

AMERICAN ELECTRIC POWER CO INC
Form 10-Q
April 26, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended March 31, 2013
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
1-3570	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) 1 Riverside Plaza, Columbus, Ohio 43215-2373 Telephone (614) 716-1000	72-0323455

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 the registrants have submitted electronically and posted on their corporate websites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

Yes X 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.

X Accelerated filer

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Large accelerated
filer

Non-accelerated
filer

Smaller reporting
company

Indicate by check mark whether Appalachian 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

Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric 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 as of
April 25, 2013

American Electric Power Company, Inc.	486,045,098
	(\$6.50 par value)
Appalachian Power Company	13,499,500
	(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
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March 31, 2013

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This combined Form 10-Q is separately filed by American Electric Power Company, Inc., Appalachian 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., a utility holding company.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
AEPGenCo	AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation and Marketing segment.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Transmission Holding Company	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	American Electric Power Transmission Company, a wholly-owned subsidiary of AEP Transmission Holding Company.
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.
BlueStar	BlueStar Energy Holdings, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
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.
CRES	Competitive Retail Electric Service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC and DCC Fuel V LLC, consolidated 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.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
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 and MidAmerican Energy Holdings Company Texas Transco, LLC formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.

Term	Meaning
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.
IEU	Industrial Energy Users-Ohio.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	An agreement by and among APCo, 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.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
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.
MWh	Megawatthour.
NOx	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
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.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
POLR	Provider of Last Resort revenues.
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, 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, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SEC	U.S. Securities and Exchange Commission.
SEET	Significantly Excessive Earnings Test.

Term	Meaning
SIA	System Integration Agreement, effective June 15, 2000, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SNF	Spent Nuclear Fuel.
SO ₂	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant, a 543 MW natural gas unit owned by SWEPCo.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III 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.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant under construction in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
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 Discussion and Analysis of Financial Condition and Results of Operations” of the 2012 Annual Report, but there are others throughout this document which may be identified by words such as “expect,” “anticipate,” “intend,” “plan,” “believe,” “will,” “should,” “could,” “would,” “project,” “continue” and similar expressions, and include statements of 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 are presented 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, growth or contraction within and changes in market demand and demographic patterns in our service territory.
- 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 drought conditions, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity and transmission lines and 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 nuclear generation, 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 and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- A reduction in the federal statutory tax rate could result in an accelerated return of deferred federal income taxes to customers.
- 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, coal, natural gas and other energy-related commodities.

- 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.
- Our ability to recover through rates or market prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for electricity, coal, natural gas and other energy-related commodities.

- Changes in utility regulation, including the implementation of ESPs and the transition to market and expected legal separation for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Our ability to successfully manage negotiations with stakeholders and obtain regulatory approval to terminate the Interconnection Agreement.
- 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 our debt.
- 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.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

The forward looking statements of AEP and its Registrant Subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see “Risk Factors” in Part I of the 2012 Annual Report and in Part II of this report.

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

EXECUTIVE OVERVIEW

Corporate Separation, Plant Transfers and Termination of Interconnection Agreement

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets at net book value to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. In December 2012, the PUCO granted the IEU and the Ohio Consumers' Counsel requests for rehearing, which were denied by the PUCO in April 2013.

Also in October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations. The filings requested approval to transfer at net book value approximately 9,200 MW of OPCo-owned generation assets to AEPGenCo. The AEP East Companies also requested FERC approval to transfer at net book value OPCo's current two-thirds ownership (867 MW) in Amos Plant Unit 3 to APCo and transfer at net book value OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). These transfers are proposed to be effective no later than December 31, 2013. Additionally, the AEP East Companies asked the FERC, effective January 1, 2014, to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' power supply resources. Under the PCA, APCo, I&M and KPCo would be individually responsible for planning their respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities. Intervenors have opposed several of these filings. The AEP East Companies responded to intervenor comments and filed a revised PCA at the FERC in March 2013. The revised PCA included certain clarifying wording changes that have been agreed upon by intervenors. A decision from the FERC is expected in the second quarter of 2013.

In December 2012, APCo and WPCo filed requests with the Virginia SCC and the WVPSC for approval of the Amos Plant and Mitchell Plant transfers discussed above. Hearings at the Virginia SCC and the WVPSC are scheduled for June 2013 and July 2013, respectively. If the transfers are approved, APCo and WPCo anticipate seeking cost recovery in upcoming rate proceedings. If APCo and WPCo are not ultimately permitted to recover their incurred costs, it could reduce future net income and cash flows and impact financial condition. See the "Plant Transfers" section of APCo and WPCo Rate Matters section of Note 3.

Also in December 2012, KPCo filed a request with the KPSC for approval of the Mitchell Plant transfer discussed above. If the transfer is approved, KPCo anticipates seeking cost recovery when filing its next base rate case. A hearing at the KPSC is scheduled for May 2013. If KPCo is not ultimately permitted to recover its incurred costs, it could reduce future net income and cash flows and impact financial condition. See the "Plant Transfer" section of KPCo Rate Matters section of Note 3.

If approved as filed, results of operations related to generation in Ohio will be largely determined by prevailing market conditions effective January 1, 2014.

Ohio Electric Security Plan Filing

2009 – 2011 ESP

In August 2012, the PUCO issued an order in a separate proceeding which implemented a Phase-In Recovery Rider (PIRR) to recover OPCo's deferred fuel costs in rates beginning September 2012. As of March 31, 2013, OPCo's net deferred fuel balance was \$501 million, excluding unrecognized equity carrying costs. Decisions from the Supreme Court of Ohio are pending related to various appeals which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance.

June 2012 – May 2015 Ohio ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that establishes base generation rates through May 2015.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to \$188.88/MW day. The RPM price is approximately \$20/MW day through May 2013 then \$33/MW day through May 2014. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 PUCO ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is expected to provide approximately \$500 million over the ESP period and will be collected from customers at \$3.50/MWh through May 2014 and \$4.00/MWh for the period June 2014 through May 2015, with \$1.00/MWh applied to the recovery of deferred capacity costs. As of March 31, 2013, OPCo's incurred deferred capacity costs balance of \$116 million, including debt carrying costs, was recorded in Regulatory Assets on the balance sheet.

If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, it could reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filing" section of Note 3.

Ohio Customer Choice

In our Ohio service territory, various CRES providers are targeting retail customers by offering alternative generation service. The reduction in gross margin as a result of customer switching in Ohio is partially offset by (a) collection of capacity revenues from CRES providers, (b) off-system sales, (c) deferral of unrecovered capacity costs, (d) Retail Stability Rider collections and (e) revenues from AEP Energy. AEP Energy is our CRES provider and part of our Generation and Marketing segment which targets retail customers, both within and outside of our retail service territory.

Customer Demand

In comparison to 2012, heating degree days in 2013 were up 59% in our western region and 44% in our eastern region. Our weather-normalized retail sales were down 1.5% compared to 2012. Our industrial sales declined 6% partially due to Ormet, a large aluminum company that lowered their production in the third quarter of 2012 by one-third and is currently in bankruptcy proceedings.

In 2013, we anticipate slight increases in retail sales across our service territories primarily driven by oil and gas related projects, including shale gas. We also anticipate decreases in industrial demand in our eastern region related to Ormet's lower production levels discussed above.

Significantly Excessive Earnings Test

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of a portion of 2010 earnings. OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO-ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's request to file the 2011 SEET one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo or in 2012 and 2013 for OPCo. Depending on the rulings in these proceedings, it could reduce

future net income and cash flows and impact financial condition. See “Ohio Electric Security Plan Filing” section of Note 3.

Turk Plant

SWEP Co constructed the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012. SWEP Co owns 73% (440 MW) of the Turk Plant and operates the facility. As of March 31, 2013, excluding costs attributable to its joint owners and a \$62 million provision for a Texas capital cost cap, SWEP Co has capitalized approximately \$1.7 billion of expenditures, including AFUDC and capitalized interest of \$328 million and related transmission costs of \$120 million.

The APSC granted approval for SWEP Co to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEP Co Arkansas jurisdictional share of the Turk Plant (approximately 20%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to the Arkansas Supreme Court's decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This portion of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the SPP market. If SWEP Co cannot recover all of its investment and expenses related to the Turk Plant, it could reduce future net income and cash flows and impact financial condition. See "Turk Plant" section of Note 3.

Texas Base Rate Case

In July 2012, SWEP Co filed a request with the PUCT to increase annual base rates by \$83 million, primarily due to the Turk Plant, based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share (approximately 33%) of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEP Co's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates. In December 2012, several intervenors filed opposing testimony with various recommendations. A decision from the PUCT is expected in the second quarter of 2013. If the PUCT does not approve full cost recovery of SWEP Co's assets, it could reduce future net income and cash flows and impact financial condition. See "2012 Texas Base Rate Case" section of Note 3.

Louisiana Formula Rate Filing

In 2012, SWEP Co initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and approved by the LPSC. The settlement increased Louisiana total rates by approximately \$2 million annually, effective March 2013, which consisted of an increase in base rates of approximately \$85 million annually offset by a decrease in fuel and other rates of approximately \$83 million annually. The March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund based on the staff review of the cost of service and the prudence of the Turk Plant to be initiated by SWEP Co no later than May 2013. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEP Co will recover all non-fuel Turk Plant costs and a full weighted-average cost of capital return on the Turk Plant portion of rate base, effective January 2013. If the LPSC orders refunds based upon the staff review of the cost of service or prudence review of the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

2011 Indiana Base Rate Case

In February 2013, the IURC issued an order that granted an \$85 million annual increase in base rates based upon a return on common equity of 10.2%. In a March 2013 order, the IURC approved an adjustment which increased the authorized annual increase in base rates from \$85 million to \$92 million. In March 2013, the Indiana Office of Utility

Consumer Counselor filed an appeal of the order with the Indiana Court of Appeals. If the order is overturned by the Indiana Court of Appeals, it could reduce future net income and cash flows. See “Indiana Base Rate Case” section of Note 3.

Environmental Rate Adjustment Clause (Environmental RAC)

In March 2013, APCo filed with the Virginia SCC for approval of an environmental RAC to recover \$39 million related to 2012 and 2011 environmental compliance costs effective February 2014 over a one year period. APCo has deferred \$28 million as of March 31, 2013 for the Virginia portion of unrecovered environmental RAC costs incurred in 2012 and 2011, excluding \$11 million of unrecognized equity carrying costs. If the Virginia SCC were to disallow any portion of the environmental RAC, it could reduce future net income and cash flows. See “Environmental Rate Adjustment Clause (Environmental RAC)” section of Note 3.

Generation Rate Adjustment Clause (Generation RAC)

In March 2013, APCo filed with the Virginia SCC for an increase in its generation RAC revenues of \$12 million for a total of \$38 million annually to collect costs related to the Dresden Plant. The generation RAC increase is expected to be effective in March 2014. APCo has deferred \$4 million as of March 31, 2013 for the Virginia portion of unrecovered costs of the Dresden Plant, excluding \$3 million of unrecognized equity carrying costs. If the Virginia SCC were to disallow any portion of the generation RAC, it could reduce future net income and cash flows.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its extended licensed life. The estimated cost of the LCM Project is \$1.2 billion to be incurred through 2018, excluding AFUDC. As of March 31, 2013, I&M has incurred \$197 million related to the LCM Project, including AFUDC.

In April 2012, I&M filed a petition with the IURC for recovery of project costs, including interest, through a new rider. Several intervenors filed testimony in Indiana with various recommendations including caps on expenditures. The IURC held a hearing in January 2013 and an order is pending. In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project. In April 2013, an intervenor filed an appeal with the Michigan Court of Appeals objecting to the issuance of the CON as well as the amount of the CON related to the LCM Project. If I&M is not ultimately permitted to recover its LCM Project costs, it could reduce future net income and cash flows and impact financial condition. See “Cook Plant Life Cycle Management Project” section of Note 3.

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. 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 3 – Rate Matters, Note 5 – Commitments, Guarantees and Contingencies and the “Litigation” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2012 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies included herein. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

ENVIRONMENTAL ISSUES

We are implementing a substantial capital investment program and incurring additional operational costs to comply with 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, NO_x, PM

and hazardous air pollutants (HAPs) 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, along with various industry groups, affected states and other parties have challenged some of the Federal EPA requirements in court. 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. We believe that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

See a complete discussion of these matters in the “Environmental Issues” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2012 Annual Report. We will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Recovery in Ohio will be dependent upon prevailing market conditions. Environmental rules could result in accelerated depreciation, impairment of assets or regulatory disallowances. If we are unable to recover the costs of environmental compliance, it would reduce future net income and cash flows and impact financial condition.

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. As of March 31, 2013, the AEP System had a total generating capacity of 37,600 MWs, of which 23,700 MWs are coal-fired. We continue to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on our coal-fired generating facilities. Based upon our estimates, investments to meet these proposed requirements range from approximately \$4 billion to \$5 billion through 2020. These amounts include investments to convert 1,570 MWs of coal generation to natural gas capacity. If natural gas conversion is not completed, the units could be retired sooner than planned.

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 more stringent standards, (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.

Subject to the factors listed above and based upon our continuing evaluation, we have given notice to the applicable RTOs of our intent to retire the following plants or units of plants before or during 2016:

Company	Plant Name and Unit	Generating Capacity (in MWs)
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/OPCo	Philip Sporn Plant, Units 1-4	600
I&M	Tanners Creek Plant, Units 1-3	495
KPCo	Big Sandy Plant, Unit 1	278
OPCo	Kammer Plant	630
OPCo	Muskingum River Plant, Units 1-4	840
OPCo	Picway Plant	100
SWEPCo	Welsh Plant, Unit 2	528

Total	4,441
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Duke Energy Corporation, the operator of W. C. Beckjord Generating Station, has announced its intent to close the facility in 2015. OPCo owns 12.5% (53 MWs) of one unit at that station. In December 2012, we retired OPCo's 165 MW Conesville Plant, Unit 3.

A decline in natural gas prices, pending environmental rules and the proposed termination of the Interconnection Agreement had an adverse impact on the recoverability of the net book values of certain coal-fired units. In 2012, we recorded a \$287 million pretax impairment charge for OPCo's net book value of certain plants totaling 1,870 MWs in the table above and the Beckjord and Conesville plants discussed above. As of March 31, 2013, the net book value of the impaired plants is zero.

As of March 31, 2013, the net book value of the regulated plants in the table above was \$449 million. This amount does not include related inventory or CWIP balances.

We are in the process of obtaining permits and other necessary regulatory approvals for either the conversion of some of our coal units to natural gas or installing emission control equipment on certain units. We are also evaluating closure of certain units based on changes in emission requirements and demand for power. The following table lists the plants or units that are either awaiting regulatory approval or are still being evaluated by management:

Company	Plant Name and Unit	Generating Capacity (in MWs)
APCo	Clinch River Plant, Units 1-2	470
I&M/AEGCo/KPCo	Rockport Plant, Units 1-2	2,620
I&M	Tanners Creek Plant, Unit 4	500
KPCo	Big Sandy Plant, Unit 2	800
OPCo	Muskingum River Plant, Unit 5	600
PSO	Northeastern Station, Units 3-4	930
SWEPCo	Flint Creek Plant	264
Total		6,184

In December 2012, KPCo announced its plan to retire Big Sandy Plant, Unit 2 in early 2015, subject to regulatory approval, and its intention to study the conversion of Big Sandy Plant, Unit 1 to natural gas.

As of March 31, 2013, the net book values of the regulated plants and nonregulated plant (Muskingum River) in the table above were \$1.3 billion and \$168 million, respectively. These amounts do not include related inventory or CWIP balances.

The rules and regulatory actions that may impact the evaluation of specific units are discussed in the following sections. Clinch River and Tanners Creek units are being considered for gas conversion. Muskingum River Plant, Unit 5 will have options to cease burning coal and retire in 2015 or cease burning coal in 2015 and complete a refueling project no later than June 2017. Big Sandy Plant, Unit 2 will have options to retrofit, retire, repower or refuel by 2015. Natural gas prices and pending environmental rules could also have an adverse impact on the accounting evaluation of the recoverability of the net book values of certain coal-fired units. To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially reduce future net income and cash flows.

Rockport Plant Clean Coal Technology Project (CCT Project)

In April 2013, I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit both of its units at the Rockport Plant with a Dry Sorbent Injection system. The estimated cost of the CCT Project is \$285 million, excluding AFUDC. The application requested deferral treatment of any unrecovered carrying costs incurred during construction and incremental post in-service depreciation expense and operation and maintenance expenses until such costs are recognized and recovered in a rider. If I&M receives approval of a CPCN, I&M will file for cost recovery associated with the retrofit using the Clean Coal Technology

Rider recovery mechanism. As of March 31, 2013, we have incurred \$61 million related to the CCT Project, including AFUDC. If we are not ultimately permitted to recover our incurred costs, it could reduce future net income and cash flows.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is \$408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at \$204 million. As of March 31, 2013, SWEPCo has incurred \$16 million related to this project, including AFUDC and company overheads. In March 2013, the APSC staff and the Arkansas Attorney General Office filed testimony that supported SWEPCo's petition. The Sierra Club continues to

oppose SWEPCo's petition. Additional hearings were held in March 2013. If SWEPCo is not ultimately permitted to fully recover the net book value of the Flint Creek Plant and its incurred environmental costs in a future base rate proceeding, it could reduce future net income and cash flows and impact financial condition.

Oklahoma Environmental Compliance Plan

In September 2012, based upon an agreement with the Federal EPA, the State of Oklahoma and other parties, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES) Unit 4 in 2016 and additional environmental controls on NES Unit 3 to continue operations through 2026. The plan requested approval for (a) an estimated \$210 million of new environmental investment, excluding AFUDC and overheads of \$46 million, that will be incurred prior to 2016 at NES Unit 3, (b) accelerated recovery through 2026 of the net book value of NES Units 3 and 4 (combined net book value of the two units is \$232 million as of March 31, 2013), (c) an estimated \$83 million of new investment incurred through 2016 at various gas units and (d) a new 15-year purchase power agreement (PPA) with a nonaffiliated entity, effective in 2016, with cost recovery through a rider, including an annual earnings component of \$3 million. Although the environmental compliance plan does not seek to put any new costs into rates at this time, PSO anticipates seeking cost recovery when filing its next base rate case, which is expected to occur no later than 2014.

In January 2013, several parties filed testimony with various recommendations. In February 2013, the OCC staff requested a stay in this proceeding, which was granted by the OCC in March 2013. The stay will be in effect until the State Implementation Plan is approved by the Federal EPA, which could be as late as February 2014. If PSO is ultimately not permitted to fully recover its net book value of NES Units 3 and 4 and other environmental compliance costs, it could reduce future net income and cash flows and impact financial condition. See "Oklahoma Environmental Compliance Plan" section of Note 3.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing the CAA's requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual state implementation plans (SIPs) or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas and Oklahoma. The Federal EPA finalized a FIP for Oklahoma that contains more stringent control requirements for SO₂ emissions from affected units in that state. The Arkansas SIP was disapproved and the state is developing a revised submittal. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the Cross-State Air Pollution Rule (CSAPR) trading programs to use those programs in place of source-specific BART for SO₂ and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the U.S. Court of Appeals for the District of Columbia Circuit and its fate is uncertain given developments in the CSAPR litigation.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for PM, SO₂, NO_x and lead, and is currently reviewing the NAAQS for ozone. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for our facilities as a result of those evaluations. We cannot currently predict the nature, stringency or timing of those requirements.

