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 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 through the issuance of final federal rules, state implementation plan calls and federal implementation plans. 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 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 CO_2 emissions. If substantial CO_2 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 CO_2 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 CO_2 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:

- Successful rate proceedings in our various jurisdictions.
- 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.
- The unfavorable 2010 tax treatment associated with future reimbursement of Medicare Part D prescription drug benefits.

These increases were partially offset by:

- A net loss incurred as a result of the February 2011 settlement of litigation with BOA and Enron.
- The write-off of a portion of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied by the WVPSC in March 2011.
- 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	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		Three Months Ended March 31, 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		Three Months Ended March 31, 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						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other 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.

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	273
Accrued Taxes	669	702
Accrued Interest	248	281
Regulatory Liability for Over-Recovered Fuel Costs	20	17
Deferred Gain and Accrued Litigation Costs	-	448
Other Current Liabilities	930	952
TOTAL CURRENT LIABILITIES	5,989	6,518
NONCURRENT LIABILITIES		
Long-term Debt		
(March 31, 2011 and December 31, 2010 amounts include $1,733 and $1,857, respectively, related to Transition Funding, DCC Fuel and Sabine)	15,631	15,502
Long-term Risk Management Liabilities	138	141
Deferred Income Taxes	7,490	7,359
Regulatory Liabilities and Deferred Investment Tax Credits	3,204	3,171
Asset Retirement Obligations	1,413	1,394
Employee Benefits and Pension Obligations	1,863	1,893
Deferred Credits and Other Noncurrent Liabilities	993	795
TOTAL NONCURRENT LIABILITIES	30,732	30,255
TOTAL LIABILITIES	36,721	36,773
Cumulative Preferred Stock Not Subject to Mandatory Redemption	60	60
Rate Matters (Note 2)		
Commitments and Contingencies (Note 3)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2011	2010
Shares Authorized	600,000,000	600,000,000
Shares Issued	502,009,606	501,114,881

(20,307,725 shares were held in treasury at March 31, 2011 and December 31, 2010)	3,263	3,257
Paid-in Capital	5,916	5,904
Retained Earnings	4,973	4,842
Accumulated Other Comprehensive Income (Loss)	(373)	(381)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	13,779	13,622
TOTAL EQUITY	13,779	13,622
TOTAL LIABILITIES AND EQUITY	$50,560	$50,455

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2011 and 2010
(in millions)
(Unaudited)

	2011	2010
OPERATING ACTIVITIES		
Net Income	$355	$346
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	403	408
Deferred Income Taxes	330	121
Gain on Settlement with BOA and Enron	(51)	-
Settlement of Litigation with BOA and Enron	(211)	-
Carrying Costs Income	(15)	(14)
Allowance for Equity Funds Used During Construction	(20)	(24)
Mark-to-Market of Risk Management Contracts	42	(69)
Amortization of Nuclear Fuel	34	30
Property Taxes	(52)	(53)
Fuel Over/Under-Recovery, Net	(27)	(97)
Change in Other Noncurrent Assets	(3)	(28)
Change in Other Noncurrent Liabilities	77	37
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	181	(617)
Fuel, Materials and Supplies	121	83
Margin Deposits	18	(20)
Accounts Payable	(126)	(83)
Customer Deposits	2	5
Accrued Taxes, Net	(96)	80
Accrued Interest	(33)	(34)
Other Current Assets	(16)	(14)
Other Current Liabilities	(83)	(55)
Net Cash Flows from Operating Activities	830	2
INVESTING ACTIVITIES		
Construction Expenditures	(540)	(609)
Change in Other Temporary Investments, Net	73	82
Purchases of Investment Securities	(454)	(445)
Sales of Investment Securities	484	473
Acquisitions of Nuclear Fuel	(27)	(38)
Acquisition of Cushion Gas from BOA	(214)	-
Proceeds from Sales of Assets	69	139
Other Investing Activities	(4)	(32)
Net Cash Flows Used for Investing Activities	(613)	(430)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	31	26
Issuance of Long-term Debt	1,014	652

Commercial Paper and Credit Facility Borrowings	318	24
Change in Short-term Debt, Net	244	931
Retirement of Long-term Debt	(777)	(638)
Commercial Paper and Credit Facility Repayments	(475)	(17)
Principal Payments for Capital Lease Obligations	(17)	(24)
Dividends Paid on Common Stock	(223)	(197)
Dividends Paid on Cumulative Preferred Stock	(1)	(1)
Net Cash Flows from Financing Activities	114	756
Net Increase in Cash and Cash Equivalents	331	328
Cash and Cash Equivalents at Beginning of Period	294	490
Cash and Cash Equivalents at End of Period	$625	$818
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$250	$271
Net Cash Paid (Received) for Income Taxes	2	(2)
Noncash Acquisitions Under Capital Leases	24	148
Government Grants Included in Accounts Receivable at March 31,	3	-
Construction Expenditures Included in Current Liabilities at March 31,	220	216
Acquisition of Nuclear Fuel Included in Current Liabilities at March 31,	-	3

See Condensed Notes to Condensed Consolidated Financial Statements.

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

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed consolidated financial statements and footnotes were prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed consolidated interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of our net income, financial position and cash flows for the interim periods. Net income for the three months ended March 31, 2011 is not necessarily indicative of results that may be expected for the year ending December 31, 2011. The condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2010 consolidated financial statements and notes thereto, which are included in our Form 10-K as filed with the SEC on February 25, 2011.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE's variability we absorb, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE and other factors. We believe that significant assumptions and judgments were applied consistently.

We are the primary beneficiary of Sabine, DCC Fuel, AEP Credit, Transition Funding and a protected cell of EIS. In addition, we have not provided material financial or other support to Sabine, DCC Fuel, Transition Funding, our protected cell of EIS and AEP Credit that was not previously contractually required. We hold a significant variable interest in DHLC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the three months ended March 31, 2011 and 2010 were $33 million and $43 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on our Condensed Consolidated Balance Sheets.

Our subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on our control and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate its assets and liabilities. Our insurance premium expense to the protected cell for the three months ended March 31, 2011 and 2010 was $30 million and $18 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on our Condensed Consolidated Balance Sheets. The amount reported as equity is the protected cell's policy holders' surplus.

I&M has a nuclear fuel lease agreement with DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III LLC (collectively DCC Fuel). DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III LLC are separate legal entities from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the DCC Fuel LLC and DCC Fuel II LLC leases are made semi-annually and began in April 2010 and October 2010, respectively. Payments on the DCC Fuel III LLC lease are made monthly and began in January 2011. Payments on the DCC Fuel III LLC lease for the three months ended March 31, 2011 were $6 million. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the 48, 54 and 54 month lease term, respectively. Based on our control of DCC Fuel, management has concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on our Condensed Consolidated Balance Sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on our control of AEP Credit, management has concluded that we are the primary beneficiary and are required to consolidate its assets and liabilities. See the tables below for the classification of AEP Credit's assets and liabilities on our Condensed Consolidated Balance Sheets. See "Securitized Accounts Receivables – AEP Credit" section of Note 10.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas restructuring law. Management has concluded that TCC is the primary beneficiary of Transition Funding because TCC has the power to direct the most significant activities of the VIE and TCC's equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled $1.8 billion and $1.8 billion at March 31, 2011 and December 31, 2010, respectively, and are included in current and long-term debt on the Condensed Consolidated Balance Sheets. Transition Funding has securitized transition assets of $1.7 billion and $1.7 billion at March 31, 2011 and December 31, 2010, respectively, which are presented separately on the face of the Condensed Consolidated Balance Sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
March 31, 2011
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	Transition Funding
ASSETS					
Current Assets	$ 40	$ 107	$ 146	$ 902	$ 130
Net Property, Plant and Equipment	142	151	-	-	-
Other Noncurrent Assets	37	93	8	-	1,711
Total Assets	$ 219	$ 351	$ 154	$ 902	$ 1,841
LIABILITIES AND EQUITY					
Current Liabilities	$ 44	$ 81	$ 62	$ 824	$ 202
Noncurrent Liabilities	175	270	74	1	1,625
Equity	-	-	18	77	14
Total Liabilities and Equity	$ 219	$ 351	$ 154	$ 902	$ 1,841

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2010
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	Transition Funding
ASSETS					
Current Assets	$ 50	$ 92	$ 131	$ 924	$ 214
Net Property, Plant and Equipment	139	173	-	-	-
Other Noncurrent Assets	34	112	1	10	1,746
Total Assets	$ 223	$ 377	$ 132	$ 934	$ 1,960
LIABILITIES AND EQUITY					
Current Liabilities	$ 33	$ 79	$ 33	$ 886	$ 221
Noncurrent Liabilities	190	298	85	1	1,725
Equity	-	-	14	47	14
	$ 223	$ 377	$ 132	$ 934	$ 1,960

Total Liabilities and Equity

DHLC is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and its voting rights equally. Each entity guarantees a 50% share of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the three months ended March 31, 2011 and 2010 were $13 million and $13 million, respectively. We are not required to consolidate DHLC as we are not the primary beneficiary, although we hold a significant variable interest in DHLC. Our equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on our Condensed Consolidated Balance Sheets.

Our investment in DHLC was:

	March 31, 2011		December 31, 2010	
	As Reported on the Consolidated Balance Sheet	Maximum Exposure	As Reported on the Consolidated Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 8	$ 8	$ 6	$ 6
Retained Earnings	1	1	2	2
SWEPCo's Guarantee of Debt	-	46	-	48
Total Investment in DHLC	$ 9	$ 55	$ 8	$ 56

We and Allegheny Energy Inc. (AYE) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). In February 2011, FirstEnergy Corp. (FirstEnergy) completed its merger with AYE, under which AYE became a wholly-owned subsidiary of FirstEnergy. Also, in February 2011, PJM directed that work on the PATH project be suspended. PATH is a series limited liability company and was created to construct a high-voltage transmission line project in the PJM region. PATH consisted of the "Ohio Series," the "West Virginia Series (PATH-WV)," both owned equally by AYE and AEP, and the "Allegheny Series" which is 100% owned by AYE. The "Ohio Series" was dissolved in February 2011. Provisions exist within the PATH-WV agreement that make it a VIE. The "Ohio Series" did not include the same provisions that make PATH-WV a VIE. The "Allegheny Series" is not considered a VIE. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on our Condensed Consolidated Balance Sheets. We and AYE share the returns and losses equally in PATH-WV. Our subsidiaries and AYE's subsidiaries provide services to the PATH companies through service agreements. At the current time, PATH-WV has no debt outstanding. However, when debt is issued, the debt to equity ratio in each series should be consistent with other regulated utilities. The entities recover costs through regulated rates.

Given the structure of the entity, we may be required to provide future financial support to PATH-WV in the form of a capital call. This would be considered an increase to our investment in the entity. Our maximum exposure to loss is to the extent of our investment. The likelihood of such a loss is remote since the FERC approved PATH-WV's request for regulatory recovery of cost and a return on the equity invested.

Our investment in PATH-WV was:

	March 31, 2011		December 31, 2010	
	As Reported on the Consolidated Balance Sheet	Maximum Exposure	As Reported on the Consolidated Balance Sheet	Maximum Exposure
		(in millions)		
Capital Contribution from AEP	$ 19	$ 19	$ 18	$ 18
Retained Earnings	7	7	6	6
Total Investment in PATH-WV	$ 26	$ 26	$ 24	$ 24

Earnings Per Share (EPS)

Basic earnings per common share is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents our basic and diluted EPS calculations included on our Condensed Consolidated Statements of Income:

	Three Months Ended March 31, 2011		2010	
	(in millions, except per share data)			
		$/share		$/share
Earnings Applicable to AEP Common Shareholders	$ 353		$ 344	
Weighted Average Number of Basic Shares Outstanding	481.1	$ 0.73	478.4	$ 0.72
Weighted Average Dilutive Effect of:				
Performance Share Units	-	-	0.3	-
Stock Options	0.1	-	-	-
Restricted Stock Units	0.2	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	481.4	$ 0.73	478.8	$ 0.72

The assumed conversion of stock options does not affect net earnings for purposes of calculating diluted earnings per share.

Options to purchase 136,250 and 437,866 shares of common stock were outstanding at March 31, 2011 and 2010, respectively, but were not included in the computation of diluted earnings per share attributable to AEP common shareholders. Since the options' exercise prices were greater than the average market price of the common shares, the effect would have been antidilutive.

Supplementary Information

Related Party Transactions	Three Months Ended March 31, 2011		2010	
	(in millions)			
AEP Consolidated Revenues – Utility Operations:				
Ohio Valley Electric Corporation (43.47% owned)	$ -		$ (9)	(a)
AEP Consolidated Revenues – Other Revenues:				
Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)	7		8	
AEP Consolidated Expenses – Purchased Electricity for Resale:				
Ohio Valley Electric Corporation (43.47% Owned)	86	(b)	77	(c)

(a) The AEP Power Pool purchased power from OVEC to serve off-system sales in an agreement that began in January 2010 and ended in June 2010.
(b) In March 2011, the AEP Power Pool began purchasing power from OVEC to serve retail sales through June 2011. The total amount reported includes $8 million related to this agreement.
(c) The AEP Power Pool purchased power from OVEC to serve retail sales in an agreement that began in January 2010 and ended in June 2010. The total amount reported includes $6 million related to this agreement.

Adjustments to Securitized Accounts Receivable Disclosure

In the "Securitized Accounts Receivable – AEP Credit" section of Note 10, we expanded our disclosure to reflect certain prior period amounts related to our securitization agreement that were not previously disclosed. These omissions were not material to our financial statements and had no impact on our previously reported net income, changes in shareholders’ equity, financial position or cash flows.

2. RATE MATTERS

As discussed in the 2010 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2010 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2011 and updates the 2010 Annual Report.

Regulatory Assets Not Yet Being Recovered

	March 31, 2011	December 31, 2010
	(in millions)	
Noncurrent Regulatory Assets (excluding fuel)		
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:		
Regulatory Assets Currently Earning a Return		
Customer Choice Deferrals - CSPCo, OPCo (a)	$ 59	$ 59
Line Extension Carrying Costs - CSPCo, OPCo (a)	58	55
Storm Related Costs - CSPCo, OPCo (a)	31	30
Storm Related Costs - TCC	25	25
Acquisition of Monongahela Power - CSPCo (a)	8	8
Other Regulatory Assets Not Yet Being Recovered	7	7
Regulatory Assets Currently Not Earning a Return		
Environmental Rate Adjustment Clause - APCo	56	56
Storm Related Costs - APCo, KGPCo, PSO, SWEPCo	45	45
Deferred Wind Power Costs - APCo	34	29
Mountaineer Carbon Capture and Storage Product Validation Facility - APCo (b)	19	60
Special Rate Mechanism for Century Aluminum - APCo	13	13
Acquisition of Monongahela Power - CSPCo (a)	4	4
Other Regulatory Assets Not Yet Being Recovered	5	4
Total Regulatory Assets Not Yet Being Recovered	$ 364	$ 395

(a) Requested to be recovered in a distribution asset recovery rider. See the "Ohio Distribution Base Rate Case" section below.

(b) APCo wrote off a portion of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC in March 2011. See

"Mountaineer Carbon Capture and Storage Project Product Validation Facility" section below.

CSPCo and OPCo Rate Matters

Ohio Electric Security Plan Filings

2009 – 2011 ESPs

The PUCO issued an order in March 2009 that modified and approved CSPCo's and OPCo's ESPs which established rates at the start of the April 2009 billing cycle. The ESPs are in effect through 2011. The order also limited 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. Some rate components and increases are exempt from these limitations. CSPCo and OPCo collected the 2009 annualized revenue increase over the last nine months of 2009.

The order provided a FAC for the three-year period of the ESP. The FAC was phased in to avoid having the resultant rate increases exceed the ordered annual caps described above. The FAC is subject to quarterly true-ups, annual accounting audits and prudency reviews. See the "2009 Fuel Adjustment Clause Audit" section below. The order allowed CSPCo and OPCo to defer any unrecovered FAC costs resulting from the annual caps and accrued associated carrying charges at CSPCo's and OPCo's weighted average cost of capital. Any deferred FAC regulatory asset balance at the end of the three-year ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. That recovery will include deferrals associated with the Ormet interim arrangement and is subject to the PUCO's ultimate decision regarding the Ormet interim arrangement deferrals plus related carrying charges. See the "Ormet Interim Arrangement" section below. The FAC deferral as of March 31, 2011 was $19 million and $498 million for CSPCo and OPCo, respectively, excluding $77 thousand and $37 million, respectively, of unrecognized equity carrying costs.

Discussed below are the significant outstanding uncertainties related to the ESP order:

The Ohio Consumers' Counsel filed a notice of appeal with the Supreme Court of Ohio raising several issues including alleged retroactive ratemaking, recovery of carrying charges on certain environmental investments, Provider of Last Resort (POLR) charges and the decision not to offset rates by off-system sales margins. In November 2009, the Industrial Energy Users-Ohio (IEU) filed a notice of appeal with the Supreme Court of Ohio challenging components of the ESP order including the POLR charge, the distribution riders for gridSMART® and enhanced reliability, the PUCO's conclusion and supporting evaluation that the modified ESPs are more favorable than the expected results of a market rate offer, the unbundling of the fuel and non-fuel generation rate components, the scope and design of the fuel adjustment clause and the approval of the plan after the 150-day statutory deadline.

In April 2011, the Supreme Court of Ohio (the Court) issued an opinion addressing the aspects of the PUCO's 2009 decision that were challenged which resulted in three reversals, only two of which may have a prospective impact. First, the Court concluded that the PUCO's decision amounted to retroactive ratemaking. Since the pertinent revenues were collected in 2009 and the OCC did not successfully pursue the remedy of obtaining a stay of the order prior to the revenues being collected, there is no remand to the PUCO or refund to customers for this error. Second, the Court held that the PUCO's conclusion that the POLR charge is cost-based conflicted with the evidence and remanded the issue to the PUCO for further consideration. Third, the Court reversed the Order's legal basis for a carrying charge associated with certain environmental investments and remanded that issue to the PUCO to determine whether an alternative legal basis supports the charge. 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 remaining months of 2011.

