AMERICAN ELECTRIC POWER CO INC
Form 10-Q
November 01, 2010
UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended September 30, 2010
OR
[ ] 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	Registrant, State of Incorporation, Address of Principal Executive Offices, and Telephone Number	I.R.S. Employer Identification No.
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
All Registrants	1 Riverside Plaza, Columbus, Ohio 43215-2373 Telephone (614) 716-1000	

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 X No

Indicate by check mark whether American Electric Power Company, Inc. has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes X 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 the AEP corporate website, if any, every Interactive

Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T 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 American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of 'large accelerated filer,' 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act.

Large accelerated filer	X	Accelerated filer	
Non-accelerated filer		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 the definitions of 'large accelerated filer,' 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act.

Large accelerated filer		Accelerated filer	
Non-accelerated filer	X	Smaller reporting company	

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act).

	Yes	No	X

Columbus Southern Power Company and Indiana Michigan Power Company meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

	Number of shares of common stock outstanding of the registrants at October 29, 2010
American Electric Power Company, Inc.	480,276,270 ($6.50 par value)
Appalachian Power Company	13,499,500 (no par value)
Columbus Southern Power Company	16,410,426 (no par value)
Indiana Michigan Power Company	1,400,000 (no par value)
Ohio Power Company	27,952,473 (no par value)
Public Service Company of Oklahoma	9,013,000 ($15 par value)
Southwestern Electric Power Company	7,536,640 ($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORTS ON FORM 10-Q
September 30, 2010

	Page
Glossary of Terms	i
Forward-Looking Information	iv
Part I. FINANCIAL INFORMATION	
Items 1, 2 and 3 - Financial Statements, Management's Financial Discussion and Analysis and Quantitative and Qualitative Disclosures About Risk Management Activities:	
American Electric Power Company, Inc. and Subsidiary Companies:	
Management's Financial Discussion and Analysis of Results of Operations	1
Quantitative and Qualitative Disclosures About Risk Management Activities	20
Condensed Consolidated Financial Statements	24
Index to Condensed Notes to Condensed Consolidated Financial Statements	29
Appalachian Power Company and Subsidiaries:	
Management's Financial Discussion and Analysis	85
Quantitative and Qualitative Disclosures About Risk Management Activities	90
Condensed Consolidated Financial Statements	91
Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	96
Columbus Southern Power Company and Subsidiaries:	
Management's Narrative Financial Discussion and Analysis	98
Quantitative and Qualitative Disclosures About Risk Management Activities	102
Condensed Consolidated Financial Statements	103
Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	108
Indiana Michigan Power Company and Subsidiaries:	
Management's Narrative Financial Discussion and Analysis	110
Quantitative and Qualitative Disclosures About Risk Management Activities	114
Condensed Consolidated Financial Statements	115
Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	120
Ohio Power Company Consolidated:	
Management's Financial Discussion and Analysis	122
Quantitative and Qualitative Disclosures About Risk Management Activities	128
Condensed Consolidated Financial Statements	129
Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	134

Public Service Company of Oklahoma:	
Management's Financial Discussion and Analysis	136
Quantitative and Qualitative Disclosures About Risk Management Activities	140
Condensed Financial Statements	141
Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	146
Southwestern Electric Power Company Consolidated:	
Management's Financial Discussion and Analysis	148
Quantitative and Qualitative Disclosures About Risk Management Activities	154
Condensed Consolidated Financial Statements	155
Index to Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries	160

Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries			161
Combined Management's Discussion and Analysis of Registrant Subsidiaries			230
Controls and Procedures			239
Part II. OTHER INFORMATION			
	Item 1.	Legal Proceedings	240
	Item 1A.	Risk Factors	240
	Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	244
	Item 5.	Other Information	244
	Item 6.	Exhibits:	244
		Exhibit 12	
		Exhibit 31(a)	
		Exhibit 31(b)	
		Exhibit 32(a)	
		Exhibit 32(b)	
SIGNATURE			245

This combined Form 10-Q 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. Each registrant makes no representation as to information relating to the other registrants.

