AMERICAN ELECTRIC POWER CO INC
Form 10-Q
May 03, 2011

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 March 31, 2011
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	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 43215-2373	
	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 April 29, 2011
American Electric Power Company, Inc.	481,790,955 ($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 OF QUARTERLY REPORTS ON FORM 10-Q
March 31, 2011

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.
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.
BOA	Bank of America Corporation.
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.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III LLC, variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
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.
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.

Term	Meaning
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.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
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.
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.

Term	Meaning
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. Many forward-looking statements appear in "Item 7 – Management's Financial Discussion and Analysis" of the 2010 Annual Report, but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document speak only as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. 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.
- 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, captive insurance entity 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 or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.

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 DISCUSSION AND ANALYSIS

EXECUTIVE OVERVIEW

Economic Conditions

Retail margins increased during the first quarter of 2011 due to successful rate proceedings in our various jurisdictions and higher overall industrial usage partially offset by decreased residential usage primarily as a result of less favorable weather. While lower in comparison to the first quarter of 2010, heating degree days were higher than normal throughout our service territories. Our industrial sales increased 7% primarily due to increased production levels by Ormet, a large aluminum manufacturer in Ohio.

Regulatory Activity

Ohio 2009 – 2011 ESPs

In April 2011, the Supreme Court of Ohio issued an opinion addressing the aspects of the PUCO's 2009 decision that were challenged resulting in three reversals, two of which may have a prospective impact. If any rate changes result from the PUCO's remand proceedings, such rate changes would be prospective from the date of the remand order through the remainder of 2011. See "Ohio Electric Security Plan Filings" section of Note 2.

Ohio January 2012 – May 2014 ESP

In January 2011, CSPCo and OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing for generation effective with the first billing cycle of January 2012 through the last billing cycle of May 2014. The SSO presents redesigned generation rates by customer class. Customer class rates vary, but on average, customers will experience base generation increases of 1.4% in 2012 and 2.7% in 2013. Under the new ESP, management estimates CSPCo and OPCo will have base generation increases, excluding riders, of $17 million and $48 million, respectively, for 2012 and $46 million and $60 million, respectively, for 2013. The April 2011 decision by the Supreme Court of Ohio referenced above in connection with the 2009-2011 ESP could impact the outcome of the January 2012 – May 2014 ESP, though the nature and extent of that impact is not presently known. See "Ohio Electric Security Plan Filings" section of Note 2.

Ohio Distribution Base Rate Case

In February 2011, CSPCo and OPCo filed with the PUCO for an annual increase in distribution rates of $34 million and $60 million, respectively. The requested increase is based upon an 11.15% return on common equity to be effective January 2012. In addition to the annual increase, CSPCo and OPCo requested recovery of the projected December 31, 2012 balance of certain distribution regulatory assets of $216 million and $159 million, respectively, to be recovered in a requested distribution asset recovery rider over seven years with additional carrying costs, beginning January 2013.

Virginia Regulatory Activity

In March 2011, APCo filed a generation and distribution base rate request with the Virginia SCC to increase annual base rates by $126 million based upon an 11.65% return on common equity to be effective no later than February 2012. The return on common equity includes a requested 0.5% renewable portfolio standards incentive as allowed by law. APCo proposed to mitigate the requested base rate increase by $51 million by maintaining current depreciation rates until the next biennial filing. If approved, APCo's net base rate increase would be $75 million. See "Virginia Biennial Base Rate Case" section of Note 2.

West Virginia Regulatory Activity

In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates. In March 2011, the WVPSC modified and approved a settlement agreement which increased annual base rates by approximately $51 million based upon a 10% return on common equity. The order also resulted in a pretax write-off of a portion of the

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Mountaineer Carbon Capture and Storage Product Validation Facility in the first quarter of 2011. See “Mountaineer Carbon Capture and Storage Project Product Validation Facility” section below. In addition, the WVPSC allowed APCo to defer and amortize $18 million of previously expensed 2009 incremental storm expenses and allowed APCo and WPCo to defer and amortize $15 million of costs that were previously expensed related to the 2010 cost reduction initiative, each over a period of seven years. See “2010 West Virginia Base Rate Case” section of Note 2.

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW coal generating 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 be $1.3 billion, excluding AFUDC, plus an additional $125 million for transmission, excluding AFUDC. The APSC, LPSC and PUCT approved SWEPCo’s original application to build the Turk Plant. In June 2010, the APSC issued an order which reversed and set aside the previously granted Certificate of Environmental Compatibility and Public Need. Various proceedings are pending that challenge the Turk Plant’s construction and its approved wetlands and air permits. In 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 portions of two transmission lines. A hearing on SWEPCo’s appeal was held in March 2011. Management is unable to predict the timing of the outcome related to this proceeding.

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, including the related transmission facilities, 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. See “Turk Plant” section of Note 2.

