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, 2009

☐ 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
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
1-6543	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 American Electric Power Company, Inc., Appalachian Power Company and Ohio 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 Columbus Southern Power Company, Indiana Michigan 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 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 whether American Electric Power Company, Inc. has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).	Yes ☒	No. ☐
Indicate by check mark whether Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company have submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).	Yes ☐	No. ☐

Indicate by check mark if disclosure of delinquent filers with respect to Appalachian Power Company, Ohio Power Company, Public Service Company of Oklahoma or Southwestern Electric 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, Ohio Power Company, Public Service Company of Oklahoma or Southwestern Electric 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, a non-accelerated filer or a smaller reporting company. See definitions of 'large accelerated filer', 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark whether Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, non-accelerated filers or smaller reporting companies. See definitions of 'large accelerated filer', 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒ (Do not check if a smaller reporting company)	Smaller reporting company	☐

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

Columbus Southern Power Company and Indiana Michigan Power Company 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
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
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
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
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, Voting, $100 par value
	4.65% Cumulative Preferred Stock, Voting, $100 par value
	5.00% Cumulative Preferred Stock, 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, 2009, 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, 2009
American Electric Power Company, Inc.	$13,810,991,818	478,054,407 ($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)
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 all of the common stock of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan 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, 2009: American Electric Power Company, Inc. Appalachian Power Company Columbus Southern Power Company Indiana Michigan 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 2009 Annual Meeting of Shareholders.	Part III
Portions of Information Statements of the following companies for 2009 Annual Meeting of Shareholders: Appalachian Power Company Ohio Power Company Public Service Company of Oklahoma Southwestern Electric Power Company	Part III

This combined Form 10-K is separately filed by American Electric Power Company, Inc., Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan 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.

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GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
AECC	Arkansas Electric Cooperative Corporation, an unaffiliated corporation
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
AEP River Operations	AEP's inland river transportation subsidiary, AEP River Operations LLC (formerly AEP MEMCO LLC), operating primarily on the Ohio, Illinois, and lower Mississippi rivers
AEPSC	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
CCS	Carbon capture and storage technology
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CO_2	Carbon dioxide and other greenhouse gases
Cook Plant	The Donald C. Cook Nuclear Plant, 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
DP&L	The Dayton Power and Light Company, an unaffiliated utility company
Duke Ohio	Duke Energy Ohio, Inc.
EMF	Electric and Magnetic Fields
EPA	United States Environmental Protection Agency
EPACT	The Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments
ETEC	East Texas Electric Cooperative
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
IGCC	Integrated Gasification Combined Cycle

Abbreviation or Acronym	Definition
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
KgPCo	Kingsport Power Company, a public utility subsidiary of AEP
KPCo	Kentucky Power Company, a public utility subsidiary of AEP
KPSC	Kentucky Public Service Commission
Lawrenceburg Plant	A 1,146 MW gas-fired unit owned by AEGCo and located near Lawrenceburg, Indiana
LLWPA	Low-Level Waste Policy Act of 1980
LPSC	Louisiana Public Service Commission
MISO	Midwest Independent Transmission System Operator
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
NO_x	Nitrogen oxide
NPC	National Power Cooperatives, Inc., an unaffiliated corporation
NRC	Nuclear Regulatory Commission
NSR Consent Decree	The 2007 settlement with the Federal EPA, the United States Department of Justice, certain states and special interest groups that ended the litigation which had alleged that APCo, CSPCo, I&M and OPCo violated the new source review requirements of the CAA.
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
Ohio Amendments	Amendments to the Ohio Act adopted in April 2008 which required electric utilities to adjust their rates by filing an ESP with the PUCO
OPCo	Ohio Power Company, a public utility subsidiary of AEP
OSS	Off-system sales
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
PM	Particulate Matter
PSO	Public Service Company of Oklahoma, a public utility subsidiary of AEP
PUCO	Public Utilities Commission of Ohio
PUCT	Public Utility Commission of Texas
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
ROE	Return on Equity
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
TA	Transmission 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

Abbreviation or Acronym	Definition
TCA	Transmission Coordination Agreement dated January 1, 1997, restated and amended, as approved by FERC in 2002, by and among, PSO, SWEPCo, TNC and AEPSC, in connection with the operation of the transmission assets of the three public utility subsidiaries
TCC	AEP Texas Central Company, formerly Central Power and Light Company, a public utility subsidiary of AEP
Texas Act	Texas electric restructuring legislation
TNC	AEP Texas North Company, formerly West Texas Utilities Company, a public utility subsidiary of AEP
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 the registrants contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although the registrants 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:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load and customer growth.
- Weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process.
- 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, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) 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 or additional regulation of flyash and similar combustion products that could impact the continued operation and cost recovery of our plants.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance).
- Resolution of litigation (including our dispute with Bank of America).
- Our ability to constrain operation and maintenance costs.
- 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 we have 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, coal, nuclear fuel and other energy-related commodities.
- Changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other

postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements.

- Prices and demand 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, and the ERCOT area of Texas 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 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, 2009, the subsidiaries of AEP had a total of 21,673 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 959,000 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, 2009, APCo and its wholly owned subsidiaries had 2,577 employees. Among the principal industries served by APCo are paper, rubber, coal mining, textile mill products and stone, clay and glass products. In addition to its AEP System interconnections, APCo is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Carolina 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 749,000 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, 2009, CSPCo had 1,283 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 primary metals, chemicals and allied products, health services and electronic machinery. In addition to its AEP System interconnections, CSPCo is interconnected with the following unaffiliated utility companies: Duke Ohio, 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 583,000 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, 2009, I&M had 3,008 employees. Among the principal industries served are primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber and chemicals and allied products, rubber products and transportation equipment. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. This lease extends through February 2010 and its termination is currently being litigated. In addition to its AEP System interconnections, I&M is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, Duke Ohio, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, Duke Indiana 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 175,000 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, 2009, KPCo had 478 employees. Among the principal industries served are petroleum refining, coal mining and chemical production. In addition to its AEP System interconnections, KPCo 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.

KgPCo (organized in Virginia in 1917) provides electric service to approximately 47,000 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, 2009, Kingsport Power Company had 57 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 710,000 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, 2009, OPCo had 2,391 employees. Among the principal industries served by OPCo are primary metals, chemical manufacturing, petroleum refining, and rubber and plastic products. In addition to its AEP System interconnections, OPCo is interconnected with the following unaffiliated utility companies: Duke Ohio, 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 531,000 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, 2009, PSO had 1,281 employees. Among the principal industries served by PSO are paper manufacturing and timber products, natural gas and oil extraction, transportation, non-metallic mineral production, oil refining and steel processing, In addition to its AEP System interconnections, PSO is interconnected with Empire District Electric Company, Oklahoma Gas and Electric Company, Southwestern Public Service Company 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 474,000 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, 2009, SWEPCo had 1,671 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 interconnected with Cleco Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

In November 2009, SWEPCo signed a letter of intent to purchase the transmission and distribution assets and to assume certain liabilities of Valley Electric Membership Corporation (VEMCO) for approximately $96 million, subject to regulatory approval by the LPSC and the APSC. VEMCO services approximately 30,000 member customers in eight parishes south of Shreveport, Louisiana. SWEPCo expects to complete the transaction in the second quarter of 2010.

TCC (organized in Texas in 1945) is engaged in the transmission and distribution of electric power to approximately 766,000 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, 2009, TCC had 1,174 employees. Among the principal industries served by TCC are chemical and petroleum refining, chemicals and allied products, oil and gas extraction, food processing, metal 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 185,000 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 an agreement effective through 2027. At December 31, 2009, TNC had 368 employees. Among the principal industries served by TNC are petroleum refining, 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, 2009, WPCo had 60 employees.

AEGCo (organized in Ohio in 1982) is an electric generating company. AEGCo sells power at wholesale to I&M, CSPCo 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 affiliated companies. The executive officers of AEP and certain of its public utility subsidiaries are employees of AEPSC. At December 31, 2009, AEPSC had 6,180 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, 2009 are as follows:

Description	**AEP System(a)**	**APCo**	**CSPCo**	**I&M**
	(in thousands)			
UTILITY OPERATIONS:				
Retail Sales				
Residential Sales	$4,405,000	$1,022,942	$749,623	$265,428
Commercial Sales	3,171,000	493,297	715,727	352,821
Industrial Sales	2,630,000	598,631	265,403	368,109
PJM Net Charges	(7,000)	(777)	(1,893)	(1,918)
Provision for Rate Refund	1,000	197	-	-
Other Retail Sales	191,000	68,123	6,341	6,572
Total Retail	10,391,000	2,182,413	1,735,201	991,012
Wholesale				
Off-System Sales	1,617,000	386,534	186,759	485,440
Transmission	232,000	(47)	(1,520)	11,698
Total Wholesale	1,849,000	386,487	185,239	497,138
Other Electric Revenues	385,000	35,594	13,898	197,158
Other Operating Revenues	108,000	8,772	3,022	193,422
Sales to Affiliates	-	263,389	67,213	306,294
Total Utility Operating Revenues	12,733,000	2,876,655	2,004,573	2,185,024
OTHER	756,000	-	-	-
TOTAL REVENUES	$13,489,000	$2,876,655	$2,004,573	$2,185,024

(a) Includes revenues of other subsidiaries not shown. Intercompany transactions have been eliminated for the year ended December 31, 2009.

Description	**OPCo**	**PSO**	**SWEPCo**
	(in thousands)		
UTILITY OPERATIONS:			
Retail Sales			
Residential Sales	$637,838	$441,743	$423,987
Commercial Sales	424,982	295,817	366,616
Industrial Sales	608,614	197,605	238,224
PJM Net Charges	(2,180)	-	-
Provision for Rate Refund	-	(1,599)	2,591
Other Retail Sales	10,140	64,695	7,658
Total Retail	1,679,394	998,261	1,039,076
Wholesale			
Off-System Sales	235,321	32,809	215,640
Transmission	(3,847)	28,571	42,740
Total Wholesale	231,474	61,380	258,380
Other Electric Revenues	30,389	15,373	17,600
Other Operating Revenues	12,570	3,980	44,928
Sales to Affiliates	1,057,747	45,756	29,318
Total Utility Operating Revenues	3,011,574	1,124,750	1,389,302
OTHER	-	-	-
TOTAL REVENUES	$3,011,574	$1,124,750	$1,389,302

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, borrowing under AEP's revolving credit agreements 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. See *Management’s Financial Discussion and Analysis of Results of Operations*, included in the 2009 Annual Reports, under the heading entitled *Financial Condition* for additional information concerning short-term funding and our access to bank lines of credit, commercial paper and capital markets.

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, 2009, 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 of AEP would be considered an immediate termination event. See *Management’s Financial Discussion and Analysis of Results of Operations*, included in the 2009 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

The credit ratings of AEP and its registrant subsidiaries as of February 23, 2010 are set forth below. In 2009, Moody’s Investors Service placed the credit ratings of AEP (the parent) on negative outlook. In 2009, Fitch Ratings placed the credit ratings of TCC and SWEPCO on negative outlook. See *Management’s Financial Discussion and Analysis of Results of Operations*, included in the 2009 Annual Reports, under the heading entitled *Financial Condition* for additional information with respect to the credit ratings of the registrants.

	Moody’s		***S&P***		***Fitch***	
Company	Senior Unsecured	Outlook*****	Senior Unsecured	Outlook*****	Senior Unsecured	Outlook*****
AEP	Baa2	N	BBB	S	BBB	S
AEP Short Term Rating	P-2	N	A-2	S	F-2	S
APCo	Baa2	S	BBB	S	BBB	S
CSPCo	A3	S	BBB	S	A-	S
I&M	Baa2	S	BBB	S	BBB	S
OPCo	Baa1	S	BBB	S	BBB+	S
PSO	Baa1	S	BBB	S	BBB+	S
SWEPCo	Baa3	S	BBB	S	BBB+	N

* S=Stable Outlook; N=Negative Outlook

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 we believe are potentially material to the AEP system are outlined below.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control mobile and stationary sources of air emissions. The major CAA programs affecting our power plants are described below. The states implement and administer many of these programs and could impose additional or more stringent requirements.

National Ambient Air Quality Standards: The CAA requires the Federal EPA to review periodically the available scientific data for six criteria pollutants and establish a concentration level in the ambient air for those substances that is adequate to protect the public health and welfare with an extra safety margin. These concentration levels are known as national ambient air quality standards (NAAQS).

Each state identifies the areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA develops and implements a plan. As the Federal EPA reviews the NAAQS, the attainment status of areas can change and states may be required to develop new SIPs. In 2008, the Federal EPA issued revised NAAQS for both ozone and fine particulate matter ($PM_{2.5}$). The $PM_{2.5}$ standard was remanded by the D.C. Circuit Court of Appeals, but a new standard has not yet been proposed. In 2009 the Obama Administration reconsidered the ozone standard and proposed a more stringent standard. Federal EPA has also proposed a new short-term standard for SO_2 and a new, lower standard for NO_2. The Federal EPA also established a lower standard for lead. These new standards could result in additional emission reductions being required from our facilities.

In 2005, the Federal EPA issued the Clean Air Interstate Rule (CAIR). It requires specific reductions in SO_2 and NO_x emissions from power plants and assists states developing new SIPs to meet the NAAQS. CAIR reduces regional emissions of SO_2 and NO_x (which can be transformed into PM and ozone) from power plants in the Eastern U.S. (28 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO_2 by 45% by 2010, and by 57% by 2015 from 2003 levels. NO_x emissions were subject to additional limits beginning in 2009, and would be reduced by a total of 61% by 2015 from 2003 levels. Reduction of both SO_2 and NO_x emissions under CAIR is to be achieved through a cap-and-trade program. In July 2008, the D.C. Circuit Court of Appeals remanded CAIR to the Federal EPA. CAIR remains in effect while Federal EPA conducts further rulemaking, and we are complying with our obligations under CAIR. We are unable to predict how the Federal EPA will respond to the remand, but we expect a proposal from Federal EPA in the spring of 2010. A SIP that complied with CAIR also established compliance with other CAA requirements, including certain visibility goals. It is uncertain how Federal EPA will deal with these requirements on remand. The Federal EPA or states may elect to seek further reductions of SO_2 and NO_x in response to more stringent PM and ozone NAAQS or restrict or eliminate the trading programs in the replacement developed for CAIR.