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP System or the System	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.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
ASU	Accounting Standard Update.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO2	Carbon Dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel LLC and DCC Fuel II LLC, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
E&R	Environmental compliance and transmission and distribution system reliability.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ERCOT	Electric Reliability Council of Texas.
ESP	

	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Utilities, Inc. and MidAmerican Energy Holdings Company Texas Transco, LLC formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or Scrubbers.

Term	Meaning
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
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.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NEIL	Nuclear Electric Insurance Limited.
NOx	Nitrogen oxide.
Nonutility Money Pool	AEP's Nonutility Money Pool.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, CSPCo, I&M, OPCo, PSO and SWEPCo.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization.

Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity.

Term	Meaning
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO2	Sulfur Dioxide.
SPP	Southwest Power Pool.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC and AEP Texas Central Transition Funding II LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas restructuring law.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Turk Plant	John W. Turk, Jr. Plant.
Utility Money Pool	AEP System's Utility Money Pool.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

- 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, customer growth and the impact of retail competition, particularly in Ohio.
- 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 resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues 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 oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash 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, cyber security threats and other catastrophic events.
- Our ability to recover through rates any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

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

EXECUTIVE OVERVIEW

Economic Conditions

Retail margins increased during the first nine months of 2010 due to successful rate proceedings in various jurisdictions and higher residential and commercial demand for electricity as a result of favorable weather throughout our service territories. In comparison to the recessionary lows of 2009, industrial sales increased 6% in the third quarter and 5% during the first nine months of 2010.

Regulatory Activity

Our significant 2010 rate proceedings include:

Kentucky – In June 2010, a settlement was approved by the KPSC to increase annual base rates by $64 million based on a 10.5% return on common equity. New rates became effective with the first billing cycle of July 2010.

Michigan – In October 2010, a settlement was approved by the MPSC to increase annual base rates by $36 million based on a 10.35% return on common equity as well as the approval of certain surcharges. New rates will become effective with the first billing cycle of December 2010.

Oklahoma – In July 2010, PSO filed for an $82 million increase in annual base rates, including $30 million that is currently being recovered through a rider. The requested increase is based on an 11.5% return on common equity. Various parties' net annual rate recommendations ranged from a rate reduction of $18 million to an increase of less than $1 million. A hearing is scheduled for December 2010.

Texas – In April 2010, a settlement was approved by the PUCT to increase SWEPCo's base rates by approximately $15 million annually, effective May 2010, including a return on equity of 10.33%. The settlement agreement also allows SWEPCo a $10 million one-year surcharge rider to recover additional vegetation management costs that SWEPCo must spend within two years.

Virginia – In July 2010, the Virginia SCC authorized an annual increase in revenues of $62 million based on a 10.53% return on equity. The order disallowed recovery of $54 million of costs related to the Mountaineer Carbon Capture and Storage Project and allowed the deferral of approximately $25 million of incremental storm expenses incurred in 2009. As a result, APCo recorded a pretax loss of $29 million in the second quarter of 2010.

West Virginia – In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates by $156 million to be effective March 2011. The request is based on an 11.75% return on common equity and includes a request for recovery of and a return on the West Virginia jurisdictional share of the Mountaineer Carbon Capture and Storage Project. A decision from the WVPSC is expected in March 2011.

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW coal unit in Arkansas, which is expected to be in service in 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. SWEPCo's share of construction costs is currently estimated to cost $1.3 billion, excluding AFUDC, plus an additional $132 million for transmission, excluding AFUDC. The APSC, LPSC and PUCT approved SWEPCo's original application to build the Turk Plant. Various proceedings are pending that challenge the Turk Plant's construction and its approved air and wetlands permits. In July 2010, the Arkansas Court of Appeals issued a decision remanding all transmission line Certificate of Environmental Compatibility and Public Need (CECPN) appeals to the APSC. As a result, a stay was not ordered and construction continues on the affected transmission lines.

1

In June 2010, the Arkansas Supreme Court denied motions for rehearing filed by the APSC and SWEPCo related to the reversal of the APSC's earlier grant of a CECPN for SWEPCo's 88 MW Arkansas portion of the Turk Plant. As a result, in June 2010, SWEPCo filed notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of its Arkansas portion of Turk Plant costs in Arkansas retail rates.