Ohio Customer Choice

In our Ohio service territory, various competitive retail electric service (CRES) providers are targeting retail customers by offering alternative generation service. Through March 31, 2011, approximately 7,800 Ohio retail customers (primarily CSPCo customers) have switched to alternative CRES providers. As a result, in comparison to the first three months of 2010, we lost approximately $18 million of generation related gross margin through March 31, 2011. We anticipate recovery of a portion of this lost margin through off-system sales, including PJM capacity revenues, and our newly created CRES provider. Our CRES provider targets retail customers in Ohio, both within and outside of our retail service territory.

Cook Plant

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. 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 “Michigan 2009 and 2010 Power Supply Cost Recovery Reconciliations” section of Note 2 and “Cook Plant Unit 1 Fire and Shutdown” section of Note 3.

As a result of the nuclear plant situation in Japan following an earthquake, we expect the Nuclear Regulatory Commission and possibly Congress to review safety procedures and requirements for nuclear generating facilities. This review could increase procedures and testing requirements and increase future operating costs at the Cook Plant.

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 Supreme Court of Texas. Review is discretionary and the Supreme Court of Texas has not yet determined if it will grant review. See "Texas Restructuring Appeals" section of Note 2.

Mountaineer Carbon Capture and Storage

Product Validation Facility (PVF)

APCo and ALSTOM Power, Inc., 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 and WPCo's May 2010 West Virginia base rate filing, APCo and WPCo requested rate base treatment of the PVF, including recovery of the related asset retirement obligation regulatory asset amortization and accretion. In March 2011, a WVPSC order denied the request for rate base treatment of the PVF largely due to its experimental operation. The base rate order provided that should APCo construct a commercial scale carbon capture and sequestration (CCS) facility, only the West Virginia portion of the PVF costs, based on load sharing among certain AEP operating companies, may be considered used and useful plant in service and included in future rate base. As a result, APCo recorded a pretax write-off of $41 million ($26 million net of tax) in the first quarter of 2011. As of March 31, 2011, APCo has recorded a noncurrent regulatory asset of $19 million related to the PVF. If APCo cannot recover its remaining investment in and accretion expenses related to the PVF, it would reduce future net income and cash flows. See "Mountaineer Carbon Capture and Storage Project" section of Note 2.

Carbon Capture and Sequestration Project with the Department of Energy (DOE)

During 2010, AEPSC, on behalf of APCo, began the project definition stage for the potential construction of a new commercial scale CCS facility under consideration at the Mountaineer Plant. AEPSC, on behalf of APCo, applied for and was selected to receive funding from the DOE for the project. The DOE will fund 50% of allowable costs incurred for the CCS facility up to a maximum of $334 million. A Front-End Engineering and Design (FEED) study, scheduled for completion during the third quarter of 2011, will refine the total cost estimate for the CCS facility. Results from the FEED study will be evaluated by management before any decision is made to seek the necessary regulatory approvals to build the CCS facility. As of March 31, 2011, APCo has incurred $25 million in total costs and has received $7 million of DOE eligible funding resulting in a net $18 million balance included in Construction Work In Progress on the Condensed Consolidated Balance Sheets. Upon the completion of the FEED study and the expected reimbursement of eligible cash expenditures, principally from the DOE, APCo expects a net investment of approximately $13 million. If APCo is unable to recover the costs of the CCS project, it would reduce future net income and cash flows. See "Mountaineer Carbon Capture and Storage Project" section of Note 2.

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" in the 2010 Annual Report. Additionally, see Note 2 – Rate Matters and Note 3 – 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 SO2, NOx, PM and hazardous air pollutants from fossil fuel-fired power plants, new proposals governing the beneficial use and disposal of coal combustion products and proposed clean water rules.

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 CO2 emissions to address concerns about global climate change. See a complete discussion of these matters in the "Environmental Issues" section of "Management's Financial Discussion and Analysis" in the 2010 Annual Report. We will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, the costs of environmental compliance could adversely affect future net income, cash flows and possibly financial condition.

Update to Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. We continue to evaluate the impact of these rules, project scope and technology available to achieve compliance. In the first quarter of 2011, we revised our cost estimates for complying with these rules. We currently estimate that the environmental investment to meet these requirements for our coal-fired generating facilities ranges from approximately $5.1 billion to $11.2 billion between 2012 and 2020. These amounts include investments to replace a portion of approximately 5,500 MWs of older coal generation units.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. The cost estimates will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans or federal implementation plans that impose standards more stringent than the proposed rules, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on our units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors.

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 SO2 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 SO2 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 SO2 emissions reduction program that takes effect in two phases. The first phase becomes effective in 2012 and requires approximately one million tons per year more SO2 emission reductions across the region than would have been required under CAIR. The second phase takes effect in 2014 and reduces SO2 emissions by an additional 800,000 tons per year. The SO2 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 CAIR. The time frames for and stringency 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 not recovered in rates or market prices. The Federal EPA requested comments on a scheme based exclusively on intrastate trading of allowances or a scheme that establishes unit-by-unit emission rates. Either of these options would provide less flexibility and exacerbate the negative impact of the rule. The proposal indicates that the requirements are expected to be finalized in June 2011 and become effective January 1, 2012.