Notable developments in significant CAA regulatory requirements affecting our operations are discussed in the following sections.

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Cross-State Air Pollution Rule (CSAPR)

In August 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in March 2012. CSAPR relies on newly-created SO₂ and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units in 28 states. Interstate trading of allowances was allowed on a restricted sub-regional basis. Arkansas and Louisiana are subject only to the seasonal NO_x program in the rule. Texas is subject to the annual programs for SO₂ and NO_x in addition to the seasonal NO_x program. The annual SO₂ allowance budgets in Indiana, Ohio and West Virginia were reduced significantly in the rule. A supplemental rule includes Oklahoma in the seasonal NO_x program. The supplemental rule was finalized in December 2011 with an increased NO_x emission budget for the 2012 compliance year. The Federal EPA issued a final Error Corrections Rule and further CSAPR revisions in 2012 to make corrections to state budgets and unit allocations and to remove the restrictions on interstate trading in the first phase of CSAPR.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. Several of the petitioners filed motions to stay the implementation of the rule pending judicial review. In December 2011, the court granted the motions for stay. In August 2012, the panel issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the Clean Air Interstate Rule until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to “overcontrol” emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. The Federal EPA and other respondents have filed petitions for rehearing but in January 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied all petitions for rehearing. The Federal EPA and other parties have filed a petition for further review at the U.S. Supreme Court. Separate appeals of the supplemental rule, the Error Corrections Rule and the further revisions have been filed, but are being held in abeyance.

The time frames and stringency of the required 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. We cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In February 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metal) and hydrogen chloride (as a surrogate for acid gases) for units burning coal 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. The effective date of the final rule was April 16, 2012 and compliance is required within three years. We are participating through various organizations in the petitions for administrative reconsideration and judicial review that have been filed. In 2012, the Federal EPA published a notice announcing that it would accept comments on its reconsideration of certain issues related to the new source standards, including clarification of the requirements that apply during periods of start-up and shut down, measurement issues and the application of variability factors that may have an impact on the level of the standards. Revisions to the new source standards consistent with the proposed rule were issued by the Federal EPA in March 2013.

The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and allows operators to exclude periods of startup and shutdown from the emissions averaging periods. The compliance time frame remains a serious concern. A one-year administrative extension may be available if the extension is necessary for the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. We are concerned about the availability of compliance extensions and the inability to foreclose citizen suits being filed under the CAA for failure

to achieve compliance by the required deadlines. We are participating in petitions for review filed in the U.S. Court of Appeals for the District of Columbia Circuit by several organizations of which we are members. Certain issues related to the standards for new coal-fired units have been severed from the main case and are being held in abeyance pending completion of the Federal EPA's reconsideration proceeding. The case is proceeding on the remaining issues and briefing was completed in April 2013.

Regional Haze

In 2011, the Federal EPA proposed to approve in part and disapprove in part the regional haze SIP submitted by the State of Oklahoma through the Department of Environmental Quality. The Federal EPA proposed 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 proposed a FIP that would require these units to install technology capable of reducing SO2 emissions to 0.06 pounds per million British thermal units within three years of the effective date of the FIP. The Federal EPA finalized the FIP in December 2011 that mirrored the proposed rule but established a five-year compliance schedule. PSO filed a petition for review of the FIP in the Tenth Circuit Court of Appeals and engaged in settlement discussions with the Federal EPA, the State of Oklahoma and other parties. In November 2012, we notified the court that the parties had reached agreement on a settlement that would provide for submission of a revised Regional Haze SIP requiring the retirement of one coal-fired unit of PSO's Northeastern Station no later than 2016, installation of emission controls on the second coal-fired Northeastern unit in 2016 and retirement of the second unit no later than 2026. The Tenth Circuit Court of Appeals is holding the appeal in abeyance pending implementation of the settlement. A revised regional haze SIP was proposed by the State of Oklahoma and submitted to the Federal EPA for review.

CO2 Regulation

In March 2012, the Federal EPA issued a proposal to regulate CO2 emissions from new fossil fuel-fired electricity generating units. The proposed rule establishes a new source performance standard of 1,000 pounds of CO2 per megawatt hour of electricity generated, a rate that most natural gas combined cycle units can meet, but that is substantially below the emission rate of a new pulverized coal generator or an integrated gas combined cycle unit that uses coal for fuel. As proposed, the rule does not apply to new gas-fired stationary combustion turbines used as peaking units, does not apply to existing, modified or reconstructed sources, and does not apply to units whose CO2 emission rate increases as a result of the addition of pollution control equipment to control criteria pollutant emissions or HAPs. The rule is not anticipated to have a significant immediate impact on the AEP System since it does not apply to existing units or units that have already commenced construction. New source performance standards affect units that have not yet received permits. The proposed standards were challenged in the U.S. Court of Appeals for the District of Columbia Circuit. That case was dismissed because the court determined that no final agency action had yet been taken. The Federal EPA is expected to finalize these standards in 2013.

In June 2012, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA's endangerment finding, its regulatory program for CO2 emissions from new motor vehicles and its plan to phase in regulation of CO2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. A petition for rehearing was filed which the court denied in December 2012. Petitioners filed petitions for further review in the U.S. Supreme Court.

The Federal EPA also finalized a rule in June 2012 that retains the current thresholds for permitting stationary sources under the PSD and Title V operating permit programs at 100,000 tons per year for new sources and 75,000 tons per year for modified sources. The Federal EPA also confirmed that it will re-evaluate these thresholds during its five-year review in 2016. Our generating units are large sources of CO2 emissions and we will continue to evaluate the permitting obligations in light of these thresholds.

Coal Combustion Residual Rule

In 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 coal-fired electric generating units. The rule contains two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another 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. In 2011, the Federal EPA issued a notice of data availability requesting comments on a number of technical reports and other data received during the comment period for the original proposal and requesting comments on potential modeling analyses to update its risk

assessment. The Federal EPA has also announced its intention to complete a risk assessment of various beneficial uses of coal ash. Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. The Federal EPA opposed the petition and is seeking additional time to coordinate the issuance of a final rule with the issuance of new effluent limitations under the Clean Water Act for utility facilities.

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 under the proposed solid waste management alternative. Regulation of these materials as hazardous wastes would significantly increase these costs. As the rule is not final, we are unable to determine a range of potential costs that are reasonably possible of occurring but expect the costs to be significant.

Clean Water Act Regulations

In 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a 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 for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. The proposed entrainment standard for new units at existing facilities requires either intake flows commensurate with closed cycle cooling or achieving entrainment reductions equivalent to 90% or greater of the reductions that could be achieved with closed cycle cooling. 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. In June 2012, the Federal EPA issued additional Notices of Data Availability and requested public comments. We submitted comments in July 2012. Issuance of a final rule is not expected until June 2013. We are preparing to begin activities to implement the rule following its issuance and an analysis of the final requirements.

In addition, the Federal EPA issued an information collection request and is developing revised effluent limitation guidelines for electricity generating facilities. A proposed rule was signed in April 2013 with a final rule expected in 2014. The Federal EPA proposed eight options of increasing stringency and cost for fly ash and bottom ash transport water, scrubber wastewater, leachate from coal combustion byproduct landfills and impoundments and other wastewaters associated with coal-fired generating units, with four labeled preferred options. Certain of the Federal EPA's preferred options have already been implemented or are part of our long-term plans. We will review the proposal in detail to evaluate whether our plants are currently meeting the proposed limitations, what technologies have been incorporated into our long-range plans and what additional costs might be incurred if the Federal EPA's most stringent options were adopted. We plan to submit detailed comments to the Federal EPA.

Climate Change

National public policy makers and regulators in the 11 states we serve have diverse views on climate change. We are currently focused on responding to these emerging views with prudent actions, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies and evaluating our assets across a range of plausible scenarios and outcomes. We are also active participants in a variety of public policy discussions at state

and federal levels to assure that proposed new requirements are feasible and the economies of the states we serve are not placed at a competitive disadvantage.

While comprehensive economy-wide regulation of CO₂ emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO₂ emissions under the existing requirements of the CAA.

Several states have adopted programs that directly regulate CO₂ emissions from power plants. The majority of the states where we have generating facilities have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. We are taking steps to comply with these requirements.

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

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

For additional information on climate change, other environmental issues and the actions we are taking to address potential impacts, see Part I of the 2012 Form 10-K under the headings entitled “Business – General – Environmental and Other Matters” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

RESULTS OF OPERATIONS

SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. 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. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are outlined below:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Transmission and distribution of electricity through assets owned and operated by our ten utility operating companies.

Transmission Operations

- Development, construction and operation of transmission facilities through investments in our wholly-owned transmission subsidiaries and transmission joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

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

- Nonregulated generation in ERCOT.
- Marketing, risk management and retail activities in ERCOT, PJM and MISO.

The table below presents Net Income by segment for the three months ended March 31, 2013 and 2012.

	Three Months Ended March 31,	
	2013	2012
	(in millions)	
Utility Operations	\$ 349	\$ 384
Transmission Operations	13	9
AEP River Operations	(2)	9
Generation and Marketing	7	(1)
All Other (a)	(3)	(11)
Net Income	\$ 364	\$ 390

(a) While not considered a reportable segment, All Other includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

AEP CONSOLIDATED

First Quarter of 2013 Compared to First Quarter of 2012

Net Income decreased from \$390 million in 2012 to \$364 million in 2013 primarily due to:

- The loss of retail customers in Ohio to various CRES providers.
- A first quarter 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of the Ohio modified stipulation.
- A write-off in the first quarter of 2013 of previously deferred 2012 Virginia storm costs resulting from the 2013 enactment of a Virginia law.
- Higher costs associated with plant outages in 2013.
- A decrease in AEP River Operations' 2013 earnings due to the impact of the 2012 drought.

These decreases were partially offset by:

- Successful rate proceedings in our various jurisdictions.
- An increase in weather-related usage.
- A decrease in Ohio depreciation expense due to the following:
 - The November 2012 impairment for certain Ohio generation plants.
 - The deferral of capacity-related depreciation costs as a result of the PUCO's July 2012 approval of OPCo's capacity deferral mechanism.

Average basic shares outstanding increased from 484 million in 2012 to 486 million in 2013. Actual shares outstanding were 486 million as of March 31, 2013.

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 electricity.

	Three Months Ended March 31,	
	2013	2012
	(in millions)	
Revenues	\$ 3,517	\$ 3,385
Fuel and Purchased Electricity	1,277	1,269
Gross Margin	2,240	2,116
Other Operation and Maintenance	879	755
Depreciation and Amortization	406	412
Taxes Other Than Income Taxes	209	211
Operating Income	746	738
Interest and Investment Income	3	1
Carrying Costs Income	4	20
Allowance for Equity Funds Used During Construction	10	20
Interest Expense	(226)	(217)
Income Before Income Tax Expense and Equity Earnings	537	562
Income Tax Expense	188	179
Equity Earnings of Unconsolidated Subsidiaries	-	1
Net Income	\$ 349	\$ 384

Summary of KWh Energy Sales for Utility Operations

	Three Months Ended March 31,	
	2013	2012
	(in millions of KWhs)	
Retail:		
Residential	16,255	14,799
Commercial	11,551	11,265
Industrial	13,761	14,647
Miscellaneous	709	721
Total Retail (a)	42,276	41,432
Wholesale	11,024	8,913
Total KWhs	53,300	50,345

(a) Represents energy delivered to distribution customers.

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,	
	2013	2012
	(in degree days)	
Eastern Region		
Actual - Heating (a)	1,818	1,261
Normal - Heating (b)	1,719	1,751
Actual - Cooling (c)	-	28
Normal - Cooling (b)	4	3
Western Region		
Actual - Heating (a)	552	347
Normal - Heating (b)	569	581
Actual - Cooling (d)	70	133
Normal - Cooling (b)	62	60

- (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.
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.
- (d)

First Quarter of 2013 Compared to First Quarter of 2012

Reconciliation of First Quarter of 2012 to First Quarter of 2013
Net Income from Utility Operations
(in millions)

First Quarter of 2012	\$ 384
Changes in Gross Margin:	
Retail Margins	117
Off-system Sales	(30)
Transmission Revenues	21
Other Revenues	16
Total Change in Gross Margin	124
Changes in Expenses and Other:	
Other Operation and Maintenance	(124)
Depreciation and Amortization	6
Taxes Other Than Income Taxes	2
Interest and Investment Income	2
Carrying Costs Income	(16)
Allowance for Equity Funds Used During Construction	(10)
Interest Expense	(9)
Equity Earnings of Unconsolidated Subsidiaries	(1)
Total Change in Expenses and Other	(150)
Income Tax Expense	(9)
First Quarter of 2013	\$ 349

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 electricity were as follows:

- Retail Margins increased \$117 million primarily due to the following:
 - A \$78 million increase in weather-related usage primarily due to 44% and 59% increases in heating degree days in our eastern and western service territories, respectively.
 - Successful rate proceedings in our service territories which include:
 - A \$61 million rate increase for OPCo.
 - A \$28 million rate increase for APCo.
 - A \$23 million rate increase for SWEPCo.
- For the rate increases described above, \$58 million of these increases relate to riders/trackers which have corresponding increases in other expense items below.

These increases were partially offset by:

- An \$87 million decrease attributable to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission

Revenues related to CRES providers detailed below.

- Margins from Off-system Sales decreased \$30 million primarily due to lower Ohio CRES capacity revenues as a result of Reliability Pricing Model pricing effective August 2012, lower PJM capacity payments and reduced trading and marketing margins, partially offset by higher physical sales volumes and margins. The decrease in Ohio CRES capacity revenues is partially offset in other expense items below.
- Transmission Revenues increased \$21 million primarily due to increased transmission revenues from Ohio customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets a portion of the lost revenues included in Retail Margins above.
- Other Revenues increased \$16 million primarily due to an increase in revenues related to recovery of equity carrying costs income on TCC's issuance of securitization bonds in March 2012. This increase is partially offset by an increase in Depreciation and Amortization expense.

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

- Other Operation and Maintenance expenses increased \$124 million primarily due to the following:
 - A \$35 million increase due to the first quarter 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of the Ohio modified stipulation.
 - A \$30 million write-off in the first quarter of 2013 of previously deferred 2012 Virginia storm costs resulting from the 2013 enactment of a Virginia law.
 - A \$26 million increase in remitted Universal Service Fund (USF) surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins.
 - An \$18 million increase in energy efficiency programs and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.
 - A \$16 million increase in plant outage and other plant operating and maintenance expenses.
 - A \$9 million increase in transmission services due to increased RTO expense within SPP.
 - A \$7 million increase due to expenses related to the completion of the 2012 sustainable cost reductions program in the first quarter of 2013.
 - A \$5 million increase in distribution maintenance expense primarily due to the January 2013 snow storm in our eastern region.

These increases were partially offset by:

- A \$25 million decrease due to an agreement reached to settle an insurance claim.
- Depreciation and Amortization expenses decreased \$6 million primarily due to the following:
 - A \$27 million decrease as a result of depreciation ceasing on certain Ohio generating plants that were impaired in November 2012.
 - A \$20 million decrease due to the deferral of capacity-related depreciation costs as a result of the PUCO's July 2012 approval of OPCo's capacity deferral mechanism.

These decreases were partially offset by:

- An \$11 million increase due to the Turk Plant being placed in service in December 2012.
- A \$6 million combined increase in depreciation for APCo and I&M primarily due to increases in depreciation rates effective February 2012 (Virginia), April 2012 (Michigan) and March 2013 (Indiana), respectively. The majority of this increase in depreciation is offset within Gross Margin.
- A \$5 million increase due to TCC's issuance of securitization bonds in March 2012. The increase in TCC's securitization related amortizations are offset within Gross Margin.
- A \$3 million increase as a result of Dresden Plant being placed in service in late January 2012.
- Overall higher depreciable property balances.
- Carrying Costs Income decreased \$16 million primarily due to the following:
 - An \$8 million decrease in carrying costs income due to the first quarter 2012 recording of debt carrying costs prior to TCC's issuance of securitization bonds in March 2012.

- An \$8 million decrease due to an increased recovery of Virginia environmental costs in new base rates as approved by the Virginia SCC in late January 2012 and decreased carrying charges related to Dresden Plant.
- Allowance for Equity Funds Used During Construction decreased \$10 million primarily due to completed construction of the Turk Plant in December 2012.
- Interest Expense increased \$9 million primarily due to a decrease in the debt component of AFUDC due to completed construction of the Turk Plant in December 2012, partially offset by lower long-term interest rates.
- Income Tax Expense increased \$9 million primarily due to favorable audit settlements for previous years recorded in 2012, partially offset by a decrease in pretax book income.

TRANSMISSION OPERATIONS

First Quarter of 2013 Compared to First Quarter of 2012

Net Income from our Transmission Operations segment increased from \$9 million in 2012 to \$13 million in 2013 primarily due to an increase in investments by our wholly-owned transmission subsidiaries and ETT.

AEP RIVER OPERATIONS

First Quarter of 2013 Compared to First Quarter of 2012

Net Income from our AEP River Operations segment decreased from income of \$9 million in 2012 to a loss of \$2 million in 2013 primarily due to the 2012 drought, which continued to have negative impacts on river conditions and 2012 crop yields, resulting in reduced grain exports.

GENERATION AND MARKETING

First Quarter of 2013 Compared to First Quarter of 2012

Net Income from our Generation and Marketing segment increased from a loss of \$1 million in 2012 to income of \$7 million in 2013 primarily due to increased retail activity resulting from our 2012 acquisition of BlueStar and higher trading and marketing margins, partially offset by lower wind production.

ALL OTHER

First Quarter of 2013 Compared to First Quarter of 2012

Net Income from All Other increased from a loss of \$11 million in 2012 to a loss of \$3 million in 2013 primarily due to a reduction in interest expense from lower long-term interest rates.

AEP SYSTEM INCOME TAXES

First Quarter of 2013 Compared to First Quarter of 2012

Income Tax Expense increased \$6 million primarily due to audit settlements for previous years recorded in 2012, partially offset by a decrease in pretax book income.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	March 31, 2013		December 31, 2012	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	\$	17,573	51.2 %	\$ 17,757 52.3 %
Short-term Debt		1,307	3.8	981 2.9
Total Debt		18,880	55.0	18,738 55.2

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AEP Common Equity	15,421	45.0	15,237	44.8
Total Debt and Equity Capitalization	\$ 34,301	100.0 %	\$ 33,975	100.0 %

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Our ratio of debt-to-total capital decreased from 55.2% as of December 31, 2012 to 55% as of March 31, 2013. Short-term debt outstanding increased primarily due to borrowing for our commercial paper program under credit facilities and our common equity increased due to earnings.

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. As of March 31, 2013, we had \$4.5 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a receivables securitization 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-and-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. As of March 31, 2013, our available liquidity was approximately \$3.7 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	\$ 1,750	June 2016
Revolving Credit Facility	1,750	July 2017
Term Credit Facility	1,000	May 2015
Total	4,500	
Cash and Cash Equivalents	179	
Total Liquidity Sources	4,679	
Less:		
AEP Commercial Paper Outstanding	661	
Letters of Credit Issued	115	
Draw on Term Credit Facility	200	
Net Available Liquidity	\$ 3,703	

We have credit facilities totaling \$3.5 billion to support our commercial paper program. The credit facilities allow us to issue letters of credit in an amount up to \$1.2 billion.