In July 2010, the Hempstead County Hunting Club filed a complaint with the Federal District Court for the Western District of Arkansas against SWEPCo, the U.S. Army Corps of Engineers, the U.S. Department of Interior and the U.S. Fish and Wildlife Service seeking an injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws. The Sierra Club, the Audubon Society and others filed a similar complaint in the same court. In October 2010, the motions for preliminary injunction were partially granted. According to the preliminary injunction, all uncompleted construction work associated with wetlands, streams or rivers at the Turk Plant must immediately stop. Mitigation measures required by the permit are authorized and may be completed. The preliminary injunction affects portions of the water intake and associated piping and portions of the transmission lines. In October 2010, the Federal District Court certified issues relating to the state law claims to the Arkansas Supreme Court, including whether those claims are within the primary jurisdiction of the APSC. The Arkansas Supreme Court has yet to consider the request. SWEPCo filed a notice of appeal with the Federal Court of Appeals for the Eighth Circuit and is seeking a stay of the preliminary injunction pending appeal.

Management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service or if SWEPCo cannot recover all of its investment in and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition.

Ohio Customer Choice

In our Ohio service territory, various certified retail electric service (CRES) providers are targeting retail customers by offering alternative generation service. As of September 30, 2010, approximately 2,000 Ohio retail customers have switched to alternative CRES providers while approximately 1,200 additional Ohio customers have provided notice of their intent to switch. As a result, in comparison to 2009, we lost approximately $5 million of generation related gross margin through September 30, 2010 and currently forecast incremental lost margins of approximately $10 million and $53 million for the fourth quarter of 2010 and for all of 2011, respectively. We anticipate recovery of a portion of this lost margin through off-system sales. In addition, we have created our own CRES provider to target retail customers in Ohio, both within and outside of our retail footprint.

Ohio Electric Security Plan Filings

During 2009, the PUCO issued an order that modified and approved CSPCo's and OPCo's ESPs which established rates through 2011. The order also limits annual 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 provides a FAC for the three-year period of the ESP. Several notices of appeal are outstanding at the Supreme Court of Ohio relating to significant issues in the determination of the approved ESP rates. CSPCo and OPCo filed their 2009 significantly excessive earnings test with the PUCO. Based upon the methodology proposed by CSPCo and OPCo, neither CSPCo's nor OPCo's 2009 return on equity was significantly excessive. In October 2010, intervenors filed testimony with the PUCO recommending CSPCo return up to $156 million of its ESP revenues to customers. If the PUCO determines that CSPCo's and/or OPCo's 2009 return on equity was significantly excessive, CSPCo and/or OPCo may be required to return a portion of their ESP revenues to customers. See "Ohio Electric Security Plan Filings" section of Note 3.

2

Proposed CSPCo and OPCo Merger

In October 2010, CSPCo and OPCo filed an application with the PUCO to merge CSPCo into OPCo. Approval of the merger will not affect CSPCo's and OPCo's rates until such time as the PUCO approves new rates, terms and conditions for the merged company. The merger is also subject to regulatory approval by the FERC. CSPCo and OPCo anticipate completion of the merger during 2011. See “Proposed CSPCo and OPCo Merger” section of Note 3.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $395 million. Management believes that I&M should recover a significant portion of repair and replacement costs through the turbine vendor’s warranty, insurance and the regulatory process. I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011. If the ultimate costs of the incident are not covered by warranty, insurance or through the related regulatory process or if any future regulatory proceedings are adverse, it could reduce future net income and cash flows and impact financial condition. See “Indiana Fuel Clause Filing” and “Michigan 2009 Power Supply Cost Recovery Reconciliation” sections of Note 3 and “Cook Plant Unit 1 Fire and Shutdown” section of Note 4.

Texas Restructuring Appeals

Pursuant to PUCT restructuring orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC also refunded other net true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT’s true-up related orders. After rulings from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not yet determined if it will grant review. See “Texas Restructuring Appeals” section of Note 3.