In April 2010, the IEU filed an additional notice of appeal with the Supreme Court of Ohio challenging alleged retroactive ratemaking, CSPCo's and OPCo's abilities to collect through the FAC amounts deferred under the Ormet interim arrangement and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

In January 2011, the PUCO issued an order on CSPCo's and OPCo's 2009 SEET filings and determined that OPCo's 2009 earnings were not significantly excessive but determined relevant CSPCo earnings exceeded the PUCO determined threshold by 2.13%. As a result, the PUCO ordered CSPCo to refund $43 million ($28 million net of tax) of its earnings to customers, which was recorded as a revenue provision on CSPCo's December 2010 books. The PUCO ordered that the significantly excessive earnings be applied first to CSPCo's FAC deferral, including unrecognized equity carrying costs, as of the date of the order, with any remaining balance to be credited to CSPCo's customers on a per kilowatt basis. That credit began with the first billing cycle in February 2011 and will continue through December 2011. Several parties, including CSPCo and OPCo, filed requests for rehearing with the PUCO, which were denied in March 2011. CSPCo and OPCo are required to file their 2010 SEET filings with the PUCO in 2011. Based upon the approach in the PUCO 2009 order, management does not currently believe that CSPCo or OPCo will have any significantly excessive earnings in 2010.

Management is unable to predict the outcome of the various ongoing ESP proceedings and litigation discussed above. If these proceedings, including future SEET filings, result in adverse rulings, it could reduce future net income and cash flows and impact financial condition.

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 on a combined company basis for generation. The rates would be effective with the first billing cycle of January 2012 through the last billing cycle of May 2014. The ESP also includes alternative energy resource requirements and addresses provisions regarding distribution service, energy efficiency requirements, economic development, job retention in Ohio and other matters. 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. 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.

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, including approximately $102 million and $84 million, respectively, of unrecognized equity carrying costs. These assets would be recovered in a requested distribution asset recovery rider over seven years with additional carrying costs, beginning January 2013. The actual balance of these distribution regulatory assets as of March 31, 2011 was $98 million and $63 million for CSPCo and OPCo, respectively, excluding $57 million and $42 million of unrecognized equity carrying costs, respectively. If CSPCo and OPCo are not ultimately permitted to fully recover their deferrals, it would reduce future net income and cash flows and impact financial condition.

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. In January 2011, CSPCo and OPCo filed an application with the FERC requesting approval for an internal corporate reorganization under which CSPCo will merge into OPCo. CSPCo and OPCo requested the reorganization transaction be effective in October 2011. Decisions are pending from the PUCO and the FERC. Management is unable to predict the outcome of this proceeding.

Requested Sporn Unit 5 Shutdown and Proposed Distribution Rider

In October 2010, OPCo filed an application with the PUCO for the approval of a December 2010 closure of Sporn Unit 5 and the simultaneous establishment of a new non-bypassable distribution rider, outside the rate caps established in the 2009 – 2011 ESP proceeding. The proposed rider would recover the net book value of the unit as well as related materials and supplies as of December 2010, which was estimated to be $59 million, as well as future closure costs incurred after December 2010. OPCo also requested authority to record the future closure costs as a regulatory asset or regulatory liability with a weighted average cost of capital carrying charge to be included in the proposed non-bypassable distribution rider after the costs are incurred. Pending PUCO approval, Sporn Unit 5 continues to operate. In April 2011, intervenors filed comments opposing OPCo’s application. A PUCO decision is pending as to whether a hearing will be ordered. Management is unable to predict the outcome of this proceeding.

2009 Fuel Adjustment Clause Audit

As required under the ESP orders, the PUCO selected an outside consultant to conduct the audit of the FAC for the period of January 2009 through December 2009. In May 2010, the outside consultant provided its confidential audit report to the PUCO. The audit report included a recommendation that the PUCO should review whether any proceeds from a 2008 coal contract settlement agreement which totaled $72 million should reduce OPCo’s FAC under-recovery balance. Of the total proceeds, approximately $58 million was recognized as a reduction to fuel expense prior to 2009 and $14 million was recognized as a reduction to fuel expense in 2009 and 2010. Hearings were held in August

2010. Management is unable to predict the outcome of this proceeding. If the PUCO orders any portion of the $58 million previously recognized gains or any future adjustments be used to reduce the FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

CSPCo, OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filings and the FAC aspect of the ESP order was upheld by the Supreme Court's April 2011 decision referenced in the "2009-2011 ESPs" section above. The approval of the FAC as part of the ESP, together with the PUCO approval of the interim arrangement, provided the basis to record regulatory assets for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, CSPCo and OPCo had $30 million and $34 million, respectively, of deferred FAC related to the interim arrangement including recognized carrying charges. These amounts exclude $1 million and $1 million, respectively, of unrecognized equity carrying costs. In November 2009, CSPCo and OPCo requested that the PUCO approve recovery of the deferrals under the interim agreement plus a weighted average cost of capital carrying charge. The interim arrangement deferrals are included in CSPCo's and OPCo's FAC phase-in deferral balances. See "Ohio Electric Security Plan Filings" section above. In the ESP proceeding, intervenors requested that CSPCo and OPCo be required to refund the Ormet-related regulatory assets and requested that the PUCO prevent CSPCo and OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request in the 2009-2011 ESP proceeding. The intervenors raised the issue again in response to CSPCo's and OPCo's November 2009 filing to approve recovery of the deferrals under the interim agreement and this issue remains pending before the PUCO. If CSPCo and OPCo are not ultimately permitted to fully recover their requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Economic Development Rider

In April 2010, the IEU filed a notice of appeal of the 2009 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The EDR collects from ratepayers the difference between the standard tariff and lower contract billings to qualifying industrial customers, subject to PUCO approval. The IEU raised several issues including claims that (a) the PUCO lost jurisdiction over CSPCo's and OPCo's ESP proceedings and related proceedings when the PUCO failed to issue ESP orders within the 150-day statutory deadline, (b) the EDR should not be exempt from the ESP annual rate limitations and (c) CSPCo and OPCo should not be allowed to apply a weighted average long-term debt carrying cost on deferred EDR regulatory assets. A decision from the Supreme Court of Ohio is pending.

In June 2010, the IEU filed a notice of appeal of the 2010 PUCO-approved EDR with the Supreme Court of Ohio raising the same issues as noted in the 2009 EDR appeal. In addition, the IEU added a claim that CSPCo and OPCo should not be able to take the benefits of the higher ESP rates while simultaneously challenging the ESP orders. A decision from the Supreme Court of Ohio is pending.

As of March 31, 2011, CSPCo and OPCo have incurred EDR costs of $48 million and $40 million, respectively, including carrying costs. Of these costs, CSPCo and OPCo have collected $43 million and $33 million, respectively, through the EDR, which CSPCo and OPCo began collecting in January 2010. The remaining $5 million and $7 million for CSPCo and OPCo, respectively, are recorded as deferred EDR regulatory assets. If CSPCo and OPCo are not ultimately permitted to recover their deferrals or are required to refund EDR revenue collected, it would reduce future net income and cash flows and impact financial condition.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. Through March 31, 2011, CSPCo and OPCo have each collected $12 million in pre-construction costs authorized in a June 2006 PUCO order and each incurred $11 million in pre-construction costs. As a result, CSPCo and OPCo each established a net regulatory liability of approximately $1 million. The order also provided that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant before June 2011, any pre-construction costs that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. Intervenors have filed motions with the PUCO requesting all pre-construction costs be refunded to Ohio ratepayers with interest.

CSPCo and OPCo will not start construction of an IGCC plant until existing statutory barriers are addressed and sufficient assurance of regulatory cost recovery exists. Management cannot predict the outcome of any cost recovery litigation concerning the Ohio IGCC plant or what effect, if any, such litigation would have on future net income and cash flows. However, if CSPCo and OPCo were required to refund all or some of the pre-construction costs collected and the costs incurred were not recoverable in another jurisdiction, it would reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in service in 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.7 billion, excluding AFUDC, plus an additional $125 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost $1.3 billion, excluding AFUDC, plus the additional $125 million for transmission, excluding AFUDC. As of March 31, 2011, excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $1.1 billion of expenditures (including AFUDC and capitalized interest of $156 million and related transmission costs of $73 million). As of March 31, 2011, the joint owners and SWEPCo have contractual construction commitments of approximately $260 million (including related transmission costs of $3 million). SWEPCo's share of the contractual construction commitments is $191 million. If the plant is cancelled, the joint owners and SWEPCo would incur contractual construction cancellation fees, based on construction status as of March 31, 2011, of approximately $101 million (including related transmission cancellation fees of $1 million). SWEPCo's share of the contractual construction cancellation fees would be approximately $74 million.

Discussed below are the significant outstanding uncertainties related to the Turk Plant:

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the 88 MW SWEPCo Arkansas jurisdictional share of the Turk Plant. Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. The Arkansas Supreme Court ultimately concluded that the APSC erred in determining the need for additional power supply resources in a proceeding separate from the proceeding in which the APSC granted the CECPN. However, the Arkansas Supreme Court approved the APSC's procedure of granting CECPNs for transmission facilities in dockets separate from the Turk Plant CECPN proceeding. SWEPCo filed a 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 the originally approved 88 MW portion of Turk Plant costs in Arkansas retail rates. In June 2010, the APSC issued an order which reversed and set aside the previously granted CECPN.

The PUCT issued an order approving a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) a cap on recovery of annual CO_2 emission costs at $28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. The Texas Industrial Energy Consumers filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant should be revoked because it was unnecessary to serve retail customers. In February 2010, the Texas District Court affirmed the PUCT's order in all respects. In March 2010, SWEPCo and the Texas Industrial Energy Consumers appealed this decision to the Texas Court of Appeals. Management is unable to predict the timing of the outcome related to this proceeding.

In November 2008, SWEPCo received its required air permit approval from the Arkansas Department of Environmental Quality and commenced construction at the site. The Arkansas Pollution Control and Ecology Commission (APCEC) upheld the air permit. The parties who unsuccessfully appealed the air permit to the APCEC filed a notice of appeal with the Circuit Court of Hempstead County, Arkansas. In December 2010, the Circuit Court affirmed the APCEC. In January 2011, the same parties filed a notice of appeal with the Arkansas Court of Appeals. A decision in that case is not likely before the third quarter of 2011.

A wetlands permit was issued by the U.S. Army Corps of Engineers in December 2009. In 2010, the Sierra Club, the Audubon Society and others filed a complaint in the Federal District Court for the Western District of Arkansas against the U.S. Army Corps of Engineers challenging the process used and the terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts, and sought a preliminary injunction to halt construction and for a temporary restraining order. In July 2010, the Hempstead County Hunting Club also 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 the Interior and the U.S. Fish and Wildlife Service seeking a temporary restraining order and preliminary injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws. The plaintiffs' federal law claims challenge the process used and terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts. The plaintiffs' state law claims challenge SWEPCo's ability to construct the Turk Plant without obtaining a certificate from the APSC. 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. 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 accepted the request. In April 2011, legislation was passed in Arkansas that clarifies the scope of the certificate exemption and the APSC's primary jurisdiction over the state law claims asserted in federal court. In response to the legislation, SWEPCo has requested the Federal District Court to withdraw the questions certified to the Arkansas Supreme Court and dismiss the state law claims.

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.

TCC Rate Matters

TEXAS RESTRUCTURING

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. The Supreme Court of Texas requested a full briefing which has concluded. The following represent issues where either the Texas District Court or the Texas Court of Appeals recommended the PUCT decision be modified:

- The Texas District Court judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs. The Texas Court of Appeals reversed the District Court's unfavorable decision. An October 2010 decision of the Supreme Court of Texas addressing the same issue for another utility upholds the Court of Appeals determination.

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The Texas District Court judge determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness. This favorable decision was affirmed by the Texas Court of Appeals.

- The Texas Court of Appeals determined that the PUCT erred by not reducing stranded costs by the "excess earnings" that had already been refunded to affiliated Retail Electric Providers (REPs). A March 2011 decision by the Supreme Court of Texas addressing the same issue for another utility overturned the Texas

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Court of Appeals decision. If the Supreme Court of Texas does not overturn TCC's Texas Court of Appeals decision, it could be unfavorable unless the PUCT allows TCC to recover the refunds previously made to the REPs. See the "TCC Excess Earnings" section below.

Management cannot predict the outcome of the pending court proceedings and the PUCT remand decisions. If TCC ultimately succeeds in its appeals, it could have a favorable effect on future net income, cash flows and possibly financial condition. If intervenors succeed in their appeals, it could reduce future net income and cash flows and possibly impact financial condition.

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In 2006, the PUCT reduced recovery of the amount securitized by $103 million of tax benefits and associated carrying costs related to TCC's generation assets. In 2006, TCC obtained a private letter ruling from the IRS which confirmed that such reduction was an IRS normalization violation. In order to avoid a normalization violation, the PUCT agreed to allow TCC to defer refunding the tax benefits of $103 million plus interest through the CTC refund period pending resolution of the normalization issue. In 2008, the IRS issued final regulations, which supported the IRS's private letter ruling which would make the refunding of or the reduction of the amount securitized by such tax benefits a normalization violation. After the IRS issued its final regulations, at the request of the PUCT, the Texas Court of Appeals remanded the tax normalization issue to the PUCT for the consideration of additional evidence including the IRS regulations. TCC is not accruing interest on the $103 million because it is not probable that the PUCT will order TCC to violate the normalization provision of the Internal Revenue Code. If interest were accrued, management estimates interest expense would have been approximately $25 million higher for the period July 2008 through March 2011.

Management believes that the PUCT will ultimately allow TCC to retain the deferred amounts, which would have a favorable effect on future net income and cash flows. Although unexpected, if the PUCT fails to issue a favorable order and orders TCC to return the tax benefits to customers, the resulting normalization violation could result in TCC's repayment to the IRS of Accumulated Deferred Investment Tax Credits (ADITC) on all property, including transmission and distribution property. This amount approximates $101 million as of March 31, 2011. It could also lead to a loss of TCC's right to claim accelerated tax depreciation in future tax returns. If TCC is required to repay its ADITC to the IRS and is also required to refund ADITC plus unaccrued interest to customers, it would reduce future net income and cash flows and impact financial condition.

TCC Excess Earnings

In 2005, a Texas appellate court issued a decision finding that a PUCT order requiring TCC to refund to the REPs excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. From 2002 to 2005, TCC refunded $55 million of excess earnings, including interest, under the overturned PUCT order. On remand, the PUCT must determine how to implement the Court of Appeals decision given that the unauthorized refunds were made to the REPs in lieu of reducing stranded costs in the true-up proceeding.

Certain parties have taken positions that, if adopted, could result in TCC being required to refund excess earnings and interest through the true-up process without receiving a refund from the REPs. If this were to occur, it would reduce future net income and cash flows and impact financial condition. A March 2011 decision by the Supreme Court of Texas addressing the same issue for another utility overturned the Texas Court of Appeals decision.

APCo and WPCo Rate Matters

Virginia Biennial Base Rate Case

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.

Rate Adjustment Clauses

In 2007, the Virginia law governing the regulation of electric utility service was amended to, among other items, provide for rate adjustment clauses (RACs) beginning in January 2009 for the timely and current recovery of costs of (a) transmission services billed by an RTO, (b) demand side management and energy efficiency programs, (c) renewable energy programs, (d) environmental compliance projects and (e) new generation facilities, including major unit modifications. In March 2011, APCo filed for approval of an environmental RAC, a renewable energy program RAC and a generation RAC simultaneous with the 2011 Virginia base rate filing. The environmental RAC is requesting recovery of environmental compliance costs incurred from January 2009 through December 2010 of $38 million annually based on a two-year amortization. The renewable energy program RAC is requesting the incremental portion of deferred wind power costs for the Camp Grove and Fowler Ridge projects of $6 million. The generation RAC is requesting recovery of the Dresden Plant, currently under construction, which APCo has requested to purchase from AEGCo.

In accordance with Virginia law, APCo is deferring incremental environmental costs incurred after December 2008 and renewable energy costs incurred after August 2009 which are not being recovered in current revenues. As of March 31, 2011, APCo has deferred $56 million of environmental costs (excluding $12 million of unrecognized equity carrying costs) and $34 million of renewable energy costs. APCo plans to seek recovery of non-incremental deferred wind power costs ($28 million as of March 31, 2011) in future rate proceedings. If the Virginia SCC were to disallow a portion of APCo's deferred costs, it would reduce future net income and cash flows.

2010 West Virginia Base Rate Case

In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates by $156 million based on an 11.75% return on common equity to be effective March 2011. 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 settlement agreement also resulted in a pretax write-off of a portion of the 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.

Mountaineer Carbon Capture and Storage Project

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 October 2009, APCo started injecting CO2 into the underground storage facilities. The injection of CO2 required the recording of an asset retirement obligation and an offsetting regulatory asset.

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. See "2010 West Virginia Base Rate Case" section above. 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.

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. If APCo is unable to recover the costs of the CCS project, it would reduce future net income and cash flows.

APCo’s Filings for an IGCC Plant

In 2008, the Virginia SCC issued an order denying APCo’s request for a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and the ongoing financing costs of the project during the construction period, as well as the capital costs, operating costs and a return on common equity once the facility is placed into commercial operation. The order was based upon the Virginia SCC's finding that the estimated cost of the plant was uncertain and may escalate. The Virginia SCC also expressed concerns that the estimated costs did not include a retrofitting of CCS facilities. During 2009, based on the order received in Virginia, the WVPSC removed the IGCC case as an active case from its docket and indicated that the conditional Certificate of Environmental Compatibility and Public Need granted in 2008 must be reconsidered if and when APCo proceeds with the IGCC plant.