Hazardous Air Pollutants: As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to

Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the Federal EPA issued a Clean Air Mercury Rule (CAMR) setting New Source Performance Standards (NSPS) for mercury emissions from new and modified coal-fired power plants and requiring all states to issue new SIPs including mercury requirements for existing coal-fired power plants. The Federal EPA issued a model federal rule based on a cap-and-trade program for mercury emissions from existing coal-fired power plants that would reduce mercury emissions to 38 tons per year from all existing plants in 2010, and to 15 tons per year in 2018.

In 2008, the D.C. Circuit Court of Appeals vacated and remanded CAMR to the Federal EPA. The Federal EPA has issued an information collection request to coal-fired power plants for emission information on mercury and several additional HAPs, and has announced its intention to issue a proposed rule in 2011. We are unable to predict at this time how the Federal EPA response to the remand will affect our facilities or their costs of operation, but it could be material.

To comply with the remand of CAIR, Federal EPA may impose NO_x and/or SO_2 budgets on a state-by-state basis rather than across a multi-state region. If Federal EPA takes this approach, we would have significantly less flexibility planning for compliance and may have to install additional environmental control equipment on some of our units. In addition, with the remand of CAMR, Federal EPA will likely establish Maximum Achievable Control Technology (MACT) standards for mercury and other hazardous air pollutants that could require installation of scrubbers on all coal units, regardless of age or size. It would be costly and inefficient to retrofit all of our units with such controls, and we will urge Federal EPA to carefully consider all of the options available to it to avoid such a result. However, we have a number of our older units, including some that are already subject to control requirements under the NSR Consent Decree, for which it may be economically inefficient to install scrubbers or other environmental controls, including CCS. The timing and ultimate disposition of those units will be dictated by environmental regulations, the economics of maintaining or retrofitting the units, transmission requirements, demand for electricity, availability and cost of replacement power, legislative mandates and capital requirements, and regulatory decisions about cost recovery of the remaining investment in retired units. In addition, if some coal units are prematurely forced to retire, we may need to make investments in new transmission lines and substations to create stronger interconnections with neighboring systems.

<u>The Acid Rain Program:</u> The 1990 Amendments to the CAA include a cap-and-trade emission reduction program for SO_2 emissions from power plants. By 2000, the program established a nationwide cap on power plant SO_2 emissions of 8.9 million tons per year. The 1990 Amendments also contain requirements for power plants to reduce NO_x emissions through the use of available combustion controls.

The success of the SO_2 cap-and-trade program encouraged the Federal EPA and the states to use it as a model for other emission reduction programs, including CAIR and CAMR. We continue to meet our obligations under the Acid Rain Program through the installation of controls, use of alternate fuels and participation in the emissions allowance markets. CAIR currently uses the SO_2 allowances originally allocated through the Acid Rain Program as the basis for its SO_2 cap-and-trade system. We are unable to predict if or how any replacement for CAIR will utilize the SO_2 allowances from the Acid Rain Program.

<u>Regional Haze</u>: The CAA establishes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment of visibility in these areas (Regional Haze program). In 2005, the Federal EPA issued its Clean Air Visibility Rule (CAVR), detailing how the CAA's best available retrofit technology (BART) requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. The final rule contains a demonstration that CAIR will result in more visibility improvements than BART for power plants subject to it. Thus, states are allowed to substitute CAIR requirements in their Regional Haze program SIPs for controls that would otherwise be required by BART. For BART-eligible facilities located in states not subject to CAIR requirements for SO_2 and NO_x

(Oklahoma, Texas and Arkansas of the AEP System), some additional controls will be required. The courts upheld the final rule.

In January 2009, the Federal EPA issued a determination that 37 states (including Indiana, Ohio, Oklahoma, Texas and Virginia) failed to submit SIPs fulfilling the Regional Haze program requirements by the deadline, and commencing a 2-year period for the development of a Federal Implementation Plan (FIP) in these states. We are unable to predict if or how the remand of CAIR or the development of a FIP to satisfy CAVR in certain states may affect our compliance obligations for the Regional Haze programs.

Clean Water Act Requirements

Our operations are also subject to the Federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits, and regulates systems that withdraw surface water for use in our power plants. In 2004, the Federal EPA issued a final rule requiring all large existing power plants with once-through cooling water systems to meet certain standards to reduce mortality of aquatic organisms pinned against the plant's cooling water intake screen or entrained in the cooling water. The standards vary based on the water bodies from which the plants draw their cooling water. We expected additional capital and operating expenses, which the Federal EPA estimated could be $193 million for our plants. We undertook site-specific studies and have been evaluating site-specific compliance or mitigation measures that could significantly change these cost estimates.

In July 2007, the Federal EPA suspended the 2004 rule, except for the requirement that permitting agencies develop best professional judgment (BPJ) controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. The result is that the BPJ control standard for cooling water intake structures in effect prior to the 2004 rule is used as the applicable standard by permitting agencies pending finalization of revised rules by the Federal EPA.

In April 2009, the U.S. Supreme Court issued a decision that allows the Federal EPA the discretion to rely on cost-benefit analysis in setting national performance standards and in providing for cost-benefit variances from those standards as part of the regulations. We cannot predict if or how the Federal EPA will apply this decision to any revision of the regulations or what effect it may have on similar requirements adopted by the states. We expect Federal EPA to issue revised rules in 2010.

Federal EPA is also engaged in rulemaking to update the technology-based standards that govern discharges from new and existing power plants under the Clean Water Act's NPDES program. These standards were last updated over 20 years ago, and EPA has issued two rounds of information collection requests to inform its rulemaking. In October 2009, Federal EPA issued a final report for the power plant sector and determined that revisions to its existing standards are necessary, but EPA has not yet proposed any specific requirements. Until new standards are proposed, we cannot predict the outcome or impact of these rules on our operations.

Coal Ash Regulation

Our operations produce a number of different coal combustion products, including flyash, bottom ash, gypsum, and other materials. In December 2008, the breach of a dike at the Tennessee Valley Authority's Kingston Station resulted in a spill of several million cubic yards of ash into a nearby river and onto private properties, prompting federal and state reviews of ash storage and disposal practices at many coal-fired electric generating facilities, including ours. AEP operates 37 ash ponds and we manage these ponds in a manner that complies with state and local requirements, including dam safety rules designed to assure the structural integrity of these facilities. We also operate a number of dry disposal facilities in accordance with state standards, including ground water monitoring and other applicable standards. Approximately 40% of AEP's coal combustion products are recycled. Federal EPA completed an extensive study of the characteristics of coal ash in 2000 and concluded that combustion wastes do not warrant regulation as hazardous waste. However, Federal EPA issued a Notice of Data Availability and request for public comment in 2007, and is expected to propose new management standards for coal ash and related wastes in early 2010, which could require conversion of ash impoundments to dry disposal facilities or impose hazardous waste regulations upon these wastes. Until these standards are proposed, we cannot predict the outcome or impact of these rules on our operations, but the costs could be material and could reduce our ability to market combustion wastes for beneficial uses.

Global Warming

Position and strategy: The topics of whether the earth is warming, how much and how fast, what role human activity plays, and what to do about it are very controversial and actively debated. The public policy makers and influencers in Washington and in the 11 states we serve have conflicting views. We are focused on taking, in the short term, actions that we see as prudent, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies, and evaluating our assets across a range of plausible scenarios and outcomes. We are also active participants in a variety of public policy discussions at state and federal levels, to assure that proposed new requirements are feasible and the economies of the states we serve are not placed at a competitive disadvantage.

We support a reasonable approach to reduce emissions of CO_2 and other greenhouse gases (generally referred to throughout as CO_2) that recognizes that a reliable and affordable electric supply is vital to economic stability. We have taken measurable, voluntary actions to reduce and offset our own CO_2 emissions. We participate in a number of voluntary programs to monitor, mitigate, and reduce CO_2 emissions, including the Federal EPA's Climate Leaders program, the DOE's CO_2 reporting program, and the Chicago Climate Exchange. We are considering several options that protect the reliability of the electric system while reducing our carbon emissions. Our strategy is to pursue multiple options including renewable energy, energy efficiency, new technologies, offsets and nuclear generation. At the same time we will continue to improve the efficiency of our plants, retire or mothball some older, inefficient coal units when factors warrant, and complete our environmental retrofit program. For additional information on legislative and regulatory responses to global warming, including limitations on CO_2 emissions, see *Management's Financial Discussion and Analysis of Results of Operations* under the headings entitled *Environmental Matters – Global Warming.* Specific steps taken to reduce CO_2 emissions include the following:

Carbon Capture and Storage

We successfully captured, transported and stored CO_2 emissions from a coal-fired power plant in deep geologic formations for the first time in October 2009, for 20 MW of our 1,300 MW Mountaineer Plant in West Virginia. The next phase of this project – to install the nation's first commercial-scale coal-derived CO_2 capture and storage system at the Mountaineer Plant—will be partially funded through the U.S. Department of Energy's (DOE) Clean Coal Power Initiative. AEP has been awarded federal grant funding of $334 million, which represents approximately half the cost of this phase of the project, exclusive of asset retirement obligations. The commercial-scale phase of AEP's CO_2 program will capture approximately 90% of the CO_2 from 235 MW of the plant's 1,300 MW of capacity.

Renewable Sources of Energy

Some of our states have passed legislation establishing renewable energy, alternative energy, and/or energy efficiency requirements or goals (including Ohio, Texas, Michigan, Virginia and West Virginia) and we are taking steps to comply with these requirements in a timely fashion. In order to meet these requirements and as a key part of its corporate sustainability effort, AEP pledged to increase its renewable power by an additional 2000 MW from its 2007 levels by 2011, subject to regulatory approval. By the end of 2009, AEP has already secured, through power purchase agreements, an additional 1,013.5 MW of renewable power. AEP's integrated resource plan contains a 10% renewable energy target by 2020, which, together with other qualifying alternative energy and energy efficiency measures, will exceed the clean energy requirements currently in effect in our states.

Limiting Emissions through Energy Efficiency

Energy efficiency is a high priority for us because it is a cost-effective way to reduce CO_2 emissions and can delay the need to build new power plants. We work closely with regulators, environmental groups, technical experts and others to develop and implement efficiency and demand response programs. We have a 2012 goal to reduce 1,000 MW of demand and 2,250,000 MWh of energy consumption. Through 2009, we have achieved 152 MW and 471,000 MWh of demand and energy reduction, respectively.

With regulatory support from the PUCO and partial funding from the DOE, AEP Ohio's gridSMART[SM] Demonstration Project will install 110,000 advanced electricity meters, smart appliances, secure integrated smart grid technology, and enable plug-in hybrid electric vehicles and other consumer systems that will help customers manage electricity use and costs. The $150 million project, $75 million of which will come from federal stimulus funds, is designed to reduce energy consumption by 18,000 MWh and peak demand by 15 MW over a three year period – eliminating the equivalent of the energy needed to power 1,800 homes. To pay for this project, the PUCO approved project trackers in customer rates that allow us to recover costs specific to these programs in a timely manner.

<u>Current and Projected CO_2 Emissions:</u> Our total CO_2 emissions in 2008 (including our ownership in the Kyger Creek and Clifty Creek plants) were approximately 155 million metric tons. We estimate that our 2009 emissions were approximately 140 million metric tons. Since 2004 our cumulative CO_2 emission reductions were 51 million metric tons by the end of 2008 from adjusted baseline levels in 1998 through 2001, and will be in excess of 70 million tons at the end of 2009. Emissions in 2010 and beyond will be affected by continued changes in our generation portfolio, market prices, the pace and scale of the economic recovery in our jurisdictions, available capital, weather, and other factors. We expect overall increases in CO_2 emissions during the 2010-2012 timeframe as our sales and generation rebound somewhat from recession lows in 2009. However, over much of the remainder of the decade we expect emissions growth to be relatively flat as increased fossil generation needed to meet modest sales growth is largely offset by retirements of some older coal-fired units and increased use of renewable energy, particularly from wind.

<u>Corporate governance:</u> Several years ago in response to a shareholder proposal, our Board of Directors created an *ad hoc* committee to evaluate our actions to mitigate the economic impact from future policies to reduce CO_2 and other emissions. Our Board of Directors continues to review environmental issues on a regular basis and in connection with its review of our strategic plan. The Board of Directors is also frequently informed of any new material environmental issues, including updates on any proposed legislation. The Board of Directors' Committee on Directors and Corporate Governance oversees our Sustainability Report, including the portion of the report that relates to environmental issues. Environmental planning and policy leadership are criteria incorporated into our executive incentive compensation plan.

Other environmental issues and matters

- Litigation with the federal and/or certain state governments and certain special interest groups regarding regulated air emissions and/or whether emissions from coal-fired generating plants cause or contribute to global warming. See *Management's Financial Discussion and Analysis of Results of Operations* under the heading entitled *Litigation - Environmental Litigation* and Note 6 to the consolidated financial statements entitled *Commitments, Guarantees and Contingencies*, included in the 2009 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. See Note 6 to the consolidated financial statements entitled *Commitments, Guarantees and Contingencies*, included in the 2009 Annual Reports, under the heading entitled *The Comprehensive Environmental Response Compensation and Liability Act* (*Superfund) and State Remediation* for further information.

Environmental Investments

Investments related to improving AEP System plants' environmental performance and compliance with air and water quality standards during 2007, 2008 and 2009 and the current estimates for 2010, 2011 and 2012 are shown below, in each case excluding AFUDC or capitalized interest. AEP expects to make substantial investments in addition to the amounts set forth below in future years in connection with the modification and addition of facilities at generating plants for environmental quality controls. Such future investments are needed in order to comply with air and water quality standards that have been adopted and have deadlines for compliance after 2012 or have been proposed and may be adopted. Future investments could be significantly greater if emissions reduction requirements are accelerated or otherwise become more onerous or if CO_2 becomes regulated. While we expect to recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions) or market prices, without such recovery 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 2009 Annual Reports, for more information regarding environmental expenditures in general.

Historical and Projected Environmental Investments

	2007 Actual	2008 Actual	2009 Actual	2010 Estimate	2011 Estimate	2012 Estimate
			(in thousands)			
Total AEP System*	$994,100	$886,800	$457,200	$321,700	$233,900	$405,600
APCo	351,900	361,200	191,900	127,000	57,600	16,200
CSPCo	130,000	162,800	73,800	76,600	20,600	39,000
I&M	9,300	22,400	19,600	10,100	800	1,600
OPCo	481,700	311,800	151,000	67,500	49,400	39,300
PSO	1,500	5,000	1,000	1,700	15,200	59,800
SWEPCo	14,300	12,000	10,700	30,400	64,800	143,900

* Includes expenditures of the subsidiaries shown and other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies. Excludes discontinued operations.