Mountaineer Carbon Capture and Storage Project

APCo and ALSTOM Power, Inc. (Alstom), an unrelated third party, jointly constructed a CO2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO2. In APCo’s July 2009 Virginia base rate filing and APCo’s May 2010 West Virginia base rate filing, APCo requested recovery of and a return on its Virginia and West Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Project costs, which resulted in a pretax write-off of approximately $54 million in the second quarter of 2010. Through September 30, 2010, APCo has recorded a noncurrent regulatory asset of $59 million related to the Mountaineer Carbon Capture and Storage Project. If APCo cannot recover its remaining investments in and expenses related to the Mountaineer Carbon Capture and Storage project, it would reduce future net income and cash flows and impact financial condition. See “Mountaineer Carbon Capture and Storage Project” section of Note 3.

Capital Expenditures

In October 2010, we announced our capital expenditure budgets of $2.6 billion and $2.9 billion for 2011 and 2012, respectively.

3

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 – Rate Matters, Note 6 – Commitments, Guarantees and Contingencies and the "Litigation" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2009 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies included herein. Adverse results in these proceedings have the potential to materially affect our net income.

ENVIRONMENTAL ISSUES

We are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. We will need to make additional investments and operational changes in response to existing and anticipated requirements such as CAA requirements to reduce emissions of SO_2, NOx, PM and hazardous air pollutants from fossil fuel-fired power plants and new proposals governing the beneficial use and disposal of coal combustion products.

We are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of our nuclear units. We are also engaged in the development of possible future requirements including the items discussed below and reductions of CO_2 emissions to address concerns about global climate change. See a complete discussion of these matters in the "Environmental Matters" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2009 Annual Report.

Clean Air Act Transport Rule (Transport Rule)

In July 2010, the Federal EPA issued a proposed rule to replace the Clean Air Interstate Rule (CAIR) that would impose new and more stringent requirements to control SO_2 and NOx emissions from fossil fuel-fired electric generating units in 31 states and the District of Columbia. Each state covered by the Transport Rule is assigned an allowance budget for SO_2 and/or NOx. Limited interstate trading is allowed on a sub-regional basis and intrastate trading is allowed among generating units. Certain of our western states (Texas, Arkansas and Oklahoma) would be subject to only the seasonal NOx program, with new limits that are proposed to take effect in 2012. The remainder of the states in which we operate would be subject to seasonal and annual NOx programs and an annual SO_2 emissions reduction program that takes effect in two phases. The first phase becomes effective in 2012 and requires approximately 1 million tons per year more SO_2 emission reductions across the region than would have been required under CAIR. The second phase takes effect in 2014 and reduces emissions by an additional 800,000 tons per year. The SO_2 and NOx programs rely on newly-created allowances rather than relying on the CAIR NOx allowances or the Title IV Acid Rain Program allowances used in the CAIR rule. The time frames for and the extent of the additional emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and our electric utility customers, as these requirements could accelerate unit retirements, increase capital requirements, constrain operations, decrease reliability and unfavorably impact financial condition if the increased costs are suspended during the early development stages not recovered in rates or market prices. Comments on the proposed rule were due on October 1, 2010. Our comments pointed out the inaccuracies of some of the assumptions used by the Federal EPA, the flawed nature of its modeling analysis and unreasonable time frame for implementing the rule. We believe that the Federal EPA made erroneous assumptions about the existence and/or capabilities of current control equipment at certain of our units, used timeframes for installation of new controls that are inconsistent with our recent experience and made questionable assumptions regarding the ability to switch fuel supplies at existing units. A notice of additional information was issued and comments on that package were accepted until October 15, 2010. The proposal indicates that the requirements are expected to be finalized in June 2011 and become effective January 1, 2012.