Through March 31, 2011, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $9 million applicable to its Virginia jurisdiction.

APCo will not start construction of the IGCC plant until sufficient assurance of full cost recovery exists in Virginia and West Virginia. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the costs are not recoverable, it would reduce future net income and cash flows and impact financial condition.

APCo’s and WPCo’s Expanded Net Energy Charge (ENEC) Filing

In September 2009, the WVPSC issued an order approving APCo’s and WPCo’s March 2009 ENEC request. The approved order provided for recovery of an under-recovered balance plus a projected increase in ENEC costs over a four-year phase-in period with an overall increase of $355 million and a first-year increase of $124 million, effective October 2009.

In June 2010, the WVPSC approved a settlement agreement for $96 million, including $10 million of construction surcharges related to APCo’s and WPCo’s second year ENEC increase. The settlement agreement allows APCo to accrue a weighted average cost of a capital carrying charge on the excess under-recovery balance due to the ENEC phase-in as adjusted for the impacts of Accumulated Deferred Income Taxes. The new rates became effective in July 2010.

In March 2011, APCo and WPCo filed their third year ENEC increase with the WVPSC to increase rates in July 2011 by $119 million, including a $21 million increase of construction surcharges, an $8 million increase of carrying charges and a $5 million decrease due to the discontinuation of the reliability surcharge. The requested increase in construction surcharges includes APCo’s West Virginia jurisdictional share of the requested purchase of the Dresden

Plant, currently under construction, from AEGCo. Intervenors, including the WVPSC staff, filed a motion with the WVPSC to remove the Dresden Plant surcharge issue from this proceeding. As of March 31, 2011, APCo's ENEC under-recovery balance was $374 million, excluding $6 million of unrecognized equity carrying costs, which is included in noncurrent regulatory assets. If the WVPSC were to disallow a portion of APCo's and WPCo's deferred ENEC costs, it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters

PSO 2008 Fuel and Purchased Power

In July 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudency review of the related costs. In March 2010, the Oklahoma Attorney General and the OIEC recommended the fuel clause adjustment rider be amended so that the shareholder's portion of off-system sales margins decrease from 25% to 10%. The Oklahoma Industrial Energy Consumers also recommended that the OCC conduct a comprehensive review of all affiliate transactions during 2007 and 2008. In July 2010, additional testimony regarding the 2007 transfer of ERCOT trading contracts to AEPEP was filed. The testimony included unquantified refund recommendations relating to re-pricing of contract transactions. Hearings will likely occur in the second quarter of 2011. If the OCC were to issue an unfavorable decision, it could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters

Michigan 2009 and 2010 Power Supply Cost Recovery (PSCR) Reconciliations (Cook Plant Unit 1 Fire and Shutdown)

In March 2010, I&M filed its 2009 PSCR reconciliation with the MPSC. The filing included an adjustment to exclude from the PSCR the incremental fuel cost of replacement power due to the Unit 1 outage from mid-December 2008 through December 2009, the period during which I&M received and recognized accidental outage insurance proceeds. In October 2010, a settlement agreement was filed with the MPSC which included deferring the Unit 1 outage issue to the 2010 PSCR reconciliation. In March 2011, I&M filed its 2010 PSCR reconciliation with the MPSC. If any fuel clause revenues or accidental outage insurance proceeds have to be paid to customers, it would reduce future net income and cash flows and impact financial condition. See the "Cook Plant Unit 1 Fire and Shutdown" section of Note 3.

FERC Rate Matters

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 2006. Intervenors objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million from 2004 through 2006 when the SECA rates terminated.

In 2006, a FERC Administrative Law Judge (ALJ) issued an initial decision finding that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that any unpaid SECA rates must be paid in the recommended reduced amount.

AEP filed briefs jointly with other affected companies asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supports AEP's position and required a compliance filing to be filed with the FERC by August 2010. In June 2010, AEP and other affected companies filed a joint request for rehearing with the FERC.

In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $3 million. A decision is pending from the FERC.

The FERC has approved settlements applicable to $112 million of SECA revenue. The AEP East companies provided reserves for net refunds for SECA settlements applicable to the remaining $108 million of SECA revenues collected. Based on the AEP East companies' analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order or the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Possible Termination of the Interconnection Agreement

In December 2010, each of the AEP Power Pool members gave notice to AEPSC and each other of their decision to terminate the Interconnection Agreement effective January 2014 or such other date approved by FERC, subject to state regulatory input. No filings have been made at the FERC. It is unknown at this time whether the AEP Power Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers or if each company will choose to operate independently. This decision to terminate is subject to management's ongoing evaluation. The AEP Power Pool members may revoke their notices of termination. If any of the AEP Power Pool members experience decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and are unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce future net income and cash flows.

PJM/MISO Market Flow Calculation Settlement Adjustments

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and dated back to the start of the MISO market in 2005. In January 2011, PJM and MISO reached a settlement agreement where the parties agreed to net various issues to zero. This settlement was filed with the FERC in January 2011. PJM and MISO are currently awaiting final approval from the FERC.

3. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on our financial statements. The Commitments, Guarantees and Contingencies note within our 2010 Annual Report should be read in conjunction with this report.

GUARANTEES

We record liabilities for guarantees in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters Of Credit

We enter into standby letters of credit with third parties. As Parent, we issue all of these letters of credit in our ordinary course of business on behalf of our subsidiaries. These letters of credit cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

We have two $1.5 billion credit facilities, under which we may issue up to $1.35 billion as letters of credit. As of March 31, 2011, the maximum future payments for letters of credit issued under the two $1.5 billion credit facilities were $124 million with maturities ranging from June 2011 to March 2012.

In March 2011, we terminated a $478 million credit agreement that was scheduled to mature in April 2011 and was used to support $472 million of variable rate Pollution Control Bonds. In March 2011, we remarketed $357 million of variable rate Pollution Control Bonds using bilateral letters of credit for $361 million to support the remarketed Pollution Control Bonds. The remaining $115 million of Pollution Control Bonds were reacquired and are held by trustees.

Guarantees Of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), a consolidated variable interest entity. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. As of March 31, 2011, SWEPCo has collected approximately $50 million through a rider for final mine closure and reclamation costs, of which $1 million is recorded in Other Current Liabilities, $26 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $23 million is recorded in Asset Retirement Obligations on our Condensed Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. The status of certain sale agreements is discussed in the 2010 Annual Report "Dispositions" section of Note 7. As of March 31, 2011, there are no material liabilities recorded for any indemnifications.

Master Lease Agreements

We lease certain equipment under master lease agreements. In December 2010, we signed a new master lease agreement with GE Capital Commercial Inc. (GE) for approximately $137 million to replace existing operating and capital leases with GE. We refinanced approximately $60 million of capital leases and approximately $77 million in operating leases. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. As of March 31, 2011, approximately $5 million was purchased and $11 million of leased assets were not included in the refinancing, but will be purchased or refinanced in the remainder of 2011.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 78% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, we are committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 78% of the unamortized balance. For equipment under other master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, we are committed to pay the difference between the actual fair value and the residual value guarantee. At March 31, 2011, the maximum potential loss for these lease agreements was approximately $14 million assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $17 million for I&M and $19 million for SWEPCo for the remaining railcars as of March 31, 2011.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five year lease term to 77% at the end of the 20-year term of the projected fair value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 million and SWEPCo's is approximately $13 million assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO2 emissions or that the Federal EPA could regulate CO2 emissions under existing CAA authorities and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. In December 2010, the defendants' petition for review by the U.S. Supreme Court was granted. The case was heard in April 2011. We believe the actions are without merit and intend to continue to defend against the claims.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011.

We are unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of

$95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. Briefing is complete and no date has been set for oral argument. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO2 public nuisance case discussed above. The court entered an order deferring argument until after June 2011. We believe the action is without merit and intend to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. We currently incur costs to dispose of these substances safely.

In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. I&M's provision is approximately $11 million. As the remediation work is completed, I&M's cost may continue to increase as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. We cannot predict the amount of additional cost, if any.

Amos Plant – State and Federal Enforcement Proceedings

In March 2010, we received a letter from the West Virginia Department of Environmental Protection, Division of Air Quality (DAQ), alleging that at various times in 2007 through 2009 the units at Amos Plant reported periods of excess opacity (indicator of compliance with PM emission limits) that lasted for more than 30 consecutive minutes in a 24-hour period and that certain required notifications were not made. We met with representatives of DAQ to discuss these occurrences and the steps we have taken to prevent a recurrence. DAQ indicated that additional enforcement action may be taken, including imposition of a civil penalty of approximately $240 thousand. We have denied that violations of the reporting requirements occurred and maintain that the proper reporting was done. In March 2011, we resolved these issues through the entry of a consent order that included the payment of a $75 thousand civil penalty and certain improvements in our opacity reports.

In March 2010, we received a request to show cause from the Federal EPA alleging that certain reporting requirements under Superfund and the Emergency Planning and Community Right-to-Know Act had been violated and inviting us to engage in settlement negotiations. The request includes a proposed civil penalty of approximately $300 thousand. We indicated our willingness to engage in good faith negotiations and provided additional information to representatives of the Federal EPA. We have not admitted that any violations occurred or that the amount of the proposed penalty is reasonable.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission. We have a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

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 significant turbine damage and a small fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. 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 these 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.

I&M maintains insurance through NEIL. As of March 31, 2011, we recorded $47 million in Prepayments and Other Current Assets on our Condensed Consolidated Balance Sheets representing amounts under NEIL insurance policies. Through March 31, 2011, I&M received partial payments of $203 million from NEIL for the cost incurred to date to repair the property damage.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The review by NEIL includes the timing of the unit's return to service and whether the return should have occurred earlier reducing the amount received under the accidental outage policy. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

OPERATIONAL CONTINGENCIES

Fort Wayne Lease

Since 1975, I&M has leased certain energy delivery assets from the City of Fort Wayne, Indiana under a long-term lease that expired on February 28, 2010. I&M negotiated with Fort Wayne to purchase the assets at the end of the lease, but no agreement was reached prior to the end of the lease.

I&M and Fort Wayne reached a settlement agreement. The agreement, signed in October 2010, is subject to approval by the IURC. I&M filed a petition with the IURC seeking approval of the agreement, including recovery in rates of payments made to Fort Wayne. If the agreement is approved, I&M will purchase the remaining leased property and settle claims Fort Wayne asserted. The agreement provides that I&M will pay Fort Wayne a total of $39 million, inclusive of interest, over 15 years and Fort Wayne will recognize that I&M is the exclusive electricity supplier in the Fort Wayne area. In April 2011, the Indiana Office of Consumer Utility Counselor filed comments opposing portions of the settlement agreement. The IURC scheduled a hearing for June 2011. If the agreement is not approved by the IURC, the parties have the right to terminate the agreement and pursue other relief.

Enron Bankruptcy

In 2001, we purchased Houston Pipeline Company (HPL) from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. In connection with our acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 55 billion cubic feet (BCF) of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of the cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, the BOA Syndicate informed HPL of a purported default by Enron under the terms of the financing arrangement. This dispute was litigated in the Enron bankruptcy proceedings and in federal courts in Texas and New York.

In 2007, the judge in the New York action issued a decision on all claims, including those that were pending trial in Texas, granting BOA summary judgment and dismissing our claims. In August 2008, the New York court entered a final judgment of $346 million. In May 2009, the judge awarded $20 million of attorneys' fees to BOA. We appealed these awards and posted bonds covering the amounts. In October 2010, the Court of Appeals affirmed the New York district court's decision as to the final judgment of $346 million and reversed the New York district court decision as to the judgment dismissing our claims against BOA in the Southern District of Texas.

In 2005, we sold our interest in HPL for approximately $1 billion. Although the assets were legally transferred, we were unable to determine all costs associated with the transfer until the BOA litigation was resolved. We indemnified the buyer of HPL against any damages up to the purchase price resulting from the BOA litigation, including the right to use the 55 BCF of natural gas through 2031. As a result, we deferred the entire gain related to the sale of HPL (approximately $380 million) pending resolution of the Enron and BOA disputes.

The deferred gain related to the sale of HPL, plus accrued interest and attorneys' fees related to the New York court's judgment was $448 million at December 31, 2010 and was included in Current Liabilities – Deferred Gain and Accrued Litigation Costs on the Condensed Consolidated Balance Sheet.

In February 2011, we reached a settlement covering all claims with BOA and Enron for $425 million. As part of the settlement, we received title to the 55 BCF of natural gas in the Bammel storage facility and recorded this asset at fair value. Under the HPL sales agreement, we have a service obligation to the buyer for the right to use the cushion gas through May 2031. We recognized the obligation as a liability and will amortize it over the life of the agreement.

The settlement resulted in a pretax gain of $51 million and a net loss after tax of $22 million primarily due to an unrealized capital loss valuation allowance of $56 million.

The following table sets forth the impact of the settlement on our financial statements:

		Three Months Ended March 31, 2011 (in millions)
Income Statement:		
Other Operation Expense - Pretax Gain on Settlement	$	51
Income Tax Expense		73
Net Loss After Tax	$	(22)
Cash Flow Statement:		
Net Income - Loss on Settlement with BOA and Enron	$	(22)
Deferred Income Taxes		91
Gain on Settlement with BOA and Enron		(51)
Settlement of Litigation with BOA and Enron		(211)
Accrued Taxes, Net		(18)
Acquisition of Cushion Gas from BOA		(214)
Cash Paid	$	(425)

		March 31, 2011 (in millions)
Balance Sheet:		
	$	214

Deferred Charges and Other Noncurrent Assets - Gas Acquired	
Deferred Credits and Other Noncurrent Liabilities - Gas Service Liability	187
Accrued Taxes - Tax Benefit on Settlement with BOA and Enron	18
Deferred Income Taxes - Deferred Tax Benefit on Gas Service Liability	66

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Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. These cases are at various pre-trial stages. In 2008, we settled all of the cases pending against us in California. We will continue to defend each remaining case where an AEP company is a defendant. We believe the provision we have for the remaining cases is adequate. We believe the remaining exposure is immaterial.

4. ACQUISITION AND DISPOSITIONS

ACQUISITION

2011

None

2010

Valley Electric Membership Corporation (Utility Operations segment)

In October 2010, SWEPCo purchased certain transmission and distribution assets of Valley Electric Membership Corporation (VEMCO) for approximately $102 million and began serving VEMCO’s 30,000 customers in Louisiana.

DISPOSITIONS

2011

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

TCC sold, at cost, $5 million of transmission facilities to ETT for the three months ended March 31, 2011.

2010

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

TCC and TNC sold, at cost, $64 million and $71 million, respectively, of transmission facilities to ETT for the three months ended March 31, 2010.

5. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for the three months ended March 31, 2011 and 2010:

	Pension Plans Three Months Ended March 31, 2011	Pension Plans Three Months Ended March 31, 2010	Other Postretirement Benefit Plans Three Months Ended March 31, 2011	Other Postretirement Benefit Plans Three Months Ended March 31, 2010
	(in millions)			
Service Cost	$ 18	$ 28	$ 11	$ 12
Interest Cost	59	63	27	28
Expected Return on Plan Assets	(79)	(78)	(27)	(26)
Amortization of Transition Obligation	-	-	-	7
Amortization of Net Actuarial Loss	30	22	7	7
Net Periodic Benefit Cost	$ 28	$ 35	$ 18	$ 28

6. BUSINESS SEGMENTS

As outlined in our 2010 Annual Report, our primary business is our electric utility operations. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily in the ERCOT market area and to a lesser extent Ohio in PJM and MISO. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

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 remainder of our activities is presented as All Other. 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.

The tables below present our reportable segment information for the three months ended March 31, 2011 and 2010 and balance sheet information as of March 31, 2011 and December 31, 2010. These amounts include certain estimates and allocations where necessary.

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended March 31, 2011						
Revenues from:						
External Customers	$3,497	$167	$62	$4	$-	$3,730
Other Operating Segments	27	5	1	1	(34)	-
Total Revenues	$3,524	$172	$63	$5	$(34)	$3,730
Net Income (Loss)	$378	$7	$1	$(31)	$-	$355

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Three Months Ended March 31, 2010						
Revenues from:						
External Customers	$3,406	$121	$47	$(5)	$-	$3,569
Other Operating Segments	20	5	-	8	(33)	-
Total Revenues	$3,426	$126	$47	$3	$(33)	$3,569
Net Income (Loss)	$344	$3	$10	$(11)	$-	$346

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
			(in millions)			
March 31, 2011						
Total Property, Plant and Equipment	$ 53,162	$ 589	$ 593	$ 10	$ (258)	$ 54,096
Accumulated Depreciation and Amortization	18,049	117	204	9	(49)	18,330
Total Property, Plant and Equipment - Net	$ 35,113	$ 472	$ 389	$ 1	$ (209)	$ 35,766
Total Assets	$ 48,772	$ 652	$ 835	$ 15,713	$ (15,412)(c)	$ 50,560

Nonutility Operations

Generation Reconciling

	Utility Operations	AEP River Operations	and Marketing	All Other (a)	Adjustments (b)	Consolidated
			(in millions)			
December 31, 2010						
Total Property, Plant and Equipment	$ 52,822	$ 574	$ 584	$ 11	$ (251)	$ 53,740
Accumulated Depreciation and Amortization	17,795	110	198	9	(46)	18,066
Total Property, Plant and Equipment - Net	$ 35,027	$ 464	$ 386	$ 2	$ (205)	$ 35,674
Total Assets	$ 48,780	$ 621	$ 881	$ 15,942	$ (15,769) (c)	$ 50,455

(a) 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.