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 by the D.C. Circuit Court of Appeals in 2008. In response, the Federal EPA has been developing a rule addressing a broad range of hazardous air pollutants from coal and oil-fired power plants. The Federal EPA Administrator signed a proposed HAPs rule in March 2011, but the rule has not yet been published in the Federal Register. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metal) and hydrochloric acid (as a surrogate for acid gases) for units burning coal and oil, on a site-wide 30-day rolling average basis. In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. Compliance is required within three years of the effective date of the final rule, which is expected by November 2011 per the Federal EPA's settlement agreement with several environmental groups. A one-year extension may be available if the extension is necessary for the installation of controls. We are developing comments to submit to the agency and collecting additional information regarding the performance of our coal-fired units. Comments will be accepted for 60 days after the rule is published in the Federal Register.

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. We have approximately 5,500 MW of older coal units for which it may be economically inefficient to install scrubbers or other environmental controls.

Regional Haze

In March 2011, the Federal EPA proposed to approve in part and disapprove in part the regional haze state implementation plan (SIP) submitted by the State of Oklahoma through the Department of Environmental Quality. The Federal EPA is proposing to approve all of the NOx control measures in the SIP and disapprove the SO2 control measures for six electric generating units, including two units owned by PSO. The Federal EPA is proposing a federal implementation plan (FIP) that would require these units to install technology capable of reducing SO2 emissions to 0.06 pounds per million British thermal unit within three years of the effective date of the FIP. The proposal is open for public comment.

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 $3.9 billion including AFUDC for units across the AEP System. Regulation of these materials as hazardous wastes would significantly increase these costs.

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Clean Water Act Regulations

In March 2011, the Federal EPA Administrator signed a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against the plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The proposed standards affect all plants withdrawing more than two million gallons of cooling water per day and establish specific intake design and intake velocity standards meant to allow fish to avoid or escape impingement. Compliance with this standard is required within eight years of the effective date of the final rule. The proposed standard for entrainment requires closed cycle cooling or a site-specific evaluation of the available measures for reducing entrainment. Plants withdrawing more than 125 million gallons of cooling water per day must submit a detailed technology study to be reviewed by the state permitting authority. We are evaluating the proposal and engaged in the collection of additional information regarding the feasibility of implementing this proposal at our facilities. Comments on the proposal are due within 90 days after the rule is published in the Federal Register.

Global Warming

While comprehensive economy-wide regulation of CO2 emissions might be mandated through new legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO2 emissions under the existing requirements of the CAA. The Federal EPA issued a final endangerment finding for CO2 emissions from new motor vehicles in December 2009 and final rules for new motor vehicles in May 2010. The Federal EPA determined that CO2 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 CO2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, state implementation plan calls and federal implementation plans. The Federal EPA is reconsidering whether to include CO2 emissions in a number of stationary source standards, including standards that apply to new and modified electric utility units and announced a settlement agreement to issue proposed new source performance standards for utility boilers that would be applicable for both new and existing utility boilers. It is not possible at this time to estimate the costs of compliance with these new standards, but they may be material.

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 and natural gas based 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 CO_2 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 3.

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 2010 Form 10-K under the headings entitled "Business – General – Environmental and Other Matters – Global Warming" and "Management's Financial Discussion and Analysis."

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 and to a lesser extent Ohio in PJM and MISO.

The table below presents our consolidated Net Income (Loss) by segment for the three months ended March 31, 2011 and 2010.

	Three Months Ended March 31,			
	2011		2010	
	(in millions)			
Utility Operations	$	378	$	344
AEP River Operations		7		3
Generation and Marketing		1		10
All Other (a)		(31)		(11)
Net Income	$	355	$	346

(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 expire in the fourth quarter of 2011.
-

Revenue sharing related to the Plaquemine Cogeneration Facility which ends in the fourth quarter of 2011.

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AEP CONSOLIDATED

First Quarter of 2011 Compared to First Quarter of 2010

Net Income increased from $346 million in 2010 to $355 million in 2011 primarily due to the following:

- Ÿ Successful rate proceedings in our various jurisdictions.
- Ÿ The first quarter 2011 deferral of 2010 costs related to storms and cost reduction initiatives as approved in our March 2011 West Virginia base rate settlement.
- Ÿ The unfavorable 2010 tax treatment associated with future reimbursement of Medicare Part D prescription drug benefits.

These increases were partially offset by:

- Ÿ A net loss incurred as a result of the February 2011 settlement of litigation with BOA and Enron.
- Ÿ The write-off of a portion of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied by the WVPSC in March 2011.
- Ÿ The less favorable weather impact across our service territory in comparison to the first quarter of 2010.

Average basic shares outstanding increased to 481 million in 2011 from 478 million in 2010. Actual shares outstanding were 482 million as of March 31, 2011.

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 total revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances and purchased power.