4

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

The Federal EPA issued the Clean Air Mercury Rule (CAMR) in 2005, setting mercury emission standards for new coal-fired power plants and requiring all states to issue new state implementation plans including mercury requirements for existing coal-fired power plants. The CAMR was vacated and remanded to the Federal EPA by the D.C. Circuit Court of Appeals in 2008. The Federal EPA issued an information collection request to owners and operators of existing power plants in 2010 to collect information to support the development of a maximum achievable control technology (MACT) standard for mercury and other hazardous air pollutant emissions under the CAA. Under the terms of a consent decree, the Federal EPA is required to issue final MACT standards for coal and oil-fired power plants by November 2011. The Federal EPA has substantial discretion in determining how to structure the MACT standards. We will urge the Federal EPA to carefully consider all of the options available so that costly and inefficient control requirements are not imposed regardless of unit size, age or other operating characteristics. However, we have approximately 5,000 MW of older coal units, including 2,000 MW of older coal-fired capacity already subject to control requirements under the NSR consent decree, for which it may be economically inefficient to install scrubbers or other environmental controls. The timing and ultimate disposition of those units will be affected by: a) the MACT standards and other environmental regulations, b) the economics of maintaining the units, c) demand for electricity, d) availability and cost of replacement power and e) regulatory decisions about cost recovery of the remaining investment in those units.

Coal Combustion Residual Rule

In June 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at our coal-fired electric generating units. The rule contains two alternative proposals, one that would impose federal hazardous waste disposal and management standards on these materials and one that would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule.

Currently, approximately 40% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, we currently use surface impoundments and landfills to manage these materials at our generating facilities and will incur significant costs to upgrade or close and replace these existing facilities. We estimate that the potential compliance costs associated with the proposed solid waste management alternative could be as high as a total of $3.9 billion for units across the AEP System. Regulation of these materials as hazardous wastes would significantly increase these costs. We will seek recovery of expenditures for pollution control technologies and associated costs from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, these costs could adversely affect future net income, cash flows and possibly financial condition.

Global Warming

While comprehensive economy-wide regulation of CO_2 emissions might be mandated through new legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing requirements of the CAA. The Federal EPA issued a final endangerment finding for CO_2 emissions from new motor vehicles in December 2009 and final rules for new motor vehicles in May 2010. The Federal EPA determined that CO_2 emissions from stationary sources will be subject to regulation under the CAA beginning in

January 2011 at the earliest and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs. These rules have been challenged in the courts. The Federal EPA is reconsidering whether to include CO_2 emissions in a number of stationary source standards, including standards that apply to new and modified electric utility units.

5

Our fossil fuel-fired generating units are very large sources of CO2 emissions. If substantial CO2 emission reductions are required, there will be significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. To the extent we install additional controls on our generating plants to limit CO2 emissions and receive regulatory approvals to increase our rates, cost recovery could have a positive effect on future earnings. Prudently incurred capital investments made by our subsidiaries in rate-regulated jurisdictions to comply with legal requirements and benefit customers are generally included in rate base for recovery and earn a return on investment. We would expect these principles to apply to investments made to address new environmental requirements. However, requests for rate increases reflecting these costs can affect us adversely because our regulators could limit the amount or timing of increased costs that we would recover through higher rates. In addition, to the extent our costs are relatively higher than our competitors' costs, such as operators of nuclear generation, it could reduce our off-system sales or cause us to lose customers in jurisdictions that permit customers to choose their supplier of generation service.

Several states have adopted programs that directly regulate CO2 emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain states, including Ohio, Michigan, Texas and Virginia, passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. We are taking steps to comply with these requirements.

Certain groups have filed lawsuits alleging that emissions of CO2 are a "public nuisance" and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. We have been named in pending lawsuits, which we are vigorously defending. It is not possible to predict the outcome of these lawsuits or their impact on our operations or financial condition. See "Carbon Dioxide Public Nuisance Claims" and "Alaskan Villages' Claims" sections of Note 4.

Future federal and state legislation or regulations that mandate limits on the emission of CO2 would result in significant increases in capital expenditures and operating costs, which in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force our utility subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. As a result, mandatory limits could have a material adverse impact on our net income, cash flows and financial condition.

For detailed information on global warming and the actions we are taking to address potential impacts, see Part I of the 2009 Form 10-K under the headings entitled "Business – General – Environmental and Other Matters – Global Warming" and "Management's Financial Discussion and Analysis of Results of Operations."