(b) Includes eliminations due to an intercompany capital lease.

(c) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

We are exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates. We manage these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Trading Strategies

Our strategy surrounding the use of derivative instruments for trading purposes focuses on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which we transact.

Risk Management Strategies

Our strategy surrounding the use of derivative instruments focuses on managing our risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. To accomplish our objectives, we primarily employ risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

We enter into power, coal, natural gas, interest rate and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with our energy business. We enter into interest rate derivative contracts in order to manage the interest rate exposure associated with our commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as they are related to energy risk management activities. We also engage in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors.

The following table represents the gross notional volume of our outstanding derivative contracts as of March 31, 2011 and December 31, 2010:

Notional Volume of Derivative Instruments

	Volume		
	March 31, 2011	December 31, 2010	Unit of Measure
	(in millions)		
Commodity:			
Power	539	652	MWHs
Coal	60	63	Tons
Natural Gas	89	94	MMBtus

Heating Oil and Gasoline		6		6	Gallons
Interest Rate	$	273	$	171	USD
Interest Rate and Foreign Currency	$	503	$	907	USD

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Fair Value Hedging Strategies

We enter into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

We enter into and designate as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline (“Commodity”) in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. We do not hedge all commodity price risk.

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. For disclosure purposes, these contracts are included with other hedging activity as “Commodity.” We do not hedge all fuel price risk.

We enter into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. We do not hedge all interest rate exposure.

At times, we are exposed to foreign currency exchange rate risks primarily when we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency’s appreciation against the dollar. We do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR FINANCIAL STATEMENTS

The accounting guidance for “Derivatives and Hedging” requires recognition of all qualifying derivative instruments as either assets or liabilities in the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of our derivative instruments, we also apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract’s term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with our estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of our risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2011 and December 31, 2010 balance sheets, we netted $7 million and $8 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $70 million and $109 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of our derivative activity on our Condensed Consolidated Balance Sheets as of March 31, 2011 and December 31, 2010:

Fair Value of Derivative Instruments
March 31, 2011

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (a)(b)	Total
			(in millions)		
Current Risk Management Assets	$ 833	$ 21	$ 5	$ (666)	$ 193
Long-term Risk Management Assets	526	11	1	(179)	359
Total Assets	1,359	32	6	(845)	552
Current Risk Management Liabilities	807	13	2	(713)	109
Long-term Risk Management Liabilities	364	7	3	(236)	138
Total Liabilities	1,171	20	5	(949)	247
Total MTM Derivative Contract Net Assets (Liabilities)	$ 188	$ 12	$ 1	$ 104	$ 305

Fair Value of Derivative Instruments
December 31, 2010

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (a)(b)	Total
			(in millions)		
Current Risk Management Assets	$ 1,023	$ 18	$ 30	$ (839)	$ 232
Long-term Risk Management Assets	546	12	2	(150)	410
Total Assets	1,569	30	32	(989)	642

Current Risk Management Liabilities	995	13	2	(881)	129
Long-term Risk Management Liabilities	387	6	3	(255)	141
Total Liabilities	1,382	19	5	(1,136)	270
Total MTM Derivative Contract Net Assets (Liabilities)	$ 187	$ 11	$ 27	$ 147	$ 372

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the Condensed Consolidated Balance Sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging." Amounts also include dedesignated risk management contracts.

The table below presents our activity of derivative risk management contracts for the three months ended March 31, 2011 and 2010:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2011 and 2010

Location of Gain (Loss)	2011	2010
	(in millions)	
Utility Operations Revenue	$ 20	$ 38
Other Revenue	2	1
Regulatory Assets (a)	2	-
Regulatory Liabilities (a)	8	42
Total Gain on Risk Management Contracts	$ 32	$ 81

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheet.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the Condensed Consolidated Statements of Income on an accrual basis.

Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, we designate a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis on the Condensed Consolidated Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the Condensed Consolidated Statements of Income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts Net Income during the period of change.

We record realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on our Condensed Consolidated Statements of Income. During the three months ended March 31, 2011, we recognized gains of $4 million on our outstanding hedging instruments, offsetting losses of $4 million on our long-term debt and an immaterial amount of hedge ineffectiveness. During the three months ended March 31, 2010, the value of the hedging instruments was immaterial and no hedge ineffectiveness was recognized.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets until the period the hedged item affects Net Income. We recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal, natural gas and heating oil and gasoline designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on our Condensed Consolidated Statements of Income, or in Regulatory Assets or Regulatory Liabilities on our Condensed Consolidated Balance Sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2011 and 2010, we designated commodity derivatives as cash flow hedges.

We reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our Condensed Consolidated Statements of Income. During the three months ended March 31, 2011 and 2010, we designated heating oil and gasoline derivatives as cash flow hedges.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three months ended March 31, 2011 and 2010, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets into Depreciation and Amortization expense on our Condensed Consolidated Statements of Income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three months ended March 31, 2011 and 2010, we designated foreign currency derivatives as cash flow hedges.

During the three months ended March 31, 2011 and 2010, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2011 and 2010. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended March 31, 2011

	Commodity		Interest Rate and Foreign Currency (in millions)		Total	
Balance in AOCI as of December 31, 2010	$	7	$	4	$	11
Changes in Fair Value Recognized in AOCI		2		(1)		1
Amount of (Gain) or Loss Reclassified from AOCI						
to Income Statement/within Balance Sheet:						
Utility Operations Revenue		-		-		-
Other Revenue		(1)		-		(1)
Purchased Electricity for Resale		-		-		-
Interest Expense		-		1		1
Regulatory Assets (a)		-		-		-
Regulatory Liabilities (a)		-		-		-
Balance in AOCI as of March 31, 2011	$	8	$	4	$	12

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended March 31, 2010

	Commodity		Interest Rate and Foreign Currency (in millions)		Total	
Balance in AOCI as of December 31, 2009	$	(2)	$	(13)	$	(15)
Changes in Fair Value Recognized in AOCI		3		(1)		2
Amount of (Gain) or Loss Reclassified from AOCI						
to Income Statement/within Balance Sheet:						
Utility Operations Revenue		-		-		-
Other Revenue		(1)		-		(1)
Purchased Electricity for Resale		1		-		1
Interest Expense		-		1		1
Regulatory Assets (a)		1		-		1
Regulatory Liabilities (a)		-		-		-
Balance in AOCI as of March 31, 2010	$	2	$	(13)	$	(11)

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheet.

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Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets at March 31, 2011 and December 31, 2010 were:

Impact of Cash Flow Hedges on our Condensed Consolidated Balance Sheet
March 31, 2011

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Hedging Assets (a)	$ 14	$ -	$ 14
Hedging Liabilities (a)	(2)	(3)	(5)
AOCI Gain (Loss) Net of Tax	8	4	12
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	5	(2)	3

Impact of Cash Flow Hedges on our Condensed Consolidated Balance Sheet
December 31, 2010

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Hedging Assets (a)	$ 13	$ 25	$ 38
Hedging Liabilities (a)	(2)	(4)	(6)
AOCI Gain (Loss) Net of Tax	7	4	11
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	3	(2)	1

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Condensed Consolidated Balance Sheets.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of March 31, 2011, the maximum length of time that we are hedging (with contracts subject to the accounting guidance for “Derivatives and Hedging”) our exposure to variability in future cash flows related to forecasted transactions is 38 months.

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, Standard and 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 use standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds our established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with our credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to our competitive retail auction loads, we are obligated to post an additional amount of collateral if our credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and our total exposure. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. We do not anticipate a downgrade below investment grade. The following table represents: (a) our aggregate fair value of such derivative contracts, (b) the amount of collateral we would have been required to post for all derivative and non-derivative contracts if our credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of March 31, 2011 and December 31, 2010:

	March 31, 2011	December 31, 2010
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 19	$ 20
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	52	45
Amount Attributable to RTO and ISO Activities	50	44

In addition, a majority of our non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, our risk management organization assesses the appropriateness of these cross-default provisions in our contracts. We do not anticipate a non-performance event under these provisions. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral we have posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering our contractual netting arrangements as of March 31, 2011 and December 31, 2010:

	March 31, 2011	December 31, 2010
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 364	$ 401
Amount of Cash Collateral Posted	29	81
Additional Settlement Liability if Cross Default Provision is Triggered	206	213

8. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for “Fair Value Measurements and Disclosures” establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For our commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are non-binding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, we include these locations within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in the nuclear trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the nuclear trusts, Cash and Cash Equivalents and Other Temporary Investments are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, bids, offers, reference data and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

Items classified as Level 2 are primarily investments in individual fixed income securities. These fixed income securities are valued using models with input data as follows:

	Type of Fixed Income Security		
Type of Input	United States Government	Corporate Debt	State and Local Government
Benchmark Yields	X	X	X
Broker Quotes	X	X	X
Discount Margins	X	X	
Treasury Market Update	X		
Base Spread	X	X	X
Corporate Actions		X	
Ratings Agency Updates		X	X
Prepayment Schedule and History			X
Yield Adjustments	X		

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange.

The book values and fair values of Long-term Debt as of March 31, 2011 and December 31, 2010 are summarized in the following table:

	March 31, 2011		December 31, 2010	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 17,052	$ 18,324	$ 16,811	$ 18,285

Fair Value Measurements of Other Temporary Investments

Other Temporary Investments include marketable securities that we intend to hold for less than one year, investments by our protected cell of EIS and funds held by trustees primarily for the repayment of debt.

The following is a summary of Other Temporary Investments:

	March 31, 2011			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
		(in millions)		
Restricted Cash (a)	$ 151	$ -	$ -	$ 151
Fixed Income Securities:				
Mutual Funds	70	-	-	70
Variable Rate Demand Notes	49	-	-	49
Equity Securities - Mutual Funds	18	8	-	26
Total Other Temporary Investments	$ 288	$ 8	$ -	$ 296

	December 31, 2010			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
		(in millions)		
Restricted Cash (a)	$ 225	$ -	$ -	$ 225
Fixed Income Securities:				
Mutual Funds	69	-	-	69
Variable Rate Demand Notes	97	-	-	97
Equity Securities - Mutual Funds	18	7	-	25
Total Other Temporary Investments	$ 409	$ 7	$ -	$ 416

(a) Primarily represents amounts held for the repayment of debt.

The following table provides the activity for our debt and equity securities within Other Temporary Investments for the three months ended March 31, 2011 and 2010:

	Three Months Ended March 31,	
	2011	2010
	(in millions)	
Proceeds From Investment Sales	$ 196	$ 241
Purchases of Investments	148	197
Gross Realized Gains on Investment Sales	-	-
Gross Realized Losses on Investment Sales	-	-

At March 31, 2011 and December 31, 2010, we had no Other Temporary Investments with an unrealized loss position. At March 31, 2011, the fair value of fixed income securities are primarily debt based mutual funds with short and intermediate maturities and variable rate demand notes. Mutual funds may be sold and do not contain maturity dates.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

We maintain trust records for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and debt investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains and other-than-temporary impairments from securities in the trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. The trust assets are recorded by jurisdiction and may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds.

The following is a summary of nuclear trust fund investments at March 31, 2011 and December 31, 2010:

	March 31, 2011			December 31, 2010		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
			(in millions)			
Cash and Cash Equivalents	$ 15	$ -	$ -	$ 20	$ -	$ -
Fixed Income Securities:						
United States Government	473	18	(1)	461	23	(1)
Corporate Debt	55	3	(2)	59	4	(2)
State and Local Government	340	2	-	341	(1)	-
Subtotal Fixed Income Securities	868	23	(3)	861	26	(3)
Equity Securities - Domestic	676	226	(113)	634	183	(123)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,559	$ 249	$ (116)	$ 1,515	$ 209	$ (126)

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The following table provides the securities activity within the decommissioning and SNF trusts for the three months ended March 31, 2011 and 2010:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(in millions)	
Proceeds From Investment Sales	$ 288	$ 232
Purchases of Investments	306	248
Gross Realized Gains on Investment Sales	5	5
Gross Realized Losses on Investment Sales	5	-

The adjusted cost of debt securities was $845 million and $835 million as of March 31, 2011 and December 31, 2010, respectively. The adjusted cost of equity securities was $450 million and $451 million as of March 31, 2011 and December 31, 2010, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at March 31, 2011 was as follows:

	Fair Value of Debt Securities (in millions)
Within 1 year	$ 78
1 year – 5 years	271
5 years – 10 years	268
After 10 years	251
Total	$ 868

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2011 and December 31, 2010. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in AEP's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2011

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
Cash and Cash Equivalents (a)	$ 417	$ -	$ -	$ 208	$ 625
Other Temporary Investments					
Restricted Cash (a)	103	-	-	48	151
Fixed Income Securities:					
Mutual Funds	70	-	-	-	70
Variable Rate Demand Notes	-	49	-	-	49
Equity Securities - Mutual Funds (b)	26	-	-	-	26
Total Other Temporary Investments	199	49	-	48	296
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	16	1,227	95	(846)	492
Cash Flow Hedges:					
Commodity Hedges (c)	9	23	-	(18)	14
Fair Value Hedges	-	5	-	-	5
Dedesignated Risk Management Contracts (d)	-	-	-	41	41
Total Risk Management Assets	25	1,255	95	(823)	552
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	5	-	10	15
Fixed Income Securities:					
United States Government	-	473	-	-	473
Corporate Debt	-	55	-	-	55
State and Local Government	-	340	-	-	340
Subtotal Fixed Income Securities	-	868	-	-	868
Equity Securities - Domestic (b)	676	-	-	-	676
Total Spent Nuclear Fuel and Decommissioning Trusts	676	873	-	10	1,559
Total Assets	$ 1,317	$ 2,177	$ 95	$ (557)	$ 3,032
Liabilities:					

Risk Management Liabilities										
Risk Management Commodity Contracts (c) (f)	$	18	$	1,110	$	22	$	(909)	$	241
Cash Flow Hedges:										
Commodity Hedges (c)		4		16		-		(18)		2
Interest Rate/Foreign Currency Hedges		-		3		-		-		3
Fair Value Hedges		-		1		-		-		1
Total Risk Management Liabilities	$	22	$	1,130	$	22	$	(927)	$	247

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
Cash and Cash Equivalents (a)	$ 170	$ -	$ -	$ 124	$ 294
Other Temporary Investments					
Restricted Cash (a)	184	-	-	41	225
Fixed Income Securities:					
Mutual Funds	69	-	-	-	69
Variable Rate Demand Notes	-	97	-	-	97
Equity Securities - Mutual Funds (b)	25	-	-	-	25
Total Other Temporary Investments	278	97	-	41	416
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	20	1,432	112	(1,013)	551
Cash Flow Hedges:					
Commodity Hedges (c)	11	17	-	(15)	13
Interest Rate/Foreign Currency Hedges	-	25	-	-	25
Fair Value Hedges	-	7	-	-	7
Dedesignated Risk Management Contracts (d)	-	-	-	46	46
Total Risk Management Assets	31	1,481	112	(982)	642
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	8	-	12	20
Fixed Income Securities:					
United States Government	-	461	-	-	461
Corporate Debt	-	59	-	-	59
State and Local Government	-	341	-	-	341
Subtotal Fixed Income Securities	-	861	-	-	861
Equity Securities - Domestic (b)	634	-	-	-	634
Total Spent Nuclear Fuel and Decommissioning Trusts	634	869	-	12	1,515
Total Assets	$ 1,113	$ 2,447	$ 112	$ (805)	$ 2,867
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 25	$ 1,325	$ 27	$ (1,114)	$ 263
Cash Flow Hedges:					
Commodity Hedges (c)	4	13	-	(15)	2

Interest Rate/Foreign Currency Hedges		-		4		-		-		4
Fair Value Hedges		-		1		-		-		1
Total Risk Management Liabilities	$	29	$	1,343	$	27	$	(1,129)	$	270

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 amounts primarily represent investments in money market funds.
(b) Amounts represent publicly traded equity securities and equity-based mutual funds.
(c) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(d) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.
(e) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.
(f) The March 31, 2011 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($1) million in 2011, $2 million in periods 2012-2014 and ($3) million in periods 2015-2018; Level 2 matures $12 million in 2011, $70 million in periods 2012-2014, $17 million in periods 2015-2016 and $18 million in periods 2017-2028; Level 3 matures $8 million in 2011, $29 million in periods 2012-2014, $11 million in periods 2015-2016 and $25 million in periods 2017-2028. Risk management commodity contracts are substantially comprised of power contracts.
(g) The December 31, 2010 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($2) million in 2011, $2 million in periods 2012-2014 and ($5) million in periods 2015-2018; Level 2 matures $13 million in 2011, $66 million in periods 2012-2014, $12 million in periods 2015-2016 and $16 million in periods 2017-2028; Level 3 matures $18 million in 2011, $24 million in periods 2012-2014, $16 million in periods 2015-2016 and $27 million in periods 2017-2028. Risk management commodity contracts are substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2011 and 2010.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as Level 3 in the fair value hierarchy:

Three Months Ended March 31, 2011	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2010	$ 85
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(2)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)	
Relating to Assets Still Held at the Reporting Date (a)	(4)
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(8)
Transfers into Level 3 (d) (f)	-
Transfers out of Level 3 (e) (f)	(8)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	10
Balance as of March 31, 2011	$ 73

Three Months Ended March 31, 2010	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2009	$ 62
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	27
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)	
Relating to Assets Still Held at the Reporting Date (a)	24
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(31)
Transfers into Level 3 (d) (f)	15
Transfers out of Level 3 (e) (f)	1
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	18
Balance as of March 31, 2010	$ 116

(a) Included in revenues on our Condensed Consolidated Statements of Income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Represents existing assets or liabilities that were previously categorized as Level 3.
(f) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(g) Relates to the net gains (losses) of those contracts that are not reflected on our Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

9. INCOME TAXES

We, along with our subsidiaries, file a consolidated federal income tax return. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the

Parent is allocated to our subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

We are no longer subject to U.S. federal examination for years before 2001. We have completed the exam for the years 2001 through 2006 and have issues that we are pursuing at the appeals level. In April 2011, the IRS's examination of the years 2007 and 2008 was concluded with a settlement of all outstanding issues. The settlement will not have a material impact on net income, cash flows or financial condition. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

We, along with our subsidiaries, file income tax returns in various state, local and foreign jurisdictions. These taxing authorities routinely examine our tax returns and we are currently under examination in several state and local jurisdictions. We believe that we have filed tax returns with positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and the ultimate resolution of these audits will not materially impact net income. With few exceptions, we are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2000.