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(in millions)	
Total Revenues	$ 3,524	$ 3,426
Fuel and Purchased Power	1,297	1,247
Gross Margin	2,227	2,179
Depreciation and Amortization	393	398
Other Operating Expenses	1,060	1,040
Operating Income	774	741
Other Income, Net	43	43
Interest Expense	232	235
Income Tax Expense	207	205
Net Income	$ 378	$ 344

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Summary of KWH Energy Sales for Utility Operations

		Three Months Ended March 31,	
		2011	2010
		(in millions of KWH)	
Retail:			
	Residential	16,949	17,774
	Commercial	11,646	11,475
	Industrial	14,329	13,381
	Miscellaneous	723	713
Total Retail (a)		43,647	43,343
Wholesale		9,151	8,137
Total KWHs		52,798	51,480

(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

	Three Months Ended March 31,	
	2011	2010
	(in degree days)	
Eastern Region		
Actual - Heating (a)	1,854	1,900
Normal - Heating (b)	1,739	1,741
Actual - Cooling (c)	3	-
Normal - Cooling (b)	3	3
Western Region		
Actual - Heating (a)	692	759
Normal - Heating (b)	579	574
Actual - Cooling (d)	109	20
Normal - Cooling (b)	58	58

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

(b) Normal Heating/Cooling represents the thirty-year average of degree days.

(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.

(d) Western Region cooling degree days are calculated on a 65 degree temperature base for PSO/SWEPCO and a 70 degree temperature base for TCC/TNC.

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First Quarter of 2011 Compared to First Quarter of 2010

Reconciliation of First Quarter of 2010 to First Quarter of 2011
Net Income from Utility Operations
(in millions)

First Quarter of 2010	$	344	
Changes in Gross Margin:			
Retail Margins		26	
Off-system Sales		12	
Transmission Revenues		8	
Other Revenues		2	
Total Change in Gross Margin		48	
Total Expenses and Other:			
Other Operation and Maintenance		(14	)
Depreciation and Amortization		5	
Taxes Other Than Income Taxes		(6	)
Carrying Costs Income		1	
Allowance for Equity Funds Used During Construction		(4	)
Interest Expense		3	
Equity Earnings of Unconsolidated Subsidiaries		3	
Total Expenses and Other		(12	)
Income Tax Expense		(2	)
First Quarter of 2011	$	378	

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased $26 million primarily due to the following:
  - Successful rate proceedings in our service territories which include:
    - A $35 million rate increase in Ohio.
    - An $18 million rate increase in Kentucky.
    - A $13 million net rate increase for SWEPCo.
    - A $10 million net rate increase for I&M.
    - A $5 million increase in margins from industrial sales partially due to an increase in production at Ormet, a major industrial customer in Ohio.

  These increases were partially offset by:
  - A $23 million decrease in rate related margins for APCo primarily due to the expiration of E&R cost recovery in Virginia and the implementation of higher interim rates in Virginia in January and February 2010.
  - A $20 million decrease in weather-related usage primarily due to 2% and 9% decreases in heating degree days in our eastern and western service territories, respectively.
  -

An $18 million decrease attributable to CSPCo customers switching to alternative competitive retail electric service (CRES) providers.

- Margins from Off-system Sales increased $12 million primarily due to an increase in PJM capacity revenues, partially offset by lower trading and marketing margins.
- Transmission Revenues increased $8 million primarily due to increased revenues in the PJM region.

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Total Expenses and Other and Income Taxes changed between years as follows:

- Other Operation and Maintenance expenses increased $14 million primarily due to:
  - A $41 million increase due to the write-off of a portion of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC in March 2011.
  - A $31 million increase in demand side management, energy efficiency, vegetation management programs and other related expenses. All of these expenses are currently recovered dollar-for-dollar in rate recovery riders/trackers in Gross Margin.
  - A $9 million increase in plant outage and other plant operating and maintenance expenses.

  These increases were partially offset by:
  - A $33 million decrease due to the deferral of 2010 costs related to storms and our cost reduction initiative. These costs were deferred as a result of the approved modified settlement agreement in our West Virginia base rate case in March 2011.
  - A $20 million decrease in administrative and general expenses primarily due to a decrease in fringe benefits.
  - A $13 million gain on the sale of land.
- Depreciation and Amortization expenses decreased $5 million primarily due to the expiration of E&R amortization of deferred carrying costs in Virginia offset by increased depreciation resulting from environmental upgrades at APCo.
- Taxes Other Than Income Taxes increased $6 million primarily due to higher property taxes in Ohio.
- Allowance for Equity Funds Used During Construction decreased $4 million primarily due to SWEPCo's completed construction of the Stall Unit in June 2010.
- Income Tax Expense increased $2 million primarily due to an increase in pretax book income and other book/tax differences which are accounted for on a flow-through basis and the regulatory accounting treatment of state income taxes, partially offset by the 2010 tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits.

AEP RIVER OPERATIONS

First Quarter of 2011 Compared to First Quarter of 2010

Net Income from our AEP River Operations segment increased from $3 million in 2010 to $7 million in 2011 primarily due to strong freight demand driven by increased grain and coal exports partially offset by higher operating expenses.