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 three months of 2013 was \$836 million. The weighted-average interest rate for our commercial paper during 2013 was 0.35%.

In February 2013, we entered into a \$1 billion term credit facility due in May 2015 to fund certain OPCo maturities on an interim basis and to facilitate the corporate separation of generation assets from transmission and distribution.

Securitized Accounts Receivable

In 2012, we renewed our receivables securitization agreement. The agreement provides a commitment of \$700 million from bank conduits to purchase receivables. A commitment of \$385 million expires in June 2013 and the remaining commitment of \$315 million expires in June 2015. We intend to extend or replace the agreement expiring in June 2013 on or before its maturity.

West Virginia Securitization of Regulatory Assets

In March 2012, West Virginia passed securitization legislation which allows the WVPSC to establish a regulatory framework for electric utilities to securitize certain deferred Expanded Net Energy Charge (ENEC) balances and other ENEC related assets. In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize \$422 million related to APCo's December 2011 under-recovered ENEC deferral balance, other ENEC-related assets and related financing costs. In March 2013, APCo, WPCo and intervenors filed a settlement agreement with the WVPSC, which recommended the WVPSC authorize APCo to securitize \$376 million plus upfront financing costs. A decision is pending from the WVPSC.

Ohio Securitization of Regulatory Assets

In March 2013, the PUCO approved OPCo's request to securitize the Deferred Asset Recovery Rider (DARR) balance. As of March 31, 2013, OPCo's DARR balance was \$277 million, including \$130 million of unrecognized equity carrying costs. The DARR is being recovered through 2018 by a non-bypassable rider. Once the securitization bonds are issued, the DARR will cease and will be replaced by the Deferred Asset Phase-in Rider, which will recover the securitized asset over a period not to exceed eight years. The securitization bonds are expected to be issued in mid-2013.

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 outstanding debt and capitalization is contractually defined in our revolving credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of March 31, 2013, this contractually-defined percentage was 51.4%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of March 31, 2013, 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 any facility if a material adverse change occurs.

The term credit facility may be drawn upon until February 2014. Repayments prior to maturity are permitted. However, any amount that is repaid may not be re-borrowed and is a permanent reduction to the facility.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. As of March 31, 2013, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of \$0.49 per share in April 2013. 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. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements 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 do not believe restrictions related to our various financing arrangements 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,	
	2013	2012
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	\$ 279	\$ 221
Net Cash Flows from Operating Activities	756	876
Net Cash Flows Used for Investing Activities	(772)	(792)
Net Cash Flows Used for Financing Activities	(84)	(19)
Net Increase (Decrease) in Cash and Cash Equivalents	(100)	65
Cash and Cash Equivalents at End of Period	\$ 179	\$ 286

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,	
	2013	2012
	(in millions)	
Net Income	\$ 364	\$ 390
Depreciation and Amortization	420	423
Other	(28)	63
Net Cash Flows from Operating Activities	\$ 756	\$ 876

Net Cash Flows from Operating Activities were \$756 million in 2013 consisting primarily of Net Income of \$364 million and \$420 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. Net cash outflows for Accrued Taxes were a result of recording the estimated federal tax loss for tax/book temporary differences.

Net Cash Flows from Operating Activities were \$876 million in 2012 consisting primarily of Net Income of \$390 million and \$423 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. A significant change in other items includes the favorable impact of a decrease in accounts receivable and the unfavorable impact of an increase in fuel inventory due to the mild weather. 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 and an increase in tax versus book temporary differences from operations.

Investing Activities

	Three Months Ended March 31,	
	2013	2012
	(in millions)	
Construction Expenditures	\$ (843)	\$ (741)
Acquisitions of Nuclear Fuel	(47)	(11)
Acquisitions of Assets/Businesses	(2)	(85)
Insurance Proceeds Related to Cook Plant Fire	72	-
Proceeds from Sales of Assets	1	8
Other	47	37
Net Cash Flows Used for Investing Activities	\$ (772)	\$ (792)

Net Cash Flows Used for Investing Activities were \$772 million in 2013 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Net Cash Flows Used for Investing Activities were \$792 million in 2012 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. Acquisitions of Assets/Businesses include our March 2012 purchase of BlueStar for \$70 million.

Financing Activities

	Three Months Ended March 31,	
	2013	2012
	(in millions)	
Issuance of Common Stock, Net	\$ 15	\$ 31
Issuance of Debt, Net	139	193
Dividends Paid on Common Stock	(230)	(229)
Other	(8)	(14)
Net Cash Flows Used for Financing Activities	\$ (84)	\$ (19)

Net Cash Flows Used for Financing Activities in 2013 were \$84 million. Our net debt issuances were \$139 million. The net issuances included issuances of \$475 million of senior unsecured notes, a \$200 million draw on a \$1 billion term credit facility and an increase in short-term borrowing of \$326 million offset by retirements of \$753 million of senior unsecured and other debt notes and \$105 million of securitization bonds. We paid common stock dividends of \$230 million. See Note 11 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows Used for Financing Activities in 2012 were \$19 million. Our net debt issuances were \$193 million. The net issuances included issuances of \$800 million securitization bonds, \$275 million of senior unsecured notes and \$67 million of notes payable offset by retirements of \$191 million of senior unsecured and other debt notes, \$50 million of pollution control bonds, \$98 million of securitization bonds and a decrease in short-term borrowing of \$600 million. We paid common stock dividends of \$229 million.

In April 2013, I&M retired \$28 million of Notes Payable related to DCC Fuel.

In April 2013, I&M reacquired \$40 million of 5.25% Pollution Control Bonds due in 2025. The variable rate bonds are held by a trustee on behalf of I&M.

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, 2013	December 31, 2012
	(in millions)	
Rockport Plant Unit 2 Future Minimum Lease Payments	\$ 1,478	\$ 1,478
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 Discussion and Analysis of Financial Condition and Results of Operations” in the 2012 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of our contractual obligations is included in our 2012 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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the “Critical Accounting Policies and Estimates” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2012 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, 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 instruments, leases, insurance, hedge accounting and consolidation policy. The ultimate pronouncements resulting from these and future projects could have an impact on 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 through its transactions 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 as we occasionally 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 conducts marketing, risk management and retail activities in ERCOT, PJM and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail 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.

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 power, coal and natural gas and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk 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 and Finance groups in accordance with our established risk management policies as 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 Chief Operating Officer, Chief Financial Officer, Executive Vice President of Energy Supply, 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.

The following table summarizes the reasons for changes in total mark-to-market (MTM) value as compared to December 31, 2012:

MTM Risk Management Contract Net Assets (Liabilities)
Three Months Ended March 31, 2013

	Utility Operations	Generation and Marketing (in millions)	Total
Total MTM Risk Management Contract Net Assets as of December 31, 2012	\$ 68	\$ 128	\$ 196
(Gain) Loss from Contracts Realized/Settled During the Period and			
Entered in a Prior Period	(12)	(10)	(22)
Fair Value of New Contracts at Inception When Entered During the			
Period (a)	-	3	3
Changes in Fair Value Due to Market Fluctuations During the			
Period (b)	-	8	8
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	6	-	6
Total MTM Risk Management Contract Net Assets as of March 31, 2013	\$ 62	\$ 129	\$ 191
Commodity Cash Flow Hedge Contracts			20
Interest Rate and Foreign Currency Cash Flow Hedge Contracts			(2)
Collateral Deposits			15
Total MTM Derivative Contract Net Assets as of March 31, 2013			\$ 224

(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 statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 8 – Derivatives and Hedging and Note 9 – 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, 2013, our credit exposure net of collateral to sub investment grade counterparties was approximately 6.6%, 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, 2013, 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 (in millions, except number of counterparties)	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
Investment Grade	\$ 592	\$ -	\$ 592	2	\$ 277
Split Rating	1	1	-	-	-
Noninvestment Grade	5	4	1	1	1
No External Ratings:					
Internal Investment Grade	91	-	91	2	24
Internal Noninvestment Grade	58	11	47	1	33
Total as of March 31, 2013	\$ 747	\$ 16	\$ 731	6	\$ 335
Total as of December 31, 2012	\$ 807	\$ 13	\$ 794	7	\$ 338

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, 2013, a near term typical change in commodity prices is not expected to materially impact 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, 2013				Twelve Months Ended December 31, 2012			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
\$ -	\$ -	\$ -	\$ -	\$ -	\$ 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, 2013 and December 31, 2012, the estimated EaR on our debt portfolio for the following twelve months was \$40 million and \$42 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

For the Three Months Ended March 31, 2013 and 2012

(in millions, except per-share and share amounts)

(Unaudited)

	Three Months Ended March 31,	
	2013	2012
REVENUES		
Utility Operations	\$ 3,489	\$ 3,363
Other Revenues	337	262
TOTAL REVENUES	3,826	3,625
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	1,031	1,053
Purchased Electricity for Resale	371	260
Other Operation	738	656
Maintenance	293	262
Depreciation and Amortization	420	423
Taxes Other Than Income Taxes	218	217
TOTAL EXPENSES	3,071	2,871
OPERATING INCOME	755	754
Other Income (Expense):		
Interest and Investment Income	3	2
Carrying Costs Income	4	20
Allowance for Equity Funds Used During Construction	15	23
Interest Expense	(232)	(229)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	545	570
Income Tax Expense	195	189
Equity Earnings of Unconsolidated Subsidiaries	14	9
NET INCOME	364	390
Net Income Attributable to Noncontrolling Interests	1	1
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	\$ 363	\$ 389
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING		
	485,823,668	483,828,101
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS		
	\$ 0.75	\$ 0.80

WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	486,344,036	484,248,868
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	\$ 0.75	\$ 0.80
CASH DIVIDENDS DECLARED PER SHARE	\$ 0.47	\$ 0.47

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 32.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

For the Three Months Ended March 31, 2013 and 2012

(in millions)

(Unaudited)

	Three Months Ended March 31,	
	2013	2012
Net Income	\$ 364	\$ 390
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of \$13 and \$6 in 2013 and 2012, Respectively	24	(11)
Securities Available for Sale, Net of Tax of \$1 and \$1 in 2013 and 2012, Respectively	1	2
Amortization of Pension and OPEB Deferred Costs, Net of Tax of \$3 and \$4 in 2013 and 2012, Respectively	6	7
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	31	(2)
TOTAL COMPREHENSIVE INCOME	395	388
Total Comprehensive Income Attributable to Noncontrolling Interests	1	1
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP		
COMMON SHAREHOLDERS	\$ 394	\$ 387

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 32.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

For the Three Months Ended March 31, 2013 and 2012

(in millions)

(Unaudited)

	AEP Common Shareholders				Accumulated		Noncontrolling	
	Common Stock				Other			
	Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Income (Loss)	Interests	Total	
TOTAL EQUITY – DECEMBER 31, 2011	504	\$ 3,274	\$ 5,970	\$ 5,890	\$ (470)	\$ 1	\$ 14,665	
Issuance of Common Stock	1	6	25					31
Common Stock Dividends				(228)		(1)		(229)
Other Changes in Equity			3	(1)				2
Net Income				389		1		390
Other Comprehensive Loss					(2)			(2)
TOTAL EQUITY – MARCH 31, 2012	505	\$ 3,280	\$ 5,998	\$ 6,050	\$ (472)	\$ 1	\$ 14,857	
TOTAL EQUITY – DECEMBER 31, 2012	506	\$ 3,289	\$ 6,049	\$ 6,236	\$ (337)	\$ -	\$ 15,237	
Issuance of Common Stock	-	2	13					15
Common Stock Dividends				(229)		(1)		(230)
Other Changes in Equity			4					4
Net Income				363		1		364
Other Comprehensive Income					31			31
TOTAL EQUITY – MARCH 31, 2013	506	\$ 3,291	\$ 6,066	\$ 6,370	\$ (306)	\$ -	\$ 15,421	

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 32.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

March 31, 2013 and December 31, 2012

(in millions)

(Unaudited)

	March 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	\$ 179	\$ 279
Other Temporary Investments		
(March 31, 2013 and December 31, 2012 Amounts Include \$247 and \$311, Respectively, Related to Transition Funding and EIS)	261	324
Accounts Receivable:		
Customers	679	685
Accrued Unbilled Revenues	210	195
Pledged Accounts Receivable – AEP Credit	884	856
Miscellaneous	133	171
Allowance for Uncollectible Accounts	(37)	(36)
Total Accounts Receivable	1,869	1,871
Fuel	839	844
Materials and Supplies	681	675
Risk Management Assets	162	191
Regulatory Asset for Under-Recovered Fuel Costs	91	88
Margin Deposits	74	76
Prepayments and Other Current Assets	241	241
TOTAL CURRENT ASSETS	4,397	4,589
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	26,389	26,279
Transmission	9,902	9,846
Distribution	15,720	15,565
Other Property, Plant and Equipment (Including Nuclear Fuel and Coal Mining)	3,986	3,945
Construction Work in Progress	2,078	1,819
Total Property, Plant and Equipment	58,075	57,454
Accumulated Depreciation and Amortization	18,945	18,691
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	39,130	38,763
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,087	5,106
Securitized Transition Assets	2,065	2,117
Spent Nuclear Fuel and Decommissioning Trusts	1,788	1,706
Goodwill	91	91
Long-term Risk Management Assets	341	368
Deferred Charges and Other Noncurrent Assets	1,651	1,627

TOTAL OTHER NONCURRENT ASSETS	11,023	11,015
TOTAL ASSETS	\$ 54,550	\$ 54,367

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 32.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY

March 31, 2013 and December 31, 2012

(dollars in millions)

(Unaudited)

	March 31, 2013	December 31, 2012
CURRENT LIABILITIES		
Accounts Payable	\$ 1,004	\$ 1,169
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	646	657
Other Short-term Debt	661	324
Total Short-term Debt	1,307	981
Long-term Debt Due Within One Year		
(March 31, 2013 and December 31, 2012 Amounts Include \$365 and \$367, Respectively, Related to Transition Funding, DCC Fuel and Sabine)	1,674	2,171
Risk Management Liabilities	94	155
Customer Deposits	299	316
Accrued Taxes	727	747
Accrued Interest	241	269
Regulatory Liability for Over-Recovered Fuel Costs	18	47
Other Current Liabilities	811	968
TOTAL CURRENT LIABILITIES	6,175	6,823
NONCURRENT LIABILITIES		
Long-term Debt		
(March 31, 2013 and December 31, 2012 Amounts Include \$2,098 and \$2,227, Respectively, Related to Transition Funding, DCC Fuel and Sabine)	15,899	15,586
Long-term Risk Management Liabilities	185	214
Deferred Income Taxes	9,556	9,252
Regulatory Liabilities and Deferred Investment Tax Credits	3,625	3,544
Asset Retirement Obligations	1,727	1,696
Employee Benefits and Pension Obligations	1,049	1,075
Deferred Credits and Other Noncurrent Liabilities	913	940
TOTAL NONCURRENT LIABILITIES	32,954	32,307
TOTAL LIABILITIES	39,129	39,130
EQUITY		
Common Stock – Par Value – \$6.50 Per Share:		
	2013	2012
Shares Authorized	600,000,000	600,000,000

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Shares Issued	506,356,262	506,004,962		
(20,336,592 Shares were Held in Treasury as of March 31, 2013 and December 31, 2012)			3,291	3,289
Paid-in Capital			6,066	6,049
Retained Earnings			6,370	6,236
Accumulated Other Comprehensive Income (Loss)			(306)	(337)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			15,421	15,237
Noncontrolling Interests			-	-
TOTAL EQUITY			15,421	15,237
TOTAL LIABILITIES AND EQUITY			\$ 54,550	\$ 54,367

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 32.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Three Months Ended March 31, 2013 and 2012

(in millions)

(Unaudited)

	Three Months Ended March 31,	
	2013	2012
OPERATING ACTIVITIES		
Net Income	\$ 364	\$ 390
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	420	423
Deferred Income Taxes	246	261
Carrying Costs Income	(4)	(20)
Allowance for Equity Funds Used During Construction	(15)	(23)
Mark-to-Market of Risk Management Contracts	34	10
Amortization of Nuclear Fuel	34	34
Property Taxes	(51)	(49)
Fuel Over/Under-Recovery, Net	(4)	112
Change in Other Noncurrent Assets	(13)	(59)
Change in Other Noncurrent Liabilities	17	(47)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(4)	207
Fuel, Materials and Supplies	(1)	(126)
Accounts Payable	(3)	(26)
Accrued Taxes, Net	(69)	(30)
Other Current Assets	(16)	(15)
Other Current Liabilities	(179)	(166)
Net Cash Flows from Operating Activities	756	876
INVESTING ACTIVITIES		
Construction Expenditures	(843)	(741)
Change in Other Temporary Investments, Net	75	79
Purchases of Investment Securities	(196)	(353)
Sales of Investment Securities	168	334
Acquisitions of Nuclear Fuel	(47)	(11)
Acquisitions of Assets/Businesses	(2)	(85)
Insurance Proceeds Related to Cook Plant Fire	72	-
Proceeds from Sales of Assets	1	8
Other Investing Activities	-	(23)
Net Cash Flows Used for Investing Activities	(772)	(792)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	15	31
Issuance of Long-term Debt	671	1,132
Commercial Paper and Credit Facility Borrowings	17	21
Change in Short-term Debt, Net	329	(583)

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Retirement of Long-term Debt	(858)	(339)
Commercial Paper and Credit Facility Repayments	(20)	(38)
Principal Payments for Capital Lease Obligations	(16)	(18)
Dividends Paid on Common Stock	(230)	(229)
Other Financing Activities	8	4
Net Cash Flows Used for Financing Activities	(84)	(19)
Net Increase (Decrease) in Cash and Cash Equivalents	(100)	65
Cash and Cash Equivalents at Beginning of Period	279	221
Cash and Cash Equivalents at End of Period	\$ 179	\$ 286

SUPPLEMENTARY INFORMATION

Cash Paid for Interest, Net of Capitalized Amounts	\$ 253	\$ 265
Net Cash Paid (Received) for Income Taxes	(19)	(65)
Noncash Acquisitions Under Capital Leases	24	20
Construction Expenditures Included in Current Liabilities as of March 31,	300	250
Noncash Assumption of Liabilities Related to Acquisitions	-	56

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 32.

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

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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, 2013 is not necessarily indicative of results that may be expected for the year ending December 31, 2013. The condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2012 consolidated financial statements and notes thereto, which are included in our Form 10-K as filed with the SEC on February 26, 2013.

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 statements of income:

	Three Months Ended March 31,			
	2013		2012	
	(in millions, except per share data)			
	\$ /share		\$ /share	
Earnings Attributable to AEP Common Shareholders	\$	363	\$	389
Weighted Average Number of Basic Shares Outstanding	485.8	\$ 0.75	483.8	\$ 0.80
Weighted Average Dilutive Effect of:				
Restricted Stock Units	0.5	-	0.4	-
Weighted Average Number of Diluted Shares Outstanding	486.3	\$ 0.75	484.2	\$ 0.80

There were no antidilutive shares outstanding as of March 31, 2013 and 2012.

2. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following table provides the components of changes in AOCI for the three months ended March 31, 2013. All amounts in the following table are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component

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For the Three Months Ended March 31, 2013

	Cash Flow Hedges		Interest Rate and Foreign Currency		Securities Available for Sale (in millions)	Pension and OPEB	Total	
	Commodity							
Balance in AOCI as of December 31, 2012	\$	(8)	\$	(30)	\$	4	\$	(337)
Change in Fair Value Recognized in AOCI		18		3		1		22
Amounts Reclassified from AOCI		2		1		-		9
Net Current Period Other Comprehensive Income		20		4		1		31
Balance in AOCI as of March 31, 2013	\$	12	\$	(26)	\$	5	\$	(297)
								\$
								(306)

Reclassifications Out of Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the three months ended March 31, 2013. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended March 31, 2013

	Amount of (Gain) Loss Reclassified from AOCI (in millions)
Gains and Losses on Cash Flow Hedges	
Commodity:	
Utility Operations Revenues	\$ -
Other Revenues	(3)
Purchased Electricity for Resale	6
Property, Plant and Equipment	-
Regulatory Assets (a)	-
Subtotal - Commodity	3
Interest Rate and Foreign Currency:	
Interest Expense	2
Subtotal - Interest Rate and Foreign Currency	2
Reclassifications from AOCI, before Income Tax (Expense) Credit	5
Income Tax (Expense) Credit	2
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	3
Gains and Losses on Available-for-Sale Securities	
Interest Income	-
Interest Expense	-
Reclassifications from AOCI, before Income Tax (Expense) Credit	-
Income Tax (Expense) Credit	-
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	-
Amortization of Pension and OPEB	
Prior Service Cost (Credit)	(5)
Actuarial (Gains)/Losses	14
Reclassifications from AOCI, before Income Tax (Expense) Credit	9
Income Tax (Expense) Credit	3
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	6
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	\$ 9

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

The following table provides details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2012. All amounts in the following table 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, 2012

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Balance in AOCI as of December 31, 2011	\$ (3)	\$ (20)	\$ (23)
Changes in Fair Value Recognized in AOCI	(20)	1	(19)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	-	-	-
Other Revenues	(1)	-	(1)
Purchased Electricity for Resale	7	-	7
Interest Expense	-	1	1
Regulatory Assets (a)	1	-	1
Balance in AOCI as of March 31, 2012	\$ (16)	\$ (18)	\$ (34)

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

The following table provides details of Other Temporary Investments included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets and the reasons for changes for the three months ended March 31, 2012. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Other Temporary Investments
Three Months Ended March 31, 2012

	(in millions)
Balance in AOCI as of December 31, 2011	\$ 2
Changes in Fair Value Recognized in AOCI	2
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income:	
Interest Income	-
Balance in AOCI as of March 31, 2012	\$ 4

3. RATE MATTERS

As discussed in the 2012 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2012 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 2013 and updates the 2012 Annual Report.

Regulatory Assets Not Yet Being Recovered

	March 31, 2013	December 31, 2012
	(in millions)	
Noncurrent Regulatory Assets		
Regulatory assets not yet being recovered pending future proceedings:		
Regulatory Assets Currently Earning a Return		
Storm Related Costs	\$ 23	\$ 23
Economic Development Rider	13	13
Other Regulatory Assets Not Yet Being Recovered	2	1
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	141	172
Medicare Part D	56	-
Virginia Environmental Rate Adjustment Clause	27	29
Ormet Delayed Payment Arrangement	20	5
Mountaineer Carbon Capture and Storage Product Validation Facility	14	14
Litigation Settlement	-	11
Deferred Wind Power Costs	5	5
Other Regulatory Assets Not Yet Being Recovered	32	31
Total Regulatory Assets Not Yet Being Recovered	\$ 333	\$ 304

If these costs are ultimately determined not to be recoverable, it would reduce future net income and cash flows and impact financial condition.

OPCo Rate Matters

Ohio Electric Security Plan Filing

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018. The PUCO's March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers' Counsel and the IEU filed appeals of that order with

the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance. As of March 31, 2013, OPCo's net deferred fuel balance was \$501 million, excluding unrecognized equity carrying costs. A decision from the Supreme Court of Ohio is pending.

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off in 2010 and a subsequent refund to customers during 2011. The IEU and the Ohio Energy Group filed appeals with the Supreme Court of Ohio challenging the PUCO's SEET decision. In December 2012, the Supreme Court of Ohio issued an order which rejected all of the intervenors' challenges and affirmed the PUCO decision.

The 2009 SEET order gave consideration for a future commitment to invest \$20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend \$20 million on this solar project or another project by the end of 2013. Management continues to evaluate other investment alternatives.

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to \$62 million of 2010 earnings, which included off-system sales in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a \$23 million refund of 2010 earnings. OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO-ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's request to file the 2011 SEET one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo or in 2012 and 2013 for OPCo.

In August 2012, the PUCO issued an order in a separate proceeding which implemented a Phase-In Recovery Rider (PIRR) to recover deferred fuel costs in rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. In November 2012, OPCo filed an appeal at the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated 2009 – 2011 ESP order, which granted a weighted average cost of capital rate. The IEU and the Ohio Consumers' Counsel also filed appeals at the Supreme Court of Ohio in November 2012 arguing that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues and reduced carrying costs due to an accumulated deferred income tax credit. These appeals could reduce OPCo's net deferred fuel balance up to the total balance, which would reduce future net income and cash flows. A decision from the Supreme Court of Ohio is pending.

Management is unable to predict the outcome of the unresolved litigation discussed above. Depending on the rulings in these proceedings, it could reduce future net income and cash flows and impact financial condition.

June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that establishes base generation rates through May 2015.

As part of the ESP decision, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the SSO load with delivery beginning six months after the receipt of final orders in both the ESP and corporate separation cases and extending through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning June 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to \$188.88/MW day. The RPM price is approximately \$20/MW day through May 2013 then \$33/MW day through May 2014. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 PUCO ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is expected to provide approximately \$500 million over the ESP period and will be collected from customers at \$3.50/MWh through May 2014 and \$4.00/MWh for the period June 2014 through May

2015, with \$1.00/MWh applied to the recovery of deferred capacity costs. As of March 31, 2013, OPCo's incurred deferred capacity costs balance of \$116 million, including debt carrying costs, was recorded in Regulatory Assets on the balance sheet. In August 2012, the IEU filed an action with the Supreme Court of Ohio stating, among other things, that OPCo's collection of its capacity costs is illegal. In April 2013, the Supreme Court of Ohio dismissed the IEU's action. If OPCo is ultimately not permitted to fully collect its deferred capacity costs, it could reduce future net income and cash flows and impact financial condition.

In January and March 2013, the PUCO issued its Orders on Rehearing for the ESP which generally upheld its August 2012 order including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and costs would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket related to the competitive bidding process.

If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, it could reduce future net income and cash flows and impact financial condition.

Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets at net book value to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. In December 2012, the PUCO granted the IEU and the Ohio Consumers' Counsel requests for rehearing, which were denied by the PUCO in April 2013.

Also in October 2012, filings at the FERC were submitted related to corporate separation. If approved as filed, results of operations related to generation in Ohio will be largely determined by prevailing market conditions effective January 1, 2014. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters.

Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates. The SDRR seeks recovery of 2012 incremental storm distribution expenses over twelve months starting with the effective date of the SDRR as approved by the PUCO. OPCo requested approval of a weighted average cost of capital carrying charge, effective April 2013. As of March 31, 2013, OPCo recorded \$61 million in Regulatory Assets on the balance sheet related to 2012 storm damage. If OPCo is not ultimately permitted to recover these storm costs, it could reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

The PUCO selected an outside consultant to conduct an audit of OPCo's FAC for 2009. The outside consultant provided its audit report to the PUCO. In January 2012, the PUCO ordered that the remaining \$65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. OPCo recorded a \$30 million net favorable adjustment on the statement of income in the second quarter of 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of any future consultant recommendation regarding valuation of the coal reserve. If the PUCO ultimately determines that additional amounts should benefit ratepayers as a result of the consultant's review of the coal reserve valuation, it could reduce future net income and cash flows and impact financial condition.

In August 2012, intervenors filed an appeal with the Supreme Court of Ohio claiming the settlement credit ordered by the PUCO should have reflected the remaining gain not already flowed through the FAC with carrying charges, which, if ordered, would be \$35 million plus carrying charges. If the Supreme Court of Ohio ultimately determines that additional amounts should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audit reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes. As of March 31, 2013, the amount of OPCo's carrying costs that could potentially be reduced due to the accumulated income tax issue is estimated to be approximately \$35 million, including \$18 million of unrecognized equity carrying costs. These amounts include the carrying costs exposure of the 2009 FAC audit, which has been appealed by an intervenor to the Supreme Court of Ohio. Decisions from the PUCO are pending. Management is unable to predict the outcome of these proceedings. If the PUCO orders result in a reduction to the FAC deferral, it could reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

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 filing and the FAC aspect of the ESP order was upheld by the Supreme Court of Ohio. The approval of the FAC as part of the ESP, together with the PUCO approval of the interim arrangement, provided the basis to record a regulatory asset for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, OPCo had \$64 million of deferred FAC costs related to the interim arrangement, excluding \$2 million of unrecognized equity carrying costs. In November 2009, OPCo requested that the PUCO approve recovery of the deferral under the interim agreement plus a weighted average cost of capital carrying charge. The deferral amount is included in OPCo's FAC phase-in deferral balance. In the 2009 – 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related regulatory asset and requested that the PUCO prevent OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request. The intervenors raised the issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement. This issue remains pending before the PUCO. If OPCo is not ultimately permitted to fully recover its requested deferrals under the interim arrangement, it could reduce future net income and cash flows and impact financial condition.

Special Rate Mechanism for Ormet

In October 2012, the PUCO issued an order approving a delayed payment plan for Ormet's October and November 2012 power billings totaling \$27 million to be paid in equal monthly installments over the period January 2014 to May 2015 without interest. In the event Ormet does not pay its \$27 million obligation, the PUCO permitted OPCo to recover the unpaid balance, up to \$20 million, in the economic development rider. To the extent unpaid amounts exceed \$20 million, it will reduce future net income and cash flows and impact financial condition.

In February 2013, Ormet filed Chapter 11 bankruptcy proceedings in the state of Delaware but is current on all payments due to OPCo. As of March 31, 2013, OPCo has a regulatory asset of \$20 million and a net receivable of \$6 million recorded related to the special rate mechanism for Ormet.

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. As of March 31, 2013, OPCo has collected \$24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions with the PUCO requesting all collected pre-construction costs be refunded to Ohio ratepayers with interest.

Management cannot predict the outcome of these proceedings concerning the Ohio IGCC plant or what effect, if any, these proceedings would have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

Turk Plant

SWEPCo constructed the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the facility. As of March 31, 2013, excluding costs attributable to its joint owners and a \$62 million provision for a Texas capital cost cap, SWEPCo has capitalized approximately \$1.7 billion of expenditures, including AFUDC and capitalized interest of \$328 million and related transmission costs of \$120 million.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant (approximately 20%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to the Arkansas Supreme Court's decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This portion of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the SPP market.

The PUCT approved 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 CO₂ 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 (TIEC) filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant should be revoked because the Turk Plant is unnecessary to serve retail customers. The Texas District Court and the Texas Court of Appeals affirmed the PUCT's order in all respects. In April 2012, SWEPCo and the TIEC filed petitions for review at the Supreme Court of Texas, which were denied in March 2013. In April 2013, SWEPCo and the TIEC filed motions for rehearing at the Supreme Court of Texas.

If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by \$83 million, primarily due to the Turk Plant, based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share (approximately 33%) of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. The filing also (a) increased depreciation expense due to the decrease in the average remaining life of the Welsh Plant to account for the change in the retirement date of the Welsh Plant Unit 2 from 2040 to 2016, (b) proposed increased vegetation management expenditures and (c) included a return on and of the Stall Unit as of December 2011 and associated operation and maintenance costs.

In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates.

In December 2012, several intervenors, including the PUCT staff, filed testimony that recommended an annual base rate increase between \$16 million and \$51 million based upon a return on common equity between 9% and 9.55%. In addition, two intervenors recommended that the Turk Plant be excluded from rate base. A decision from the PUCT is expected in the second quarter of 2013. If the PUCT does not approve full cost recovery of SWEPCo's assets, it could

reduce future net income and cash flows and impact financial condition.

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and approved by the LPSC. The settlement increased Louisiana total rates by approximately \$2 million annually, effective March 2013, which consisted of an increase in base rates of approximately \$85 million annually offset by a decrease in fuel and other rates of approximately \$83 million annually. The March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund based on the staff review of the cost of service and the prudence of the Turk Plant to be initiated by SWEPCo no later than May 2013. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover all non-fuel Turk Plant costs and a full weighted-average cost of capital return on the Turk Plant portion of rate base, effective January 2013. If the LPSC orders refunds based upon the staff review of the cost of service or prudence review of the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is \$408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at \$204 million. As of March 31, 2013, SWEPCo has incurred \$16 million related to this project, including AFUDC and company overheads. In March 2013, the APSC staff and the Arkansas Attorney General Office filed testimony that supported SWEPCo's petition. The Sierra Club continues to oppose SWEPCo's petition. Additional hearings were held in March 2013. If SWEPCo is not ultimately permitted to fully recover the net book value of the Flint Creek Plant and its incurred environmental costs in a future base rate proceeding, it could reduce future net income and cash flows and impact financial condition.

APCo and WPCo Rate Matters

Plant Transfers

In October 2012, the AEP East Companies submitted several filings with the FERC regarding the transfer of certain generation plants within the AEP System. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters. In December 2012, APCo and WPCo filed requests with the Virginia SCC and the WVPSC for approval to transfer at net book value to APCo a two-thirds interest in Amos Plant Unit 3 and a one-half interest in the Mitchell Plant, comprising 1,647 MW of average annual generating capacity presently owned by OPCo. In April 2013, several intervenors filed testimony with the Virginia SCC and made recommendations relating to APCo's proposed asset transfers including the issuance of a Request for Proposal for APCo's resource needs. Hearings at the Virginia SCC and the WVPSC are scheduled for June 2013 and July 2013, respectively. If the transfers are approved, APCo and WPCo anticipate seeking cost recovery in upcoming rate proceedings. If APCo and WPCo are not ultimately permitted to recover their incurred costs, it could reduce future net income and cash flows and impact financial condition.

APCo IGCC Plant

As of March 31, 2013, 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 \$10 million applicable to its Virginia jurisdiction. If the costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Environmental Rate Adjustment Clause (Environmental RAC)

In March 2013, APCo filed with the Virginia SCC for approval of an environmental RAC to recover \$39 million related to 2012 and 2011 environmental compliance costs effective February 2014 over a one-year period. In March 2013, the environmental RAC surcharge expired related to the collection of 2009 and 2010 environmental compliance costs. APCo has deferred \$28 million as of March 31, 2013 for the Virginia portion of unrecovered

environmental RAC costs incurred in 2012 and 2011, excluding \$11 million of unrecognized equity carrying costs. If the Virginia SCC were to disallow any portion of the environmental RAC, it could reduce future net income and cash flows.

Generation Rate Adjustment Clause (Generation RAC)

In March 2013, APCo filed with the Virginia SCC for an increase in its generation RAC revenues of \$12 million for a total of \$38 million annually to collect costs related to the Dresden Plant. The generation RAC increase is expected to be effective in March 2014. APCo has deferred \$4 million as of March 31, 2013 for the Virginia portion of unrecovered costs of the Dresden Plant, excluding \$3 million of unrecognized equity carrying costs. If the Virginia SCC were to disallow any portion of the generation RAC, it could reduce future net income and cash flows.

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

In March 2012, West Virginia passed securitization legislation which allows the WVPSC to establish a regulatory framework for electric utilities to securitize certain deferred ENEC balances and other ENEC-related assets. In August 2012, APCo and WPCo filed a request with the WVPSC for a financing order to securitize a total of \$422 million related to the December 2011 under-recovered ENEC deferral balance including other ENEC-related assets of \$13 million and related future financing costs of \$7 million. Upon completion of the securitization, APCo would offset its current ENEC rates by an amount to recover the securitized balance over the securitization period. In March 2013, APCo, WPCo and intervenors filed a settlement agreement with the WVPSC which recommended the WVPSC authorize APCo to securitize \$376 million plus upfront financing costs. As of March 31, 2013, APCo's ENEC under-recovery balance of \$287 million, net of 2012 and 2013 over-recovery, was recorded in Regulatory Assets on the balance sheet, excluding \$4 million of unrecognized equity carrying costs and \$14 million of other ENEC-related assets.

In April 2013, APCo and WPCo filed to keep total rates unchanged with a portion of the ENEC to be specifically identified for the amount to be securitized in accordance with the proposed securitization settlement agreement. The remaining ENEC rate is proposed to include (a) the proposed transfer of certain generation facilities from OPCo and the APCo/WPCo merger, (b) construction surcharges and (c) ongoing ENEC costs. Decisions on these issues are pending with the WVPSC.

Virginia Storm Costs

In March 2013, due to the 2013 enactment of a Virginia law, APCo wrote off \$30 million of previously deferred 2012 Virginia storm costs. The change in law affected the test years to be included in APCo's next biennial Virginia base rate filing in March 2014 and the determination of how these costs are treated in the Virginia jurisdictional biennial earnings test for 2012 actual results and 2013 estimated results. The 2013 earnings component will be reviewed quarterly to determine if any storm costs can be deferred. If this quarterly test allows APCo to recover previously expensed storm costs, it could increase future net income and cash flows.

PSO Rate Matters

Oklahoma Environmental Compliance Plan

In September 2012, based upon an agreement with the Federal EPA, the State of Oklahoma and other parties, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES) Unit 4 in 2016 and additional environmental controls on NES Unit 3 to continue operations through 2026. The plan requested approval for (a) an estimated \$210 million of new environmental investment, excluding AFUDC and overheads of \$46 million, that will be incurred prior to 2016 at NES Unit 3, (b) accelerated recovery through 2026 of

the net book value of NES Units 3 and 4 (combined net book value of the two units is \$232 million as of March 31, 2013), (c) an estimated \$83 million of new investment incurred through 2016 at various gas units and (d) a new 15-year purchase power agreement (PPA) with a nonaffiliated entity, effective in 2016, with cost recovery through a rider, including an annual earnings component of \$3 million. Although the environmental compliance plan does not seek to put any new costs into rates at this time, PSO anticipates seeking cost recovery when filing its next base rate case, which is expected to occur no later than 2014.

In January 2013, testimony filed by the OCC staff and the Oklahoma Office of the Attorney General (OOAG) recommended no earnings component on the PPA and to delay final decisions until 2020 on parts of the plan including cost recovery of the net book value of NES Unit 3 and any increases in fuel costs due to reductions in the output of energy from NES Unit 3 beginning in 2021. The testimony recommended that cost recovery could extend past 2026 on parts of the plan and recommended a \$175 million cost cap on NES Unit 3 environmental investment excluding AFUDC and overheads.

In March 2013, the OCC staff and the OOAG filed additional testimony revising the recommended cost cap on NES Unit 3 to \$210 million, excluding AFUDC and overheads, and recommended conditional approval of the planned NES Unit 3 retirement subject to OCC approval in 2020 provided the planned retirement is consistent with environmental rules at that time.

Also, an intervenor representing some of PSO's large industrial users opposed the majority of PSO's plan, including recommending no cost recovery of NES Units 3 and 4 book value amounts not recovered at the time of their retirement and no recovery of the PPA costs, including earnings on the PPA. In February 2013, the OCC staff requested a stay in this proceeding, which was granted by the OCC in March 2013. The stay will be in effect until the State Implementation Plan is approved by the Federal EPA, which could be as late as February 2014.