For a discussion of the tax implications of our settlement with BOA and Enron, see "Enron Bankruptcy" section of Note 3.

Federal Tax Legislation

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded in March 2010. This reduction did not materially affect our cash flows or financial condition. For the three months ended March 31, 2010, deferred tax assets decreased $56 million, partially offset by recording net tax regulatory assets of $35 million in our jurisdictions with regulated operations, resulting in a decrease in net income of $21 million.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions will not have a material impact on net income or financial condition.

10. FINANCING ACTIVITIES

Long-term Debt

Type of Debt		March 31, 2011			December 31, 2010	
			(in millions)			
Senior Unsecured Notes	$	12,069		$	11,669	
Pollution Control Bonds		2,213			2,263	
Notes Payable		387			396	
Securitization Bonds		1,755			1,847	
Junior Subordinated Debentures		315			315	
Spent Nuclear Fuel Obligation (a)		265			265	
Other Long-term Debt		91			91	
Unamortized Discount (net)		(43	)		(35	)
Total Long-term Debt Outstanding		17,052			16,811	
Less Portion Due Within One Year		1,421			1,309	

Long-term Portion	$	15,631	$	15,502

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation to the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation of $307 million at March 31, 2011 and December 31, 2010, are included in Spent Nuclear Fuel and Decommissioning Trusts on our Condensed Consolidated Balance Sheets.

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2011 are shown in the tables below.

Company	Type of Debt		Principal Amount (in millions)	Interest Rate (%)	Due Date
Issuances:					
APCo	Senior Unsecured Notes	$	350	4.60	2021
APCo	Pollution Control Bonds		65	2.00	2012
APCo	Pollution Control Bonds		75 (a)	Variable	2036
APCo	Pollution Control Bonds		54 (a)	Variable	2042
APCo	Pollution Control Bonds		50 (a)	Variable	2036
APCo	Pollution Control Bonds		50 (a)	Variable	2042
I&M	Pollution Control Bonds		52 (a)	Variable	2021
I&M	Pollution Control Bonds		25 (a)	Variable	2019
OPCo	Pollution Control Bonds		50 (a)	Variable	2014
PSO	Senior Unsecured Notes		250	4.40	2021
Total Issuances		$	1,021 (b)		

(a) These pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year on our Condensed Consolidated Balance Sheets.
(b) Amount indicated on the statement of cash flows of $1,014 million is net of issuance costs and premium or discount.

Company	Type of Debt		Principal Amount Paid (in millions)	Interest Rate (%)	Due Date
Retirements and Principal Payments:					
APCo	Pollution Control Bonds	$	75	Variable	2036
APCo	Pollution Control Bonds		54	Variable	2042
APCo	Pollution Control Bonds		50	Variable	2042
APCo	Pollution Control Bonds		50	Variable	2036
I&M	Pollution Control Bonds		52	Variable	2021
I&M			25	Variable	2019

	Pollution Control Bonds				
I&M	Notes Payable		5	Variable	2015
OPCo	Pollution Control Bonds		65	Variable	2036
OPCo	Pollution Control Bonds		50	Variable	2014
OPCo	Pollution Control Bonds		50	Variable	2014
PSO	Senior Unsecured Notes		200	6.00	2032
Non-Registrant:					
AEP Subsidiaries	Notes Payable		5	Variable	2017
AEGCo	Senior Unsecured Notes		4	6.33	2037
TCC	Securitization Bonds		34	5.96	2013
TCC	Securitization Bonds		58	4.98	2013
Total Retirements and Principal Payments		$	777		

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 Notes Payable related to DCC Fuel.

As of March 31, 2011, trustees held, on our behalf, $418 million of our reacquired Pollution Control Bonds.

Dividend Restrictions

Parent Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. Our income derives from our common stock equity in the earnings of our utility subsidiaries.

Pursuant to the leverage restrictions in our credit agreements, we must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements. None of AEP’s retained earnings were restricted for the purpose of the payment of dividends.

We have issued $315 million of Junior Subordinated Debentures. The debentures will mature on March 1, 2063, subject to extensions to no later than March 1, 2068, and are callable at par any time on or after March 1, 2013. We have the option to defer interest payments on the 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 anticipate any deferral of those interest payments in the foreseeable future.

Utility Subsidiaries’ Restrictions

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. Specifically, most of our public utility subsidiaries have agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%. At March 31, 2011, the amount of restricted net assets of AEP’s subsidiaries that may not be distributed to Parent in the form of a loan, advance or dividend was approximately $7 billion.

The Federal Power Act prohibits the utility subsidiaries from participating “in the making or paying of any dividends of such public utility from any funds properly included in capital account.” The term “capital account” is not defined in the Federal Power Act or its regulations. Management understands “capital account” to mean the par value of the common stock multiplied by the number of shares outstanding. This restriction does not limit the ability of the utility subsidiaries to pay dividends out of retained earnings.

Short-term Debt

Our outstanding short-term debt was as follows:

	March 31, 2011		December 31, 2010	
Type of Debt	Outstanding Amount (in millions)	Interest Rate (a)	Outstanding Amount (in millions)	Interest Rate (a)
Securitized Debt for Receivables (b)	$ 620	0.30 %	$ 690	0.31 %
Commercial Paper	813	0.48 %	650	0.52 %
Line of Credit – Sabine Mining Company (c)	-	- %	6	2.15 %
Total Short-term Debt	$ 1,433		$ 1,346	

(a) Weighted average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.
(c) Sabine Mining Company is a consolidated variable interest entity. This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

We have two $1.5 billion credit facilities, under which we may issue up to $1.35 billion as letters of credit. As of March 31, 2011, the maximum future payments for letters of credit issued under the two $1.5 billion credit facilities were $124 million.

In March 2011, we terminated a $478 million credit agreement that was scheduled to mature in April 2011 and was used to support $472 million of variable rate Pollution Control Bonds. In March 2011, we remarketed $357 million of variable rate Pollution Control Bonds using bilateral letters of credit for $361 million to support the remarketed Pollution Control Bonds. The remaining $115 million of Pollution Control Bonds were reacquired and are held by trustees.

Securitized Accounts Receivable – AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. AEP Credit continues to service the receivables. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables and accelerate AEP Credit's cash collections.

In July 2010, AEP Credit renewed its receivables securitization agreement. The agreement provides a commitment of $750 million from bank conduits to finance receivables from AEP Credit. A commitment of $375 million expires in July 2011 and the remaining commitment of $375 million expires in July 2013.

Accounts receivable information for AEP Credit is as follows:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(dollars in millions)	
Effective Interest Rate on Securitization of Accounts Receivable	0.31 %	0.23 %
Net Uncollectible Accounts Receivable Written Off	$ 11	$ 4

	March 31, 2011	December 31, 2010
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 893	$ 923
Total Principal Outstanding	620	690
Delinquent Securitized Accounts Receivable	42	50
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	21	26
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	297	354

Customer accounts receivable retained and securitized for our operating companies are managed by AEP Credit. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

11. COST REDUCTION INITIATIVES

In April 2010, we began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions were eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

We recorded a charge to Other Operation expense of $293 million in 2010 primarily related to the headcount reduction initiatives. These costs related primarily to severance benefits. We do not expect additional costs to be incurred related to this initiative.

	Total (in millions)	
Balance as of December 31, 2010	$	17
Incurred		-
Settled		(5)
Adjustments		(1)
Balance as of March 31, 2011	$	11

The remaining accruals are included primarily in Other Current Liabilities on the Condensed Consolidated Balance Sheets.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S DISCUSSION AND ANALYSIS

EXECUTIVE OVERVIEW

Regulatory Activity

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 March 2011, the WVPSC modified and approved a settlement agreement which increased annual base rates by approximately $46 million based upon a 10% return on common equity. The order also resulted in a pretax write-off of a portion of the 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 $14 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.

In a November 2009 proceeding established by the WVPSC to explore options to meet WPCo's future power supply requirements, the WVPSC issued an order approving a joint stipulation among APCo, WPCo, the WVPSC staff and the Consumer Advocate Division. The order approved the recommendation of the signatories to the stipulation that WPCo merge into APCo and be supplied from APCo's existing power resources. Merger approvals from the WVPSC, Virginia SCC and the FERC are required. No merger approval filings have been made. See "WPCo Merger with APCo" section of Note 2.

Mountaineer Carbon Capture and Storage Project 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 May 2010 West Virginia base rate filing, APCo 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.

Proposed Acquisition of Dresden Plant

During the first quarter of 2011, APCo and AEGCo filed with the Virginia and West Virginia regulatory commissions seeking approval for APCo’s purchase of the partially completed Dresden Plant from AEGCo at cost. The Dresden Plant is located near Dresden, Ohio and is a natural gas, combined cycle power plant. AEGCo resumed construction in the first quarter of 2011 following a suspension in 2009 due to economic conditions. When completed, the Dresden Plant will have a generating capacity of 580 MW.

Litigation and Environmental Issues

In the ordinary course of business, APCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2010 Annual Report. Also, see Note 2 – Rate Matters and Note 3 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 143. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the “Executive Overview” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page 201 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

	Three Months Ended March 31, 2011	2010
	(in millions of KWH)	
Retail:		
Residential	3,959	4,528
Commercial	1,698	1,787
Industrial	2,619	2,463
Miscellaneous	210	222
Total Retail	8,486	9,000
Wholesale	1,827	1,703
Total KWHs	10,313	10,703

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31,	
	2011	2010
	(in degree days)	
Actual - Heating (a)	1,330	1,577
Normal - Heating (b)	1,337	1,399
Actual - Cooling (c)	6	-
Normal - Cooling (b)	6	6

(a) Eastern 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.

First Quarter of 2011 Compared to First Quarter of 2010

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

First Quarter of 2010	$	70
Changes in Gross Margin:		
Retail Margins		(60)
Off-system Sales		1
Transmission Revenue		2
Total Change in Gross Margin		(57)
Total Expenses and Other:		
Other Operation and Maintenance		8
Depreciation and Amortization		8
Taxes Other Than Income Taxes		(1)
Carrying Costs Income		(2)
Interest Expense		(1)
Total Expenses and Other		12
Income Tax Expense		14
First Quarter of 2011	$	39

The major components of the decrease 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 decreased $60 million primarily due to the following:
  - A $46 million decrease primarily due to a 13% decrease in residential usage, a 5% decrease in commercial usage and lower retail rates.
  - A $23 million decrease in rate relief 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. This decrease in retail margins had corresponding decreases of $17 million related to riders/trackers recognized in other expense items discussed below.

  These decreases were partially offset by:
  - A $21 million increase due to lower capacity settlement expenses under the Interconnection Agreement net of recovery in West Virginia and environmental deferrals in Virginia.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $8 million primarily due to the following:
  - A $32 million decrease due to the deferral of storm costs and costs related to 2010 cost reduction initiatives. These costs were deferred as a result of the approved modified settlement agreement of APCo’s West Virginia base rate case in March 2011.
  - A $6 million decrease in employee-related expenses.

- A $6 million decrease primarily due to lower overhead line maintenance expenses.
- A $5 million decrease in maintenance expenses in 2011 resulting primarily from a 2010 planned outage at the Amos Plant.

These decreases were partially offset by:

- A $41 million increase due to the write-off of a portion of the Mountaineer Carbon Capture and Storage Project Product Validation Facility as denied for recovery by the WVPSC in March 2011.
- Depreciation and Amortization expenses decreased $8 million primarily due to the expiration of E&R amortization of deferred carrying costs in Virginia, partially offset by an increased depreciation base resulting from environmental upgrades at the Amos Plant.
- Income Tax Expense decreased $14 million primarily due to a decrease in pretax book income.

FINANCIAL CONDITION

LIQUIDITY

APCo participates in the Utility Money Pool, which provides access to AEP's liquidity. APCo has $250 million of Senior Unsecured Notes that matured in April 2011. APCo relies upon ready access to capital markets, cash flows from operations and access to the Utility Money Pool to fund its maturities, current operations and capital expenditures. See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 201 for additional discussion of liquidity.

Credit Ratings

APCo's ultimate access to capital markets may depend on its credit ratings. In addition, a credit rating downgrade of APCo by one of the rating agencies could increase APCo's borrowing costs. Failure to maintain investment grade ratings may constrain APCo's ability to participate in the Utility Money Pool or the amount of APCo's receivables securitized by AEP Credit. Counterparty concerns about APCo's credit quality could subject APCo to additional collateral demands under adequate assurance clauses under derivative and non-derivative energy contracts.

CASH FLOW

Cash flows for the three months ended March 31, 2011 and 2010 were as follows:

	2011	2010
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 951	$ 2,006
Net Cash Flows from Operating Activities	250,841	178,522
Net Cash Flows Used for Investing Activities	(492,622)	(167,978)
Net Cash Flows from (Used for) Financing Activities	243,214	(10,308)
Net Increase in Cash and Cash Equivalents	1,433	236
Cash and Cash Equivalents at End of Period	$ 2,384	$ 2,242

Operating Activities

Net Cash Flows from Operating Activities were $251 million in 2011. APCo produced Net Income of $39 million during the period and had noncash expense items of $69 million for Depreciation and Amortization and $61 million for Deferred Income Taxes. The other changes in assets and liabilities 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. The activity in working capital relates to a number of items. The $110 million inflow from Accounts Receivable, Net was primarily due to a decrease in accrued unbilled revenues due to usual seasonal fluctuations and timing of settlements of receivables from affiliated companies. The $71 million outflow from Accounts Payable was primarily due to decreased energy purchases and reduced operation and maintenance expenses. The $62 million inflow from Fuel, Materials and Supplies was primarily due to a reduction in fuel inventory and a decrease in the average cost of coal per ton. The $32 million outflow from Accrued Taxes, Net was primarily the result of a decrease in federal income tax accruals.

Net Cash Flows from Operating Activities were $179 million in 2010. APCo produced Net Income of $70 million during the period and a noncash expense item of $77 million for Depreciation and Amortization. The other changes in assets and liabilities 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. The activity in working capital relates to a number of items. The $98 million outflow from Accounts

Payable was primarily due to payments for storm costs accrued in fourth quarter of 2009 and decreased purchases of energy from the system pool. The $81 million inflow from Accounts Receivable, Net was primarily due to a decrease in accrued revenues due to usual seasonal fluctuations and timing of settlements of receivables from affiliated companies. The $41 million inflow from Fuel, Materials and Supplies was primarily due to a reduction in fuel inventory and a decrease in the average cost of coal per ton.

Investing Activities

Net Cash Flows Used for Investing Activities during 2011 and 2010 were $493 million and $168 million, respectively. Construction expenditures of $113 million and $167 million in 2011 and 2010, respectively, were primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades. Environmental upgrades primarily include installation of FGD equipment at the Amos Plant. During 2011, APCo increased loans to the Utility Money Pool by $384 million.

Financing Activities

Net Cash Flows from Financing Activities were $243 million in 2011. APCo issued $350 million of Senior Unsecured Notes and $295 million of Pollution Control Bonds, partially offset by the retirement of $230 million of Pollution Control Bonds. APCo had a net decrease of $128 million in borrowings from the Utility Money Pool. In addition, APCo paid $38 million in common stock dividends.

Net Cash Flows Used for Financing Activities were $10 million in 2010. APCo had a net increase of $118 million in borrowings from the Utility Money Pool. APCo retired $100 million of Notes Payable - Affiliated and issued $17.5 million of Pollution Control Bonds in 2010. In addition, APCo paid $44 million in common stock dividends.

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

Long-term debt issuances, retirements and principal payments made during the first three months of 2011 were:

Issuances

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$	350,000	4.60	2021
Pollution Control Bonds		65,350	2.00	2012
Pollution Control Bonds		75,000 (a)	Variable	2036
Pollution Control Bonds		50,275 (a)	Variable	2036
Pollution Control Bonds		54,375 (a)	Variable	2042
Pollution Control Bonds		50,000 (a)	Variable	2042

(a) These pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year - Nonaffiliated on APCo's Condensed Consolidated Balance Sheets.