RESULTS OF OPERATIONS

SEGMENTS

Our reportable segments and their related business activities are as follows:

Utility Operations
- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

AEP River Operations
- Commercial barging operations that transport coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

Generation and Marketing
- Wind farms and marketing and risk management activities primarily in ERCOT.

The table below presents our consolidated Income (Loss) Before Extraordinary Loss by segment for the three and nine months ended September 30, 2010 and 2009.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in millions)			
Utility Operations	$ 541	$ 448	$ 1,017	$ 1,121
AEP River Operations	14	10	16	22
Generation and Marketing	-	5	17	33
All Other (a)	2	(17)	(10)	(45)
Income Before Extraordinary Loss	$ 557	$ 446	$ 1,040	$ 1,131

(a) While not considered a business segment, All Other includes:
- Parent’s guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which settle and completely expire in 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

AEP CONSOLIDATED

Third Quarter of 2010 Compared to Third Quarter of 2009

Income Before Extraordinary Loss in 2010 increased $111 million compared to 2009 primarily due to successful rate proceedings in our various jurisdictions and favorable weather throughout our service territory.

Average basic shares outstanding increased to 480 million in 2010 from 477 million in 2009.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009

Income Before Extraordinary Loss in 2010 decreased $91 million compared to 2009 primarily due to $182 million of charges incurred (net of tax) related to the cost reduction initiatives partially offset by successful rate proceedings in our various jurisdictions and favorable weather conditions throughout our service territory.

Average basic shares outstanding increased to 479 million in 2010 from 452 million in 2009 primarily due to the April 2009 issuance of 69 million shares of AEP common stock. Actual shares outstanding were 480 million as of September 30, 2010.

Our results of operations are discussed below by operating segment.

UTILITY OPERATIONS

We believe that a discussion of the results from our Utility Operations segment on a gross margin basis is most appropriate in order to further understand the key drivers of the segment. Gross margin represents utility operating revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances and purchased power.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in millions)			
Revenues	$3,907	$3,389	$10,544	$9,712
Fuel and Purchased Power	1,427	1,145	3,784	3,337
Gross Margin	2,480	2,244	6,760	6,375
Depreciation and Amortization	413	412	1,205	1,173
Other Operating Expenses	1,057	988	3,411	2,975
Operating Income	1,010	844	2,144	2,227
Other Income, Net	39	42	124	97
Interest Expense	238	232	710	679
Income Tax Expense	270	206	541	524
Income Before Extraordinary Loss	$541	$448	$1,017	$1,121

Summary of KWH Energy Sales for Utility Operations
For the Three and Nine Months Ended September 30, 2010 and 2009

	Three Months Ended September 30,		Nine Months Ended September 30,	
Energy/Delivery Summary	2010	2009	2010	2009
	(in millions of KWH)			
Retail:				
Residential	17,817	15,968	48,250	44,730
Commercial	14,032	13,569	38,508	37,773
Industrial	14,460	13,642	42,503	40,563
Miscellaneous	832	798	2,328	2,291
Total Retail (a)	47,141	43,977	131,589	125,357
Wholesale	10,689	8,285	25,846	22,229
Total KWHs	57,830	52,262	157,435	147,586

(a) Includes energy delivered to customers served by AEP's Texas Wires Companies.

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income. In general, degree day changes in our eastern region have a larger effect on net income than changes in our western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Utility Operations
For the Three and Nine Months Ended September 30, 2010 and 2009

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in degree days)			
Eastern Region				
Actual - Heating (a)	1	6	1,976	1,982
Normal - Heating (b)	7	7	1,918	1,969
Actual - Cooling (c)	859	509	1,294	813
Normal - Cooling (b)	691	703	984	993
Western Region				
Actual - Heating (a)	-	-	764	540
Normal - Heating (b)	1	1	596	601
Actual - Cooling (d)	1,471	1,349	2,357	2,309
Normal - Cooling (b)	1,353	1,362	2,168	2,174

(a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.