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 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 37,000 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, OPCo, and AEPSC are parties to the AEP Interconnection Agreement, which has been approved by the FERC. This agreement defines how the member companies share the costs and benefits associated with their generating plants. This sharing is based upon each company’s “member load ratio.” The member load ratio is calculated monthly by dividing each 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 member companies. The member load ratio multiplied by the aggregate generation capacity of all the member companies determines each member company's capacity obligation. The difference between each member company's obligation and its own generation capacity determines the capacity surplus or deficit of each member company. The agreement requires the deficit companies to make monthly capacity equalization payments to the surplus companies based on the surplus companies' average fixed cost of generation. Member companies that deliver energy to other member companies to meet their internal load requirements are reimbursed at average variable costs. In addition, all member companies share off-system sales margins based upon each member company's member load ratio. Consequently, the agreement provides a strong risk sharing and mitigation arrangement among the member companies. As of December 31, 2009, the member-load-ratios were as follows:

	Peak Demand (MW)	Member-Load Ratio (%)
APCo	8,308	35.6
CSPCo	4,209	18.0
I&M	4,245	18.2
KPCo	1,674	7.2

OPCo	4,901	21.0

APCo, CSPCo, I&M, KPCo and OPCo are parties to the AEP System Interim Allowance Agreement (Allowance Agreement), which has been approved by the FERC and provides, among other things, for the transfer of SO_2 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, 2007, 2008 and 2009:

	2007	**2008**	**2009**
		(in thousands)	
APCo	$454,800	$575,300	$668,700
CSPCo	173,000	233,200	257,600
I&M	(93,200)	(153,000)	(100,900)
KPCo	41,200	65,000	31,600
OPCo	(575,800)	(720,500)	(857,000)

PSO, SWEPCo and AEPSC are parties to a Restated and Amended Operating Agreement (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 their business operations incompatible with the CSW Operating Agreement. As a result, with FERC approval, these companies as of May 1, 2006, 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, 2007, 2008 and 2009:

	2007	**2008**	**2009**
		(in thousands)	
PSO	$(17,500)	$(57,000)	$(22,762)
SWEPCo	16,800	59,900	22,762

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. 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 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. Because TCC and TNC have exited the generation business, these two companies are no longer parties to the System Integration 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 and in adjacent regions. 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 netting 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, 2009, counterparties have posted approximately $52 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 $203 million with counterparties and exchanges). Since open trading contracts are valued based on market prices of various commodities, exposures change daily. See *Management's Financial Discussion and Analysis of Results of Operations*, included in the 2009 Annual Reports, under the heading entitled *Quantitative and Qualitative Disclosures About Risk Management Activities* for additional information.

Fuel Supply

The following table shows the sources of fuel used by the AEP System:

	2007	**2008**	**2009**
Coal and Lignite	85%	86%	88%
Natural Gas	6%	6%	6%
Nuclear	9%	8%	5%
Hydroelectric and other	<1%	<1%	1%

Price increases in one or more fuel sources relative to other fuels may result in increased use of other fuels. Variations in the generation of nuclear power are primarily related to a 2008 forced outage caused by a low pressure turbine blade failure event, refueling and maintenance outages.

Coal and Lignite*:* AEP's public utility subsidiaries procure coal and lignite under a combination of purchasing arrangements including long-term contracts, affiliate operations and spot agreements with various producers and coal trading firms. The economic climate in 2009 exerted downward pressure on electric demand, resulting in lower market prices for fuel. This lower demand led to a significant decrease in AEP's coal consumption in 2009. As a result of decreased coal consumption and corresponding increases in fuel inventory, AEP initiated discussions with its coal suppliers in an effort to better match deliveries with consumption and to minimize the impact on fuel inventory costs, carrying costs and cash.

Most of the coal purchased by AEP is procured through term contracts. Generally, the prices paid under these term contracts are often lower than spot coal market prices. As term contracts expire they are replaced with new agreements, often at higher prices. The price we paid for coal delivered in 2009 rose from the prior year primarily as a result of this contract replacement process.

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

	2007	2008	2009
Total coal delivered to AEP System plants (thousands of tons)	72,644	77,054	75,909
Average price per ton of purchased coal	$36.65	$47.14	$49.54

Management believes 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, leases or controls more than 9,000 railcars, 697 barges, 18 towboats and a coal handling terminal with 18 million tons of annual capacity to move and store coal for use in our generating facilities. See AEP River 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 coal supplies at AEP System plants vary from time to time depending on various factors, including, but not limited to, demand for electric power, unit outages, transportation infrastructure limitations, space limitations, plant coal consumption rates, availability of acceptable coals, labor issues and weather conditions which may interrupt production or deliveries. At December 31, 2009, the System's coal inventory was approximately 61 days.

In cases of emergency or shortage, AEP has developed programs to conserve coal supplies at its plants. Such programs have been filed and reviewed with federally approved electric reliability organizations. 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 nearly 96 billion cubic feet of natural gas during 2009 for generating power. This represents a slight decrease from 2008 due to reduced demand in AEP's western jurisdictions. Many 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, as needed.

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. I&M also continues to lease a portion of its nuclear fuel requirements.

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 entered into an agreement to provide for onsite dry cask storage. Initial loading of spent nuclear fuel into the dry casks is tentatively scheduled to begin in 2012.

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 spent nuclear fuel disposal program. In 2009, when the most recent study was done, the estimated cost of decommissioning and disposal of low-level radioactive waste for the Cook Plant ranged from $831 million to $1.5 billion in 2009 non-discounted dollars. At December 31, 2009, the total decommissioning trust fund balance for the Cook Plant was approximately $1.1 billion. The balance of funds available to decommission Cook Plant will differ based on contributions and investment returns. 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;
- 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. We will seek recovery from customers through our regulated rates if actual decommissioning costs exceed our projections. See Note 6 to the consolidated financial statements, entitled *Commitments, Guarantees and Contingencies* under the heading *Nuclear Contingencies*, included in the 2009 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 Utah licenses a low-level radioactive waste disposal site which currently accepts low-level radioactive waste from Michigan. I&M ships some of its low level waste to a facility in Utah. There is currently no set date limiting I&M's access to the Utah facility. I&M stores the remaining type of low-level waste onsite. In order to have capacity for the duration of its licensed operation of Cook Plant for onsite storage of waste not shipped to Utah, I&M will have to modify its existing facilities sometime in the next ten to fifteen years.

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, 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 2012, 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

I&M*:* The Unit Power Agreement between AEGCo and I&M, dated March 31, 1982, 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 a demand charge for the right to receive such power (and an energy charge for any associated energy taken by I&M). The 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 that I&M would have paid AEGCo under the terms of the Unit Power Agreement between AEGCo and I&M for such entitlement. The KPCo unit power agreement expires in December 2022.

CSPCo*:* The Unit Power Agreement between AEGCo and CSPCo, dated March 15, 2007, provides for the sale by AEGCo to CSPCo of all the capacity and associated unit contingent energy and ancillary services available to AEGCo at the Lawrenceburg Plant that are scheduled and dispatched by CSPCo. CSPCo is obligated to pay a capacity charge (whether or not power is available from the Lawrenceburg Plant), and the fuel, operating and maintenance charges associated with the energy dispatched by CSPCo, and to reimburse AEGCo for other costs associated with the operation and ownership of the Lawrenceburg Plant. The agreement will continue in effect until December 31, 2017 unless extended as set forth in the agreement.

OVEC: AEP and several unaffiliated utility companies jointly own OVEC. The aggregate equity participation of AEP in OVEC is 43.47%. Until 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 in March 2026. AEP and the other owners have authorized environmental investments related to their ownership interests. As of December 2009, OVEC's Board of Directors has authorized capital expenditures totaling approximately $1 billion in connection with the engineering and construction of flue gas desulfurization projects and the associated scrubber waste disposal landfills at its two generating plants. OVEC's Board of Directors has delayed for an indeterminate period final completion of construction at both of the plants. If approved and fully funded, the estimated total cost to complete the scrubber and landfill projects would be in excess of $1.3 billion, which OVEC would expect to finance through issuing debt.

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 approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC. See *Item 1 –Utility Operations - Regulation—Rates*. The FERC regulates and approves the rates for wholesale transmission transactions. See *Item 1 –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 –Utility Operations - Competition*.

AEP Transmission Pool

Transmission Agreement: APCo, CSPCo, I&M, KPCo and OPCo operate their transmission lines as a single interconnected and coordinated system in the AEP East transmission zone and are parties to the Transmission Agreement (TA), defining how they share the costs and benefits associated with their relative ownership of the bulk transmission system (lines operated at 138kV and above and stations containing extra high voltage equipment). The TA has been approved by the FERC. Sharing under the TA 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, 2009 are set forth above in the section titled *ELECTRIC GENERATION* – AEP Power Pool and CSW Operating Agreement.

In June 2009, AEP filed with FERC to amend the TA in order to add WPCo and KgPCo and to reallocate PJM costs on an individual basis instead of on a Member-Load-Ratio basis. In August 2009, FERC accepted the proposed amendment to the TA for filing, suspended it for a nominal period, to become effective on the first day of the month after a final FERC order in the proceeding, as requested, subject to refund. FERC established a hearing and settlement procedure. Settlement discussions in the case are currently underway.

The following table shows the net (credits) or charges allocated among the parties to the TA during the years ended December 31, 2007, 2008 and 2009:

	2007	**2008**	**2009**
		(in thousands)	
APCo	$(25,000)	$(29,000)	$(12,500)
CSPCo	51,900	55,000	51,300
I&M	(34,600)	(37,000)	(38,400)
KPCo	(800)	(2,000)	(8,800)
OPCo	8,500	13,000	8,400

Transmission Coordination Agreement, OATT, and ERCOT Protocols: PSO, SWEPCo, TNC and AEPSC are parties to the TCA. Under the TCA, a coordinating committee is charged with the responsibility of (i) overseeing the coordinated planning of the transmission facilities of the parties to the agreement, 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. Pursuant to the TCA, AEPSC has responsibility for monitoring the reliability of their transmission systems and administering the OATT on behalf of the other parties to the agreement. The TCA also provides for the allocation among the parties of revenues collected for transmission and ancillary services provided under the OATT. 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 pursuant to the TCA, SPP OATT and ERCOT protocols as described above during the years ended December 31, 2007, 2008 and 2009:

	2007	2008	2009
	(in thousands)		
PSO	$500	$8,200	$11,000
SWEPCo	(500)	(8,200)	(11,000)
TCC	1,100	1,500	1,700
TNC	(1,100)	(1,500)	(1,700)

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 –Utility Operations – Electric Transmission and Distribution - 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 TA 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

The AEP East Companies are members of PJM (a FERC-approved RTO). SWEPCo and PSO are members of the SPP (another FERC-approved RTO). RTOs operate, plan and control utility transmission assets in a manner designed to provide open access to such assets in a way that prevents discrimination between participants owning transmission assets and those that do not. 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 2009 Annual Reports under the heading entitled *Regional Transmission Rate Proceedings at the FERC* for additional information regarding RTOs.

REGULATION

General

Except for transmission and/or retail generation sales in certain of its jurisdictions, AEP's public utility subsidiaries' retail rates and certain other matters are subject to traditional cost-based regulation by the state utility commissions. AEP's subsidiaries are also subject to regulation by the FERC under the FPA with respect to wholesale power and transmission service transactions as well as certain unbundled retail transmission rates mainly in Ohio. 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 provides the FERC limited “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 CO_2 emissions.

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 adjusted 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, 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.

Public utilities have traditionally financed capital investments until the new asset was placed in service. Provided the asset was found to be a prudent investment, it was then added to rate base and entitled to a return through rate recovery. Given long lead times in construction, the high costs of plant and equipment and difficult capital markets, we are actively pursuing strategies to accelerate rate recognition of investments and cash flow. AEP representatives continue to engage our state commissioners and legislators on alternative ratemaking options to reduce regulatory lag and enhance certainty in the process. These options include pre-approvals, a return on construction work in progress, rider/trackers, securitization, formula rates and the inclusion of future test-year projections into rates.

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 only. In Ohio, rates for electric service are unbundled for generation, transmission and distribution service. 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.

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. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2009 Annual Reports, for more information regarding pending rate matters.

Indiana: I&M provides retail electric service in Indiana at bundled rates approved by the IURC, with rates set on a cost-of-service basis. Indiana provides for timely fuel and purchased power cost recovery through a fuel cost recovery mechanism.

Ohio*:* CSPCo and OPCo each operate as a functionally separated utility and provide “default” retail electric service to customers at unbundled rates pursuant to the Ohio Act. CSPCo and OPCo provide distribution services to retail customers at cost based rates approved by the PUCO. Transmission services are provided at OATT rates based on rates established by the FERC. CSPCo and OPCo’s generation/supply rates are subject to their Electric Security Plans that the PUCO modified and approved in a March 2009 order. The order established standard service offer rates in effect through 2011. The order also provides a fuel adjustment clause for the three-year period of the ESP. The order has been appealed by various parties to the Supreme Court of

Ohio. Although the Supreme Court of Ohio has rejected or dismissed a number of procedural and other challenges to the order, the order remains on appeal with that Court.

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 or below the amount included in base rates are recovered or refunded 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 in the year following when new annual factors are established.

Texas: TCC has sold all of its generation assets. TNC has one active generation unit. However, all of the output from that unit is sold to a non-utility affiliate pursuant to an agreement effective through 2027. Retail customers in TCC's and TNC's ERCOT service area of Texas are served through non-affiliated Retail Electric Providers ("REPs"). TCC and TNC provide 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. Effective September 2009, competition in the SPP area of Texas has been delayed until certain steps defined by statute and by PUCT rule have been accomplished. As such, the PUCT continues to approve base and fuel rates for SWEPCo's Texas operations on a cost of service basis.

Virginia: APCo currently provides retail electric service in Virginia at unbundled rates approved by the VSCC. Virginia generally allows for timely recovery of fuel costs through a fuel adjustment clause. Transmission services are provided at OATT rates based on rates established by the FERC. APCo is permitted to retain a minimum of 25% of the margins from its off-system sales with the remaining margins from such sales credited against its fuel adjustment clause factor with a true-up to actual. In addition to base rates and fuel cost recovery, APCo is permitted to recover a variety of costs through rate adjustment clauses.