GENERATION AND MARKETING

First Quarter of 2011 Compared to First Quarter of 2010

Net Income from our Generation and Marketing segment decreased from $10 million in 2010 to $1 million in 2011 primarily due to reduced inception gains from ERCOT marketing activities and lower gross margins at the Oklaunion Plant.

ALL OTHER

First Quarter of 2011 Compared to First Quarter of 2010

Net Income from All Other decreased from a loss of $11 million in 2010 to a loss of $31 million in 2011 primarily due to losses incurred in the February 2011 settlement of litigation with BOA and Enron.

AEP SYSTEM INCOME TAXES

First Quarter of 2011 Compared to First Quarter of 2010

Income Tax Expense increased $71 million in comparison to 2010 primarily due to an increase in pre-tax book income and the unrealized capital loss valuation allowance related to a deferred tax asset associated with the settlement of litigation with BOA and Enron, offset in part by the 2010 tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. Target debt to equity ratios are included in our credit arrangements as covenants that must be met for borrowing to continue.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	March 31, 2011		December 31, 2010	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 17,052	52.8 %	$ 16,811	52.8 %
Short-term Debt	1,433	4.4	1,346	4.2
Total Debt	18,485	57.2	18,157	57.0
Preferred Stock of Subsidiaries	60	0.2	60	0.2
AEP Common Equity	13,779	42.6	13,622	42.8
Total Debt and Equity Capitalization	$ 32,324	100.0 %	$ 31,839	100.0 %

Our ratio of debt-to-total capital increased from 57% in 2010 to 57.2% in 2011.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We believe we have adequate liquidity under our existing credit facilities. At March 31, 2011, we had $3 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a sale of receivables agreement. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At March 31, 2011, our available liquidity was approximately $2.6 billion as illustrated in the table below:

		Amount (in millions)	Maturity
Commercial Paper Backup:			
	Revolving Credit Facility	$ 1,454	April 2012
	Revolving Credit Facility	1,500	June 2013
Total		2,954	
Cash and Cash Equivalents		625	
Total Liquidity Sources		3,579	
Less:	AEP Commercial Paper Outstanding	813	
	Letters of Credit Issued	124	

Net Available Liquidity	$	2,642

We have credit facilities totaling $3 billion to support our commercial paper program. The credit facilities allow us to issue letters of credit in an amount up to $1.35 billion.

In March 2011, we terminated a $478 million credit facility, used for letters of credit to support variable rate debt, that was scheduled to mature in April 2011. In March 2011, we issued bilateral letters of credit to support the remarketing of $357 million of the variable rate debt and reacquired $115 million which are held by a trustee on our behalf.

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during the first quarter of 2011 was $1.2 billion. The weighted-average interest rate for our commercial paper during 2011 was 0.4%.

Securitized Accounts Receivables

In 2010, we renewed our receivables securitization agreement. The agreement provides a commitment of $750 million from bank conduits to purchase receivables. A commitment of $375 million expires in July 2011 and the remaining commitment of $375 million expires in July 2013. We intend to extend or replace the agreement expiring in July 2011 on or before its maturity.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and capitalization is contractually defined in our revolving credit agreements. Debt as defined in the revolving credit agreements excludes junior subordinated debentures, securitization bonds and debt of AEP Credit. At March 31, 2011, this contractually-defined percentage was 53%. Nonperformance under these covenants could result in an event of default under these credit agreements. At March 31, 2011, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements and in a majority of our non-exchange traded commodity contracts which would permit the lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our revolving credit agreements.

The revolving credit facilities do not permit the lenders to refuse a draw on either facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At March 31, 2011, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.46 per share in April 2011. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. AEP’s income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements, charter provisions and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends.

We have the option to defer interest payments on the AEP Junior Subordinated Debentures for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock.

We do not believe restrictions related to our various financing arrangements, charter provisions and regulatory requirements will have any significant impact on Parent’s ability to access cash to meet the payment of dividends on its common stock.

Credit Ratings

We do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade, but our access to the commercial paper market may depend on our credit ratings. In addition, downgrades in our credit ratings by one of the rating agencies could increase our borrowing costs. Counterparty concerns about the credit quality of AEP or its utility subsidiaries could subject us to additional collateral demands under adequate assurance clauses under our derivative and non-derivative energy contracts.

CASH FLOW

Managing our cash flows is a major factor in maintaining our liquidity strength.

	Three Months Ended March 31,	
	2011	2010
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 294	$ 490
Net Cash Flows from Operating Activities	830	2
Net Cash Flows Used for Investing Activities	(613)	(430)
Net Cash Flows from Financing Activities	114	756
Net Increase in Cash and Cash Equivalents	331	328
Cash and Cash Equivalents at End of Period	$ 625	$ 818

Cash from operations and short-term borrowings provides working capital and allows us to meet other short-term cash needs.