Retirements and Principal Payments

Type of Debt		Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Pollution Control Bonds	$	75,000	Variable	2036
Pollution Control Bonds		50,275	Variable	2036
Pollution Control Bonds		54,375	Variable	2042
Pollution Control Bonds		50,000	Variable	2042
Land Note		5	13.718	2026

CONTRACTUAL OBLIGATION INFORMATION

A summary of contractual obligations is included in the 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.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” 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 and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 201 for a discussion of accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “Quantitative And Qualitative Disclosures About Market Risk” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 201 for a discussion of market risk.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
REVENUES		
Electric Generation, Transmission and Distribution	$751,012	$845,990
Sales to AEP Affiliates	78,691	78,771
Other Revenues	2,117	1,862
TOTAL REVENUES	831,820	926,623
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	180,581	180,640
Purchased Electricity for Resale	69,218	63,683
Purchased Electricity from AEP Affiliates	224,189	267,502
Other Operation	113,276	90,040
Maintenance	32,293	63,110
Depreciation and Amortization	69,099	77,430
Taxes Other Than Income Taxes	27,103	26,280
TOTAL EXPENSES	715,759	768,685
OPERATING INCOME	116,061	157,938
Other Income (Expense):		
Interest Income	320	291
Carrying Costs Income	3,439	5,764
Allowance for Equity Funds Used During Construction	883	1,163
Interest Expense	(52,939)	(51,727)
INCOME BEFORE INCOME TAX EXPENSE	67,764	113,429
Income Tax Expense	28,784	43,147
NET INCOME	38,980	70,282
Preferred Stock Dividend Requirements Including Capital Stock Expense	200	225
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$38,780	$70,057

The common stock of APCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$260,458	$1,475,393	$1,085,980	$ (50,254)	$2,771,577
Common Stock Dividends			(44,000)		(44,000)
Preferred Stock Dividends			(200)		(200)
Capital Stock Expense		27	(25)		2
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					2,727,379
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $940				(1,746)	(1,746)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $562				1,043	1,043
NET INCOME			70,282		70,282
TOTAL COMPREHENSIVE INCOME					69,579
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2010	$260,458	$1,475,420	$1,112,037	$ (50,957)	$2,796,958
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	$260,458	$1,475,496	$1,133,748	$ (48,023)	$2,821,679
Common Stock Dividends			(37,500)		(37,500)
Preferred Stock Dividends			(200)		(200)
Capital Stock Expense		3			3
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					2,783,982
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $275				511	511

Amortization of Pension and OPEB Deferred Costs, Net of Tax of $418				777	777
NET INCOME			38,980		38,980
TOTAL COMPREHENSIVE INCOME					40,268
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2011	$260,458	$1,475,499	$1,135,028	$ (46,735)	$2,824,250

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2011 and December 31, 2010
(in thousands)
(Unaudited)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$2,384	$951
Advances to Affiliates	383,537	-
Accounts Receivable:		
Customers	153,002	166,878
Affiliated Companies	101,346	145,972
Accrued Unbilled Revenues	58,693	108,210
Miscellaneous	1,348	3,090
Allowance for Uncollectible Accounts	(7,045)	(6,667)
Total Accounts Receivable	307,344	417,483
Fuel	167,153	230,697
Materials and Supplies	91,068	89,370
Risk Management Assets	38,923	53,242
Accrued Tax Benefits	109,294	104,435
Regulatory Asset for Under-Recovered Fuel Costs	18,131	18,300
Prepayments and Other Current Assets	29,707	35,811
TOTAL CURRENT ASSETS	1,147,541	950,289
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,096,419	4,736,150
Transmission	1,874,320	1,852,415
Distribution	2,760,683	2,740,752
Other Property, Plant and Equipment	348,613	348,013
Construction Work in Progress	209,978	562,280
Total Property, Plant and Equipment	10,290,013	10,239,610
Accumulated Depreciation and Amortization	2,882,681	2,843,087
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,407,332	7,396,523
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,485,103	1,486,625
Long-term Risk Management Assets	40,266	38,420
Deferred Charges and Other Noncurrent Assets	128,641	125,296
TOTAL OTHER NONCURRENT ASSETS	1,654,010	1,650,341
TOTAL ASSETS	$10,208,883	$9,997,153

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2011 and December 31, 2010
(Unaudited)

	2011	2010
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$-	$128,331
Accounts Payable:		
General	155,890	223,144
Affiliated Companies	133,716	166,884
Long-term Debt Due Within One Year – Nonaffiliated	479,673	479,672
Risk Management Liabilities	22,746	27,993
Customer Deposits	59,385	58,451
Deferred Income Taxes	40,752	44,180
Accrued Taxes	76,268	75,619
Accrued Interest	71,566	57,871
Other Current Liabilities	81,662	93,286
TOTAL CURRENT LIABILITIES	1,121,658	1,355,431
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,496,032	3,081,469
Long-term Risk Management Liabilities	13,339	10,873
Deferred Income Taxes	1,679,963	1,642,072
Regulatory Liabilities and Deferred Investment Tax Credits	554,577	562,381
Employee Benefits and Pension Obligations	302,517	306,460
Deferred Credits and Other Noncurrent Liabilities	198,811	199,041
TOTAL NONCURRENT LIABILITIES	6,245,239	5,802,296
TOTAL LIABILITIES	7,366,897	7,157,727
Cumulative Preferred Stock Not Subject to Mandatory Redemption	17,736	17,747
Rate Matters (Note 2)		
Commitments and Contingencies (Note 3)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260,458	260,458
Paid-in Capital	1,475,499	1,475,496
Retained Earnings	1,135,028	1,133,748
Accumulated Other Comprehensive Income (Loss)	(46,735)	(48,023)
TOTAL COMMON SHAREHOLDER’S EQUITY	2,824,250	2,821,679
TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY	$10,208,883	$9,997,153

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
OPERATING ACTIVITIES		
Net Income	$38,980	$70,282
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	69,099	77,430
Deferred Income Taxes	60,802	19,121
Carrying Costs Income	(3,439)	(5,764)
Allowance for Equity Funds Used During Construction	(883)	(1,163)
Mark-to-Market of Risk Management Contracts	(1,553)	(12,977)
Fuel Over/Under-Recovery, Net	(9,857)	(11,804)
Change in Other Noncurrent Assets	10,237	11,082
Change in Other Noncurrent Liabilities	12,013	(2,568)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	109,662	80,813
Fuel, Materials and Supplies	61,846	41,054
Accounts Payable	(71,056)	(97,732)
Accrued Taxes, Net	(32,472)	24,150
Other Current Assets	6,505	(4,250)
Other Current Liabilities	957	(9,152)
Net Cash Flows from Operating Activities	250,841	178,522
INVESTING ACTIVITIES		
Construction Expenditures	(113,132)	(167,412)
Change in Advances to Affiliates, Net	(383,537)	-
Other Investing Activities	4,047	(566)
Net Cash Flows Used for Investing Activities	(492,622)	(167,978)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	640,770	17,376
Change in Advances from Affiliates, Net	(128,331)	117,879
Retirement of Long-term Debt – Nonaffiliated	(229,655)	(5)
Retirement of Long-term Debt – Affiliated	-	(100,000)
Retirement of Cumulative Preferred Stock	(8)	(4)
Principal Payments for Capital Lease Obligations	(1,876)	(1,790)
Dividends Paid on Common Stock	(37,500)	(44,000)
Dividends Paid on Cumulative Preferred Stock	(200)	(200)
Other Financing Activities	14	436
Net Cash Flows from (Used for) Financing Activities	243,214	(10,308)
Net Increase in Cash and Cash Equivalents	1,433	236
Cash and Cash Equivalents at Beginning of Period	951	2,006

Cash and Cash Equivalents at End of Period	$2,384	$2,242
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$36,992	$38,971
Net Cash Paid for Income Taxes	629	-
Noncash Acquisitions Under Capital Leases	368	20,369
Government Grants Included in Accounts Receivable at March 31,	572	-
Construction Expenditures Included in Current Liabilities at March 31,	38,071	43,262

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to APCo's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to APCo. The footnotes begin on page 143.

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS

EXECUTIVE OVERVIEW

Ohio Customer Choice

In CSPCo's service territory, various competitive retail electric service (CRES) providers are targeting retail customers by offering alternative generation service. Through March 31, 2011, approximately 7,500 CSPCo retail customers have switched from CSPCo to alternative CRES providers. As a result, in comparison to the first three months of 2010, CSPCo lost approximately $18 million of generation related gross margin through March 31, 2011. Management anticipates recovery of a portion of this lost margin through off-system sales, including PJM capacity revenues.

Regulatory Activity

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 which resulted in three reversals, only 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 remaining months of 2011. See "Ohio Electric Security Plan Filings" section of Note 2.

January 2012 – May 2014 ESP

In January 2011, CSPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing for generation. The rates would be 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 will have base generation increases, excluding riders, of $17 million for 2012 and $46 million 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 filed with the PUCO for an annual increase in distribution rates of $34 million. 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 requested recovery of the projected December 31, 2012 balance of certain distribution regulatory assets of $216 million, including approximately $102 million of unrecognized equity carrying costs. These assets would be recovered in a requested distribution asset recovery rider over seven years with additional carrying costs, beginning January 2013. The actual balance of these distribution regulatory assets as of March 31, 2011 was $98 million, excluding $57 million of unrecognized equity carrying costs. If CSPCo is not ultimately permitted to fully recover its deferrals, it would reduce future net income and cash flows and impact financial condition. See "Ohio Distribution Base Rate Case" section of Note 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. In January 2011, CSPCo and OPCo filed an application with the FERC requesting approval for an internal corporate reorganization under which CSPCo will merge into OPCo. CSPCo and OPCo requested the reorganization transaction be effective in October 2011. Decisions are pending from the PUCO and the FERC. See “Proposed CSPCo and OPCo Merger” section of Note 2.

Litigation and Environmental Issues

In the ordinary course of business, CSPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2010 Annual Report. Also, see Note 2 – Rate Matters and Note 3 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 143. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Executive Overview" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 201 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

		Three Months Ended March 31, 2011	2010
		(in millions of KWH)	
Retail:			
	Residential	2,127	2,226
	Commercial	1,995	2,002
	Industrial	1,270	1,111
	Miscellaneous	14	13
Total Retail		5,406	5,352
Wholesale		863	719
Total KWHs		6,269	6,071

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2011	2010
	(in degree days)	
Actual - Heating (a)	1,928	1,965
Normal - Heating (b)	1,784	1,784
Actual - Cooling (c)	1	-
Normal - Cooling (b)	3	3

(a) Eastern 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.

First Quarter of 2011 Compared to First Quarter of 2010

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

First Quarter of 2010	$	52	
Changes in Gross Margin:			
Retail Margins		10	
Off-system Sales		12	
Total Change in Gross Margin		22	
Total Expenses and Other:			
Other Operation and Maintenance		1	
Depreciation and Amortization		(4	)
Taxes Other Than Income Taxes		(3	)
Interest Expense		2	
Other Income		1	
Total Expenses and Other		(3	)
Income Tax Expense		(6	)
First Quarter of 2011	$	65	

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 $10 million due to the following:
  - A $12 million increase in revenue due to the implementation of PUCO approved rider rates in June 2010 related to the Energy Efficiency & Peak Demand Reduction (EE/PDR) Programs. This increase in Retail Margins was offset by a corresponding increase in Other Operation and Maintenance as discussed below.
  - A $10 million increase associated with the final 2009 SEET order.
  - A $4 million increase in revenues due to the implementation of PUCO approved rider rates in September 2010 related to the Environmental Investment Carrying Cost Rider.

  These increases were partially offset by:
  - An $18 million decrease attributable to 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.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $1 million primarily due to:
  -

A $7 million decrease in transmission expense primarily due to the Transmission Agreement modification effective November 2010, a portion of which is included in the Ohio Transmission Cost Recovery Rider.

- A $3 million decrease in employee-related expenses.

These decreases were partially offset by:

- A $12 million increase in expenses due to the implementation of PUCO approved EE/PDR programs. This increase in Other Operation and Maintenance expense was offset by a corresponding increase in Retail Margins as discussed above.

- Depreciation and Amortization expenses increased $4 million as a result of recognizing the deferred debt and equity carrying charges on deferred fuel as permitted under the final 2009 SEET order.

- Taxes Other Than Income Taxes increased $3 million due to an increase in property taxes.
- Income Tax Expense increased $6 million primarily due to an increase in pre-tax book income, offset in part by the 2010 tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” 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 and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 201 for a discussion of accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “Quantitative And Qualitative Disclosures About Market Risk” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 201 for a discussion of market risk.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
REVENUES		
Electric Generation, Transmission and Distribution	$503,371	$501,019
Sales to AEP Affiliates	40,725	15,832
Other Revenues	506	588
TOTAL REVENUES	544,602	517,439
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	112,913	114,441
Purchased Electricity for Resale	23,517	19,645
Purchased Electricity from AEP Affiliates	101,611	98,799
Other Operation	71,067	77,326
Maintenance	29,100	24,283
Depreciation and Amortization	41,426	37,487
Taxes Other Than Income Taxes	50,149	47,057
TOTAL EXPENSES	429,783	419,038
OPERATING INCOME	114,819	98,401
Other Income (Expense):		
Interest Income	167	142
Carrying Costs Income	3,654	2,221
Allowance for Equity Funds Used During Construction	771	921
Interest Expense	(19,748)	(21,784)
INCOME BEFORE INCOME TAX EXPENSE	99,663	79,901
Income Tax Expense	34,105	28,251
NET INCOME	65,558	51,650
Capital Stock Expense	25	39
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$65,533	$51,611

The common stock of CSPCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$41,026	$580,663	$788,139	$ (49,993)	$1,359,835
Common Stock Dividends			(31,250)		(31,250)
Capital Stock Expense		39	(39)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,328,585
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $555				(1,031)	(1,031)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $333				619	619
NET INCOME			51,650		51,650
TOTAL COMPREHENSIVE INCOME					51,238
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2010	$41,026	$580,702	$808,500	$ (50,405)	$1,379,823
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	$41,026	$580,812	$915,713	$ (51,336)	$1,486,215
Common Stock Dividends			(62,500)		(62,500)
Capital Stock Expense		25	(25)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,423,715
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $114				213	213
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $344				639	639

NET INCOME			65,558		65,558
TOTAL COMPREHENSIVE INCOME					66,410
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2011	$41,026	$580,837	$918,746	$ (50,484)	$1,490,125

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2011 and December 31, 2010
(in thousands)
(Unaudited)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$1,385	$509
Other Cash Deposits	2,260	2,260
Advances to Affiliates	63,706	54,202
Accounts Receivable:		
Customers	50,017	50,187
Affiliated Companies	44,261	66,788
Accrued Unbilled Revenues	14,205	32,821
Miscellaneous	4,715	14,374
Allowance for Uncollectible Accounts	(1,618)	(1,584)
Total Accounts Receivable	111,580	162,586
Fuel	64,555	72,882
Materials and Supplies	41,290	42,033
Emission Allowances	26,461	28,486
Risk Management Assets	22,221	23,774
Accrued Tax Benefits	1,453	8,797
Regulatory Asset for Under-Recovered Fuel Costs	19,199	-
Margin Deposits	11,162	14,762
Prepayments and Other Current Assets	11,066	26,864
TOTAL CURRENT ASSETS	376,338	437,155
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	2,719,642	2,686,294
Transmission	676,250	662,312
Distribution	1,804,501	1,796,023
Other Property, Plant and Equipment	203,744	203,593
Construction Work in Progress	142,609	172,793
Total Property, Plant and Equipment	5,546,746	5,521,015
Accumulated Depreciation and Amortization	1,959,482	1,927,112
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,587,264	3,593,903
OTHER NONCURRENT ASSETS		
Regulatory Assets	303,741	298,111
Long-term Risk Management Assets	23,080	22,089
Deferred Charges and Other Noncurrent Assets	125,746	152,932
TOTAL OTHER NONCURRENT ASSETS	452,567	473,132
TOTAL ASSETS	$4,416,169	$4,504,190

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
March 31, 2011 and December 31, 2010
(Unaudited)

	2011	2010
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$80,031	$98,925
Affiliated Companies	55,640	78,617
Long-term Debt Due Within One Year – Nonaffiliated	150,000	-
Risk Management Liabilities	13,053	15,967
Customer Deposits	30,222	29,441
Accrued Taxes	175,816	226,572
Accrued Interest	25,189	22,533
Other Current Liabilities	93,112	111,868
TOTAL CURRENT LIABILITIES	623,063	583,923
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,288,900	1,438,830
Long-term Risk Management Liabilities	7,653	6,223
Deferred Income Taxes	619,951	604,828
Regulatory Liabilities and Deferred Investment Tax Credits	164,212	163,888
Employee Benefits and Pension Obligations	135,202	136,643
Deferred Credits and Other Noncurrent Liabilities	87,063	83,640
TOTAL NONCURRENT LIABILITIES	2,302,981	2,434,052
TOTAL LIABILITIES	2,926,044	3,017,975
Rate Matters (Note 2)		
Commitments and Contingencies (Note 3)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 24,000,000 Shares		
Outstanding – 16,410,426 Shares	41,026	41,026
Paid-in Capital	580,837	580,812
Retained Earnings	918,746	915,713
Accumulated Other Comprehensive Income (Loss)	(50,484)	(51,336)
TOTAL COMMON SHAREHOLDER'S EQUITY	1,490,125	1,486,215
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$4,416,169	$4,504,190

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

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COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
OPERATING ACTIVITIES		
Net Income	$65,558	$51,650
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	41,426	37,487
Deferred Income Taxes	31,902	8,327
Allowance for Equity Funds Used During Construction	(771)	(921)
Mark-to-Market of Risk Management Contracts	(669)	(11,609)
Property Taxes	27,283	24,131
Fuel Over/Under-Recovery, Net	(4,891)	26,139
Change in Other Noncurrent Assets	(9,041)	(4,994)
Change in Other Noncurrent Liabilities	5,100	(46)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	43,606	5,553
Fuel, Materials and Supplies	10,033	(9,795)
Accounts Payable	(35,549)	(22,402)
Accrued Taxes, Net	(48,059)	(24,444)
Other Current Assets	4,645	(428)
Other Current Liabilities	(25,526)	(1,619)
Net Cash Flows from Operating Activities	105,047	77,029
INVESTING ACTIVITIES		
Construction Expenditures	(45,732)	(42,906)
Change in Other Cash Deposits	-	10,290
Change in Advances to Affiliates, Net	(9,504)	(37,818)
Acquisitions of Assets	(201)	(190)
Proceeds from Sales of Assets	2,439	789
Other Investing Activities	12,179	-
Net Cash Flows Used for Investing Activities	(40,819)	(69,835)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	-	149,625
Change in Advances from Affiliates, Net	-	(24,202)
Retirement of Long-term Debt – Affiliated	-	(100,000)
Principal Payments for Capital Lease Obligations	(852)	(1,120)
Dividends Paid on Common Stock	(62,500)	(31,250)
Other Financing Activities	-	71
Net Cash Flows Used for Financing Activities	(63,352)	(6,876)
Net Increase in Cash and Cash Equivalents	876	318
Cash and Cash Equivalents at Beginning of Period	509	1,096
Cash and Cash Equivalents at End of Period	$1,385	$1,414

SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$16,396	$18,631
Net Cash Paid for Income Taxes	518	-
Noncash Acquisitions Under Capital Leases	139	8,353
Government Grants Included in Accounts Receivable at March 31,	1,938	-
Construction Expenditures Included in Current Liabilities at March 31,	8,572	13,891

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to CSPCo's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to CSPCo. The footnotes begin on page 143.