West Virginia*:* APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a cost-of-service basis. West Virginia generally allows for timely recovery of fuel costs through an expanded net energy clause which trues up to actual expenses.

Other Jurisdictions*:* The public utility subsidiaries of AEP also provide service at cost based regulated bundled rates in Arkansas, Kentucky, Louisiana and Tennessee and regulated unbundled rates in Michigan. These jurisdictions provide for the timely recovery of fuel costs through fuel adjustment clauses that true-up to actual expenses.

The following table illustrates certain regulatory information with respect to the states in which the public utility subsidiaries of AEP operate:

Jurisdiction	**Percentage of AEP System Retail Revenues** (1)	**Percentage of OSS Profits Shared with Ratepayers**	**AEP Utility Subsidiaries Operating in that Jurisdiction**	**Authorized Return on Equity** (2)
Ohio	33%	No sharing included in ESPs	OPCo	(3)
			CSPCo	(3)
Texas	12%	Not Applicable in ERCOT	TCC (4)	9.96%
			TNC (4)	9.96%
		90% in SPP	SWEPCo	15.70%
Virginia	12%	75%	APCo	10.20%
West Virginia	10%	100%	APCo	10.50%
			WPCo	10.50%
Oklahoma	10%	75%	PSO	10.50%
Indiana	10%	50% after certain level (5)	I&M	10.50%
Kentucky	5%	60% to 70% after certain levels (6)	KPCo	10.50%
Louisiana	3%	50% to 100% after certain levels (7)	SWEPCo	10.57%
Arkansas	2%	50% to 100% after certain levels (8)	SWEPCo	10.25%
Michigan	2%	100% in one area, 0% in the other area	I&M	13.00%
Tennessee	1%	Not Applicable	Kingsport	12.00%

(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, 2009.

(2) Identifies the predominant authorized return on equity and may not include other, less significant, permitted recovery. Actual return on equity varies from authorized return on equity.

(3) CSPCo's and OPCo's generation revenues are governed by its Electric Security Plans (ESP) filed and approved by the PUCO. Starting in April 2009, the ESP became effective which authorized rate increases during the ESP period, subject to caps that limit the rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. Some rate components and increases are exempt from the cap limitations. The ESP also provided for a fuel adjustment clause for the three-year period of the ESP. CSPCo and OPCo provide distribution services at cost based rates approved by the PUCO. Transmission services are provided at OATT rates based on rates established by the FERC.

(4) Operating in the ERCOT region of Texas and consists of distribution and transmission functions. Generation operations were divested in compliance with the Texas electric restructuring.

(5) There is an annual $37.5 million credit established for off-system sales in base rates. If the off-system sales profits exceed the amount built into base rates, I&M reimburses ratepayers 50% of the excess.

(6) There is an annual $24.9 million credit established for off-system sales in base rates. If the monthly off-system sales profits do not meet the monthly level built into base rates, ratepayers reimburse KPCo 70% of the shortfall. If the monthly off-system sales profits exceed the monthly base amount built into base rates, KPCo reimburses ratepayers 70% of the excess up to and including $30 million annually. After $30 million, the percentage drops to 60%.

(7) Below $0.874 million, 100% is shared with customers; from $0.874 million to $1.3 million, 85% is shared with customers; above $1.3 million, 50% is shared with customers.

(8) Below $0.759 million, 100% is shared with customers; from $0.759 million to $1.2 million, 85% is shared with customers; above $1.2 million, 50% is shared with customers.

FERC

Under the FPA, the FERC regulates rates for interstate power sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. The FERC regulations require AEP to provide open access transmission service at FERC-approved rates. The FERC also regulates unbundled transmission service to retail customers. The 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 the FERC, under which much of its wholesale marketing activity takes place. The FERC requires each public utility that owns or controls interstate transmission facilities to, directly or through an RTO, 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 FERC also requires all transmitting utilities, directly or through an RTO, to establish an OASIS, which electronically posts transmission information such as available capacity and prices, and requires utilities to comply with Standards of Conduct that prohibit utilities' transmission employees from providing non-public transmission information to the utility's marketing employees.

The FERC oversees RTOs, entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals. The AEP East Companies are members of PJM. SWEPCo and PSO are members of SPP.

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 the FERC and state regulators are permitted to review the books and records of any company within a holding company system. EPACT gives the FERC limited "backstop" transmission siting authority as well as increased utility merger oversight.

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 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, and approved by, the various state commissions. Occasionally, these rates are negotiated with the customer, and then filed with the state commissions for approval. While competition for retail electric service is required by law in the states of Michigan and Ohio, the public utility subsidiaries of AEP believe that they are unlikely to be materially affected by this competition in an adverse manner.

In Ohio, CSPCo has seen an increase in the number of customers, and their associated loads, switching from CSPCo to generation service from other providers (although as of December 31, 2009, the amount switching was less than 1% of CSPCo's entire load.) In February 2010 the PUCO granted a retail supply subsidiary of AEP a certificate to operate as a competitive retail electric service provider in Ohio.

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.

AEP RIVER OPERATIONS

Our AEP River Operations 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 of 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 permit AEP utility subsidiary affiliates to use certain of our equipment at rates that reflect our cost. 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. AEP River Operations includes approximately 2,287 barges, 46 towboats and 26 harbor boats that we own or lease. These assets are separate from the barges and towboats dedicated exclusively to transporting coal for use as fuel in our own generating facilities discussed under the prior segment. See *Item 1 – Utility Operations - Electric Generation —Fuel Supply—Coal and Lignite.*

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. The industry continues to experience 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 Segment consists of non-utility generating assets and a competitive power supply and energy trading and marketing business. We enter into short and long-term transactions to buy or sell capacity, energy and ancillary services primarily in the ERCOT market. As of December 31, 2009, the assets utilized in this segment included approximately 310 MW of company-owned domestic wind power facilities**,** 177 MW of domestic wind power from long-term purchase power agreements and 377 MW of coal-fired capacity which was obtained through an agreement effective through 2027 that transfers TNC's interest in the Oklaunion power station to AEP Energy Partners, Inc. TNC transfered its coal-fired generation capacity to comply with the separation requirements of the Texas Act. The power obtained from the Oklaunion power station is 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.

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. Most 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.

Turk Plant construction and operation permits could be reversed on appeal. *(Applies to SWEPCo)*

In November 2007, the APSC granted approval for SWEPCo to build the Turk Plant in Arkansas by issuing a Certificate of Environmental Compatibility and Public Need. In June 2009, the Arkansas Court of Appeals issued a unanimous decision that would reverse the APSC's grant of its permission for construction of the Turk Plant to serve Arkansas retail customers. In October 2009, the Arkansas Supreme Court granted the petitions filed by SWEPCo and the APSC to review the Arkansas Court of Appeals decision. While the appeal is pending, SWEPCo is continuing construction on the plant.

In November 2008, SWEPCo received the required air permit approval for the Turk Plant from the Arkansas Department of Environmental Quality. In December 2008, certain opponents filed an appeal of the air permit with the Arkansas Pollution Control and Ecology Commission. The commission upheld the air permit in a January 2010 ruling. These same opponents filed a petition with the Federal EPA to review the air permit. In December 2009, the Federal EPA rejected their petition on every issue except one, where the Federal EPA asked the ADEQ to supplement the air permit record on one aspect of its Best Available Control Technology analysis. The Turk Plant cannot be placed into service without an air permit. If SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service, it would reduce net income, cash flow and possibly harm our financial condition unless the resultant losses can be fully recovered, with a return on unrecovered balances, through rates in all of its jurisdictions.

Rate recovery approved in Ohio may be overturned on appeal, may not provide full recovery of fuel costs and/or may have to be returned. *(Applies to AEP, OPCo and CSPCo)*

The PUCO issued an order in March 2009 that modified and approved the Electric Security Plans ("ESPs") of CSPCo and OPCo. The ESPs established rates in effect through 2011. The ESP order generally authorized rate increases during the ESP period, subject to caps that limit the rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. The order also provides a fuel adjustment clause ("FAC") for the three-year period of the ESP. The FAC increase will be phased in to avoid having the resultant rate increases exceed the ordered annual caps. The order allows CSPCo and OPCo to defer unrecovered FAC costs and to accrue carrying charges on such deferrals at CSPCo's and OPCo's weighted average cost of capital. The deferred FAC balance at the end of the three-year ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. Although the Supreme Court of Ohio has rejected or dismissed a number of procedural and other challenges to the order, the order remains on appeal with that Court.

Under our ESP orders, CSPCo and OPCo may be required to return recovery awarded if their earnings meet a certain threshold identified by the Significantly Excessive Earnings Test (SEET). The PUCO must determine if rate adjustments included in the ESP result in significantly excessive earnings. If so, the excess amount must be returned to customers. The PUCO's decision on the SEET review of CSPCo's and OPCo's 2009 earnings is not expected to be finalized until a SEET filing is made by CSPCo and OPCo in 2010 and the PUCO issues an order. The PUCO staff recommended that the SEET be calculated on an individual company basis and not on a combined CSPCo/OPCo basis.

If the PUCO and/or the Supreme Court of Ohio reverses all or part of the rate recovery, if deferred fuel costs are not fully recovered for other reasons, or if the PUCO determines CSPCo's or OPCo's earnings are significantly excessive, it could reduce future net income and cash flows and harm our financial condition.

Rate recovery approved in Texas may be overturned on appeal. *(Applies to AEP)*

In March 2008, the PUCT issued an order that increased TCC's annual pretax income by approximately $50 million. Various parties appealed the PUCT decision. In February 2009, the Texas District Court affirmed the PUCT in most respects. In March 2009, various intervenors appealed the Texas District Court decision to the

Texas Court of Appeals. Management is unable to predict the outcome of these proceedings. If the appeals are successful, it could reduce future net income and cash flows.

Our request for rate recovery in Texas may not be approved in its entirety. *(Applies to AEP and SWEPCo)*

In August 2009, SWEPCo filed a base rate case with the PUCT to increase non-fuel base rates by approximately $75 million annually based on a requested return on common equity of 11.5%. If the PUCT denies all or part of the requested rate recovery, it could reduce future net income and cash flows.

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

In July 2009, APCo filed a base rate case with the Virginia SCC requesting an increase in the generation and distribution portions of its base rates of $169 million (later adjusted to $154 million) annually and a 13.35% return on equity. If the Virginia SCC denies all or part of the requested rate recovery, it could reduce future net income and cash flows and harm our financial condition.

Our request for rate recovery in Kentucky may not be approved in its entirety. *(Applies to AEP)*

In December 2009, KPCo filed a base rate case with the Kentucky Public Service Commission requesting an increase in its base rates by $124 million annually and a 11.75% return on equity. If the Kentucky Public Service Commission denies all or part of the requested rate recovery, it could reduce future net income and cash flows and harm our financial condition.

Our request for rate recovery in Michigan may not be approved in its entirety. *(Applies to I&M)*

In January 2010, I&M filed a base rate case with the Michigan Public Service Commission seeking a $63 million increase in revenue, based on 11.75% return on equity. If the Michigan Public Service Commission denies all or part of the requested rate recovery, it could reduce future net income and cash flows and harm our financial condition.

Our future access to assets used to serve a major customer is in question. *(Applies to I&M)*

Since 1975 I&M has leased certain energy delivery assets from the City of Fort Wayne, Indiana under a long-term lease that expires on February 28, 2010. I&M has been negotiating with Fort Wayne to purchase the remaining assets at the end of the lease, but no agreement has been reached. Fort Wayne issued a technical notice of default under the lease to I&M in August 2009. In October 2009, I&M filed for declaratory and injunctive relief in Indiana state court. The court had ordered additional mediation. I&M will seek recovery in rates for any amount it may pay related to this dispute. At this time, management cannot predict the outcome of this dispute. While management believes any triggered costs should be recoverable from customers, any unrecovered costs could reduce future net income and cash flows.

Oklahoma may require us to refund fuel costs that we have collected. *(Applies to PSO)*

PSO under-recovered $42 million of fuel costs resulting from a reallocation of purchased power costs among AEP West companies for periods prior to 2002. PSO recovered the $42 million by offsetting it against an existing fuel over-recovery during the period June 2007 through May 2008. An association of industrial consumers has contended that PSO should not have collected the $42 million without specific OCC approval and that the OCC should require PSO to refund what it collected through its fuel clause. The OCC has heard the association's appeal and a decision is pending. If the OCC were to order PSO to refund all or a part of the $42 million, it could reduce future net income and cash flows.

We may not recover costs incurred to begin constructing generating plants that are canceled. *(Applies to each registrant)*

Our business plan for the construction of new generating units involves a number of risks, including construction delays, nonperformance by equipment and other third party suppliers, and increases in equipment and labor costs. To limit the risks of these construction projects, we enter into equipment purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals and/or siting or environmental permits. If any of these projects is canceled for any reason, including our failure to receive necessary regulatory approvals and/or siting or environmental permits, we could incur significant cancellation penalties under the equipment purchase orders and construction contracts. In addition, if we have recorded any construction work or investments as a regulatory asset we may need to impair that asset in the event the project is canceled.

Rate regulation may delay or deny full recovery of capital improvements, additions and other 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. There may also be a delay between the timing of when these costs are incurred and when these costs are recovered. Traditionally, we have financed capital investments and improvements until the new asset was placed in service. Provided the asset was found to be a prudent investment, the asset was then added to rate base and entitled to a return through rate recovery. Long lead times in construction, the high costs of plant and equipment and difficult capital markets have heightened the risks involved in our capital investments and improvements. While we are actively pursuing strategies to accelerate rate recognition of investments and cash flow, including pre-approvals, a return on construction work in progress, rider/trackers, formula rates and the inclusion of future test-year projections into rates, there can be no assurance that these will be adopted, 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.

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

Our operations are structured to comply with all applicable federal and state laws and regulations and we take measures to minimize the risk of significant disruptions. Material disruptions at one or more of our operational facilities, however, could negatively impact our revenues, operating and capital expenditures and results of operations. Such events may also create additional risks related to the supply and/or cost of equipment and materials. We could experience unexpected but significant interruption due to several events, including:

- major facility or equipment failure;
- an environmental event such as a serious spill or release;
- fires, floods, droughts, earthquakes, hurricanes or other natural disasters;
- wars, terrorist acts or threats and other catastrophic events;
- significant health impairments or disease events, and;
- other serious operational problems.