If PSO is ultimately not permitted to fully recover its net book value of NES Units 3 and 4 and other environmental compliance costs, it could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters

2011 Indiana Base Rate Case

In February 2013, the IURC issued an order that granted an \$85 million annual increase in base rates based upon a return on common equity of 10.2%. In a March 2013 order, the IURC approved an adjustment which increased the authorized annual increase in base rates from \$85 million to \$92 million. In March 2013, the Indiana Office of Utility Consumer Counselor (OUCC) filed a request for reconsideration with the IURC, which was denied. Also in March 2013, the OUCC filed an appeal of the order with the Indiana Court of Appeals. If the order is overturned by the Indiana Court of Appeals, it could reduce future net income and cash flows.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its extended licensed life. The estimated cost of the LCM Project is \$1.2 billion to be incurred through 2018, excluding AFUDC. As of March 31, 2013, I&M has incurred \$197 million related to the LCM Project, including AFUDC.

In April 2012, I&M filed a petition with the IURC for recovery of project costs, including interest, through a new rider. In August 2012, intervenors filed testimony in Indiana. The Indiana Michigan Power Company Industrial Group recommended that I&M recover \$229 million in a rider with the remaining costs to be requested in future base rate cases. The Indiana Office of Utility Consumer Counselor (OUCC) recommended a maximum of \$408 million of LCM Project costs be recovered in a rider, and a maximum of \$299 million for projects the OUCC believes are not related to the LCM Project to be recovered in future base rates. The IURC held a hearing in January 2013 and an order is pending.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project. In April 2013, an intervenor filed an appeal with the Michigan Court of Appeals objecting to the issuance of the CON as well as the amount of the

CON related to the LCM Project. If I&M is not ultimately permitted to recover its LCM Project costs, it could reduce future net income and cash flows and impact financial condition.

Rockport Plant Clean Coal Technology Project (CCT Project)

In April 2013, I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit both of its units at the Rockport Plant with a Dry Sorbent Injection system. The estimated cost of the CCT Project is \$285 million, excluding AFUDC. The application requested deferral treatment of any unrecovered carrying costs incurred during construction and incremental post in-service depreciation expense and operation and maintenance expenses until such costs are recognized and recovered in a rider. If I&M receives approval of a CPCN, I&M will file for cost recovery associated with the retrofit using the Clean Coal Technology Rider recovery mechanism. As of March 31, 2013, we have incurred \$61 million related to the CCT Project, including AFUDC. If we are not ultimately permitted to recover our incurred costs, it could reduce future net income and cash flows.

KPCo Rate Matters

Plant Transfer

In October 2012, the AEP East Companies submitted several filings with the FERC. See the “Corporate Separation and Termination of Interconnection Agreement” section of FERC Rate Matters. In December 2012, KPCo filed a request with the KPSC for approval to transfer at net book value to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity presently owned by OPCo. If the transfer is approved, KPCo anticipates seeking cost recovery when filing its next base rate case. In March 2013, KPCo issued a Request for Proposal to purchase up to 250 MW of long-term capacity and energy. KPCo also requested costs related to the Big Sandy Plant Unit 2 FGD project be established as a regulatory asset and be recovered in KPCo’s next base rate case. As of March 31, 2013, KPCo has incurred \$28 million related to the FGD project, which is recorded in Deferred Charges and Other Noncurrent Assets on the balance sheet.

In April 2013, the Kentucky Industrial Utility Customers, Inc. (KIUC) filed testimony that recommended (a) the one-half transfer interest of the Mitchell Plant be limited to a 20% interest contingent on a determination that the net book value is less than market value, (b) the transfer should occur on June 1, 2015 and (c) that the request to defer the FGD project costs be denied. If the Mitchell Plant transfer is approved, the KIUC requested that the shareholder’s portion of off-system sales decrease from 40% to zero. A hearing at the KPSC is scheduled for May 2013. If KPCo is not ultimately permitted to recover its incurred costs, it could reduce future net income and cash flows and impact financial condition.

FERC Rate Matters

Corporate Separation and Termination of Interconnection Agreement

In October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo’s generation assets from its distribution and transmission operations. The filings requested approval to transfer at net book value approximately 9,200 MW of OPCo-owned generation assets to a new wholly-owned company, AEPGenCo. The AEP East Companies also requested FERC approval to transfer at net book value OPCo’s current two-thirds ownership (867 MW) in Amos Plant Unit 3 to APCo and transfer at net book value OPCo’s Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). These transfers are proposed to be effective no later than December 31, 2013. Additionally, the AEP East Companies asked the FERC, effective January 1, 2014, to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants’ respective power supply resources. Under the PCA, APCo, I&M and KPCo would be individually responsible for planning their respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a

common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities. Intervenor comments have opposed several of these filings. The AEP East Companies responded to intervenor comments and filed a revised PCA at the FERC in March 2013. The revised PCA included certain clarifying wording changes that have been agreed upon by intervenors. A decision from the FERC is expected in the second quarter of 2013.

Similar asset transfer filings have been made at the KPSC, the Virginia SCC and the WVPSC. See the “Plant Transfers” section of APCo and WPCo Rate Matters and the “Plant Transfer” section of KPCo Rate Matters.

4. 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 effect on our financial statements. The Commitments, Guarantees and Contingencies note within our 2012 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 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 credit facilities totaling \$3.5 billion, under which we may issue up to \$1.2 billion as letters of credit. As of March 31, 2013, the maximum future payments for letters of credit issued under the credit facilities were \$115 million with maturities ranging from April 2013 to April 2014.

We have \$402 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for \$407 million. The letters of credit have maturities ranging from March 2014 to March 2015.

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 \$115 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. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study completed in 2010, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately \$58 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of March 31, 2013, SWEPCo has collected approximately \$60 million through a rider for final mine closure and reclamation costs, of which \$11 million is recorded in Deferred Credits and Other Noncurrent Liabilities and \$49 million is recorded in Asset Retirement Obligations on our condensed 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 2012 Annual Report “Dispositions” section of Note 6. As of March 31, 2013, there were no material liabilities recorded for any indemnifications.

Master Lease Agreements

We lease certain equipment under master lease agreements. Under the 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. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of March 31, 2013, the maximum potential loss for these lease agreements was approximately \$19 million assuming the fair value of the equipment is zero at the end of the lease term.

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 \$14 million and \$15 million for I&M and SWEPCo, respectively, for the remaining railcars as of March 31, 2013.

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. The maximum potential losses related to the guarantee are approximately \$12 million and \$13 million for I&M and SWEPCo, respectively, 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 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. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. In March 2012, the court granted the defendants' motion for dismissal on several grounds, including the doctrine of collateral estoppel and the applicable statute of limitations. Plaintiffs appealed the decision to the Fifth Circuit Court of Appeals. We will continue to defend against the claims. 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 CO₂ 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. In September 2012, the Ninth Circuit Court of Appeals affirmed the trial court's decision, holding that the CAA displaced Kivalina's claims for damages. Plaintiffs filed seeking further review in the U.S. Supreme Court. We believe the action is without merit and will continue 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 reserve is approximately \$10 million. As the remediation work is completed, I&M's cost may change 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.

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.

Nuclear Incident Insurance

Prior to April 2013, I&M carried insurance coverage for a nuclear or nonnuclear incident at the Cook Plant for property damage, decommissioning and decontamination in the amount of \$2.8 billion. Effective April 2013, insurance coverage for a nonnuclear incident at the Cook Plant was reduced to \$1.7 billion. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

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. We settled, received summary judgment or were dismissed from all of these cases. The plaintiffs appealed the Nevada federal district court's dismissal of several cases involving AEP companies to the U.S. Court of Appeals for the Ninth Circuit. In April 2013, the appellate court reversed in part, and affirmed in part, the district court's orders in these cases. The appellate court reversed the district court's holding that the state antitrust claims were preempted by the Natural Gas Act and the order dismissing AEP from two of the cases on personal jurisdiction grounds and affirmed the decision denying leave to the plaintiffs to amend their complaints in two of the cases. The defendants are considering seeking further review in the U.S. Supreme Court. We will continue to defend the cases. We believe the provision we have is adequate.

5. ACQUISITION

2012

BlueStar Energy (Generation and Marketing segment)

In March 2012, we completed the acquisition of BlueStar Energy Holdings, Inc. (BlueStar) and its independent retail electric supplier BlueStar Energy Solutions for \$70 million. This transaction also included goodwill of \$15 million, intangible assets associated with sales contracts and customer accounts of \$58 million and liabilities associated with supply contracts of \$25 million. BlueStar has been in operation since 2002. Beginning in June 2012, BlueStar began doing business as AEP Energy. AEP Energy provides electric supply for retail customers in Ohio, Illinois and other deregulated electricity markets and also provides energy solutions throughout the United States, including demand response and energy efficiency services.

6. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost (credit) for the plans for the three months ended March 31, 2013 and 2012:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2013	2012	2013	2012
	(in millions)			
Service Cost	\$ 17	\$ 19	\$ 6	\$ 12
Interest Cost	50	56	18	26
Expected Return on Plan Assets	(69)	(80)	(27)	(25)
Amortization of Prior Service Cost (Credit)	1	-	(17)	(5)

Amortization of Net Actuarial Loss	46	37	16	14
Net Periodic Benefit Cost (Credit)	\$ 45	\$ 32	\$ (4)	\$ 22

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7. BUSINESS SEGMENTS

As outlined in our 2012 Annual Report, our primary business is the generation, transmission and distribution of electricity. 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. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are outlined below:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Transmission and distribution of electricity through assets owned and operated by our ten utility operating companies.

Transmission Operations

- Development, construction and operation of transmission facilities through investments in our wholly-owned transmission subsidiaries and transmission joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

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

- Nonregulated generation in ERCOT.
- Marketing, risk management and retail activities in ERCOT, PJM and MISO.

The remainder of our activities is presented as All Other. While not considered a reportable segment, All Other includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

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The tables below present our reportable segment information for the three months ended March 31, 2013 and 2012 and balance sheet information as of March 31, 2013 and December 31, 2012. These amounts include certain estimates and allocations where necessary.

	Utility Operations	Transmission Operations	Nonutility Operations Generation AEP River and Marketing (in millions)	All Other (a)	Reconciling Adjustments	Consolidated
Three Months Ended March 31, 2013						
Revenues from:						
External Customers	\$ 3,486	\$ 3	\$ 128	\$ 206	\$ 3	\$ - \$ 3,826
Other Operating Segments	31	5	5	-	2	(43) -
Total Revenues	\$ 3,517	\$ 8	\$ 133	\$ 206	\$ 5	\$ (43) \$ 3,826
Net Income (Loss)	\$ 349	\$ 13	\$ (2)	\$ 7	\$ (3)	\$ - \$ 364

	Utility Operations	Transmission Operations	Nonutility Operations Generation AEP River and Marketing (in millions)	All Other (a)	Reconciling Adjustments	Consolidated
Three Months Ended March 31, 2012						
Revenues from:						
External Customers	\$ 3,362	\$ 1	\$ 172	\$ 85	\$ 5	\$ - \$ 3,625
Other Operating Segments	23	2	7	-	2	(34) -
Total Revenues	\$ 3,385	\$ 3	\$ 179	\$ 85	\$ 7	\$ (34) \$ 3,625
Net Income (Loss)	\$ 384	\$ 9	\$ 9	\$ (1)	\$ (11)	\$ - \$ 390

	Utility Operations	Transmission Operations	Nonutility Operations Generation AEP River and Marketing (in millions)	All Other (a)	Reconciling Adjustments (b)	Consolidated
March 31, 2013						
Total Property, Plant and Equipment	\$ 56,152	\$ 921	\$ 638	\$ 625	\$ 8	\$ (269) \$ 58,075

Accumulated Depreciation and Amortization	18,585	5	169	254	7	(75)	18,945
Total Property, Plant and Equipment - Net	\$ 37,567	\$ 916	\$ 469	\$ 371	\$ 1	\$ (194)	\$ 39,130
Total Assets	\$ 51,534	\$ 1,409	\$ 640	\$ 1,003	\$ 17,795	\$ (17,831)(c)	\$ 54,550
<div> <div>Nonutility Operations Generation</div> <div> <div>Utility Operations</div> <div>Transmission Operations</div> <div>AEP River Operations</div> <div>and Marketing (in millions)</div> <div>All Other (a)</div> <div>Reconciling Adjustments (b)</div> <div>Consolidated</div> </div> </div>							
December 31, 2012							
Total Property, Plant and Equipment	\$ 55,707	\$ 748	\$ 636	\$ 621	\$ 8	\$ (266)	\$ 57,454
Accumulated Depreciation and Amortization	18,344	4	161	246	7	(71)	18,691
Total Property, Plant and Equipment - Net	\$ 37,363	\$ 744	\$ 475	\$ 375	\$ 1	\$ (195)	\$ 38,763
Total Assets	\$ 51,477	\$ 1,216	\$ 670	\$ 1,005	\$ 17,191	\$ (17,192)(c)	\$ 54,367

(a) All Other includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

(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.

8. 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

Risk Management Strategies

Our strategy surrounding the use of derivative instruments primarily focuses on managing our risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. Our risk management strategies also include the use of derivative instruments for trading purposes, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which we transact. To accomplish our objectives, we primarily employ risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. 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, 2013 and December 31, 2012:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume		Unit of Measure
	March 31, 2013	December 31, 2012	
	(in millions)		
Commodity:			
Power	406	498	MWhs
Coal	7	10	Tons
Natural Gas	176	147	MMBtus
Heating Oil and Gasoline	6	6	Gallons
Interest Rate	\$ 214	\$ 235	USD
Interest Rate and Foreign Currency	\$ 874	\$ 1,199	USD

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 activities 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 future borrowings of fixed-rate debt. Our forecasted 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 on the condensed balance sheets 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, 2013 and December 31, 2012 condensed balance sheets, we netted \$14 million and \$7 million, respectively, of cash collateral received from third parties against short-term and long-term risk

management assets and \$29 million and \$50 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 balance sheets as of March 31, 2013 and December 31, 2012:

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Fair Value of Derivative Instruments
March 31, 2013

Balance Sheet Location	Risk Management			Gross Amounts	Gross	Net
	Contracts	Hedging	Contracts Interest Rate and Foreign Currency	of Risk Management Assets/ Liabilities Recognized	Amounts Offset in the Statement of Financial Position (b)	Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	(a)	(in millions)		
Current Risk Management Assets	\$ 509	\$ 39	\$ 4	\$ 552	\$ (390)	\$ 162
Long-term Risk Management Assets	471	6	1	478	(137)	341
Total Assets	980	45	5	1,030	(527)	503
Current Risk Management Liabilities	467	23	1	491	(397)	94
Long-term Risk Management Liabilities	329	2	6	337	(152)	185
Total Liabilities	796	25	7	828	(549)	279
Total MTM Derivative Contract Net						
Assets (Liabilities)	\$ 184	\$ 20	\$ (2)	\$ 202	\$ 22	\$ 224

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management			Gross Amounts	Gross	Net
	Contracts	Hedging	Contracts Interest Rate and Foreign Currency	of Risk Management Assets/ Liabilities Recognized	Amounts Offset in the Statement of Financial Position (b)	Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	(a)	(in millions)		
	\$ 589	\$ 32	\$ 3	\$ 624	\$ (433)	\$ 191

Current Risk Management Assets						
Long-term Risk Management Assets						
Management Assets	528	5	1	534	(166)	368
Total Assets	1,117	37	4	1,158	(599)	559
Current Risk Management Liabilities						
Management Liabilities	546	43	35	624	(469)	155
Long-term Risk Management Liabilities						
Management Liabilities	383	6	6	395	(181)	214
Total Liabilities	929	49	41	1,019	(650)	369
Total MTM Derivative Contract Net						
Assets (Liabilities)	\$ 188	\$ (12)	\$ (37)	\$ 139	\$ 51	\$ 190

- (a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
- (b) Amounts primarily 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 de-designated risk management contracts.
- (c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents our activity of derivative risk management contracts for the three months ended March 31, 2013 and 2012:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2013 and 2012

Location of Gain (Loss)	2013		2012	
			(in millions)	
Utility Operations Revenues	\$	8	\$	10
Other Revenues		14		3
Regulatory Assets (a)		2		(21)
Regulatory Liabilities (a)		(6)		14
Total Gain on Risk Management Contracts	\$	18	\$	6

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

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 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 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 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 statements of income. During the three months ended March 31, 2013, we recognized losses of \$1 million on our hedging instruments and offsetting gains of \$1 million on our long-term debt. During the three months ended March 31, 2012, we recognized gains of \$1 million on our hedging instruments and offsetting losses of \$1 million on our long-term debt. During the three months ended March 31, 2013 and 2012, hedge ineffectiveness was immaterial.

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 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 and natural gas 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 statements of income, or in Regulatory Assets or Regulatory Liabilities on our condensed balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2013 and 2012, we designated power, coal and natural gas derivatives as cash flow hedges.

We reclassify gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on our condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our condensed

statements of income. During the three months ended March 31, 2013 and 2012, 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) on our condensed balance sheets into Interest Expense on our condensed statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2013 and 2012, 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 balance sheets into Depreciation and Amortization expense on our condensed 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, 2013, we did not designate any foreign currency derivatives as cash flow hedges. During the three months ended March 31, 2012, we designated foreign currency derivatives as cash flow hedges.

During the three months ended March 31, 2013 and 2012, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our condensed balance sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2013 and 2012, see Note 2.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets as of March 31, 2013 and December 31, 2012 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
March 31, 2013

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Hedging Assets (a)	\$ 24	\$ -	\$ 24
Hedging Liabilities (a)	4	2	6
AOCI Gain (Loss) Net of Tax	12	(26)	(14)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	10	(4)	6

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2012

	Commodity	Interest Rate and Foreign Currency (in millions)	Total
Hedging Assets (a)	\$ 24	\$ -	\$ 24
Hedging Liabilities (a)	36	37	73
AOCI Gain (Loss) Net of Tax	(8)	(30)	(38)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(8)	(4)	(12)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the condensed 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, 2013, 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 30 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.

When we use standardized master agreements, we 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. AEP and its subsidiaries have not experienced a downgrade below investment grade. The following table represents: (a) our 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, 2013 and December 31, 2012:

	March 31, 2013	December 31, 2012
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	\$ 5	\$ 7
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	37	32
Amount Attributable to RTO and ISO Activities	35	31

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. 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, 2013 and December 31, 2012:

	March 31, 2013	December 31, 2012
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual		

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Netting Arrangements	\$	366	\$	469
Amount of Cash Collateral Posted		12		8
Additional Settlement Liability if Cross Default Provision is Triggered		231		328

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9. 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. Our market risk oversight staff independently monitors our valuation policies and procedures and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and monthly reports, regarding compliance with policies and procedures. The CORC consists of our Chief Operating Officer, Chief Financial Officer, Executive Vice President of Energy Supply, Senior Vice President of Commercial Operations and Chief Risk Officer.

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 nonbinding 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. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of our contracts being classified as Level 3 is the inability to substantiate our energy price curves in the market. A significant portion of our Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

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. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalents funds. Fixed income securities do not trade on an exchange and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by

securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. 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.