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS

EXECUTIVE OVERVIEW

Regulatory Activity

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 "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, management expects 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.

Litigation and Environmental Issues

In the ordinary course of business, I&M is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2010 Annual Report. Also, see Note 2 – Rate Matters and Note 3 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 143. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Executive Overview" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 201 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

		Three Months Ended March 31, 2011	2010
		(in millions of KWH)	
Retail:			
	Residential	1,836	1,765
	Commercial	1,263	1,208
	Industrial	1,844	1,800
	Miscellaneous	23	18
Total Retail		4,966	4,791
Wholesale		2,096	1,906
Total KWHs		7,062	6,697

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2011	2010
	(in degree days)	
Actual - Heating (a)	2,392	2,174
Normal - Heating (b)	2,175	2,172
Actual - Cooling (c)	-	-
Normal - Cooling (b)	1	1

(a) Eastern 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.

First Quarter of 2011 Compared to First Quarter of 2010

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

First Quarter of 2010	$	45
Changes in Gross Margin:		
Retail Margins		13
FERC Municipals and Cooperatives		2
Off-system Sales		2
Other Revenues		(2)
Total Change in Gross Margin		15
Total Expenses and Other:		
Other Operation and Maintenance		(6)
Taxes Other Than Income Taxes		(1)
Other Income		(1)
Interest Expense		1
Total Expenses and Other		(7)
Income Tax Expense		(8)
First Quarter of 2011	$	45

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 $13 million primarily due to the following:
  · An $8 million increase due to Michigan rate settlement effective in December 2010.
  · A $7 million increase in margins from residential sales primarily due to higher usage reflecting favorable weather.

Total Expenses and Other and Income Tax Expense changed between years as follows:

· Other Operation and Maintenance expenses increased $6 million primarily due to the following:
  · A $10 million increase in transmission expense primarily due to the Transmission Agreement modification effective November 2010.

  This increase was partially offset by:
  · A $5 million decrease in administrative and general expenses.
· Income Tax Expense increased $8 million primarily due to an increase in pretax book income and federal income tax adjustments related to prior year tax returns.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” 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 and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 201 for a discussion of accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “Quantitative And Qualitative Disclosures About Market Risk” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 201 for a discussion of market risk.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
REVENUES		
Electric Generation, Transmission and Distribution	$456,862	$438,024
Sales to AEP Affiliates	74,868	84,217
Other Revenues - Affiliated	24,331	27,966
Other Revenues - Nonaffiliated	4,431	2,849
TOTAL REVENUES	560,492	553,056
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	115,062	119,181
Purchased Electricity for Resale	29,292	29,767
Purchased Electricity from AEP Affiliates	79,584	82,250
Other Operation	133,211	130,681
Maintenance	51,000	48,444
Depreciation and Amortization	34,087	33,831
Taxes Other Than Income Taxes	22,262	21,032
TOTAL EXPENSES	464,498	465,186
OPERATING INCOME	95,994	87,870
Other Income (Expense):		
Interest Income	696	485
Allowance for Equity Funds Used During Construction	3,199	4,435
Interest Expense	(25,191)	(26,101)
INCOME BEFORE INCOME TAX EXPENSE	74,698	66,689
Income Tax Expense	29,271	21,631
NET INCOME	45,427	45,058
Preferred Stock Dividend Requirements	85	85
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$45,342	$44,973

The common stock of I&M is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$56,584	$981,292	$656,608	$ (21,701)	$1,672,783
Common Stock Dividends			(25,750)		(25,750)
Preferred Stock Dividends			(85)		(85)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,646,948
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $422				(784)	(784)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $117				218	218
NET INCOME			45,058		45,058
TOTAL COMPREHENSIVE INCOME					44,492
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2010	$56,584	$981,292	$675,831	$ (22,267)	$1,691,440
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	$56,584	$981,294	$677,360	$ (20,889)	$1,694,349
Common Stock Dividends			(18,750)		(18,750)
Preferred Stock Dividends			(85)		(85)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,675,514
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $286				531	531
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $128				237	237

NET INCOME			45,427		45,427
TOTAL COMPREHENSIVE INCOME					46,195
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2011	$56,584	$981,294	$703,952	$ (20,121)	$1,721,709

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2011 and December 31, 2010
(in thousands)
(Unaudited)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$912	$361
Advances to Affiliates	56,813	-
Accounts Receivable:		
Customers	56,396	76,193
Affiliated Companies	62,023	149,169
Accrued Unbilled Revenues	28,066	19,449
Miscellaneous	11,714	10,968
Allowance for Uncollectible Accounts	(1,687)	(1,692)
Total Accounts Receivable	156,512	254,087
Fuel	79,584	87,551
Materials and Supplies	177,955	178,331
Risk Management Assets	26,436	27,526
Accrued Tax Benefits	68,504	71,113
Deferred Cook Plant Fire Costs	46,532	45,752
Prepayments and Other Current Assets	24,607	33,713
TOTAL CURRENT ASSETS	637,855	698,434
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,781,344	3,774,262
Transmission	1,197,343	1,188,665
Distribution	1,427,078	1,411,095
Other Property, Plant and Equipment (including nuclear fuel and coal mining)	715,565	719,708
Construction Work in Progress	301,781	301,534
Total Property, Plant and Equipment	7,423,111	7,395,264
Accumulated Depreciation, Depletion and Amortization	3,153,696	3,124,998
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,269,415	4,270,266
OTHER NONCURRENT ASSETS		
Regulatory Assets	534,389	556,254
Spent Nuclear Fuel and Decommissioning Trusts	1,558,535	1,515,227
Long-term Risk Management Assets	31,923	31,485
Deferred Charges and Other Noncurrent Assets	85,384	77,229
TOTAL OTHER NONCURRENT ASSETS	2,210,231	2,180,195
TOTAL ASSETS	$7,117,501	$7,148,895

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2011 and December 31, 2010
(dollars in thousands)
(Unaudited)

	2011	2010
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 42,769
Accounts Payable:		
General	84,677	121,665
Affiliated Companies	69,464	105,221
Long-term Debt Due Within One Year - Nonaffiliated		
(March 31, 2011 and December 31, 2010 amounts include $78,332 and $77,457,		
respectively, related to DCC Fuel)	155,332	154,457
Risk Management Liabilities	13,663	16,785
Customer Deposits	29,240	29,264
Accrued Taxes	78,574	62,637
Accrued Interest	23,045	27,444
Other Current Liabilities	142,392	140,710
TOTAL CURRENT LIABILITIES	596,387	700,952
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,843,771	1,849,769
Long-term Risk Management Liabilities	7,992	6,530
Deferred Income Taxes	780,312	760,105
Regulatory Liabilities and Deferred Investment Tax Credits	866,458	852,197
Asset Retirement Obligations	974,935	963,029
Deferred Credits and Other Noncurrent Liabilities	317,865	313,892
TOTAL NONCURRENT LIABILITIES	4,791,333	4,745,522
TOTAL LIABILITIES	5,387,720	5,446,474
Cumulative Preferred Stock Not Subject to Mandatory Redemption	8,072	8,072
Rate Matters (Note 2)		
Commitments and Contingencies (Note 3)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56,584	56,584
Paid-in Capital	981,294	981,294
Retained Earnings	703,952	677,360
Accumulated Other Comprehensive Income (Loss)	(20,121)	(20,889)
TOTAL COMMON SHAREHOLDER’S EQUITY	1,721,709	1,694,349

TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$7,117,501	$7,148,895

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
OPERATING ACTIVITIES		
Net Income	$45,427	$45,058
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	34,087	33,831
Deferred Income Taxes	25,087	18,442
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	11,616	(20,025)
Allowance for Equity Funds Used During Construction	(3,199)	(4,435)
Mark-to-Market of Risk Management Contracts	(658)	(20,345)
Amortization of Nuclear Fuel	34,240	30,090
Fuel Over/Under Recovery, Net	4,156	16,439
Change in Other Noncurrent Assets	(6,066)	(11,056)
Change in Other Noncurrent Liabilities	13,327	28,926
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	97,575	28,078
Fuel, Materials and Supplies	8,343	(18,972)
Accounts Payable	(71,206)	13,171
Accrued Taxes, Net	14,479	23,964
Other Current Assets	(1,475)	(13,044)
Other Current Liabilities	3,865	38,068
Net Cash Flows from Operating Activities	209,598	188,190
INVESTING ACTIVITIES		
Construction Expenditures	(54,733)	(104,796)
Change in Advances to Affiliates, Net	(56,813)	28,826
Purchases of Investment Securities	(305,945)	(247,632)
Sales of Investment Securities	287,761	232,078
Acquisitions of Nuclear Fuel	(27,132)	(37,616)
Other Investing Activities	17,029	500
Net Cash Flows Used for Investing Activities	(139,833)	(128,640)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	76,864	-
Change in Advances from Affiliates, Net	(42,769)	-
Retirement of Long-term Debt - Nonaffiliated	(82,354)	-
Retirement of Long-term Debt - Affiliated	-	(25,000)
Principal Payments for Capital Lease Obligations	(2,128)	(8,524)
Dividends Paid on Common Stock	(18,750)	(25,750)
Dividends Paid on Cumulative Preferred Stock	(85)	(85)
Other Financing Activities	8	24
Net Cash Flows Used for Financing Activities	(69,214)	(59,335)

Net Increase in Cash and Cash Equivalents	551	215
Cash and Cash Equivalents at Beginning of Period	361	779
Cash and Cash Equivalents at End of Period	$912	$994

SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$28,542	$30,056
Net Cash Paid (Received) for Income Taxes	(1,033)	-
Noncash Acquisitions Under Capital Leases	693	8,476
Construction Expenditures Included in Current Liabilities at March 31,	21,651	29,496
Acquisition of Nuclear Fuel Included in Current Liabilities at March 31,	377	2,705

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to I&M's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to I&M. The footnotes begin on page 143.

OHIO POWER COMPANY CONSOLIDATED

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S DISCUSSION AND ANALYSIS

EXECUTIVE OVERVIEW

Ohio Customer Choice

In OPCo's service territory, various competitive retail electric service (CRES) providers are targeting retail customers by offering alternative generation service. Through March 31, 2011, approximately 300 OPCo retail customers have switched from OPCo to alternative CRES providers. As a result, in comparison to the first three months of 2010, OPCo lost approximately $600 thousand of generation related gross margin through March 31, 2011. Management anticipates recovery of a portion of this lost margin through off-system sales, including PJM capacity revenues.

Regulatory Activity

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 which resulted in three reversals, only 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 remaining months of 2011. See "Ohio Electric Security Plan Filings" section of Note 2.

January 2012 – May 2014 ESP

In January 2011, 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 OPCo will have base generation increases, excluding riders, of $48 million for 2012 and $60 million 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, OPCo filed with the PUCO for an annual increase in distribution rates of $60 million. The requested increase is based upon an 11.15% return on common equity to be effective January 2012. In addition to the annual increase, OPCo requested recovery of the projected December 31, 2012 balance of certain distribution regulatory assets of $159 million including approximately $84 million of unrecognized equity carrying costs. These assets would be recovered in a requested distribution asset recovery rider over seven years with additional carrying costs, beginning January 2013. The actual balance of these distribution regulatory assets as of March 31, 2011 was $63 million excluding $42 million of unrecognized equity carrying costs. If OPCo is not ultimately permitted to fully recover its deferrals, it would reduce future net income and cash flows and impact financial condition.

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. In January 2011, CSPCo and OPCo filed an application with the FERC requesting approval for an internal corporate reorganization under which CSPCo will merge into OPCo. CSPCo and OPCo requested the reorganization transaction be effective in October 2011. Decisions are pending from the PUCO and the FERC.

Litigation and Environmental Issues

In the ordinary course of business, OPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2010 Annual Report. Also, see Note 2 – Rate Matters and Note 3 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 143. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Executive Overview" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 201 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

		Three Months Ended March 31,	
		2011	2010
		(in millions of KWH)	
Retail:			
	Residential	2,324	2,284
	Commercial	1,393	1,359
	Industrial	3,275	3,058
	Miscellaneous	20	20
Total Retail		7,012	6,721
Wholesale		1,907	1,342
Total KWHs		8,919	8,063

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31,	
	2011	2010
	(in degree days)	
Actual - Heating (a)	2,242	2,157
Normal - Heating (b)	2,042	2,043
Actual - Cooling (c)	1	-
Normal - Cooling (b)	1	1

(a) Eastern 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.

First Quarter of 2011 Compared to First Quarter of 2010

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

First Quarter of 2010	$	92
Changes in Gross Margin:		
Retail Margins		22
Transmission Revenues		3
Other Revenues		1
Total Change in Gross Margin		26
Total Expenses and Other:		
Other Operation and Maintenance		(19)
Depreciation and Amortization		(3)
Taxes Other Than Income Taxes		(2)
Carrying Costs Income		2
Interest Expense		3
Total Expenses and Other		(19)
Income Tax Expense		1
First Quarter of 2011	$	100

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 $22 million primarily due to the following:
  - A $14 million increase in revenue due to the implementation of PUCO approved rider rates in June 2010 related to the Energy Efficiency & Peak Demand Reduction (EE/PDR) Programs. This increase in Retail Margins was offset by a corresponding increase in Other Operation and Maintenance as discussed below.
  - A $13 million increase in revenues due to increases in residential, commercial and industrial customer usage. The industrial increase was driven primarily by increased Ormet load.
  - A $7 million increase in revenues due to the implementation of PUCO approved rider rates in September 2010 related to the Environmental Investment Carrying Cost Rider.
  - A $5 million increase in revenues due to a January 2011 Universal Service Fund surcharge rate increase. This increase in Retail Margins was offset by a corresponding increase in Other Operation and Maintenance as discussed below.

  These increases were partially offset by:
  - A $12 million decrease in capacity settlements under the Interconnection Agreement.

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Transmission Revenues increased $3 million primarily due to the Transmission Agreement modification effective November 2010, a portion of which is included in the Ohio Transmission Cost Recovery Rider.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased $19 million primarily due to the following:
  - A $14 million increase in expenses due to the implementation of PUCO approved EE/PDR programs. This increase in Other Operation and Maintenance expense was offset by a corresponding increase in Retail Margins as discussed above.
  - A $7 million increase due to a favorable 2010 employee benefit adjustment.
  - A $6 million increase in maintenance expenses from planned and forced outages at various plants.

- A $5 million increase in remitted Universal Service Fund surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase in Other Operation and Maintenance expense was offset by a corresponding increase in Retail Margins as discussed above.

These increases were partially offset by:

- An $11 million gain from the sale of land in January 2011.
- Income Tax Expense decreased $1 million primarily due to the 2010 tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits, partially offset by an increase in pretax book income.

FINANCIAL CONDITION

LIQUIDITY

OPCo participates in the Utility Money Pool, which provides access to AEP's liquidity. OPCo relies upon ready access to capital markets, cash flows from operations and access to the Utility Money Pool to fund current operations and capital expenditures. See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 201 for additional discussion of liquidity.

Credit Ratings

OPCo's ultimate access to capital markets may depend on its credit ratings. In addition, a credit rating downgrade of OPCo by one of the rating agencies could increase OPCo's borrowing costs. Failure to maintain investment grade ratings may constrain OPCo's ability to participate in the Utility Money Pool or the amount of OPCo's receivables securitized by AEP Credit. Counterparty concerns about OPCo's credit quality could subject OPCo to additional collateral demands under adequate assurance clauses under derivative and non-derivative energy contracts.

CASH FLOW

Cash flows for the three months ended March 31, 2011 and 2010 were as follows:

	2011	2010
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 440	$ 1,984
Net Cash Flows from Operating Activities	229,340	251,324
Net Cash Flows Used for Investing Activities	(10,877)	(258,305)
Net Cash Flows from (Used for) Financing Activities	(217,699)	6,150
Net Increase (Decrease) in Cash and Cash Equivalents	764	(831)
Cash and Cash Equivalents at End of Period	$ 1,204	$ 1,153

Operating Activities

Net Cash Flows from Operating Activities were $229 million in 2011. OPCo produced Net Income of $100 million during the period and noncash expense items of $92 million for Depreciation and Amortization, $29 million for Deferred Income Taxes and $25 million for Property Taxes. The other changes in assets and liabilities 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. The current period activity in working capital relates to a number of items. Accounts Payable had a $51 million outflow primarily due to timing differences of payments. Accounts Receivable, Net had a $45 million inflow primarily due to a settlement with AEP

Ohio Transmission Company and settlements of allowance sales to affiliated companies. Fuel, Materials and Supplies had a $45 million inflow primarily due to a decrease in coal inventory reflecting increased customer usage for electricity. The $23 million outflow from Accrued Taxes, Net is primarily due to temporary timing differences of payments for property taxes partially offset by an increase of federal income tax related accruals.