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 2,191 MW, or 8-9% of the electricity we generate. 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 any 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 market and transmission 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 structures in various regional power markets. The rules governing the various regional power markets, including SPP and PJM, may also change from time to time which could affect our costs or revenues. Because the manner in which RTOs will evolve remains unclear, we are unable to assess fully the impact that changes in these power markets may have on our business.

The amount we charged third parties for using our transmission facilities is subject to refund. *(Applies to AEP, APCo, CSPCo, I&M and OPCo.)*

In July 2003, the FERC issued an order directing PJM and 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. 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. Because intervenors objected to this decision, the SECA fees we collected ($220 million) are subject to refund.

In August 2006, an ALJ ruled that the SECA rates charged were unfair, unjust and discriminatory, and that new compliance filings and refunds should be made. The FERC has not ruled on the matter. If the FERC upholds the decision of the ALJ, it would disallow $90 million of the AEP East companies' remaining unsettled $108 million of unsettled gross SECA revenues. AEP has settled $112 million of SECA revenues for $10 million. We have recorded a provision for estimated settlement refunds. Any payments in excess of the reserve balance could harm our results of operations and financial position.

We could be subject to higher costs and/or penalties related to mandatory reliability standards. *(Applies to each registrant.)*

As a result of EPACT, owners and operators of the bulk power transmission system are subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation and enforced by the FERC. These standards, which previously were being applied on a voluntary basis, became mandatory in June 2007. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and is guided by reliability and market interface principles. Compliance with new reliability standards may subject us to higher operating costs and/or increased capital expenditures. While we expect to recover costs and expenditures from customers through regulated rates, there can be no assurance that the applicable commissions will approve full recovery in a timely manner. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties, which likely would not be recoverable from customers through regulated rates.

At times, demand for power could exceed our supply capacity. *(Applies to each registrant.)*

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. This would increase the pressure on our short-term debt financing capacity in times of tight liquidity. We may not always have the ability to pass these costs on to our customers, and the time lag between incurring costs and recovery can be long. 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

If we are unable to access capital markets on reasonable terms, it could have an adverse impact on our net income, cash flows and financial condition. *(Applies to each registrant)*

We rely on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows. Volatility and reduced liquidity in the financial markets could affect our ability to raise capital and fund our capital needs, including construction costs and refinancing maturing indebtedness. In addition, if capital is available only on less than reasonable terms or to borrowers whose creditworthiness is better than ours, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could have an adverse impact on net income, cash flows and financial condition.

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)*

The credit ratings agencies periodically review our capital structure and the quality and stability of our earnings. Any negative ratings actions could constrain the capital available to us 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. In periods of market turmoil, access to capital is difficult for all borrowers. 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.

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.

Our pension plan requires additional significant contributions. *(Applies to each registrant.)*

The performance of the capital markets affects the value of the assets that are held in trust to satisfy future obligations under our defined benefit pension plan. The volatility of the capital markets in recent years has led to a decline in the market value of these assets. Also, a decline in interest rates on corporate bonds in 2009 has impacted the benchmark discount rate in a way that results in a higher calculated pension liability. Accordingly, our future required contributions to fund obligations under our defined benefit plan could increase significantly.

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 could be subject to regulatory restrictions. AEP indebtedness and common stock dividends are effectively subordinated to all subsidiary indebtedness and preferred stock obligations.

Our operating results may fluctuate on a seasonal or quarterly basis and with general economic conditions. *(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.

Further, deteriorating economic conditions generally result in reduced consumption by our customers, particularly industrial customers who may curtail operations or cease production entirely, while an expanding economic environment generally results in increased revenues. As a result, our overall operating results in the future may fluctuate on the basis of prevailing economic conditions. For example, off-system sales volumes decreased by 50% and industrial KWH sales were down 16% in 2009, a period of prolonged diminished economic activity.

Failure to attract and retain an appropriately qualified workforce could harm our results of operations. *(Applies to each registrant.)*

Certain events, such as an aging workforce without appropriate replacements, mismatch of skillset or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect the ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be negatively affected.

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.

For example, in our continuing environmental investment program, we chose to retrofit wet flue gas desulfurization systems on several of our units utilizing the jet bubbling reactor technology. These include two co-owned units each at the Kyger Creek and Clifty Creek plants, three co-owned units at the Cardinal plant and one co-owned unit at the Conesville plant; and, in preliminary stages, a unit each at our Muskingum River and Big Sandy plants. Due to unfavorable operating results, we completed an extensive review of the design and manufacture of jet bubbling reactor internal components. Our review concluded that there are fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. We are negotiating with the original equipment manufacturer to develop a repair or replacement corrective action plan. We might incur losses or delays if the original equipment manufacturer does not remediate the deficiencies in a timely manner.

Changes in commodity prices and the costs of transport 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 exposed to changes in the price and availability of coal and the price and availability to transport 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 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 nearly all of our projected needs for the next two years as well as a majority of our needs beyond that timeframe. At some future point, additional costs may be incurred if forthcoming regulation changes require supplemental allowances for compliance. If and when we obtain additional allowances 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. Our ability to make off-system sales at a profit is highly dependent on the price of natural gas. As the price of natural gas falls, other market participants that utilize natural gas-fired generation will be able to offer electricity at increasingly competitive prices relative to our off-system sales prices, so the margins we realize from sales will be lower and, on occasion, we may need to curtail operation of marginal plants.

Prices for coal, natural gas and emission allowances have shown material upward and downward swings 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, 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.

Risks Relating to State Restructuring

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

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 TCC's generation assets 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 Restructuring Legislation and related rules, other parties have appealed the PUCT's final order as unwarranted or too large. Management cannot predict the ultimate outcome of any future court appeals or any future remanded PUCT proceeding.

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

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 seventy REPs. In 2009, TCC's largest customer accounted for 28% of its operating revenue and its second largest customer accounted for 17% of its operating revenue; TNC's largest customer (a non-utility affiliate) accounted for 30% of its operating revenues and its second largest customer accounted for 18% of its operating revenues. Adverse economic conditions, structural problems in the 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 existing environmental laws are significant. *(Applies to each registrant)*

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. Approximately 90% of the electricity generated by the AEP system is produced by the combustion of fossil fuels. Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generating plants are potentially subject to increased regulations, controls and mitigation expenses. 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 net income 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. While we expect to recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions) or market prices, without such recovery those costs could reduce our future net income and cash flows, and possibly harm our financial condition.

Regulation of CO_2 emissions, either through legislation or by the Federal EPA, could materially increase costs to us and our customers or cause some of our electric generating units to be uneconomical to operate or maintain. *(Applies to each registrant)*

In June 2009, the U.S. House of Representatives passed the American Clean Energy Security Act (ACES). ACES is a comprehensive energy and global warming bill that includes a number of provisions that would directly affect our business, including energy efficiency and renewable electricity standards, funding for carbon capture and sequestration demonstration projects, CO_2 emission standards, and an economy-wide cap and trade program for large sources of CO_2 emissions that would reduce emissions by 17% in 2020 and just over 80% by 2050 from 2005 levels. The Senate Environment and Public Works Committee passed a bill out of committee in September. Costs of compliance with the proposed legislation could adversely affect our net income and financial position.

Separately, in December 2009, the Federal EPA issued a final endangerment finding under the CAA regarding emissions from motor vehicles. Several groups have filed challenges to the endangerment finding. The endangerment finding will lead to regulation of CO_2 and other gases under existing laws. Management believes some policy approaches being discussed would have significant and widespread negative consequences for the national economy and major U.S. industrial enterprises, including us and our customers.

If CO_2 and other emission standards are imposed, the standards could require significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. While we expect that costs of complying with new CO_2 and other GHG emission standards will be treated like all other reasonable costs of serving customers and should be recoverable from customers as costs of doing business, without such recovery those costs could reduce our future net income and cash flows and harm our financial condition.

Courts adjudicating nuisance and other similar claims against us may order us to limit or reduce our CO_2 emissions. *(Applies to each registrant)*

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The Second Circuit Court of Appeals reinstated this lawsuit on appeal after the lower court had dismissed it. Similarly, in October 2009, the Fifth Circuit Court of Appeals reversed a decision by the trial court dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina.

The trial courts adjudicating these reinstated nuisance claims may order the defendants, including us, to limit or reduce CO_2 emissions. This or similar remedies could require us to purchase power from third parties to fulfill our commitments to supply power to our customers. This could have a material impact on our costs. While management believes such costs should be recoverable from customers as costs of doing business, without such recovery those costs could reduce our future net income and cash flows and harm our financial condition.

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 certain 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.

We may not fully recover the costs of repairing or replacing damaged equipment in Cook Plant Unit 1. *(Applies to AEP and I&M)*

Cook Plant Unit 1 is a 1,084 MW nuclear generating unit located in Bridgman, Michigan. In September 2008, I&M shut down Unit 1 due to turbine vibrations, which resulted in a fire on the electric generator. Unit 1 resumed operations in December 2009 at reduced power, but repair of the property damage and replacement of the turbine rotors and other equipment are estimated to cost approximately $395 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process.

In 2009, I&M entered into a settlement agreement with intervenors to collect a prior under-recovered fuel balance. Under the settlement agreement, a subdocket was established to consider issues relating to the Unit 1 shutdown, the use of the accidental outage insurance proceeds and I&M's fuel procurement practices. Management cannot predict the outcome of the subdocket proceeding or future fuel clause proceedings, including the treatment of the accidental outage insurance proceeds and whether any fuel clause revenues or insurance proceeds recognized will have to be refunded which could reduce future net income and cash flows.

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

We sell power from our generation facilities into the spot market and other competitive power markets 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, the rate of return on our capital investments is not determined 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 can 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, the 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 the 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;
- outages of major generation or transmission facilities;
- 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.)*

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 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.)*

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.)*

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.)*

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.

Proposed financial derivatives reforms could increase the liquidity needs and costs of our commercial trading operations. *(Applies to each registrant.)*

In 2009, legislation was introduced in Congress to reform financial markets that could significantly alter how over-the-counter ("OTC") derivatives are regulated. In December 2009, the U.S. House of Representatives adopted legislation that would increase regulatory oversight of OTC energy derivatives, including (1) requiring standardized OTC derivatives to be traded on registered exchanges regulated by the CFTC, (2) imposing new and potentially higher capital and margin requirements, and (3) authorizing the establishment of overall volume and position limits. The legislation contains certain exceptions that apply to end-users of energy commodities which could reduce, but not eliminate, the applicability of these measures to us and other end-users. These requirements would cause our OTC transactions to be more costly and have an adverse effect on our liquidity due to additional capital requirements. In addition, as these reforms aim to standardize OTC products it could limit the effectiveness of our hedging programs because we would have less ability to tailor OTC derivatives to match the precise risk we are seeking to protect.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

GENERATION FACILITIES

UTILITY OPERATIONS

At December 31, 2009, 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	Nuclear MW	Lignite MW	Hydro MW	Oil MW	Total MW
AEGCo	2	(a)	1,310	1,186					2,496
APCo	17	(b)(c)	5,093	516			678		6,287
CSPCo	7	(d)	2,378	1,357				3	3,738
I&M	9	(a)	2,305		2,191(e)		15		4,511
KPCo	1		1,060						1,060
OPCo	8	(b)(c)	8,467				26		8,493
PSO	8	(f)	1,026	3,552				25	4,603
SWEPCo	10	(g)	1,848	2,152		850			4,850
TNC	6	(f)(h)	377	262				8	647
System Totals	68		23,864	9,025	2,191	850	719	36	36,685
Percentage of System Totals			65.0	24.6	6.0	2.3	2.0	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.

(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 Duke Ohio and DP&L. Its percentage ownership interest is reflected in this table.

(e) Cook Unit 1 currently is not operating at the full capacity set forth here. For further information, see *Cook Nuclear Plant* below.

(f) PSO and TNC, along with Oklahoma Municipal Power Authority and The Public Utilities Board of the City of Brownsville, Texas, are joint owners of the Oklaunion power station. PSO and TNC's ownership interest is reflected in this portion of the table. TNC has transferred its interest to a non-utility affiliate through 2027.

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

(h) TNC's gas-fired and oil-fired generation has been 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	1,084,000	1,107,000
Net Capacity Factors (a)		
2009	2.8%(b)	83.1%
2008	59.2%(b)	96.6%
2007	97.4%	83.8%
2006	80.4%	86.5%

(a) Net Capacity Factor values for Unit 1 in 2007 through 2009 reflect Nominal Net Electrical Rating in Kilowatts of 1,084,000. The Net Capacity Factor values for Unit 1 in 2006 reflect the previous Nominal Net Electrical Rating in Kilowatts of 1,036,000. The Net Electrical Rating changed in 2007 due to low pressure turbine replacement.

(b) Unit 1 Net Capacity Factor for 2008 and 2009 was impacted by a 2008 forced outage caused by a low pressure turbine blade failure event. The reduced capacity repaired turbine is projected to be replaced with a full capacity turbine in late 2011.

Costs associated with the operation (including 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. 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.

GENERATION AND MARKETING

In addition to the generating facilities described above, AEP has ownership interests in other electrical generating facilities. Information concerning these facilities at December 31, 2009 is listed below.

Facility	**Fuel**	**Location**	**Capacity Total MW**	**Ownership Interest**	**Status**
Desert Sky Wind Farm	Wind	Texas	161	100%	Exempt Wholesale Generator(a)
Trent Wind Farm	Wind	Texas	150	100%	Exempt Wholesale Generator(a)
Total			311		

(a) As defined under rules issued pursuant to EPACT.

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)	224,416	(b)	2,116
APCo	52,151		734
CSPCo (a)	15,567		—
I&M	22,009		615
KgPCo	1,359		—
KPCo	11,044		258
OPCo	30,748		509
PSO	21,365		—
SWEPCo	21,497		—
TCC	29,610		—
TNC	17,362		—
WPCo	1,705		—

(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.

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

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 approximately $2.2 billion of construction expenditures, excluding AFUDC, for 2010. 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.