Operating Activities

	Three Months Ended March 31,	
	2011	2010
	(in millions)	
Net Income	$ 355	$ 346
Depreciation and Amortization	403	408
Other	72	(752)
Net Cash Flows from Operating Activities	$ 830	$ 2

Net Cash Flows from Operating Activities were $830 million in 2011 consisting primarily of Net Income of $355 million and $403 million of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Significant changes in other items include the favorable impact of decreases in fuel inventory and receivables from customers and the unfavorable impact of reducing accounts payable. Deferred Income Taxes increased primarily due to provisions in the Small Business Jobs Act and the Tax Relief, Unemployment Insurance Reauthorization and Jobs Creation Act, the settlement with BOA and Enron and an increase in tax versus book temporary differences from operations. In February 2011, we paid $425 million to BOA. $211 million of this payment was to settle litigation with BOA and Enron. The remaining $214 million to acquire cushion gas is discussed in Investing Activities below.

Net Cash Flows from Operating Activities were $2 million in 2010 consisting primarily of Net Income of $346 million and $408 million of noncash Depreciation and Amortization offset by $752 million in Other. Other includes a $656 million increase in securitized receivables under the application of new accounting guidance for "Transfers and Servicing" related to our sale of receivables agreement. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Significant changes in other items include an increase in under-recovered fuel primarily in Ohio and West Virginia and the favorable impact of decreases in fuel inventory and tax receivables. Deferred Income Taxes increased primarily due to the American Recovery and Reinvestment Act of 2009 extending bonus depreciation provisions, a change in tax accounting method and an increase in tax versus book temporary differences from operations.

Investing Activities

	Three Months Ended March 31,			
	2011		2010	
	(in millions)			
Construction Expenditures	$	(540)	$	(609)
Acquisitions of Nuclear Fuel		(27)		(38)
Acquisition of Cushion Gas from BOA		(214)		-
Proceeds from Sales of Assets		69		139
Other		99		78
Net Cash Flows Used for Investing Activities	$	(613)	$	(430)

Net Cash Flows Used for Investing Activities were $613 million in 2011 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. We paid $214 million to BOA for cushion gas as part of a litigation settlement.

Net Cash Flows Used for Investing Activities were $430 million in 2010 primarily due to Construction Expenditures for our new generation, environmental and distribution investments. Proceeds from Sales of Assets in 2010 include $135 million for sales of transmission assets in Texas to ETT.

Financing Activities

	Three Months Ended March 31,			
	2011		2010	
	(in millions)			
Issuance of Common Stock, Net	$	31	$	26
Issuance/Retirement of Debt, Net		324		952
Dividends Paid on Common Stock		(223)		(197)
Other		(18)		(25)
Net Cash Flows from Financing Activities	$	114	$	756

Net Cash Flows from Financing Activities in 2011 were $114 million. Our net debt issuances were $324 million. The issuances included $600 million senior unsecured notes, $421 million of pollution control bonds and an increase in short-term borrowing of $87 million offset by retirements of $214 million of senior unsecured and debt notes, $471 million of pollution control bonds and $92 million of securitization bonds. We paid common stock dividends of $223 million. See Note 10 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows from Financing Activities were $756 million in 2010. Our net debt issuances were $952 million. The issuances included $500 million of senior unsecured notes and $158 million of pollution control bonds, a $280 million increase in commercial paper outstanding offset by retirements of $490 million of senior unsecured notes, $86 million of securitization bonds and $54 million of pollution control bonds. Our short-term debt securitized by receivables increased $656 million under the application of new accounting guidance for "Transfers and Servicing" related to our sale of receivables agreement. We paid common stock dividends of $197 million.

In April 2011, APCo retired $250 million of 5.55% Senior Unsecured Notes due in 2011.

In April 2011, I&M retired $30 million of its DCC Fuel debt notes.

OFF-BALANCE SHEET ARRANGEMENTS

In prior periods, under a limited set of circumstances, we entered into off-balance sheet arrangements for various reasons including reducing operational expenses and spreading risk of loss to third parties. Our current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements that we enter in the normal course of business. The following identifies significant off-balance sheet arrangements:

	March 31, 2011	December 31, 2010
	(in millions)	
Rockport Plant Unit 2 Future Minimum Lease Payments	$ 1,774	$ 1,774
Railcars Maximum Potential Loss From Lease Agreement	25	25

For complete information on each of these off-balance sheet arrangements see the "Off-balance Sheet Arrangements" section of "Management's Financial Discussion and Analysis" in the 2010 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of our contractual obligations is included in our 2010 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the "Cash Flow" section above.