Net Cash Flows from Operating Activities were $251 million in 2010. OPCo produced Net Income of $92 million during the period and noncash expense items of $89 million for Depreciation and Amortization, $41 million for Deferred Income Taxes and $24 million for Property Taxes. The other changes in assets and liabilities 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. The activity in working capital primarily relates to a number of items. Accounts Receivable, Net had a $62 million inflow primarily due to decreased sales to affiliates and settlement of allowance sales to affiliated companies. Fuel, Materials and Supplies had a $57 million inflow primarily due to a decrease in coal inventory deliveries. Accrued Taxes, Net had a $30 million outflow due to temporary timing differences of payments for property taxes partially offset by a decrease of federal income tax related accruals. The $38 million change in Fuel Over/Under-Recovery, Net reflects the deferral of fuel costs as a fuel clause was reactivated in 2009 under OPCo's ESP.

Investing Activities

Net Cash Flows Used for Investing Activities were $11 million in 2011. Construction Expenditures of $50 million primarily related to environmental upgrades, as well as projects to improve service reliability for transmission and distribution. Environmental includes FGD project upgrades at various plants and landfill improvements. This decrease was partially offset by $23 million in Proceeds from Sales of Assets and an $18 million decrease in loans to the Utility Money Pool.

Net Cash Flows Used for Investing Activities were $258 million in 2010. OPCo had a net increase in loans to the Utility Money Pool of $179 million as well as Construction Expenditures of $78 million. The Construction Expenditures primarily related to environmental upgrades, as well as projects to improve service reliability for transmission and distribution. Environmental upgrades include FGD projects at the Amos Plant.

Financing Activities

Net Cash Flows Used for Financing Activities were $218 million in 2011. OPCo retired $165 million of Pollution Control Bonds in March 2011. In addition, OPCo paid $100 million of dividends on common stock. These decreases were partially offset by the issuance of $50 million of Pollution Control Bonds in March 2011.

Net Cash Flows from Financing Activities were $6 million during 2010. OPCo issued $86 million of Pollution Control Bonds in March 2010. This increase was partially offset by the payment of $75 million of dividends on common stock.

Long-term debt issuances and retirements during the first three months of 2011 were:

Issuances

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Pollution Control Bonds	$	50,000 (a)	Variable	2014

(a) These pollution control bonds are subject to redemption earlier than the maturity date. Consequently, this bond has been classified for maturity purposes as Long-term Debt Due Within One Year - Nonaffiliated on OPCo's Condensed Consolidated Balance Sheets.

Retirements

Type of Debt	Principal Amount Paid	Interest Rate	Due Date

		(in thousands)	(%)	
Pollution Control Bonds	$	65,000	Variable	2036
Pollution Control Bonds		50,000	Variable	2014
Pollution Control Bonds		50,000	Variable	2014

CONTRACTUAL OBLIGATION INFORMATION

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” 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 and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 201 for a discussion of accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “Quantitative And Qualitative Disclosures About Market Risk” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 201 for a discussion of market risk.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
REVENUES		
Electric Generation, Transmission and Distribution	$626,806	$543,700
Sales to AEP Affiliates	225,049	306,768
Other Revenues – Affiliated	7,018	6,574
Other Revenues – Nonaffiliated	3,955	4,231
TOTAL REVENUES	862,828	861,273
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	294,483	331,017
Purchased Electricity for Resale	44,897	38,890
Purchased Electricity from AEP Affiliates	27,694	22,191
Other Operation	99,718	89,156
Maintenance	64,312	56,231
Depreciation and Amortization	91,986	89,361
Taxes Other Than Income Taxes	55,161	53,084
TOTAL EXPENSES	678,251	679,930
OPERATING INCOME	184,577	181,343
Other Income (Expense):		
Interest Income	291	405
Carrying Costs Income	7,077	4,874
Allowance for Equity Funds Used During Construction	432	1,031
Interest Expense	(37,272)	(39,975)
INCOME BEFORE INCOME TAX EXPENSE	155,105	147,678
Income Tax Expense	54,693	55,775
NET INCOME	100,412	91,903
Less: Preferred Stock Dividend Requirements	183	183
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$100,229	$91,720

The common stock of OPCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$321,201	$1,123,149	$1,908,803	$ (118,458)	$3,234,695
Common Stock Dividends			(75,287)		(75,287)
Preferred Stock Dividends			(183)		(183)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					3,159,225
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $817				(1,517)	(1,517)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $949				1,762	1,762
NET INCOME			91,903		91,903
TOTAL COMPREHENSIVE INCOME					92,148
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2010	$321,201	$1,123,149	$1,925,236	$ (118,213)	$3,251,373
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	$321,201	$1,123,153	$1,852,889	$ (128,819)	$3,168,424
Common Stock Dividends			(100,000)		(100,000)
Preferred Stock Dividends			(183)		(183)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					3,068,241
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $43				80	80
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,078				2,002	2,002

NET INCOME			100,412		100,412
TOTAL COMPREHENSIVE INCOME					102,494
TOTAL COMMON SHAREHOLDER'S					
EQUITY – MARCH 31, 2011	$321,201	$1,123,153	$1,853,118	$ (126,737)	$3,170,735

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2011 and December 31, 2010
(in thousands)
(Unaudited)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$1,204	$440
Advances to Affiliates	82,684	100,500
Accounts Receivable:		
Customers	83,643	86,186
Affiliated Companies	158,008	198,845
Accrued Unbilled Revenues	27,402	27,928
Miscellaneous	853	2,368
Allowance for Uncollectible Accounts	(2,181)	(2,184)
Total Accounts Receivable	267,725	313,143
Fuel	217,945	257,289
Materials and Supplies	128,509	134,181
Risk Management Assets	27,776	30,773
Accrued Tax Benefits	13,781	69,021
Prepayments and Other Current Assets	33,549	33,998
TOTAL CURRENT ASSETS	773,173	939,345
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,894,869	6,890,110
Transmission	1,249,671	1,234,677
Distribution	1,638,926	1,626,390
Other Property, Plant and Equipment	359,626	359,254
Construction Work in Progress	143,808	153,110
Total Property, Plant and Equipment	10,286,900	10,263,541
Accumulated Depreciation and Amortization	3,690,781	3,606,777
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,596,119	6,656,764
OTHER NONCURRENT ASSETS		
Regulatory Assets	959,912	934,011
Long-term Risk Management Assets	29,384	28,012
Deferred Charges and Other Noncurrent Assets	163,024	189,195
TOTAL OTHER NONCURRENT ASSETS	1,152,320	1,151,218
TOTAL ASSETS	$8,521,612	$8,747,327

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2011 and December 31, 2010
(Unaudited)

	2011	2010
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 143,376	$ 170,240
Affiliated Companies	108,344	136,215
Long-term Debt Due Within One Year – Nonaffiliated	50,000	165,000
Risk Management Liabilities	17,431	22,166
Customer Deposits	23,996	28,228
Accrued Taxes	190,471	229,253
Accrued Interest	45,089	46,184
Other Current Liabilities	93,953	98,687
TOTAL CURRENT LIABILITIES	672,660	895,973
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,364,651	2,364,522
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	10,149	8,403
Deferred Income Taxes	1,522,242	1,531,639
Regulatory Liabilities and Deferred Investment Tax Credits	129,893	126,403
Employee Benefits and Pension Obligations	243,759	246,517
Deferred Credits and Other Noncurrent Liabilities	190,907	188,830
TOTAL NONCURRENT LIABILITIES	4,661,601	4,666,314
TOTAL LIABILITIES	5,334,261	5,562,287
Cumulative Preferred Stock Not Subject to Mandatory Redemption	16,616	16,616
Rate Matters (Note 2)		
Commitments and Contingencies (Note 3)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	1,123,153	1,123,153
Retained Earnings	1,853,118	1,852,889
Accumulated Other Comprehensive Income (Loss)	(126,737)	(128,819)
TOTAL COMMON SHAREHOLDER’S EQUITY	3,170,735	3,168,424

TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$8,521,612	$8,747,327

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
OPERATING ACTIVITIES		
Net Income	$100,412	$91,903
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	91,986	89,361
Deferred Income Taxes	29,038	41,462
Carrying Costs Income	(7,077)	(4,874)
Allowance for Equity Funds Used During Construction	(432)	(1,031)
Mark-to-Market of Risk Management Contracts	(818)	(13,704)
Property Taxes	24,950	24,242
Fuel Over/Under-Recovery, Net	(16,306)	(38,025)
Change in Other Noncurrent Assets	(11,927)	(5,008)
Change in Other Noncurrent Liabilities	11,271	(1,741)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	45,418	62,075
Fuel, Materials and Supplies	45,016	57,032
Accounts Payable	(51,223)	(10,190)
Customer Deposits	(4,232)	829
Accrued Taxes, Net	(22,818)	(30,082)
Accrued Interest	(1,095)	2,243
Other Current Assets	480	(8,331)
Other Current Liabilities	(3,303)	(4,837)
Net Cash Flows from Operating Activities	229,340	251,324
INVESTING ACTIVITIES		
Construction Expenditures	(50,248)	(78,398)
Change in Advances to Affiliates, Net	17,816	(178,947)
Acquisitions of Assets	(1,288)	(823)
Proceeds from Sales of Assets	22,843	2,047
Other Investing Activities	-	(2,184)
Net Cash Flows Used for Investing Activities	(10,877)	(258,305)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	49,917	85,487
Retirement of Long-term Debt – Nonaffiliated	(165,000)	-
Principal Payments for Capital Lease Obligations	(2,271)	(2,101)
Dividends Paid on Common Stock	(100,000)	(75,287)
Dividends Paid on Cumulative Preferred Stock	(183)	(183)
Other Financing Activities	(162)	(1,766)
Net Cash Flows from (Used for) Financing Activities	(217,699)	6,150

Net Increase (Decrease) in Cash and Cash Equivalents	764	(831)
Cash and Cash Equivalents at Beginning of Period	440	1,984
Cash and Cash Equivalents at End of Period	$1,204	$1,153
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$36,936	$36,243
Net Cash Paid for Income Taxes	755	-
Noncash Acquisitions Under Capital Leases	330	22,559
Construction Expenditures Included in Current Liabilities at March 31,	15,559	12,894

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

OHIO POWER COMPANY CONSOLIDATED
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to OPCo's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to OPCo. The footnotes begin on page 143.

PUBLIC SERVICE COMPANY OF OKLAHOMA

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S DISCUSSION AND ANALYSIS

EXECUTIVE OVERVIEW

Litigation and Environmental Issues

In the ordinary course of business, PSO is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2010 Annual Report. Also, see Note 2 – Rate Matters and Note 3 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 143. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Executive Overview" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 201 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

		Three Months Ended March 31,	
		2011	2010
		(in millions of KWH)	
Retail:			
	Residential	1,540	1,555
	Commercial	1,130	1,070
	Industrial	1,123	1,145
	Miscellaneous	279	269
Total Retail		4,072	4,039
Wholesale		234	349
Total KWHs		4,306	4,388

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31,	
	2011	2010
	(in degree days)	

Actual - Heating (a)	1,257	1,330
Normal - Heating (b)	1,058	1,047
Actual - Cooling (c)	33	8
Normal - Cooling (b)	13	13

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

First Quarter of 2011 Compared to First Quarter of 2010

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

First Quarter of 2010	$	4
Changes in Gross Margin:		
Other Revenues		(2)
Total Change in Gross Margin		(2)
Total Expenses and Other:		
Other Operation and Maintenance		15
Depreciation and Amortization		3
Interest Expense		1
Total Expenses and Other		19
Income Tax Expense		(6)
First Quarter of 2011	$	15

The major components of the decrease 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:

- Other Revenues decreased $2 million primarily due to lower gains on the sale of emission allowances.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $15 million primarily due to the following:
  - A $5 million decrease in maintenance of overhead lines primarily due to a decrease in vegetation management activities.
  - A $4 million decrease in plant maintenance expense resulting primarily from the 2011 deferral of generation maintenance expenses as a result of PSO’s base rate case.
  - A $2 million decrease in transmission expense primarily due to SPP formula rate adjustments.
- Depreciation and Amortization expenses decreased $3 million primarily due to a decrease in amortization of regulatory assets related to the Lawton settlement which was fully recovered in August 2010.
- Income Tax Expense increased $6 million primarily due to an increase in pretax book income.

FINANCIAL CONDITION

LIQUIDITY

PSO participates in the Utility Money Pool, which provides access to AEP's liquidity. PSO has $75 million of Senior Unsecured Notes that will mature in the second quarter of 2011. PSO relies upon ready access to capital markets, cash flows from operations and access to the Utility Money Pool to fund its maturities, current operations and capital expenditures. See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 201 for additional discussion of liquidity.

Credit Ratings

PSO's ultimate access to capital markets may depend on its credit ratings. In addition, a credit rating downgrade of PSO by one of the rating agencies could increase PSO's borrowing costs. Failure to maintain investment grade ratings may constrain PSO's ability to participate in the Utility Money Pool or the amount of PSO's receivables securitized by AEP Credit. Counterparty concerns about PSO's credit quality could subject PSO to additional collateral demands under adequate assurance clauses under derivative and non-derivative energy contracts.

CASH FLOW

Cash flows for the three months ended March 31, 2011 and 2010 were as follows:

	2011	2010
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 470	$ 796
Net Cash Flows from (Used for) Operating Activities	98,230	(60,332)
Net Cash Flows from (Used for) Investing Activities	(35,602)	5,380
Net Cash Flows from (Used for) Financing Activities	(62,344)	55,082
Net Increase in Cash and Cash Equivalents	284	130
Cash and Cash Equivalents at End of Period	$ 754	$ 926

Operating Activities

Net Cash Flows from Operating Activities were $98 million in 2011. PSO produced Net Income of $15 million during the period and had noncash expense items of $24 million for Depreciation and Amortization and $15 million for Deferred Income Taxes, partially offset by a $28 million increase in the deferral of Property Taxes. The other changes in assets and liabilities 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. The activity in working capital relates to a number of items. The $29 million inflow from Accounts Receivable, Net was primarily due to decreases in both affiliated and customer receivables. The $11 million inflow from Accrued Taxes, Net was the result of an increase in property tax accruals.

Net Cash Flows Used for Operating Activities were $60 million in 2010. PSO produced Net Income of $4 million during the period and had noncash expense items of $27 million for Depreciation and Amortization and $21 million for Deferred Income Taxes, partially offset by a $28 million increase in the deferral of Property Taxes. The other changes in assets and liabilities 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. The activity in working capital relates to a $15 million inflow from Accounts Payable primarily due to timing differences for payments to affiliates and payments of items accrued at December 31, 2009. The $82 million outflow from Fuel Over/Under-Recovery, Net was primarily due to refunding to customers the prior month's fuel over-recoveries through lower fuel factors.

Investing Activities

Net Cash Flows Used for Investing Activities during 2011 was $36 million and Net Cash Flows from Investing Activities during 2010 was $5 million. Construction Expenditures of $33 million and $55 million in 2011 and 2010, respectively, were primarily related to projects for improved generation, transmission and distribution service reliability, customer service work and storm restoration. During 2010, PSO had a net decrease of $63 million in loans to the Utility Money Pool.

Financing Activities

Net Cash Flows Used for Financing Activities were $62 million during 2011. PSO issued $250 million of Senior Unsecured Notes, partially offset by the retirement of $200 million of Senior Unsecured Notes. PSO had a net decrease of $91 million in borrowings from the Utility Money Pool. In addition, PSO paid $16 million in common stock dividends.

Net Cash Flows from Financing Activities were $55 million during 2010. PSO had a net increase of $69 million in borrowings from the Utility Money Pool. This inflow was partially offset by $13 million paid in common stock dividends.

Long-term debt issuances and retirements during the first three months of 2011 were:

Issuances

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$	250,000	4.40	2021

Retirements

Type of Debt		Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Senior Unsecured Notes	$	200,000	6.00	2032

CONTRACTUAL OBLIGATION INFORMATION

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” 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 and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 201 for a discussion of accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “Quantitative And Qualitative Disclosures About Market Risk” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 201 for a discussion of market risk.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
REVENUES		
Electric Generation, Transmission and Distribution	$284,587	$228,551
Sales to AEP Affiliates	2,796	8,670
Other Revenues	620	534
TOTAL REVENUES	288,003	237,755
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	91,748	40,972
Purchased Electricity for Resale	41,179	44,980
Purchased Electricity from AEP Affiliates	16,611	10,992
Other Operation	44,404	49,662
Maintenance	20,721	30,939
Depreciation and Amortization	23,863	27,288
Taxes Other Than Income Taxes	10,596	10,300
TOTAL EXPENSES	249,122	215,133
OPERATING INCOME	38,881	22,622
Other Income (Expense):		
Interest Income	52	182
Carrying Costs Income	647	867
Allowance for Equity Funds Used During Construction	366	247
Interest Expense	(15,938)	(17,363)
INCOME BEFORE INCOME TAX EXPENSE	24,008	6,555
Income Tax Expense	8,619	2,416
NET INCOME	15,389	4,139
Preferred Stock Dividend Requirements	49	53
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$15,340	$4,086

The common stock of PSO is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 143.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$157,230	$364,231	$290,880	$ (599)	$811,742
Common Stock Dividends			(12,687)		(12,687)
Preferred Stock Dividends			(53)		(53)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					799,002
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $62				116	116
NET INCOME			4,139		4,139
TOTAL COMPREHENSIVE INCOME					4,255
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2010	$157,230	$364,231	$282,279	$ (483)	$803,257
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	$157,230	$364,307	$312,441	$ 8,494	$842,472
Common Stock Dividends			(16,250)		(16,250)
Preferred Stock Dividends			(49)		(49)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					826,173
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $239				(443)	(443)
NET INCOME			15,389		15,389
TOTAL COMPREHENSIVE INCOME					14,946
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2011	$157,230	$364,307			