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 classified as Level 2 measurement inputs. 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, 2013 and December 31, 2012 are summarized in the following table:

	March 31, 2013		December 31, 2012	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	\$ 17,573	\$ 20,448	\$ 17,757	\$ 20,907

Fair Value Measurements of Other Temporary Investments

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

The following is a summary of Other Temporary Investments:

Other Temporary Investments	Cost	March 31, 2013		Estimated Fair Value
		Gross Unrealized Gains	Gross Unrealized Losses	
		(in millions)		
Restricted Cash (a)	\$ 167	\$ -	\$ -	\$ 167
Fixed Income Securities:				
Mutual Funds	76	-	-	76
Equity Securities - Mutual Funds	10	8	-	18
Total Other Temporary Investments	\$ 253	\$ 8	\$ -	\$ 261

Other Temporary Investments	Cost	December 31, 2012		Estimated Fair Value
		Gross Unrealized Gains	Gross Unrealized Losses	
		(in millions)		
Restricted Cash (a)	\$ 241	\$ -	\$ -	\$ 241
Fixed Income Securities:				
Mutual Funds	65	2	-	67
Equity Securities - Mutual Funds	10	6	-	16
Total Other Temporary Investments	\$ 316	\$ 8	\$ -	\$ 324

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

The following table provides the activity for our fixed income and equity securities within Other Temporary Investments for the three months ended March 31, 2013 and 2012:

Three Months Ended March 31,

	2013	2012
	(in millions)	
Proceeds from Investment Sales \$	-	\$ -
Purchases of Investments	11	-
Gross Realized Gains on Investment Sales	-	-
Gross Realized Losses on Investment Sales	-	-

As of March 31, 2013 and December 31, 2012, we had no Other Temporary Investments with an unrealized loss position. As of March 31, 2013, fixed income securities are primarily debt based mutual funds with short and intermediate maturities. Mutual funds may be sold and do not contain maturity dates.

For details of Other Temporary Investments included in Accumulated Other Comprehensive Income (Loss) on the balance sheet and the reasons for changes for the three months ended March 31, 2013 and 2012, see Note 2.

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 fixed income 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 fixed income investments held in these trusts and generally intends to sell fixed income 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 as of March 31, 2013 and December 31, 2012:

	March 31, 2013			December 31, 2012		
	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	\$ 14	\$ -	\$ -	\$ 17	\$ -	\$ -
Fixed Income Securities:						
United States						
Government	642	53	(1)	648	58	(1)
Corporate Debt	37	5	(1)	35	5	(1)

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State and Local Government	279	-	(2)	270	1	(1)
Subtotal Fixed Income Securities	958	58	(4)	953	64	(3)
Equity Securities - Domestic	816	360	(81)	736	285	(77)
Spent Nuclear Fuel and Decommissioning Trusts	\$ 1,788	\$ 418	\$ (85)	\$ 1,706	\$ 349	\$ (80)

The following table provides the securities activity within the decommissioning and SNF trusts for the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31,	
	2013	2012
	(in millions)	
Proceeds from Investment Sales \$	168	\$ 334
Purchases of Investments	185	353
Gross Realized Gains on Investment Sales	3	2
Gross Realized Losses on Investment Sales	2	1

The adjusted cost of fixed income securities was \$900 million and \$889 million as of March 31, 2013 and December 31, 2012, respectively. The adjusted cost of equity securities was \$456 million and \$451 million as of March 31, 2013 and December 31, 2012, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of March 31, 2013 was as follows:

	Fair Value of Fixed Income Securities (in millions)
Within 1 year	\$ 95
1 year – 5 years	356
5 years – 10 years	274
After 10 years	233
Total	\$ 958

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, 2013 and December 31, 2012. 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 our valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2013

	Level 1	Level 2	Level 3 (in millions)	Other	Total
Assets:					
Cash and Cash Equivalents (a)	\$ 6	\$ 1	\$ -	\$ 172	\$ 179
Other Temporary Investments					
Restricted Cash (a)	151	6	-	10	167
Fixed Income Securities:					
Mutual Funds	76	-	-	-	76
Equity Securities - Mutual Funds (b)	18	-	-	-	18
Total Other Temporary Investments	245	6	-	10	261
Risk Management Assets					
Risk Management Commodity Contracts (c)					
(d)	43	810	117	(507)	463
Cash Flow Hedges:					
Commodity Hedges (c)	4	40	1	(21)	24
Fair Value Hedges	-	2	-	3	5
De-designated Risk Management Contracts (e)	-	-	-	11	11
Total Risk Management Assets	47	852	118	(514)	503
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	5	-	-	9	14
Fixed Income Securities:					
United States Government	-	642	-	-	642
Corporate Debt	-	37	-	-	37
State and Local Government	-	279	-	-	279
Subtotal Fixed Income Securities	-	958	-	-	958
Equity Securities - Domestic (b)	816	-	-	-	816
Total Spent Nuclear Fuel and Decommissioning Trusts	821	958	-	9	1,788
Total Assets	\$ 1,119	\$ 1,817	\$ 118	\$ (323)	\$ 2,731
Liabilities:					

Risk Management Liabilities											
Risk Management Commodity Contracts (c)											
(d)	\$	44	\$	700	\$	42	\$	(518)	\$	268	
Cash Flow Hedges:											
Commodity Hedges (c)		1	24	-	(21)	4					
Interest Rate/Foreign Currency Hedges		-	2	-	-	2					
Fair Value Hedges		-	2	-	3	5					
Total Risk Management Liabilities		\$	45	\$	728	\$	42	\$	(536)	\$	279

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

	Level 1	Level 2	Level 3 (in millions)	Other	Total
Assets:					
Cash and Cash Equivalents (a)	\$ 6	\$ 1	\$ -	\$ 272	\$ 279
Other Temporary Investments					
Restricted Cash (a)	227	5	-	9	241
Fixed Income Securities:					
Mutual Funds	67	-	-	-	67
Equity Securities - Mutual Funds (b)	16	-	-	-	16
Total Other Temporary Investments	310	5	-	9	324
Risk Management Assets					
Risk Management Commodity Contracts (c)					
(g)	47	938	131	(599)	517
Cash Flow Hedges:					
Commodity Hedges (c)	8	28	-	(12)	24
Fair Value Hedges	-	2	-	2	4
De-designated Risk Management Contracts (e)	-	-	-	14	14
Total Risk Management Assets	55	968	131	(595)	559
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	7	-	-	10	17
Fixed Income Securities:					
United States Government	-	648	-	-	648
Corporate Debt	-	35	-	-	35
State and Local Government	-	270	-	-	270
Subtotal Fixed Income Securities	-	953	-	-	953
Equity Securities - Domestic (b)	736	-	-	-	736
Total Spent Nuclear Fuel and Decommissioning Trusts	743	953	-	10	1,706
Total Assets	\$ 1,114	\$ 1,927	\$ 131	\$ (304)	\$ 2,868
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)					
(g)	\$ 45	\$ 838	\$ 45	\$ (636)	\$ 292
Cash Flow Hedges:					
Commodity Hedges (c)	-	48	-	(12)	36
Interest Rate/Foreign Currency Hedges	-	37	-	-	37

Fair Value Hedges		-		2		-		2		4
Total Risk Management Liabilities	\$	45	\$	925	\$	45	\$	(646)	\$	369

- (a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 and Level 2 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) The March 31, 2013 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures \$6 million in 2013, (\$4) million in periods 2014-2016 and (\$3) million in periods 2017-2018; Level 2 matures \$17 million in 2013, \$73 million in periods 2014-2016, \$14 million in periods 2017-2018 and \$6 million in periods 2019-2030; Level 3 matures \$6 million in 2013, \$27 million in periods 2014-2016, \$18 million in periods 2017-2018 and \$24 million in periods 2019-2030. Risk management commodity contracts are substantially comprised of power contracts.
- (e) 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.
- (f) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions.
- (g) The December 31, 2012 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures \$9 million in 2013, (\$3) million in periods 2014-2016 and (\$4) million in periods 2017-2018; Level 2 matures \$16 million in 2013, \$61 million in periods 2014-2016, \$16 million in periods 2017-2018 and \$7 million in periods 2019-2030; Level 3 matures \$18 million in 2013, \$31 million in periods 2014-2016, \$13 million in periods 2017-2018 and \$24 million in periods 2019-2030. 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, 2013 and 2012.

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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, 2013		Net Risk Management Assets (Liabilities) (in millions)	
Balance as of December 31, 2012	\$		86
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)			(4)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)			(5)
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income			1
Purchases, Issuances and Settlements (c)			(6)
Transfers into Level 3 (d) (e)			6
Transfers out of Level 3 (e) (f)			-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)			(2)
Balance as of March 31, 2013	\$		76

Three Months Ended March 31, 2012		Net Risk Management Assets (Liabilities) (in millions)	
Balance as of December 31, 2011	\$		69
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)			(12)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)			3
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income			1
Purchases, Issuances and Settlements (c)			16
Transfers into Level 3 (d) (e)			17
Transfers out of Level 3 (e) (f)			(12)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)			10
Balance as of March 31, 2012	\$		92

- (a) Included in revenues on the condensed 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) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
- (f) Represents existing assets or liabilities that were previously categorized as Level 3.
- (g) Relates to the net gains (losses) of those contracts that are not reflected on the condensed statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

The following table quantifies the significant unobservable inputs used in developing the fair value of our Level 3 positions as of March 31, 2013:

	Fair Value		Valuation Technique	Significant Unobservable Input	Input/Range	
	Assets (in millions)	Liabilities			Low	High
Energy Contracts	\$ 114	\$ 37	Discounted Cash Flow	Forward Market Price (a)	\$ 11.59	\$ 133.27

				Counterparty Credit Risk (b)	354
FTRs	4	5	Discounted Cash Flow	Forward Market Price (a)	(13.65) 9.67
Total	\$ 118	\$ 42			

(a) Represents market prices in dollars per MWh.

(b) Represents average price of credit default swaps used to calculate counterparty credit risk, reported in basis points.

10. INCOME TAXES

AEP System Tax Allocation Agreement

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.

Federal and State Income Tax Audit Status

The IRS examination of years 2009 and 2010 started in October 2011. Although the outcome of tax audits is uncertain, in our 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 materially impact 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. However, we believe that we have filed tax returns with positions that may be challenged by these tax authorities. We believe 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 2008.

11. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding as of March 31, 2013 and December 31, 2012:

Type of Debt	March 31, 2013	December 31, 2012
	(in millions)	
Senior Unsecured Notes	\$ 12,462	\$ 12,712
Pollution Control Bonds	1,958	1,958
Notes Payable	398	427
Securitization Bonds	2,176	2,281
Spent Nuclear Fuel		
Obligation (a)	265	265
Other Long-term Debt	341	140
Fair Value of Interest Rate		
Hedges	1	3
Unamortized Discount, Net	(28)	(29)
Total Long-term Debt		
Outstanding	17,573	17,757
Long-term Debt Due		
Within One Year	1,674	2,171
Long-term Debt	\$ 15,899	\$ 15,586

(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 were \$309 million and \$308 million as of March 31, 2013 and December 31, 2012, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on our condensed balance sheets.

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2013 are shown in the tables below:

Company	Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Issuances:				
AEP	Other Long-term Debt	\$ 200 (a)	Variable	2015
	Senior Unsecured			
I&M	Notes	250	3.20	2023
Non-Registrant:				
	Senior Unsecured			
AEPTCo	Notes	25	4.83	2043
	Senior Unsecured			
TNC	Notes	125	3.09	2023
	Senior Unsecured			
TNC	Notes	75	4.48	2043
Total Issuances		\$ 675 (b)		

(a) Draw on a \$1 billion term credit facility due in May 2015 to fund certain OPCo maturities on an interim basis and to facilitate the corporate separation of generation assets from transmission and distribution.

(b) Amount indicated on the statement of cash flows is net of issuance costs and premium or discount and will not tie to the total issuances.

Company	Type of Debt	Principal Amount Paid (in millions)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
I&M	Notes Payable	\$ 4	Variable	2015
I&M	Notes Payable	6	Variable	2016
I&M	Notes Payable	4	2.12	2016
I&M	Notes Payable	11	Variable	2016
	Senior Unsecured			
OPCo	Notes	250	5.50	2013
	Senior Unsecured			
OPCo	Notes	250	5.50	2013
SWEPCo	Notes Payable	1	4.58	2032
Non-Registrant:				
AEP Subsidiaries	Notes Payable	1	Variable	2017
			7.59 -	
AEP Subsidiaries	Notes Payable	1	8.03	2026
	Securitization			
TCC	Bonds	67	4.98	2013
	Securitization			
TCC	Bonds	38	5.96	2013
	Senior Unsecured			
TNC	Notes	225	5.50	2013

Total Retirements and Principal Payments	\$	858
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In April 2013, I&M retired \$28 million of Notes Payable related to DCC Fuel.

In April 2013, I&M reacquired \$40 million of 5.25% Pollution Control Bonds due in 2025. The variable rate bonds are held by a trustee on behalf of I&M.

In April 2013, AEGCo retired \$4 million of 6.33% Senior Unsecured Notes due in 2037.

As of March 31, 2013, trustees held, on our behalf, \$533 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.

Utility Subsidiaries' Restrictions

Various financing arrangements 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, several of our public utility subsidiaries have credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%.

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 book value of the common stock. 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:

Type of Debt	March 31, 2013		December 31, 2012	
	Outstanding Amount (in millions)	Interest Rate (a)	Outstanding Amount (in millions)	Interest Rate (a)
Securitized Debt for Receivables (b)	\$ 646	0.23 %	\$ 657	0.26 %
Commercial Paper	661	0.36 %	321	0.42 %
Line of Credit – Sabine (c)	-	- %	3	1.82 %
Total Short-term Debt	\$ 1,307		\$ 981	

(a) Weighted average rate.

(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

(c) This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 4.

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.

Accounts receivable information for AEP Credit is as follows:

	Three Months Ended March 31,	
	2013	2012
	(dollars in millions)	
Effective Interest Rates on Securitization of Accounts Receivable	0.23 %	0.26 %
Net Uncollectible Accounts Receivable Written Off	\$ 7	\$ 8
	March 31, 2013	December 31, 2012
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral		
Less Uncollectible Accounts	\$ 863	\$ 835
Total Principal Outstanding	646	657
Delinquent Securitized Accounts Receivable	38	37
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	21	21
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	256	316

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.

12. 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, variable interests held by related parties 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, AEP Credit, Transition Funding and our protected cell of EIS that was not previously contractually required. We hold a significant variable interest in DHLIC 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, 2013 and 2012 were \$44 million and \$55 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on the condensed balance sheets.

I&M has nuclear fuel lease agreements with DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC and DCC Fuel V 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. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the three months ended March 31, 2013 and 2012 were \$26 million

and \$17 million, respectively. 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 respective lease terms, which do not exceed 54 months. Based on our control of DCC Fuel, management 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 the condensed 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 the condensed balance sheets. See "Securitized Accounts Receivables – AEP Credit" section of Note 11.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. 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 \$2.2 billion and \$2.3 billion as of March 31, 2013 and December 31, 2012, respectively, and are included in current and long-term debt on the condensed balance sheets. Transition Funding has securitized transition assets of \$2 billion and \$2.1 billion as of March 31, 2013 and December 31, 2012, respectively, which are presented separately on the face of the condensed 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. See the tables below for the classification of Transition Funding's assets and liabilities on the condensed 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, 2013 and 2012 was \$15 million and \$15 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the condensed balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

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, 2013

(in millions)

	SWEP Sabine	I&M DCC Fuel	AEP Credit	TCC Transition Funding	Protected Cell of EIS
ASSETS					
Current Assets	\$ 64	\$ 128	\$ 871	\$ 174	\$ 144
Net Property, Plant and Equipment	167	146	-	-	-
Other Noncurrent Assets	66	73	1	2,114 (a)	5
Total Assets	\$ 297	\$ 347	\$ 872	\$ 2,288	\$ 149
LIABILITIES AND EQUITY					
Current Liabilities	\$ 31	\$ 112	\$ 827	\$ 293	\$ 49
Noncurrent Liabilities	266	235	1	1,977	72
Equity	-	-	44	18	28
Total Liabilities and Equity	\$ 297	\$ 347	\$ 872	\$ 2,288	\$ 149

(a) Includes an intercompany item eliminated in consolidation of \$87 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES

December 31, 2012

(in millions)

	SWEP Sabine	I&M DCC Fuel	AEP Credit	TCC Transition Funding	Protected Cell of EIS
ASSETS					
Current Assets	\$ 57	\$ 133	\$ 843	\$ 250	\$ 130
Net Property, Plant and Equipment	170	176	-	-	-
Other Noncurrent Assets	55	92	1	2,167 (a)	4
Total Assets	\$ 282	\$ 401	\$ 844	\$ 2,417	\$ 134
LIABILITIES AND EQUITY					
Current Liabilities	\$ 32	\$ 121	\$ 800	\$ 304	\$ 43
Noncurrent Liabilities	250	280	1	2,095	66
Equity	-	-	43	18	25
Total Liabilities and Equity	\$ 282	\$ 401	\$ 844	\$ 2,417	\$ 134

(a) Includes an intercompany item eliminated in consolidation of \$89 million.

DHLC is a mining operator that sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and voting rights equally. Each entity guarantees 50% 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, 2013 and 2012 were \$18 million and \$14 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 the condensed balance sheets.

Our investment in DHLC was:

	March 31, 2013		December 31, 2012	
	As Reported	Maximum	As Reported	Maximum
	on		on	
	the Balance	Exposure	the Balance	Exposure
	Sheet	(in millions)	Sheet	
Capital Contribution from SWEPCo	\$8	\$8	\$8	\$8
Retained Earnings	1	1	1	1
SWEPCo's Guarantee of Debt	-	40	-	49
Total Investment in DHLC	\$9	\$49	\$9	\$58

We and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it 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 balance sheets. We and FirstEnergy share the returns and losses equally in PATH-WV. Our subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. The entities recover costs through regulated rates.

In August 2012, the PJM board cancelled the PATH Project, our transmission joint venture with FirstEnergy, and removed it from the 2012 Regional Transmission Expansion Plan. In November 2012, the FERC issued an order accepting AEP's and FirstEnergy's abandonment cost recovery filing which requested authority to recover prudently-incurred costs associated with the PATH Project, subject to refund based on the outcome of hearings and settlement procedures.

Our investment in PATH-WV was:

	March 31, 2013		December 31, 2012	
	As Reported	Maximum	As Reported	Maximum
	on		on	
	the Balance	Exposure	the Balance	Exposure
	Sheet	(in millions)	Sheet	
Capital Contribution from AEP	\$19	\$19	\$19	\$19
Retained Earnings	12	12	12	12

Total Investment in PATH-WV	\$31	\$31	\$31	\$31

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13. SUSTAINABLE COST REDUCTIONS

In April 2012, we initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. We selected a consulting firm to facilitate an organizational and process evaluation and a second firm to evaluate our current employee benefit programs. The process resulted in involuntary severances and was completed by the end of the first quarter of 2013. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

We recorded a charge of \$47 million to Other Operation expense in 2012 primarily related to severance benefits as a result of the sustainable cost reductions initiative. In addition, the sustainable cost reduction activity for the three months ended March 31, 2013 is described in the following table:

	Sustainable Cost Reduction Activity (in millions)
Balance as of December 31, 2012	\$ 25
Incurred	16
Settled	(19)
Adjustments	(7)
Balance as of March 31, 2013	\$ 15

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the condensed statements of income. Approximately 94% of the expense was within the Utility Operations segment. The remaining liability is included in Other Current Liabilities on the condensed balance sheets. We do not expect additional costs to be incurred related to this initiative.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Regulatory Activity

Plant Transfers and Termination of Interconnection Agreement

Based upon the PUCO's approval of OPCo's corporate separation plan in October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations. The AEP East Companies also requested FERC approval to transfer at net book value OPCo's current two-thirds ownership (867 MW) in Amos Plant Unit 3 to APCo and transfer at net book value OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). These transfers are proposed to be effective no later than December 31, 2013. Additionally, the AEP East Companies asked the FERC, effective January 1, 2014, to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, APCo would be individually responsible for planning its respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities. Intervenor have opposed several of these filings. The AEP East Companies responded to intervenor comments and filed a revised PCA at the FERC in March 2013. The revised PCA included certain clarifying wording changes that have been agreed upon by intervenors. A decision from the FERC is expected in the second quarter of 2013.

