Form 10-K, Ex 4(d).
4(c)	First Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of 5.50% Senior Notes, Series A, due 2013 and 5.50% Senior Notes, Series D, due 2013.	2003 Form 10-K, Ex 4(e).
4(d)	Second Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of 6.65% Senior Notes, Series B, due 2033 and 6.65% Senior Notes, Series E, due 2033.	2003 Form 10-K, Ex 4(f).
4(e)	Third Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of 3.00% Senior Notes, Series C, due 2005 and 3.00% Senior Notes, Series F, due 2005.	2003 Form 10-K, Ex 4(g).
4(f)	Fourth Supplemental Indenture, dated as of February 1, 2003, between TCC and Bank One, N.A., as Trustee, establishing the terms of Floating Rate Notes, Series A, due 2005 and Floating Rate Notes, Series B, due 2005.	2003 Form 10-K, Ex 4(h).
4(g)	Series Supplement, dated as of October 11, 2006 between AEP Texas Central Transition Funding II LLC and The Bank of New York, as Trustee, establishing the Series A Transition Bonds	Form 8-K, Item 8.01, dated October 11, 2006, Ex 4.2.
10(a)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(b).
10(b)	Purchase and Sale Agreement, dated as of September 3, 2004, by and between TCC and City of San Antonio (acting by and through the City Public Service Board of San Antonio) and Texas Genco, L.P.	Form 10-Q, Ex. 10(a), September 30, 2004.
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the TCC 2006Annual Report (for the fiscal year ended December 31, 2006) which are incorporated by reference in this filing.	
21	List of subsidiaries of TCC.	AEP 2006 Form 10-K, Ex 21, File No. 1-3525.
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: TNC‡File No. 0-340		
3(a)	Restated Articles of Incorporation, as amended, and Articles of Amendment to the Articles of Incorporation.	1996 Form 10-K, Ex 3.5.
3(b)	Articles of Amendment to Restated Articles of Incorporation of TNC dated December 17, 2002.	2002 Form 10-K; Ex 3(b).
3(c)	By-Laws of TNC (amended as of May 1, 2000).	Form 10-Q, Ex 3.4, March 31, 2000.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(a)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between TNC and Bank One, N.A., as Trustee.	2003 Form 10-K, Ex 4(b).
4(b)	First Supplemental Indenture, dated as of February 1, 2003, between TNC and Bank One, N.A., as Trustee, establishing the terms of 5.50% Senior Notes, Series A, due 2013 and 5.50% Senior Notes, Series D, due 2013.	2003 Form 10-K, Ex 4(c).
10(a)	Transmission Coordination Agreement, dated October 29, 1998, among PSO, TCC, TNC, SWEPCo and AEPSC.	2002 Form 10-K; Ex 10(b).
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the TNC 2006 Annual Report (for the fiscal year ended December 31, 2006) which are incorporated by reference in this filing.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	

‡ Certain instruments defining the rights of holders of long-term debt of the registrants included in the financial statements of registrants filed herewith have been omitted because the total amount of securities authorized thereunder does not exceed 10% of the total assets of registrants. The registrants hereby agree to furnish a copy of any such omitted instrument to the SEC upon request.