NEW GENERATION

AEP is in various stages of construction of the following generation facilities:

Operating Company	**Project Name**	**Location**	**Total Projected Cost (a) (in millions)**	**Fuel Type**	**Plant Type**	**Nominal MW Capacity**	**Commercial Operation Date (Projected)**
AEGCo	Dresden (b)	OH	$321 (c)	Gas	Combined-cycle	580	2013
SWEPCo	Stall	LA	$389	Gas	Combined-cycle	500	2010
SWEPCo	Turk (d)	AR	$1,622 (d)	Coal	Ultra-supercritical	600	2012
APCo	Mountaineer	WV	(e)	Coal	IGCC	629	(e)
CSPCo/OPCo	Great Bend	OH	(e)	Coal	IGCC	629	(e)

(a) Amount excludes AFUDC.
(b) In September 2007, AEGCo purchased the partially completed Dresden plant from Dresden Energy LLC, a subsidiary of Dominion Resources, Inc., for $85 million, which is included in the "Total Projected Cost" section above.
(c) During 2009, AEGCo suspended construction of the Dresden Plant. As a result, AEGCo has stopped recording AFUDC and will resume recording AFUDC once construction is resumed.
(d) SWEPCo owns approximately 73%, or 440 MW, totaling $1.2 billion in capital investment. See "Turk Plant" section below.
(e) Construction of IGCC plants is subject to regulatory approvals.

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in-service in 2012. SWEPCo owns 73% of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.6 billion, excluding AFUDC, with SWEPCo's share estimated to cost $1.2 billion, excluding AFUDC. Several notices of appeal are outstanding at the Arkansas Supreme Court and the PUCT. See Note 4 to the consolidated financial statements entitled *Rate Matters* under the heading *Turk Plant* for more information.

TRANSMISSION INITIATIVES

We continue our pursuit of transmission opportunities throughout the U.S. In 2009, we announced that our recently formed transmission company, AEP Transmission Company, LLC, will pursue new transmission investments within our retail service territories. We plan to invest approximately $120 million in these projects in 2010. Through joint ventures with various other companies, we have existing and/or planned transmission projects and opportunities outside of our retail service territories. See *Management's Financial Discussion and Analysis of Results of Operations* included in the 2009 Annual Reports under the heading *Transmission Initiatives*, for more information.

CONSTRUCTION EXPENDITURES

The following table shows construction expenditures (including environmental expenditures) during 2007, 2008 and 2009 and a current estimate of 2010 construction expenditures, in each case excluding AFUDC, capitalized interest and assets acquired under leases.

	2007 **Actual** (b)	**2008** **Actual** (c)	**2009** **Actual** (d)	**2010** **Estimate**
		(in thousands)		
Total AEP System (a)	$3,414,000	$3,981,200	$2,496,300	$2,181,200
APCo	715,700	755,800	446,600	380,500
CSPCo	330,800	435,700	280,100	256,100
I&M	282,400	372,400	357,900	265,200
OPCo	806,000	675,200	389,900	301,800
PSO	302,600	274,200	167,900	166,300
SWEPCo	516,800	689,300	475,800	446,200

(a) Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies. Excludes discontinued operations.
(b) Excludes $512 million for the purchase of Lawrenceburg, Dresden (AEGCo) and Darby (CSPCo) and Cash Flow Statement Adjustments (Statement of Cash Flow Including AFUDC Debt Equals $3,556,000).
(c) Excludes Cash Flow Statement Adjustments (Statement of Cash Flow Including AFUDC Debt Equals $3,800,000).
(d) Excludes Cash Flow Statement Adjustments (Statement of Cash Flow Including AFUDC Debt Equals $2,792,000).

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 6 to the consolidated financial statements entitled *Commitments, Guarantees and Contingencies* under the heading *Nuclear Contingencies* 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, PSO and SWEPCo. None.

CSPCo and I&M. 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, 2010.

Name	Age	Office (a)
Michael G. Morris	63	Chairman of the Board, President and Chief Executive Officer
Nicholas K. Akins	49	Executive Vice President
Carl L. English	63	Chief Operating Officer
John B. Keane	63	Executive Vice President, General Counsel and Secretary
Venita McCellon-Allen	50	Executive Vice President
Charles R. Patton	50	Executive Vice President
Robert P. Powers	55	President-AEP Utilities
Brian X. Tierney	42	Executive Vice President and Chief Financial Officer
Susan Tomasky	56	President – AEP Transmission

(a) All of the executive officers have been employed by AEPSC or System companies in various capacities (AEP, as such, has no employees) for the past five years. Mr. Akins became an executive officer of AEP in June 2006, Mr. English in August, 2004, Mr. Keane in July 2004, Ms. McCellon-Allen in July 2008, Mr. Patton in October 2009, Mr. Powers in October 2001, Mr. Tierney in January 2008 and Ms. Tomasky in January 2000. All of the above officers are appointed annually for a one-year term by the board of directors of AEP.

APCo, OPCo, PSO and SWEPCo. The names of the executive officers of APCo, OPCo, PSO and SWEPCo, the positions they hold with these companies, their ages as of February 1, 2010, and a brief account of their business experience during the past five years appear below. The directors and executive officers of APCo, OPCo, PSO and SWEPCo are elected annually to serve a one-year term.

Name	Age	Position	Period
Michael G. Morris (a)(b)	63	Chairman of the Board, President, Chief Executive Officer and Director of AEP	2004-Present
		Chairman of the Board, Chief Executive Officer and Director of APCo, OPCo, PSO and SWEPCo	2004-Present
Nicholas K. Akins (a)	49	Executive Vice President of AEP	2006-Present
		Vice President and Director of APCo, OPCo, PSO and SWEPCo	2006-Present
		President and Chief Operating Officer of SWEPCo	2004-2006
Carl L. English (a)	63	Chief Operating Officer	2008-Present
		President-AEP Utilities of AEP	2004-2007
		Director and Vice President of APCo, OPCo, PSO and SWEPCo	2004-Present
John B. Keane (c)	63	Executive Vice President, General Counsel and Secretary of AEP	2004-Present
		Director of APCo, OPCo , PSO and SWEPCo	2004-Present

Name	Age	Position	Period
Venita McCellon-Allen (a)	50	Executive Vice President	2008-Present
		Director and Vice President of APCo and OPCo	2009-Present
		Director and Vice President of PSO and SWEPCo	2008-2009
		President and Chief Operating Officer of SWEPCo	2006-2008
		Director and Senior Vice President-Shared Services of AEPSC	2004-2006
		Director of APCo, OPCo and SWEPCo	2004-2006
Charles R. Patton	50	Executive Vice President	2009-Present
		Senior Vice President-Regulatory and Public Policy	2008-2009
		President and Chief Operating Officer of TCC and TNC	2004-2008
		Director and Vice President of PSO and SWEPCo	2009-Present
Robert P. Powers (a)	55	President-AEP Utilities of AEP	2008-Present
		Executive Vice President of AEP	2004-2007
		Director and Vice President of APCo and OPCo	2001-Present
		Director and Vice President of PSO and SWEPCo	2008-Present
Brian X. Tierney (a)	42	Executive Vice President	2008-Present
		Chief Financial Officer	2009-Present
		Director and Vice President of APCo and OPCo	2008-Present
		Director and Vice President of PSO and SWEPCo	2009-Present
		Senior Vice President—Commercial Operations of AEPSC	2005-2007
		Senior Vice President— Energy Marketing of AEPSC	2003-2005
Susan Tomasky (a)	56	President-AEP Transmission	2008-Present
		Executive Vice President of AEP	2004-Present
		Chief Financial Officer of AEP	2001-2006
		Vice President and Director of APCo, OPCo, PSO and SWEPCo	2000-Present

(a) Messrs. Morris, Akins, English, Powers and Tierney and Ms. McCellon-Allen and Ms. Tomasky are directors of CSPCo and I&M.

(b) Mr. Morris is a director of Alcoa, Inc. and The Hartford Financial Services Group, Inc.

(c) Mr. Keane is a director of CSPCo.

APCo:

Name	Age	Position	Period
Dana E. Waldo	58	President and Chief Operating Officer of APCo	2004-Present

OPCo:

Name	Age	Position	Period
Joseph Hamrock	46	President and Chief Operating Officer of CSPCo and OPCo	2008-Present
		Senior Vice President and Chief Information Officer of AEPSC	2003-2007

PSO:

Name	Age	Position	Period
Stuart Solomon	48	President and Chief Operating Officer of PSO	2004-Present

SWEPCo:

Name	Age	Position	Period
Paul Chodak, III	46	President and Chief Operating Officer of SWEPCo	2008-Present
		Director-New Generation of AEPSC	2007-2008
		Director-Environmental Programs of AEPSC	2004-2007

PART II

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

AEP. In addition to the discussion below, the remaining information required by this item is incorporated herein by reference to the material under *AEP Common Stock and Dividend Information* and Note 14 to the consolidated financial statements entitled *Financing Activities* under the heading *Dividend Restrictions* in the 2009 Annual Report.

APCo, CSPCo, I&M, OPCo, PSO and SWEPCo. 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 2009, 2008 and 2007 are incorporated by reference to the material under *Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss)* and Note 14 to the consolidated financial statements entitled *Financing Activities* under the heading *Dividend Restrictions* in the 2009 Annual Reports.

As indicated in the following table, during the quarter ended December 31, 2009, neither AEP (nor its publicly-traded subsidiaries) purchased 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
10/01/09 – 10/31/09	-	$ -	-	$ -
11/01/09 – 11/30/09	-	-	-	-
12/01/09 – 12/31/09	-	-	-	-
Total	-	$ -	-	$ -

ITEM 6. SELECTED FINANCIAL DATA

CSPCo and I&M. Omitted pursuant to Instruction I(2)(a).

AEP, APCo, OPCo, PSO and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Selected Consolidated Financial Data* in the 2009 Annual Reports.

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

CSPCo and I&M. 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 2009 Annual Reports.

AEP, APCo, OPCo, PSO 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 2009 Annual Reports.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

AEP, APCo, CSPCo, I&M, OPCo, PSO 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 2009 Annual Reports.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo. 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

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo. None.

ITEM 9A. CONTROLS AND PROCEDURES

During 2009, management, including the principal executive officer and principal financial officer of each of American Electric Power Company, Inc., Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (each a "Registrant" and collectively 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, 2009, 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 2009 that materially affected, or are reasonably likely to materially affect, the Registrants' internal controls over financial reporting.

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2009. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2009 and, therefore, concluded that each Registrant's internal control over financial reporting was effective.

Additional information required by this item of the Registrants is incorporated by reference to *Management's Report on Internal Control over Financial Reporting*, included in the 2009 Annual Report of each Registrant.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

CSPCo and I&M. 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 2010 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 2010 annual meeting of shareholders.

APCo, OPCo, PSO and SWEPCo:

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 2010 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, OPCo, PSO and 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 APCo, OPCo, PSO and 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 the Chief Executive Officer, Chief Financial Officer or principal accounting officer of APCo, OPCo, PSO and SWEPCo, 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.

ITEM 11. EXECUTIVE COMPENSATION

CSPCo and I&M. 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* of the definitive proxy statement of AEP for the 2010 annual meeting of shareholders and the 2009 Annual Reports, page (vi).

APCo, OPCo, PSO and SWEPCO. 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 2010 annual meeting of stockholders.

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

CSPCo and I&M. 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 2010 annual meeting of shareholders.

APCo, OPCo, PSO and SWEPCO. 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 2010 annual meeting of stockholders.

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

CSPCo and I&M: 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 2010 annual meeting of shareholders.

APCo, **OPCo, PSO and SWEPCo:** **Certain Relationships and Related Transactions.** None. **Director Independence**. None of the directors of APCo, OPCo, PSO 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, 2009 and December 31, 2008, and fees billed for other services rendered by Deloitte & Touche LLP during those periods.

	2009	2008
Audit Fees (1)	$11,411,000	$11,762,000
Audit-Related Fees (2)	1,680,000	1,184,000
Tax Fees (3)	275,000	697,000
TOTAL	$13,366,000	$13,643,000

(1) Audit fees in 2008 and 2009 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 5 regarding the Company's internal control over financial reporting. This category also includes work generally only the independent registered public accounting firm can reasonably be expected to provide.

(2) Audit related fees consisted principally of regulatory, statutory, employee benefit plan audits.

(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, OPCo, PSO and SWEPCo. The information required by this item is incorporated herein by reference to the definitive information statement of each company for the 2010 annual meeting of stockholders.

CSPCo and I&M.

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 2010 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, 2008 and 2009, 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 description of principal accounting fees and services for AEP, above.

	CSPCo		**I&M**	
	2009	2008	2009	2008
Audit Fees	$1,038,130	$1,092,225	$1,612,867	$1,681,029
Audit-Related Fees	25,994	109,947	37,851	169,218
Tax Fees	25,536	64,724	39,304	99,616
TOTAL	$1,089,660	$1,266,896	$1,690,022	$1,949,863

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.	
AEP and Subsidiary Companies:	
Reports of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2009, 2008 and 2007; Consolidated Balance Sheets as of December 31, 2009 and 2008; Consolidated Statements of Cash Flows for the years ended December 31, 2009, 2008 and 2007; Consolidated Statements of Changes in Equity and Comprehensive Income (Loss) for the years ended December 31, 2009, 2008 and 2007; Notes to Consolidated Financial Statements.	
APCo, CSPCo and I&M:	
Consolidated Statements of Income for the years ended December 31, 2009, 2008 and 2007; Consolidated Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss) for the years ended December 31, 2009, 2008 and 2007; Consolidated Balance Sheets as of December 31, 2009 and 2008; Consolidated Statements of Cash Flows for the years ended December 31, 2009, 2008 and 2007; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
OPCo and SWEPCo:	
Consolidated Statements of Income for the years ended December 31, 2009, 2008 and 2007; Consolidated Statements of Changes in Equity and Comprehensive Income (Loss) for the years ended December 31, 2009, 2008 and 2007; Consolidated Balance Sheets as of December 31, 2009 and 2008; Consolidated Statements of Cash Flows for the years ended December 31, 2009, 2008 and 2007; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
PSO:	
Statements of Operations for the years ended December 31, 2009, 2008 and 2007; Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss) for the years ended December 31, 2009, 2008 and 2007; Balance Sheets as of December 31, 2009 and 2008; Statements of Cash Flows for the years ended December 31, 2009, 2008 and 2007; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
2. EXHIBITS:	
Exhibits for AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo are listed in the Exhibit Index beginning on page E-1 and are incorporated herein by reference	S-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/ BRIAN X. TIERNEY
(Brian X. Tierney, Executive Vice President and Chief Financial Officer)

Date: February 26, 2010

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 26, 2010
(ii) Principal Financial Officer:		
/s/ BRIAN X. TIERNEY **(Brian X. Tierney)**	Executive Vice President and Chief Financial Officer	February 26, 2010
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Senior Vice President, Controller and Chief Accounting Officer	February 26, 2010
(iv) A Majority of the Directors:		
*E. R. BROOKS *DONALD M. CARLTON * JAMES F. CORDES *RALPH D. CROSBY, JR. *LINDA A. GOODSPEED *THOMAS E. HOAGLIN *LESTER A. HUDSON, JR. *LIONEL L. NOWELL, III *RICHARD L. SANDOR *KATHRYN D. SULLIVAN *SARA MARTINEZ TUCKER *JOHN F. TURNER		

*By: /s/ BRIAN X. TIERNEY
(Brian X. Tierney, Attorney-in-Fact) February 26, 2010

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.

PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ BRIAN X. TIERNEY
(Brian X. Tierney, Vice President and Chief Financial Officer)

Date: February 26, 2010

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 26, 2010
(ii) Principal Financial Officer:		
/s/ BRIAN X. TIERNEY **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Director	February 26, 2010
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 26, 2010
(iv) A Majority of the Directors:		
*NICHOLAS K. AKINS *CARL L. ENGLISH *JOHN B. KEANE *CHARLES R. PATTON *ROBERT P. POWERS *BARBARA D. RADOUS *SUSAN TOMASKY *DENNIS E. WELCH		
*By: /s/ BRIAN X. TIERNEY **(Brian X. Tierney, Attorney-in-Fact)**		February 26, 2010

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
OHIO POWER COMPANY

By: /s/ BRIAN X. TIERNEY
(Brian X. Tierney, Vice President and Chief Financial Officer)

Date: February 26, 2010

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 26, 2010
(ii) Principal Financial Officer:		
/s/ BRIAN X. TIERNEY **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Director	February 26, 2010
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 26, 2010
(iv) A Majority of the Directors:		
*NICHOLAS K. AKINS *CARL L. ENGLISH *JOHN B. KEANE *VENITA MCCELLON-ALLEN *ROBERT P. POWERS *BARBARA D. RADOUS *SUSAN TOMASKY *DENNIS E. WELCH		
*By: /s/ BRIAN X. TIERNEY **(Brian X. Tierney, Attorney-in-Fact)**		February 26, 2010

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/ BRIAN X. TIERNEY
(**Brian X. Tierney Vice President and Chief Financial Officer)**

Date: February 26, 2010

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 26, 2010
(ii) Principal Financial Officer:		
/s/ BRIAN X. TIERNEY **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Director	February 26, 2010
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 26, 2010
(iv) A Majority of the Directors:		

*NICHOLAS K. AKINS
*J. EDWARD EHLER
*CARL L. ENGLISH
*ALLEN R. GLASSBURN
*JOANN M. GREVENOW
*SCOTT M. KRAWEC
*MARC E. LEWIS
*VENITA MCCELLON-ALLEN
*HELEN J. MURRAY
*MARK A. PEIFER
*ROBERT P. POWERS
*SUSANNE M. MOORMAN ROWE
*SUSAN TOMASKY

*By: /s/ BRIAN X. TIERNEY February 26, 2010
(Brian X. Tierney, Attorney-in-Fact)

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: AEP‡ File No. 1-3525		
*3(a)	Composite of the Restated Certificate of Incorporation of AEP, dated April 28, 2009.	
*3(b)	Composite By-Laws of AEP, as amended as of April 28, 2009.	
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
4(c)	Junior Subordinated Indenture dated as of March 1, 2008 between AEP and The Bank of New York as Trustee.	Registration Statement 333-156387, Ex 4(c)(d)
4(d)	Second Amended and Restated $1.5 Billion Credit Agreement, dated as of March 31, 2008, among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and JP Morgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(a) September 30, 2008
4(e)	Second Amended and Restated $1.5 Billion Credit Agreement, dated as of March 31, 2008, among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and Barclays Bank plc as Administrative Agent.	Form 10-Q, Ex 10(b) September 30, 2008
4(f)	$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(c) September 30, 2008
4(g)	Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(d) September 30, 2008
4(h)	$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10 (e) September 30, 2008
4(i)	Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as	Form 10-Q, Ex 10(f) September 30, 2008

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Administrative Agent.	
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.	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)	Restated and Amended Transmission Coordination Agreement, dated April 15, 2002, among PSO, SWEPCo, TNC and AEPSC.	
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)	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(h)	Consent Decree with U.S. District Court.	Form 8-K, Ex 10.1 dated October 9, 2007
†10(i)	AEP Accident Coverage Insurance Plan for Directors.	1985 Form 10-K, Ex 10(g)
†10(j)	AEP Retainer Deferral Plan for Non-Employee Directors, effective January 1, 2005, as amended February 9, 2007.	2007 Form 10-K, Ex 10(j)(i)
†10(k)	AEP Stock Unit Accumulation Plan for Non-Employee Directors, as amended.	2003 Form 10-K, Ex 10(k)(2)
†10(k)(1)	First Amendment to AEP Stock Unit Accumulation Plan for Non-Employee Directors dated as of February 9, 2007.	2006 Form 10-K, Ex 10(j)(2)(A)
†10(l)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(l)(1)(A)
†10(l)(1)	Guaranty by AEP of AEPSC Excess Benefits Plan.	1990 Form 10-K, Ex 10(h)(1)(B)
†10(l)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2008 (Non-Qualified).	2008 Form 10-K, Ex 10(l)(2)
†10(l)(3)	AEPSC Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3)
†10(l)(3)(A)	First Amendment to AEPSC Umbrella Trust for Executives.	2008 Form 10-K, Ex 10(l)(3)(A)
†10(m)(1)	Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.	2003 Form 10-K, Ex 10(m)(1)
†10(m)(1)(A)	Amendment to Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 9, 2008.	2008 Form 10-K, Ex 10(m)(1)(A)
†10(m)(2)	Memorandum of agreement between Susan Tomasky and AEPSC dated January 3, 2001.	2000 Form 10-K, Ex 10(s)
†10(m)(3)	Letter Agreement dated June 23, 2000 between AEPSC and Holly K. Koeppel.	2002 Form 10-K, Ex 10(m)(3)(A)
†10(m)(4)	Employment Agreement dated July 29, 1998 between	2002 Form 10-K, Ex 10(m)(4)

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
		AEPSC and Robert P. Powers.		
†10(m)(4)(A)		Amendment to Employment Agreement dated December 9, 2008 between AEPSC and Robert P. Powers.		2008 Form 10-K, Ex 10(m)(4)(A)
†10(m)(5)		Letter Agreement dated June 9, 2004 between AEPSC and Carl English.		Form 10-Q, Ex 10(b), September 30, 2004
†10(m)(6)		Letter Agreements dated June 14, 2004 and June 17, 2004 between AEPSC and John B. Keane.		2006 Form 10-K, Ex 10(l)(6)
†10(n)		AEP System Senior Officer Annual Incentive Compensation Plan, amended and restated effective December 13, 2006.		Form 8-K, Ex 10.1 dated April 25, 2007
†10(o)(1)		AEP System Survivor Benefit Plan, effective January 27, 1998.		Form 10-Q, Ex 10, September 30, 1998
†10(o)(1)(A)		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)(1)(B)		Second Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 1, 2008.		2008 Form 10-K, Ex 10(o)(1)(B)
†10(p)		AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.		2008 Form 10-K, Ex 10(p)
†10(q)		AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.		2002 Form 10-K, Ex 10(r)
†10(r)		Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.		2008 Form 10-K, Ex 10(r)
*†10(s)		AEP Change In Control Agreement, effective November 1, 2009.		
†10(t)(1)		Amended and Restated AEP System Long-Term Incentive Plan.		Form 8-K, Item 1.01, dated April 26, 2005
†10(t)(1)(A)		First Amendment to Amended and Restated AEP System Long-Term Incentive Plan.		2007 Form 10-K, Ex 10(t)(1)(A)
†10(t)(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(t)(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(t)(3)(A)		Amendment to Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.		2008 Form 10-K, Ex 10(t)(3)(A)
*†10(u)		AEP System Stock Ownership Requirement Plan Amended and Restated Effective January 1, 2010.		
†10(v)		Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.		2008 Form 10-K, Ex 10(v)
*12		Statement re: Computation of Ratios.		
*13		Copy of those portions of the AEP 2009 Annual Report (for the fiscal year ended December 31, 2009) 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		

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
		States Code.		
*32(b)		Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.		
101.INS		XBRL Instance		
101.SCH		XBRL Taxonomy Extension Schema		
101.CAL		XBRL Taxonomy Extension Calculation		
101.DEF		XBRL Taxonomy Extension Definition		
101.LAB		XBRL Taxonomy Extension Labels		
101.PRE		XBRL Taxonomy Extension Presentation		
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)		Composite By-Laws of APCo, amended as of February 26, 2008.		2007 Form 10-K, Ex 3(b)
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) Registration Statement No. 333-161940, Ex 4(b)(c)(d)
4(b)		$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.		Form 10-Q, Ex10(c) September 30, 2008
4(c)		Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.		Form 10-Q, Ex 10(d) September 30, 2008
4(d)		$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.		Form 10-Q, Ex 10(e) September 30, 2008
4(e)		Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.		Form 10-Q, Ex 10(f) September 30, 2008
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) 1989 Form 10-K, Ex 10(a)(1)(F) 1992 Form 10-K, Ex 10(a)(1)(B)

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
10(a)(2)		Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended March 13, 2006.		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) 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.		1985 Form 10-K, Ex 10(b) 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.		1996 Form 10-K, Ex 10(l), File No. 1-3525
10(f)		Consent Decree with U.S. District Court.		Form 8-K, Ex 10.1 dated October 9, 2007
†10(g)		AEP System Senior Officer Annual Incentive Compensation Plan amended and restated effective December 13, 2006.		Form 8-K, Ex 10.1 dated April 25, 2007
†10(h)(1)		AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008.		2008 Form 10-K, Ex 10(h)(1)
†10(h)(2)		AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2008 (Non-Qualified).		2008 Form 10-K, Ex 10(h)(2)
†10(h)(3)		AEPSC Umbrella Trust for Executives.		1993 Form 10-K, Ex 10(g)(3), File No. 1-3525
†10(h)(3)(A)		First Amendment to AEPSC Umbrella Trust for Executives.		2008 Form 10-K, Ex 10(h)(3)(A)
†10(i)		Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.		2003 Form 10-K, Ex 10(m)(1)
†10(i)(A)		Amendment to Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 9, 2008.		2008 Form 10-K, Ex 10(i)(A)
†10(i)(2)		Memorandum of Agreement between Susan Tomasky and AEPSC dated January 3, 2001.		2000 Form 10-K, Ex 10(s), File No. 1-3525
†10(i)(3)		Letter Agreement dated June 23, 2000 between AEPSC and Holly K. Koeppel.		2002 Form 10-K, Ex 10(m)(3)(A)
†10(i)(4)		Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.		2002 Form 10-K, Ex 10(m)(4)
†10(i)(4)(A)		Amendment to Employment Agreement dated December 9, 2008 between AEPSC and Robert P. Powers.		2008 Form 10-K, Ex 10(i)(4)(A)
†10(i)(5)		Letter Agreement dated June 9, 2004 between AEPSC and Carl English.		Form 10-Q, Ex 10(b), September 30, 2004
†10(i)(6)		Letter Agreements dated June 14, 2004 and June 17, 2004 between AEPSC and John B. Keane.		2006 Form 10-K, Ex 10(h)(5)
†10(j)		AEP System Senior Officer Annual Incentive Compensation Plan, amended and restated effective December 13, 2006.		Form 8-K, Ex 10.1 dated April 25, 2007

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(k)(1)	AEP System Survivor Benefit Plan, effective January 27, 1998.	Form 10-Q, Ex 10, September 30, 1998
†10(k)(1)(A)	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(k)(1)(B)	Second Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 1, 2008.	2008 Form 10-K, Ex 10(k)(1)(B)
*†10(l)	AEP Change In Control Agreement, effective November 1, 2009.	
†10(m)(1)	Amended and Restated AEP System Long-Term Incentive Plan.	Form 8-K, Ex 10.1, dated April 26, 2005
10(m)(1)(A)	First Amendment to Amended and Restated AEP System Long-Term Incentive Plan.	2007 Form 10-K, Ex 10(l)(1)(A)
†10(m)(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), November 5, 2004
†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)(3)(A)	Amendment to Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	2008 Form 10-K, Ex10(m)(3)(A)
*†10(n)	AEP System Stock Ownership Requirement Plan Amended and Restated Effective January 1, 2010.	
†10(o)	Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.	2008 Form 10-K, Ex 10(n)
†10(p)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(o)
†10(q)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(r)
†10(r)	Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(q)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the APCo 2009 Annual Report (for the fiscal year ended December 31, 2009) which are incorporated by reference in this filing.	
21	List of subsidiaries of APCo.	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)	Amended Code of Regulations of CSPCo.	Form 10-Q, Ex 3(b) June 30, 2008
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo and Bankers Trust	Registration Statement No. 333-54025, Ex 4(a)(b)(c)(d) Registration Statement No. 333-128174, Ex 4(b)(c)(d)

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
		Company, as Trustee.		Registration Statement No. 333-150603. Ex 4(b)
4(b)		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) Registration Statement No. 333-150603 Ex 4(b)
4(c)		Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated May 16, 2008, establishing terms of 6.05% Senior Notes, Series G, due 2018.		Form 8-K, Ex 4(a), dated May 16, 2008
4(d)		$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.		Form 10-Q, Ex 10(c) September 30, 2008
4(e)		Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.		Form 10-Q, Ex 10(d) September 30, 2008
4(f)		$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.		Form 10-Q, Ex 10(e) September 30, 2008
4(g)		Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.		Form 10-Q, Ex 10(f) September 30, 2008
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)(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.		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)(1)		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) 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525
10(b)(2)		Unit Power Agreement, dated March 15, 2007 between AEGCo and CSPCo.		2007 Form 10-K, Ex 10(b)(2)
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), File No. 1-3525 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,		2004 Form 10-K, Ex 10(d)(1)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Kingsport Power Company and Wheeling Power Company.	
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.	1996 Form 10-K, Ex 10(l), File No. 1-3525
10(f)	Consent Decree with U.S. District Court.	Form 8-K, Ex 10.1 dated October 9, 2007
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the CSPCo 2009 Annual Report (for the fiscal year ended December 31, 2009) which are incorporated by reference in this filing.	
21	List of subsidiaries of CSPCo.	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)	Composite By-Laws of I&M, amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
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) Registration Statement No. 333-156182, Ex 4(b)
4(b)	Company Order and Officer's Certificate to The Bank of New York, dated January 15, 2009 establishing terms of 7.00% Senior Notes, Series I due 2019.	Form 8-K, Ex 4(a) dated January 15, 2009
4(c)	$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex.10(c) September 30, 2008
4(d)	Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex.10(d) September 30, 2008