If APCo experiences decreases in revenues or increases in expenses as a result of changes to its relationship with affiliates and is unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce future net income and cash flows.

In December 2012, APCo filed requests with the Virginia SCC and the WVPSC for approval of the Amos Plant and Mitchell Plant transfers discussed above. Hearings at the Virginia SCC and the WVPSC are scheduled for June 2013 and July 2013, respectively. If the transfers are approved, APCo anticipates seeking cost recovery in upcoming rate proceedings. If APCo is not ultimately permitted to recover its incurred costs, it could reduce future net income and cash flows and impact financial condition. See the "Plant Transfers" section of APCo and WPCo Rate Matters section of Note 3.

Environmental Rate Adjustment Clause (Environmental RAC)

In March 2013, APCo filed with the Virginia SCC for approval of an environmental RAC to recover \$39 million related to 2012 and 2011 environmental compliance costs effective February 2014 over a one-year period. APCo has deferred \$28 million as of March 31, 2013 for the Virginia portion of unrecovered environmental RAC costs incurred in 2012 and 2011, excluding \$11 million of unrecognized equity carrying costs. If the Virginia SCC were to disallow any portion of the environmental RAC, it could reduce future net income and cash flows. See "Environmental Rate Adjustment Clause (Environmental RAC)" section of Note 3.

Generation Rate Adjustment Clause (Generation RAC)

In March 2013, APCo filed with the Virginia SCC for an increase in its generation RAC revenues of \$12 million for a total of \$38 million annually to collect costs related to the Dresden Plant. The generation RAC increase is expected to

be effective in March 2014. APCo has deferred \$4 million as of March 31, 2013 for the Virginia portion of unrecovered costs of the Dresden Plant, excluding \$3 million of unrecognized equity carrying costs. If the Virginia SCC were to disallow any portion of the generation RAC, it could reduce future net income and cash flows.

Securitization of Regulatory Assets

In March 2012, West Virginia passed securitization legislation which allows the WVPSC to establish a regulatory framework for electric utilities to securitize certain deferred Expanded Net Energy Charge (ENEC) balances and

other ENEC related assets. In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize \$422 million related to APCo's December 2011 under-recovered ENEC deferral balance, other ENEC-related assets and related financing costs. In March 2013, APCo, WPCo and intervenors filed a settlement agreement with the WVPSC, which recommended the WVPSC authorize APCo to securitize \$376 million plus upfront financing costs. A decision is pending from the WVPSC.

WPCo Merger with APCo

In December 2011, APCo and WPCo filed an application with the WVPSC requesting approval to merge WPCo into APCo. In December 2012, APCo and WPCo filed merger applications with the Virginia SCC and the FERC. A hearing at the Virginia SCC is scheduled for June 2013. No hearing date has been scheduled in West Virginia.

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 predict the eventual resolution, timing or amount of any loss, fine or penalty. 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 2 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies in the 2012 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 133. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the “Executive Overview” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” section beginning on page 187 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31,	
	2013	2012
	(in millions of KWhs)	
Retail:		
Residential	4,001	3,450
Commercial	1,742	1,626
Industrial	2,588	2,604
Miscellaneous	217	202
Total Retail	8,548	7,882
Wholesale	2,281	1,381
Total KWhs	10,829	9,263

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,	
	2013	2012
	(in degree days)	
Actual - Heating (a)	1,404	921
Normal - Heating (b)	1,312	1,343
Actual - Cooling (c)	-	26
Normal - Cooling (b)	7	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 2013 Compared to First Quarter of 2012

Reconciliation of First Quarter of 2012 to First Quarter of 2013

Net Income

(in millions)

First Quarter of 2012	\$	75
Changes in Gross Margin:		
Retail Margins		60
Transmission Revenues		3
Other Revenues		(2)
Total Change in Gross Margin		61
Changes in Expenses and Other:		
Other Operation and Maintenance		(57)
Depreciation and Amortization		(7)
Carrying Costs Income		(8)
Interest Expense		3
Total Change in Expenses and Other		(69)
Income Tax Expense		4
First Quarter of 2013	\$	71

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 electricity were as follows:

- Retail Margins increased \$60 million primarily due to the following:
 - A \$36 million increase in weather-related usage primarily due to a 52% increase in heating degree days.
 - A \$28 million increase due to higher rates in Virginia and West Virginia. For this increase, \$7 million have a corresponding increase in Depreciation and Amortization expenses below.
 - A \$4 million increase due to lower capacity settlement expenses under the Interconnection Agreement, net of recovery in West Virginia and environmental deferrals in Virginia. This increase was primarily the result of the completion of the Dresden Plant in January 2012.
 - A \$3 million increase in residential margins primarily due to higher non-weather related usage.

These increases were partially offset by:

- A \$9 million increase in other variable electric generation expenses.
- Transmission Revenues increased \$3 million primarily due to increased Network Integration Transmission Service (NITS) revenue requirements. These NITS revenues are offset in Other Operation and Maintenance expenses below.

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

- Other Operation and Maintenance expenses increased \$57 million primarily due to the following:

A \$30 million write-off in the first quarter of 2013 of previously deferred 2012 Virginia storm costs resulting from the 2013 enactment of a Virginia law.

- A \$15 million increase in distribution maintenance expense primarily due to the January 2013 snow storm.
- A \$4 million increase in transmission expenses due to higher NITS expenses. These expenses are offset in Transmission Revenues above.
- A \$3 million increase due to the first quarter 2013 deferral of over-recovered transmission costs for the Virginia Transmission Rate Adjustment Clause as allowed by the Virginia SCC.
- Depreciation and Amortization expenses increased \$7 million primarily due to:
 - A \$3 million increase as a result of increased depreciation rates in Virginia effective February 2012. The majority of this increase in depreciation is offset within Gross Margin.
 - A \$3 million increase as a result of the Dresden Plant being placed in service in late January 2012.

- Carrying Costs Income decreased \$8 million primarily due to an increased recovery of Virginia environmental costs in new base rates as approved by the Virginia SCC in late January 2012 and decreased carrying charges related to Dresden Plant.
- Interest Expense decreased \$3 million primarily due to lower long-term interest rates.
- Income Tax Expense decreased \$4 million primarily due to a decrease in pretax book income and other book/tax differences which are accounted for on a flow-through basis, partially offset by the regulatory accounting treatment of state income taxes.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” in the 2012 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” beginning on page 187 for a discussion of accounting pronouncements.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

For the Three Months Ended March 31, 2013 and 2012

(in thousands)

(Unaudited)

	Three Months Ended March 31,	
	2013	2012
REVENUES		
Electric Generation, Transmission and Distribution	\$872,732	\$738,599
Sales to AEP Affiliates	76,860	64,301
Other Revenues	1,902	2,576
TOTAL REVENUES	951,494	805,476
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	204,939	186,884
Purchased Electricity for Resale	65,456	65,356
Purchased Electricity from AEP Affiliates	222,942	156,017
Other Operation	78,908	74,319
Maintenance	99,386	46,335
Depreciation and Amortization	87,903	80,413
Taxes Other Than Income Taxes	27,400	26,962
TOTAL EXPENSES	786,934	636,286
OPERATING INCOME	164,560	169,190
Other Income (Expense):		
Interest Income	331	343
Carrying Costs Income	103	7,785
Allowance for Equity Funds Used During Construction	770	513
Interest Expense	(48,204)	(51,307)
INCOME BEFORE INCOME TAX EXPENSE	117,560	126,524
Income Tax Expense	47,012	51,213
NET INCOME	\$70,548	\$75,311

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
 CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
 For the Three Months Ended March 31, 2013 and 2012
 (in thousands)
 (Unaudited)

	Three Months Ended March 31,	
	2013	2012
Net Income	\$70,548	\$75,311
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of \$677 and \$290 in 2013 and 2012, Respectively	1,258	(539)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of \$193 and \$484 in 2013 and 2012, Respectively	358	900
TOTAL OTHER COMPREHENSIVE INCOME	1,616	361
TOTAL COMPREHENSIVE INCOME	\$72,164	\$75,672

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY

For the Three Months Ended March 31, 2013 and 2012

(in thousands)

(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY –					
DECEMBER 31, 2011	\$260,458	\$1,573,752	\$1,160,747	\$ (58,543)	\$2,936,414
Common Stock Dividends			(50,000)		(50,000)
Net Income			75,311		75,311
Other Comprehensive Income				361	361
TOTAL COMMON SHAREHOLDER'S EQUITY –					
MARCH 31, 2012	\$260,458	\$1,573,752	\$1,186,058	\$ (58,182)	\$2,962,086
TOTAL COMMON SHAREHOLDER'S EQUITY –					
DECEMBER 31, 2012	\$260,458	\$1,573,752	\$1,248,250	\$ (29,898)	\$3,052,562
Common Stock Dividends			(50,000)		(50,000)
Net Income			70,548		70,548
Other Comprehensive Income				1,616	1,616
TOTAL COMMON SHAREHOLDER'S EQUITY –					
MARCH 31, 2013	\$260,458	\$1,573,752	\$1,268,798	\$ (28,282)	\$3,074,726

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

March 31, 2013 and December 31, 2012

(in thousands)

(Unaudited)

	March 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	\$ 1,256	\$ 3,576
Advances to Affiliates	23,203	23,024
Accounts Receivable:		
Customers	166,609	158,380
Affiliated Companies	68,145	96,213
Accrued Unbilled Revenues	80,762	70,825
Miscellaneous	1,236	1,344
Allowance for Uncollectible Accounts	(3,315)	(6,087)
Total Accounts Receivable	313,437	320,675
Fuel	192,283	185,813
Materials and Supplies	107,464	105,208
Risk Management Assets	23,127	30,960
Accrued Tax Benefits	27,560	50,032
Regulatory Asset for Under-Recovered Fuel Costs	67,703	74,906
Prepayments and Other Current Assets	17,089	18,690
TOTAL CURRENT ASSETS	773,122	812,884
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,644,518	5,632,665
Transmission	2,048,965	2,042,144
Distribution	3,030,491	2,991,898
Other Property, Plant and Equipment	377,305	373,327
Construction Work in Progress	271,320	266,247
Total Property, Plant and Equipment	11,372,599	11,306,281
Accumulated Depreciation and Amortization	3,246,522	3,196,639
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,126,077	8,109,642
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,372,601	1,435,704
Long-term Risk Management Assets	24,016	34,360
Deferred Charges and Other Noncurrent Assets	120,929	115,078
TOTAL OTHER NONCURRENT ASSETS	1,517,546	1,585,142
TOTAL ASSETS	\$ 10,416,745	\$ 10,507,668

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2013 and December 31, 2012
(Unaudited)

	March 31, 2013	December 31, 2012
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	\$ 96,651	\$ 173,965
Accounts Payable:		
General	164,028	195,203
Affiliated Companies	123,971	137,088
Long-term Debt Due Within One Year – Nonaffiliated	574,679	574,679
Risk Management Liabilities	12,048	16,698
Customer Deposits	66,245	67,339
Deferred Income Taxes	13,611	11,715
Accrued Taxes	82,692	74,967
Accrued Interest	66,901	51,442
Other Current Liabilities	84,164	110,657
TOTAL CURRENT LIABILITIES	1,284,990	1,413,753
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,127,920	3,127,763
Long-term Risk Management Liabilities	12,764	18,476
Deferred Income Taxes	1,943,095	1,928,683
Regulatory Liabilities and Deferred Investment Tax Credits	614,587	607,680
Employee Benefits and Pension Obligations	203,744	204,207
Deferred Credits and Other Noncurrent Liabilities	154,919	154,544
TOTAL NONCURRENT LIABILITIES	6,057,029	6,041,353
TOTAL LIABILITIES	7,342,019	7,455,106
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
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	1,573,752	1,573,752
Retained Earnings	1,268,798	1,248,250
Accumulated Other Comprehensive Income (Loss)	(28,282)	(29,898)
TOTAL COMMON SHAREHOLDER’S EQUITY	3,074,726	3,052,562
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	\$ 10,416,745	\$ 10,507,668

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Three Months Ended March 31, 2013 and 2012

(in thousands)

(Unaudited)

	Three Months Ended March 31,	
	2013	2012
OPERATING ACTIVITIES		
Net Income	\$ 70,548	\$ 75,311
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	87,903	80,413
Deferred Income Taxes	17,185	27,343
Carrying Costs Income	(103)	(7,785)
Allowance for Equity Funds Used During Construction	(770)	(513)
Mark-to-Market of Risk Management Contracts	9,404	(2,426)
Fuel Over/Under-Recovery, Net	20,135	24,741
Change in Other Noncurrent Assets	28,314	(11,020)
Change in Other Noncurrent Liabilities	5,634	8,866
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	7,238	100,202
Fuel, Materials and Supplies	(8,726)	(45,137)
Accounts Payable	(20,597)	(24,787)
Accrued Taxes, Net	30,197	22,142
Other Current Assets	642	(269)
Other Current Liabilities	(10,917)	(16,921)
Net Cash Flows from Operating Activities	236,087	230,160
INVESTING ACTIVITIES		
Construction Expenditures	(110,552)	(117,359)
Change in Advances to Affiliates, Net	(179)	(398)
Other Investing Activities	(179)	2,295
Net Cash Flows Used for Investing Activities	(110,910)	(115,462)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	(258)	-
Change in Advances from Affiliates, Net	(77,314)	(14,208)
Retirement of Long-term Debt – Nonaffiliated	(7)	(49,506)
Principal Payments for Capital Lease Obligations	(1,238)	(1,637)
Dividends Paid on Common Stock	(50,000)	(50,000)
Other Financing Activities	1,320	139
Net Cash Flows Used for Financing Activities	(127,497)	(115,212)
Net Decrease in Cash and Cash Equivalents	(2,320)	(514)
Cash and Cash Equivalents at Beginning of Period	3,576	2,317
Cash and Cash Equivalents at End of Period	\$ 1,256	\$ 1,803

SUPPLEMENTARY INFORMATION

Cash Paid for Interest, Net of Capitalized Amounts	\$	31,018	\$	46,159
Net Cash Paid (Received) for Income Taxes		231		(2,984)
Noncash Acquisitions Under Capital Leases		1,548		1,037
Construction Expenditures Included in Current Liabilities as of March 31,		35,733		30,998

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

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

The condensed notes to APCo's condensed 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.

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

EXECUTIVE OVERVIEW

Regulatory Activity

Termination of Interconnection Agreement

Based upon the PUCO's approval of OPCo's corporate separation plan in October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations and transfer at net book value certain plants to APCo and KPCo. These transfers are proposed to be effective no later than December 31, 2013. Additionally, the AEP East Companies asked the FERC, effective January 1, 2014, to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, I&M would be individually responsible for planning its respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, I&M to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities. Intervenors have opposed several of these filings. The AEP East Companies responded to intervenor comments and filed a revised PCA at the FERC in March 2013. The revised PCA included certain clarifying wording changes that have been agreed upon by intervenors. A decision from the FERC is expected in the second quarter of 2013.

If I&M experiences decreases in revenues or increases in expenses as a result of changes to its relationship with affiliates and is unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce future net income and cash flows.

2011 Indiana Base Rate Case

In February 2013, the IURC issued an order that granted an \$85 million annual increase in base rates based upon a return on common equity of 10.2%. In a March 2013 order, the IURC approved an adjustment which increased the authorized annual increase in base rates from \$85 million to \$92 million. In March 2013, the Indiana Office of Utility Consumer Counselor filed an appeal of the order with the Indiana Court of Appeals. If the order is overturned by the Indiana Court of Appeals, it could reduce future net income and cash flows. See the "Indiana Base Rate Case" section of Note 3.

Rockport Plant Clean Coal Technology Project (CCT Project)

In April 2013, I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit both of its units at the Rockport Plant with a Dry Sorbent Injection system. The estimated cost of the CCT Project is \$285 million, excluding AFUDC, of which I&M's ownership share is \$142 million. The application requested deferral treatment of any unrecovered carrying costs incurred during construction and incremental post in-service depreciation expense and operation and maintenance expenses until such costs are recognized and recovered in a rider. If I&M receives approval of a CPCN, I&M will file for cost recovery associated with the retrofit using the Clean Coal Technology Rider recovery mechanism. As of March 31, 2013, I&M has incurred \$31 million related to the CCT Project, including AFUDC. If I&M is not ultimately permitted to recover its incurred costs, it could reduce future net income and cash flows.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its extended licensed life. The estimated cost of the LCM Project is \$1.2 billion to be incurred through 2018, excluding AFUDC. As of March 31, 2013, I&M has incurred \$197 million related to the LCM Project, including AFUDC.

In April 2012, I&M filed a petition with the IURC for recovery of project costs, including interest, through a new rider. Several intervenors filed testimony in Indiana with various recommendations including caps on expenditures. The IURC held a hearing in January 2013 and an order is pending. In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project. In April 2013, an intervenor filed an appeal with the Michigan Court of Appeals objecting to the issuance of the CON as well as the amount of the CON related to the LCM Project. If I&M is not ultimately permitted to recover its LCM Project costs, it could reduce future net income and cash flows and impact financial condition. See “Cook Plant Life Cycle Management Project” section of Note 3.

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 predict the eventual resolution, timing or amount of any loss, fine or penalty. 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 2 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies in the 2012 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 133. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the “Executive Overview” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” section beginning on page 187 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2013 2012 (in millions of KWhs)	
Retail:		
Residential	1,726	1,569
Commercial	1,188	1,165
Industrial	1,813	1,833
Miscellaneous	20	23
Total Retail	4,747	4,590
Wholesale	2,580	1,961
Total KWhs	7,327	6,551

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,

	2013	2012
	(in degree days)	
Actual - Heating (a)	2,287	1,622
Normal - Heating (b)	2,155	2,184
Actual - Cooling (c)	-	29
Normal - Cooling (b)	2	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 2013 Compared to First Quarter of 2012

Reconciliation of First Quarter of 2012 to First Quarter of 2013

Net Income

(in millions)

First Quarter of 2012	\$	39
Changes in Gross Margin:		
Retail Margins		24
FERC Municipals and Cooperatives		(1)
Off-system Sales		(1)
Other Revenues		3
Total Change in Gross Margin		25
Changes in Expenses and Other:		
Other Operation and Maintenance		(13)
Depreciation and Amortization		(7)
Other Income		3
Interest Expense		1
Total Change in Expenses and Other		(16)
Income Tax Expense		(5)
First Quarter of 2013	\$	43

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 electricity were as follows:

- Retail Margins increased \$24 million primarily due to the following:
 - A \$20 million increase due to rate increases in Indiana effective March 2013 and Michigan effective April 2012, higher PJM revenue and higher Indiana Demand Side Management (DSM) revenue. The PJM and DSM increases were partially offset in expense items below.
 - An \$8 million increase in weather-related usage primarily due to a 41% increase in heating degree days.
- These increases were partially offset by:
 - A \$3 million decrease in capacity settlement revenues under the Interconnection Agreement.
- Other Revenues increased \$3 million primarily due to I&M's River Transportation Division (RTD) revenues from barging activities. The increase in RTD revenue was offset by a corresponding increase in Other Operation and Maintenance expenses for barging activities discussed below.