MINE SAFETY INFORMATION

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of DHLC, CSPCo, through its ownership of Conesville Coal Preparation Company (CCPC), and OPCo, through its use of the Conner Run fly ash impoundment, are subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. DHLC, CCPC and Conner Run received the following notices of violation and proposed assessments under the Mine Act for the quarter ended March 31, 2011:

	DHLC	CCPC	Conner Run
Number of Citations for Violations of Mandatory Health or Safety Standards under 104 *	-	-	-
Number of Orders Issued under 104(b) *	-	-	-
Number of Citations and Orders for Unwarrantable Failure to Comply with Mandatory Health or Safety Standards under 104(d) *	-	-	-
Number of Flagrant Violations under 110(b)(2) *	-	-	-
Number of Imminent Danger Orders Issued under 107(a) *	-	-	-
Total Dollar Value of Proposed Assessments	$ 2,144	$ -	$ -
Number of Mining-related Fatalities	-	-	-

* References to sections under the Mine Act

DHLC currently has a legal action pending before the Mine Safety and Health Administration (MSHA) challenging four violations issued by MSHA following an employee fatality in March 2009. A second legal action pending before MSHA relates to a citation issued as a result of a dragline boom issue.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the "Critical Accounting Policies and Estimates" section of "Management's Financial Discussion and Analysis" in the 2010 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

ACCOUNTING PRONOUNCEMENTS

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, financial statements, contingencies, financial instruments, emission allowances, fair value measurements, leases, insurance, hedge accounting, consolidation policy and discontinued operations. We also expect to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on our future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and transacts in wholesale electricity, coal and emission allowance trading and marketing contracts. These risks include commodity price risk, interest rate risk and credit risk. In addition, we are exposed to foreign currency exchange risk because occasionally we procure various services and materials used in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Generation and Marketing segment, operating primarily within ERCOT and to a lesser extent Ohio in PJM and MISO, primarily transacts in wholesale energy marketing contracts. This segment is exposed to certain market risks as a marketer of wholesale electricity. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

All Other includes natural gas operations which holds forward natural gas contracts that were not sold with the natural gas pipeline and storage assets. These contracts are financial derivatives, which settle and expire in the fourth quarter of 2011. Our risk objective is to keep these positions generally risk neutral through maturity.

We employ risk management contracts including physical forward purchase and sale contracts and financial forward purchase and sale contracts. We engage in risk management of electricity, coal, natural gas and emission allowances and to a lesser degree other commodities associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the commercial operations group in accordance with the market risk policy approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our President, Chief Financial Officer, Senior Vice President of Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the CORC.

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The following table summarizes the reasons for changes in total mark-to-market (MTM) value as compared to December 31, 2010:

MTM Risk Management Contract Net Assets (Liabilities)
Three Months Ended March 31, 2011

	Utility Operations	Generation and Marketing	All Other	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets at December 31, 2010	$ 91	$ 140	$ 2	$ 233
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(20)	(7)	(1)	(28)
Fair Value of New Contracts at Inception When Entered During the Period (a)	2	-	-	2
Net Option Premiums Received for Unexercised or Unexpired Option Contracts Entered During the Period	-	-	-	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	4	5	-	9
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	13	-	-	13
Total MTM Risk Management Contract Net Assets at March 31, 2011	$ 90	$ 138	$ 1	229
Commodity Cash Flow Hedge Contracts				12
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(3)
Fair Value Hedge Contracts				4
Collateral Deposits				63
Total MTM Derivative Contract Net Assets at March 31, 2011				$ 305

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) Relates to the net gains (losses) of those contracts that are not reflected on the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 7 – Derivatives and Hedging and Note 8 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. We use Moody’s Investors Service, Standard & Poor’s and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of March 31, 2011, our credit exposure net of collateral to sub investment grade counterparties was approximately 7.93%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of March 31, 2011, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
		(in millions, except number of counterparties)			
Investment Grade	$ 551	$ 9	$ 542	1	$ 129
Split Rating	2	-	2	1	2
Noninvestment Grade	7	1	6	3	6
No External Ratings:					
Internal Investment Grade	185	2	183	4	118
Internal Noninvestment Grade	70	13	57	1	31
Total as of March 31, 2011	$ 815	$ 25	$ 790	10	$ 286
Total as of December 31, 2010	$ 946	$ 33	$ 913	7	$ 347

Value at Risk (VaR) Associated with Risk Management Contracts

We use a risk measurement model, which calculates VaR, to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of March 31, 2011, a near term typical change in commodity prices is not expected to have a material effect on our net income, cash flows or financial condition.

The following table shows the end, high, average and low market risk as measured by VaR for the trading portfolio for the periods indicated:

VaR Model

Three Months Ended March 31, 2011				Twelve Months Ended December 31, 2010			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ -	$ 1	$ -	$ -	$ -	$ 2	$ 1	$ -

We back-test our VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

As our VaR calculation captures recent price movements, we also perform regular stress testing of the portfolio to understand our exposure to extreme price movements. We employ a historical-based method whereby the current portfolio is subjected to actual, observed price movements from the last four years in order to ascertain which historical price movements translated into the largest potential MTM loss. We then research the underlying positions, price movements and market events that created the most significant exposure and report the findings to the Risk Executive Committee or the CORC as appropriate.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which our interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of March 31, 2011 and December 31, 2010, the estimated EaR on our debt portfolio for the following twelve months was $3 million and $5 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2011 and 2010
(in millions, except per-share and share amounts)
(Unaudited)