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
4(e)		$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.		Form 10-Q, Ex.10(e) September 30, 2008
4(f)		Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.		Form 10-Q, Ex.10(f) September 30, 2008
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.		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)(1)		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) 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525
10(b)(2)		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(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), File No. 1-3525 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.		1996 Form 10-K, Ex 10(l), File No. 1-3525
10(f)		Consent Decree with U.S. District Court.		Form 8-K, Ex 10.1 dated October 9, 2007
10(g)		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 2008 Annual Report (for the fiscal year ended December 31, 2009) which are		

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
		incorporated by reference in this filing.		
21		List of subsidiaries of I&M.		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: 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)		Amended Code of Regulations of OPCo.		Form 10-Q, Ex 3(b), June 30, 2008
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) Registration Statement No. 333-139802, Ex 4(b)(c)(d)
4(b)		Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated April 5, 2007, establishing terms of Floating Rate Notes, Series B.		Form 8-K, Ex 4(a) dated April 5, 2007
*4(c)		Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated September 24, 2009, establishing terms of 5.375% Senior Notes, Series M due 2021.		Form 8-K, Ex 4(a) dated September 24, 2009
4(d)		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)
4(e)		$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.		Form 10-Q, Ex 10(c) September 30, 2008
4(f)		Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.		Form 10-Q, Ex 10(d) September 30, 2008
4(g)		$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.		Form 10-Q, Ex 10(e) September 30, 2008
4(h)		Amendment, dated as of April 25, 2008, to $350		Form 10-Q, Ex 10(f) September 30, 2008

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	
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 July 10, 1953, among OVEC and the Sponsoring Companies, as amended, March 13, 2006.	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, 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) 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.	1985 Form 10-K, Ex 10(b), File No. 1-3525 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.	1996 Form 10-K, Ex 10(l), File No. 1-3525
10(f)	Consent Decree with U.S. District Court.	Form 8-K, Item Ex 10.1 dated October 9, 2007
10(g)(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(g)(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(h)	AEP System Senior Officer Annual Incentive Compensation Plan amended and restated effective December 13, 2006.	Form 8-K, Ex 10.1 dated April 25, 2007
†10(i)(1)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(j)(1)
†10(i)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2008. (Non-Qualified).	2008 Form 10-K, Ex 10(j)(2)
†10(i)(3)	AEPSC Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3), File No. 1-3525
†10(i)(3)(A)	First Amendment to AEPSC Umbrella Trust for Executives.	2008 Form 10-K, Ex 10(j)(3)(A)

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
†10(j)(1)		Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.		2003 Form 10-K, Ex 10(m)(1)
†10(j)(1)(A)		Amendment to Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 9, 2008.		2008 Form 10-K, Ex 10(k)(1)(A)
†10(j)(2)		Memorandum of agreement between Susan Tomasky and AEPSC dated January 3, 2001.		2000 Form 10-K, Ex 10(s), File No. 1-3525
†10(j)(3)		Letter Agreement dated June 23, 2000 between AEPSC and Holly K. Koeppel.		2002 Form 10-K, Ex 10(m)(3)(A)
†10(j)(4)		Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.		2002 Form 10-K, Ex 10(m)(4)
†10(j)(4)(A)		Amendment to Employment Agreement dated December 9, 2008 between AEPSC and Robert P. Powers.		2008 Form 10-K, Ex 10(k)(4)(A)
†10(j)(5)		Letter Agreement dated June 9, 2004 between AEPSC and Carl English.		Form 10-Q, Ex 10(b), September 30, 2004, File No. 1-3525
†10(j)(6)		Letter Agreements dated June 14, 2004 and June 17, 2004 between AEPSC and John B. Keane.		2006 Form 10-K, Ex 10(j)(5)
†10(k)		AEP System Senior Officer Annual Incentive Compensation Plan, amended and restated effective December 13, 2006.		Form 8-K, Ex 10.1 dated April 25, 2007
†10(l)(1)		AEP System Survivor Benefit Plan, effective January 27, 1998.		Form 10-Q, Ex 10, September 30, 1998
†10(l)(1)(A)		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(l)(1)(B)		Second Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 1, 2008.		2008 Form 10-K, Ex 10(m)(1)(B)
*†10(m)		AEP Change In Control Agreement, effective November 1, 2009.		
†10(n)(1)		Amended and Restated AEP System Long-Term Incentive Plan.		Form 8-K, Ex 10.1, dated April 26, 2005
10(n)(1)(A)		First Amendment to Amended and Restated AEP System Long-Term Incentive Plan.		2007 Form 10-K, Ex 10(n)(1)(A)
†10(o)		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), November 5, 2004, File No. 1-3525
†10(p)(1)		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(p)(1)(A)		Amendment to Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.		2008 Form 10-K, Ex 10(q)(1)(A)
*†10(q)		AEP System Stock Ownership Requirement Plan Amended and Restated Effective January 1, 2010.		
†10(r)		Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.		2008 Form 10, Ex 10(s)
†10(s)		AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.		2008 Form 10, Ex 10(t)
†10(y)		AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.		2002 Form 10-K, Ex 10(r)
†10(u)		Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.		2008 Form 10, Ex 10(v)
*12		Statement re: Computation of Ratios.		
*13		Copy of those portions of the OPCo 2009 Annual Report (for the fiscal year ended December 31, 2009) which are incorporated by reference in this filing.		
21		List of subsidiaries of OPCo.		2006 Form 10-K, Ex 21, File No. 1-3525

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*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)	Certificate of Amendment to Restated Certificate of Incorporation of PSO.	Form 10-Q, Ex 3(a), June 30, 2008
3(b)	Composite By-Laws of PSO amended as of February 26, 2008.	2007 Form 10-K, Ex 3 (b)
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, Ex 4(a)(b) Registration Statement No. 333-114665, Ex 4(b)(c) Registration Statement No. 333-133548, Ex 4(b)(c) Registration Statement No. 333-156319, Ex 4(b)(c)
*4(b)	Eighth Supplemental Indenture, dated as of November 13, 2009 between PSO and The Bank of New York Mellon, as Trustee, establishing terms of the 5.15% Senior Notes, Series H, due 2019.	Form 8-K, Ex 4(a), dated November 13, 2009
4(c)	$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(c) September 30, 2008
4(d)	Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(d) September 30, 2008
4(e)	$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(e) September 30, 2008
4(f)	Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(f) September 30, 2008
10(a)	Restated and Amended Operating Agreement, among PSO, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006.	Form 10-Q, Ex 10(a), March 31, 2006

Exhibit Designation		Nature of Exhibit		Previously Filed as Exhibit to:
*10(b)		Restated and Amended Transmission Coordination Agreement, dated April 15, 2002, among PSO, SWEPCo, TNC and AEPSC.		
†10(c)		AEP System Senior Officer Annual Incentive Compensation Plan amended and restated effective December 13, 2006.		Form 8-K, Ex 10.1 dated April 25, 2007
†10(d)(1)		AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008.		2008 Form 10-K, Ex 10(d)(1)
†10(d)(2)		AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2008 (Non-Qualified).		2008 Form 10-K, Ex 10(d)(2)
†10(d)(3)		AEPSC Umbrella Trust for Executives.		1993 Form 10-K, Ex 10(g)(3), File No. 1-3525
†10(d)(3)(A)		First Amendment to AEPSC Umbrella Trust for Executives.		2008 Form 10-K, Ex 10(d)(3)(A)
†10(e)		Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.		2003 Form 10-K, Ex 10(m)(1)
†10(e)(A)		Amendment to Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 9, 2008.		2008 Form 10-K, Ex 10(e)(A)
†10(e)(2)		Memorandum of Agreement between Susan Tomasky and AEPSC dated January 3, 2001.		2000 Form 10-K, Ex 10(s), File No. 1-3525
†10(e)(3)		Letter Agreement dated June 23, 2000 between AEPSC and Holly K. Koeppel.		2002 Form 10-K, Ex 10(m)(3)(A)
†10(e)(4)		Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.		2002 Form 10-K, Ex 10(m)(4)
†10(e)(4)(A)		Amendment to Employment Agreement dated December 9, 2008 between AEPSC and Robert P. Powers.		2008 Form 10-K, Ex 10(e)(4)(A)
†10(e)(5)		Letter Agreement dated June 9, 2004 between AEPSC and Carl English.		Form 10-Q, Ex 10(b), September 30, 2004
†10(e)(6)		Letter Agreements dated June 14, 2004 and June 17, 2004 between AEPSC and John B. Keane.		2006 Form 10-K, Ex 10(h)(5)
†10(f)		AEP System Senior Officer Annual Incentive Compensation Plan, amended and restated effective December 13, 2006.		Form 8-K, Ex 10.1 dated April 25, 2007
†10(g)(1)		AEP System Survivor Benefit Plan, effective January 27, 1998.		Form 10-Q, Ex 10, September 30, 1998
†10(g)(1)(A)		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(g)(1)(B)		Second Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 1, 2008.		2008 Form 10-K, Ex 10(g)(1)(B)
*†10(h)		AEP Change In Control Agreement, effective November 1, 2009.		
†10(i)(1)		Amended and Restated AEP System Long-Term Incentive Plan.		Form 8-K, Ex 10.1, dated April 26, 2005
10(i)(1)(A)		First Amendment to Amended and Restated AEP System Long-Term Incentive Plan.		2007 Form 10-K, Ex 10(l)(1)(A
†10(i)(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), November 5, 2004
†10(i)(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(i)(3)(A)		Amendment to Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.		2008 Form 10-K, Ex 10(i)(3)(A)
*†10(j)		AEP System Stock Ownership Requirement Plan Amended and Restated Effective January 1, 2010.		

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(k)	Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.	2008 Form 10-K, Ex 10(j)
†10(l)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(k)
†10(m)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(p)
†10(n)	Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(m)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the PSO 2009 Annual Report (for the fiscal year ended December 31, 2009) which are incorporated by reference in this filing.	
21	List of subsidiaries of PSO.	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)	Composite of Amended Restated Certificate of Incorporation of SWEPCo.	2008 Form 10-K, Ex 3(a)
3(b)	Composite By-Laws of SWEPCo amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	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) Registration Statement No. 333-145669, Ex 4(c)(d) Registration Statement No. 333-161539, Ex 4(b)(c)
4(b)	$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(c) September 30, 2008
4(c)	Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(d) September 30, 2008
4(d)	$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase	Form 10-Q, Ex 10(e) September 30, 2008

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Bank, N.A., as Administrative Agent.	
4(e)	Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(f) September 30, 2008
10(a)	Restated and Amended Operating Agreement, among PSO, TCC, TNC, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006.	Form 10-Q, Ex 10(a), March 31, 2006
*10(b)	Restated and Amended Transmission Coordination Agreement, dated April 15, 2002, among PSO, SWEPCo, TNC and AEPSC.	
†10(c)	AEP System Senior Officer Annual Incentive Compensation Plan amended and restated effective December 13, 2006.	Form 8-K, Ex 10.1 dated April 25, 2007
†10(d)(1)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(d)(1)
†10(d)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2008 (Non-Qualified).	2008 Form 10-K, Ex 10(d)(2)
†10(d)(3)	AEPSC Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3), File No. 1-3525
†10(d)(3)(A)	First Amendment to AEPSC Umbrella Trust for Executives.	2008 Form 10-K, Ex 10(d)(3)(A)
†10(e)	Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.	2003 Form 10-K, Ex 10(m)(1)
†10(e)(A)	Amendment to Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 9, 2008.	2008 Form 10-K, Ex 10(e)(A)
†10(e)(2)	Memorandum of Agreement between Susan Tomasky and AEPSC dated January 3, 2001.	2000 Form 10-K, Ex 10(s), File No. 1-3525
†10(e)(3)	Letter Agreement dated June 23, 2000 between AEPSC and Holly K. Koeppel.	2002 Form 10-K, Ex 10(m)(3)(A)
†10(e)(4)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K, Ex 10(m)(4)
†10(e)(4)(A)	Amendment to Employment Agreement dated December 9, 2008 between AEPSC and Robert P. Powers.	2008 Form 10-K, Ex 10(e)(4)(A)
†10(e)(5)	Letter Agreement dated June 9, 2004 between AEPSC and Carl English.	Form 10-Q, Ex 10(b), September 30, 2004
†10(e)(6)	Letter Agreements dated June 14, 2004 and June 17, 2004 between AEPSC and John B. Keane.	2006 Form 10-K, Ex 10(h)(5)
†10(f)	AEP System Senior Officer Annual Incentive Compensation Plan, amended and restated effective December 13, 2006.	Form 8-K, Ex 10.1 dated April 25, 2007
†10(g)(1)	AEP System Survivor Benefit Plan, effective January 27, 1998.	Form 10-Q, Ex 10, September 30, 1998
†10(g)(1)(A)	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(g)(1)(B)	Second Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 1, 2008.	2008 Form 10-K, Ex 10(g)(1)(B)
*†10(h)	AEP Change In Control Agreement, effective November 1, 2009.	
†10(i)(1)	Amended and Restated AEP System Long-Term Incentive Plan.	Form 8-K, Ex 10.1, dated April 26, 2005
10(i)(1)(A)	First Amendment to Amended and Restated AEP System	2007 Form 10-K, Ex 10(l)(1)(A

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Long-Term Incentive Plan.	
†10(i)(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), November 5, 2004
†10(i)(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(i)(3)(A)	Amendment to Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	2008 Form 10-K, Ex 10(i)(3)(A)
*†10(j)	AEP System Stock Ownership Requirement Plan Amended and Restated Effective January 1, 2010.	
†10(k)	Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.	2008 Form 10-K, Ex 10(j)
†10(l)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(k)
†10(m)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(p)
†10(n)	Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(m)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the SWEPCo 2009 Annual Report (for the fiscal year ended December 31, 2009) which are incorporated by reference in this filing.	
21	List of subsidiaries of SWEPCo.	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.	

‡ 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.