	2011	2010
REVENUES		
Utility Operations	$3,497	$3,406
Other Revenues	233	163
TOTAL REVENUES	3,730	3,569
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	1,056	1,014
Purchased Electricity for Resale	275	238
Other Operation	686	673
Maintenance	265	271
Depreciation and Amortization	403	408
Taxes Other Than Income Taxes	213	207
TOTAL EXPENSES	2,898	2,811
OPERATING INCOME	832	758
Other Income (Expense):		
Interest and Investment Income	2	3
Carrying Costs Income	15	14
Allowance for Equity Funds Used During Construction	20	24
Interest Expense	(242)	(250)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	627	549
Income Tax Expense	278	207
Equity Earnings of Unconsolidated Subsidiaries	6	4
NET INCOME	355	346
Less: Net Income Attributable to Noncontrolling Interests	1	1
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	354	345
Less: Preferred Stock Dividend Requirements of Subsidiaries	1	1
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$353	$344
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	481,144,270	478,429,535
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.73	$0.72

WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	481,365,806	478,844,632
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.73	$0.72
CASH DIVIDENDS DECLARED PER SHARE	$0.46	$0.41

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2011 and 2010
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock				Accumulated Other		
	Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2009	498	$ 3,239	$ 5,824	$ 4,451	$ (374)	$ -	$ 13,140
Issuance of Common Stock	1	5	21				26
Common Stock Dividends				(196)		(1)	(197)
Preferred Stock Dividend Requirements of Subsidiaries				(1)			(1)
Other Changes in Equity			2	(2)			-
SUBTOTAL – EQUITY							12,968
COMPREHENSIVE INCOME							
Other Comprehensive Income, Net of Taxes:							
Cash Flow Hedges, Net of Tax of $2					4		4
Securities Available for Sale, Net of Tax of $-					1		1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $3					5		5
NET INCOME				345		1	346
TOTAL COMPREHENSIVE INCOME							356
TOTAL EQUITY – MARCH 31, 2010	499	$ 3,244	$ 5,847	$ 4,597	$ (364)	$ -	$ 13,324
TOTAL EQUITY – DECEMBER 31, 2010	501	$ 3,257	$ 5,904	$ 4,842	$ (381)	$ -	$ 13,622
Issuance of Common Stock	1	6	25				31

Common Stock Dividends				(222)		(1)	(223)
Preferred Stock Dividend Requirements of Subsidiaries				(1)			(1)
Other Changes in Equity			(13)				(13)
SUBTOTAL – EQUITY							13,416
COMPREHENSIVE INCOME							
Other Comprehensive Income, Net of Taxes:							
Cash Flow Hedges, Net of Tax of $1					1		1
Securities Available for Sale, Net of Tax of $-					1		1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $3					6		6
NET INCOME				354		1	355
TOTAL COMPREHENSIVE INCOME							363
TOTAL EQUITY – MARCH 31, 2011	502	$ 3,263	$ 5,916	$ 4,973	$ (373)	$ -	$ 13,779

See Condensed Notes to Condensed Consolidated Financial Statements.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2011 and December 31, 2010
(in millions)
(Unaudited)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$625	$294
Other Temporary Investments		
(March 31, 2011 and December 31, 2010 amounts include $212 and $287, respectively, related to Transition Funding and EIS)	296	416
Accounts Receivable:		
Customers	627	683
Accrued Unbilled Revenues	138	195
Pledged Accounts Receivable - AEP Credit	914	949
Miscellaneous	106	137
Allowance for Uncollectible Accounts	(36)	(41)
Total Accounts Receivable	1,749	1,923
Fuel	714	837
Materials and Supplies	614	611
Risk Management Assets	193	232
Accrued Tax Benefits	301	389
Regulatory Asset for Under-Recovered Fuel Costs	70	81
Margin Deposits	70	88
Prepayments and Other Current Assets	157	145
TOTAL CURRENT ASSETS	4,789	5,016
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	24,766	24,352
Transmission	8,677	8,576
Distribution	14,338	14,208
Other Property, Plant and Equipment (including nuclear fuel and coal mining)	3,835	3,846
Construction Work in Progress	2,480	2,758
Total Property, Plant and Equipment	54,096	53,740
Accumulated Depreciation and Amortization	18,330	18,066
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	35,766	35,674
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,957	4,943
Securitized Transition Assets	1,707	1,742
Spent Nuclear Fuel and Decommissioning Trusts	1,559	1,515
Goodwill	76	76
Long-term Risk Management Assets	359	410
Deferred Charges and Other Noncurrent Assets	1,347	1,079
TOTAL OTHER NONCURRENT ASSETS	10,005	9,765

TOTAL ASSETS	$50,560	$50,455

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
March 31, 2011 and December 31, 2010
(dollars in millions)
(Unaudited)

	2011	2010
CURRENT LIABILITIES		
Accounts Payable	$ 884	$ 1,061
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	620	690
Other Short-term Debt	813	656
Total Short-term Debt	1,433	1,346
Long-term Debt Due Within One Year	1,421	1,309
Risk Management Liabilities	109	129
Customer Deposits	275	