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

- Other Operation and Maintenance expenses increased \$13 million primarily due to the following:
 - A \$5 million increase in steam maintenance expenses related to a Rockport Plant outage in the first quarter of 2013.

A \$4 million increase in RTD expenses for barging activities. The increase in RTD expenses was offset by a corresponding increase in Other Revenues from barging activities discussed above.

A \$3 million increase in customer service costs primarily due to higher DSM expenses. The increase in DSM expenses was offset by a corresponding increase in Retail Margins discussed above.

- Depreciation and Amortization expenses increased \$7 million primarily due to higher depreciable base and higher depreciation rates reflecting a change in Tanners Creek Plant's estimated life approved in Michigan effective April 2012 and in Indiana effective March 2013. The majority of the increase in depreciation is offset within Gross Margin.
- Other Income increased \$3 million primarily due to an increase in equity AFUDC.
- Income Tax Expense increased \$5 million primarily due to an increase in pretax book income and the regulatory accounting treatment of state income taxes.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” in the 2012 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” beginning on page 187 for a discussion of accounting pronouncements.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

For the Three Months Ended March 31, 2013 and 2012

(in thousands)

(Unaudited)

	Three Months Ended March 31,	
	2013	2012
REVENUES		
Electric Generation, Transmission and Distribution	\$490,603	\$436,027
Sales to AEP Affiliates	54,977	75,915
Other Revenues - Affiliated	35,825	30,711
Other Revenues - Nonaffiliated	1,988	3,554
TOTAL REVENUES	583,393	546,207
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	104,865	112,370
Purchased Electricity for Resale	41,812	35,910
Purchased Electricity from AEP Affiliates	101,376	87,953
Other Operation	145,238	135,216
Maintenance	45,514	42,265
Depreciation and Amortization	40,902	33,979
Taxes Other Than Income Taxes	22,456	22,189
TOTAL EXPENSES	502,163	469,882
OPERATING INCOME	81,230	76,325
Other Income (Expense):		
Interest Income	2,055	1,251
Allowance for Equity Funds Used During Construction	5,646	3,011
Interest Expense	(24,211)	(25,053)
INCOME BEFORE INCOME TAX EXPENSE	64,720	55,534
Income Tax Expense	21,263	16,313
NET INCOME	\$43,457	\$39,221

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

For the Three Months Ended March 31, 2013 and 2012

(in thousands)

(Unaudited)

	Three Months Ended March 31,	
	2013	2012
Net Income	\$43,457	\$39,221
OTHER COMPREHENSIVE INCOME, NET OF TAXES		
Cash Flow Hedges, Net of Tax of \$1,682 and \$1,322 in 2013 and 2012, Respectively	3,123	2,456
Amortization of Pension and OPEB Deferred Costs, Net of Tax of \$94 and \$150 in 2013 and 2012, Respectively	176	279
TOTAL OTHER COMPREHENSIVE INCOME	3,299	2,735
TOTAL COMPREHENSIVE INCOME	\$46,756	\$41,956

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY

For the Three Months Ended March 31, 2013 and 2012

(in thousands)

(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	\$56,584	\$980,896	\$751,721	\$ (28,221)	\$1,760,980
Common Stock Dividends			(12,500)		(12,500)
Net Income			39,221		39,221
Other Comprehensive Income				2,735	2,735
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2012	\$56,584	\$980,896	\$778,442	\$ (25,486)	\$1,790,436
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	\$56,584	\$980,896	\$795,178	\$ (28,883)	\$1,803,775
Common Stock Dividends			(12,500)		(12,500)
Net Income			43,457		43,457
Other Comprehensive Income				3,299	3,299
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2013	\$56,584	\$980,896	\$826,135	\$ (25,584)	\$1,838,031

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

March 31, 2013 and December 31, 2012

(in thousands)

(Unaudited)

	March 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	\$ 572	\$ 1,562
Advances to Affiliates	321,985	116,977
Accounts Receivable:		
Customers	61,032	61,776
Affiliated Companies	56,574	79,886
Accrued Unbilled Revenues	20,223	11,218
Miscellaneous	4,757	12,260
Allowance for Uncollectible Accounts	(206)	(229)
Total Accounts Receivable	142,380	164,911
Fuel	61,935	53,406
Materials and Supplies	193,486	195,147
Risk Management Assets	18,086	26,974
Accrued Tax Benefits	18,676	20,547
Deferred Cook Plant Fire Costs	-	80,000
Prepayments and Other Current Assets	62,064	62,723
TOTAL CURRENT ASSETS	819,184	722,247
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,072,402	4,062,733
Transmission	1,283,763	1,278,236
Distribution	1,569,475	1,553,358
Other Property, Plant and Equipment (Including Nuclear Fuel and Coal Mining)	715,495	725,313
Construction Work in Progress	375,413	341,063
Total Property, Plant and Equipment	8,016,548	7,960,703
Accumulated Depreciation, Depletion and Amortization	3,244,675	3,232,135
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,771,873	4,728,568
OTHER NONCURRENT ASSETS		
Regulatory Assets	546,013	540,019
Spent Nuclear Fuel and Decommissioning Trusts	1,787,529	1,705,772
Long-term Risk Management Assets	16,595	23,569
Deferred Charges and Other Noncurrent Assets	117,899	111,364
TOTAL OTHER NONCURRENT ASSETS	2,468,036	2,380,724
TOTAL ASSETS	\$ 8,059,093	\$ 7,831,539

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2013 and December 31, 2012
(dollars in thousands)
(Unaudited)

	March 31, 2013	December 31, 2012
CURRENT LIABILITIES		
Accounts Payable:		
General	\$ 126,312	\$ 208,701
Affiliated Companies	52,078	104,631
Long-term Debt Due Within One Year – Nonaffiliated (March 31, 2013 and December 31, 2012 Amounts Include \$110,888 and \$119,890, Respectively, Related to DCC Fuel)	197,066	203,953
Risk Management Liabilities	8,691	31,517
Customer Deposits	30,923	31,142
Accrued Taxes	80,002	67,675
Accrued Interest	20,175	26,859
Other Current Liabilities	113,770	122,053
TOTAL CURRENT LIABILITIES	629,017	796,531
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,085,514	1,853,713
Long-term Risk Management Liabilities	9,497	13,898
Deferred Income Taxes	1,056,567	1,019,160
Regulatory Liabilities and Deferred Investment Tax Credits	1,023,242	948,292
Asset Retirement Obligations	1,212,754	1,192,313
Deferred Credits and Other Noncurrent Liabilities	204,471	203,857
TOTAL NONCURRENT LIABILITIES	5,592,045	5,231,233
TOTAL LIABILITIES	6,221,062	6,027,764
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
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	980,896	980,896
Retained Earnings	826,135	795,178
Accumulated Other Comprehensive Income (Loss)	(25,584)	(28,883)
TOTAL COMMON SHAREHOLDER'S EQUITY	1,838,031	1,803,775
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	\$ 8,059,093	\$ 7,831,539

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Three Months Ended March 31, 2013 and 2012

(in thousands)

(Unaudited)

	Three Months Ended March 31,	
	2013	2012
OPERATING ACTIVITIES		
Net Income	\$ 43,457	\$ 39,221
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	40,902	33,979
Deferred Income Taxes	26,791	26,638
Amortization of Incremental Nuclear Refueling Outage Expenses, Net	(5,840)	(4,878)
Allowance for Equity Funds Used During Construction	(5,646)	(3,011)
Mark-to-Market of Risk Management Contracts	9,238	(5,624)
Amortization of Nuclear Fuel	34,000	33,585
Fuel Over/Under-Recovery, Net	417	(3,493)
Change in Other Noncurrent Assets	(9,217)	(9,931)
Change in Other Noncurrent Liabilities	8,577	32,710
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	22,531	49,885
Fuel, Materials and Supplies	(6,868)	(13,890)
Accounts Payable	(31,801)	(4,269)
Accrued Taxes, Net	14,198	30,624
Other Current Assets	8,487	(6,197)
Other Current Liabilities	(13,443)	(23,279)
Net Cash Flows from Operating Activities	135,783	172,070
INVESTING ACTIVITIES		
Construction Expenditures	(153,262)	(72,867)
Change in Advances to Affiliates, Net	(205,008)	(48,248)
Purchases of Investment Securities	(184,299)	(352,877)
Sales of Investment Securities	167,670	334,400
Acquisitions of Nuclear Fuel	(46,739)	(10,936)
Insurance Proceeds Related to Cook Plant Fire	72,000	-
Other Investing Activities	3,077	8,745
Net Cash Flows Used for Investing Activities	(346,561)	(141,783)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	247,771	-
Retirement of Long-term Debt – Nonaffiliated	(24,864)	(16,074)
Principal Payments for Capital Lease Obligations	(1,265)	(1,890)
Dividends Paid on Common Stock	(12,500)	(12,500)
Other Financing Activities	646	(200)

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Net Cash Flows from (Used for) Financing Activities	209,788	(30,664)
Net Decrease in Cash and Cash Equivalents	(990)	(377)
Cash and Cash Equivalents at Beginning of Period	1,562	1,020
Cash and Cash Equivalents at End of Period	\$ 572	\$ 643

SUPPLEMENTARY INFORMATION

Cash Paid for Interest, Net of Capitalized Amounts	\$ 30,116	\$ 29,398
Net Cash Paid (Received) for Income Taxes	(8,007)	(23,095)
Noncash Acquisitions Under Capital Leases	1,355	2,009
Construction Expenditures Included in Current Liabilities as of March 31,	42,430	26,957
Acquisition of Nuclear Fuel Included in Current Liabilities as of March 31,	1,485	-

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

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 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.

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OHIO POWER COMPANY AND SUBSIDIARY

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OHIO POWER COMPANY AND SUBSIDIARY
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Ohio Customer Choice

In OPCo's service territory, various CRES providers are targeting retail customers by offering alternative generation service. The reduction in gross margin as a result of customer switching in Ohio is partially offset by (a) collection of capacity revenues from CRES providers, (b) off-system sales, (c) deferral of unrecovered capacity costs and (d) Retail Stability Rider collections.

Regulatory Activity

Ohio Electric Security Plan Filing

2009 – 2011 ESP

In August 2012, the PUCO issued an order in a separate proceeding which implemented a Phase-In Recovery Rider (PIRR) to recover OPCo's deferred fuel costs in rates beginning September 2012. As of March 31, 2013, OPCo's net deferred fuel balance was \$501 million, excluding unrecognized equity carrying costs. Decisions from the Supreme Court of Ohio are pending related to various appeals which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance.

June 2012 – May 2015 Ohio ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that establishes base generation rates through May 2015.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to \$188.88/MW day. The RPM price is approximately \$20/MW day through May 2013 then \$33/MW day through May 2014. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 PUCO ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is expected to provide approximately \$500 million over the ESP period and will be collected from customers at \$3.50/MWh through May 2014 and \$4.00/MWh for the period June 2014 through May 2015, with \$1.00/MWh applied to the deferred capacity costs. As of March 31, 2013, OPCo's incurred deferred capacity costs balance of \$116 million, including debt carrying costs, was recorded in Regulatory Assets on the balance sheet.

If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, it could reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filing" section of Note 3.

Corporate Separation, Plant Transfers and Termination of Interconnection Agreement

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets at net book value to AEPGenCo. AEPGenCo will also assume the

associated generation liabilities. In December 2012, the PUCO granted the IEU and the Ohio Consumers' Counsel requests for rehearing, which were denied by the PUCO in April 2013.

Also in October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations. The filings requested approval to transfer at net book value approximately 9,200 MW of OPCo-owned generation assets to AEPGenCo. The AEP East Companies also requested FERC approval to transfer at net book value OPCo's current two-thirds ownership (867 MW) in Amos Plant Unit 3 to APCo and transfer at net book value OPCo's Mitchell Plant to APCo and KPCo

in equal one-half interests (780 MW each). These transfers are proposed to be effective no later than December 31, 2013. Additionally, the AEP East Companies asked the FERC, effective January 1, 2014, to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Intervenor comments have opposed several of these filings. The AEP East Companies responded to intervenor comments and filed a revised PCA at the FERC in March 2013. The revised PCA included certain clarifying wording changes that have been agreed upon by intervenors. A decision from the FERC is expected in the second quarter of 2013.

Significantly Excessive Earnings Test

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of a portion of 2010 earnings. OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO-ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's request to file the 2011 SEET one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo or in 2012 and 2013 for OPCo. Depending on the rulings in these proceedings, it could reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filing" section of Note 3.

Securitization of Regulatory Assets

In March 2013, the PUCO approved OPCo's request to securitize the Deferred Asset Recovery Rider (DARR) balance. As of March 31, 2013, OPCo's DARR balance was \$277 million, including \$130 million of unrecognized equity carrying costs. The DARR is being recovered through 2018 by a non-bypassable rider. Once the securitization bonds are issued, the DARR will cease and will be replaced by the Deferred Asset Phase-in Rider, which will recover the securitized asset over a period not to exceed eight years. The securitization bonds are expected to be issued in mid-2013.

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 predict the eventual resolution, timing or amount of any loss, fine or penalty. 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 2 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies in the 2012 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 133. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 187 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2013 2012 (in millions of KWhs)	
Retail:		
Residential	4,264	3,879
Commercial	3,386	3,236
Industrial	4,082	4,721
Miscellaneous	35	31
Total Retail (a)	11,767	11,867
Wholesale	3,044	2,506
Total KWhs	14,811	14,373

(a) Represents energy delivered to distribution customers.

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, 2013 2012 (in degree days)	
Actual - Heating (a)	1,971	1,397
Normal - Heating (b)	1,885	1,918
Actual - Cooling (c)	-	28
Normal - Cooling (b)	3	2

- (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 2013 Compared to First Quarter of 2012

Reconciliation of First Quarter of 2012 to First Quarter of 2013

Net Income
(in millions)

First Quarter of 2012	\$	151
Changes in Gross Margin:		
Retail Margins		1
Off-system Sales		(31)
Transmission Revenues		11
Other Revenues		(1)
Total Change in Gross Margin		(20)
Changes in Expenses and Other:		
Other Operation and Maintenance		(47)
Depreciation and Amortization		42
Carrying Costs Income		1
Other Income		(1)
Interest Expense		4
Total Change in Expenses and Other		(1)
First Quarter of 2013	\$	130

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 electricity were as follows:

- Retail Margins increased \$1 million primarily due to the following:
 - A \$61 million increase in revenues associated with the Universal Service Fund (USF) surcharge, Retail Stability Rider, Deferred Asset Recovery Rider and Distribution Investment Recovery Rider. The majority of these increases have corresponding increases in other expense items below.
 - A \$21 million increase in weather-related usage primarily due to a 41% increase in heating degree days.
 - A \$9 million increase in weather-normalized usage in the residential and commercial classes.

These increases were partially offset by:

- An \$87 million decrease attributable to customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
- A \$7 million decrease due to lower sales to Buckeye Power, Inc. to provide backup energy under the Cardinal Station Agreement.
- A \$6 million decrease in capacity settlement revenues under the Interconnection Agreement. This decrease was primarily a result of APCo's completion of the Dresden Plant in January 2012.
- Margins from Off-system Sales decreased \$31 million primarily due to lower CRES capacity revenues as a result of Reliability Pricing Model pricing effective August 2012, lower PJM capacity payments and reduced trading and marketing margins, partially offset by higher physical sales volumes and margins. The decrease in CRES

capacity revenues is partially offset in other expense items below.

- Transmission Revenues increased \$11 million primarily due to increased transmission revenues from customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets lost revenues included in Retail Margins above.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased \$47 million primarily due to the following:
 - A \$35 million increase due to the first quarter 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of the Ohio modified stipulation.
 - A \$26 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.
 - A \$4 million increase due to expenses related to the completion of the 2012 sustainable cost reductions program in the first quarter of 2013.
- These increases were partially offset by:
 - An \$8 million decrease due to the deferral of capacity-related costs as a result of the PUCO's July 2012 approval of the capacity deferral mechanism.
 - An \$8 million decrease primarily due to the 2012 reversal of storm damage deferrals as a result of the PUCO's February 2012 rejection of the Ohio modified stipulation.
- Depreciation and Amortization expenses decreased \$42 million primarily due to the following:
 - A \$27 million decrease as a result of depreciation ceasing on certain generating plants that were impaired in November 2012.
 - A \$20 million decrease due to the deferral of capacity-related depreciation costs as a result of the PUCO's July 2012 approval of the capacity deferral mechanism.
- Interest Expense decreased \$4 million primarily due to the redemption of long-term debt.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” in the 2012 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” beginning on page 187 for a discussion of accounting pronouncements.

OHIO POWER COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2013 and 2012
(in thousands)
(Unaudited)

	Three Months Ended March 31,	
	2013	2012
REVENUES		
Electric Generation, Transmission and Distribution	\$933,681	\$1,040,831
Sales to AEP Affiliates	285,642	181,757
Other Revenues – Affiliated	7,840	9,111
Other Revenues – Nonaffiliated	6,627	5,524
TOTAL REVENUES	1,233,790	1,237,223
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	409,584	369,993
Purchased Electricity for Resale	43,185	58,134
Purchased Electricity from AEP Affiliates	80,381	88,683
Other Operation	184,187	130,342
Maintenance	74,295	80,604
Depreciation and Amortization	92,324	134,430
Taxes Other Than Income Taxes	105,021	105,418
TOTAL EXPENSES	988,977	967,604
OPERATING INCOME	244,813	269,619
Other Income (Expense):		
Interest Income	363	1,098
Carrying Costs Income	3,263	2,758
Allowance for Equity Funds Used During Construction	1,304	1,123
Interest Expense	(50,173)	(54,261)
INCOME BEFORE INCOME TAX EXPENSE	199,570	220,337
Income Tax Expense	69,796	69,507
NET INCOME	\$129,774	\$150,830

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

OHIO POWER COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2013 and 2012
(in thousands)
(Unaudited)

	Three Months Ended March 31,	
	2013	2012
Net Income	\$129,774	\$150,830
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of \$574 and \$937 in 2013 and 2012, Respectively	1,066	(1,741)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of \$1,760 and \$1,745 in 2013 and 2012, Respectively	3,269	3,241
TOTAL OTHER COMPREHENSIVE INCOME	4,335	1,500
TOTAL COMPREHENSIVE INCOME	\$134,109	\$152,330

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

OHIO POWER COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY

For the Three Months Ended March 31, 2013 and 2012

(in thousands)

(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	\$321,201	\$1,744,099	\$2,582,600	\$ (197,722)	\$4,450,178
Common Stock Dividends			(75,000)		(75,000)
Net Income			150,830		150,830
Other Comprehensive Income				1,500	1,500
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2012	\$321,201	\$1,744,099	\$2,658,430	\$ (196,222)	\$4,527,508
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	\$321,201	\$1,744,099	\$2,626,134	\$ (165,725)	\$4,525,709
Common Stock Dividends			(75,000)		(75,000)
Net Income			129,774		129,774
Other Comprehensive Income				4,335	4,335
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2013	\$321,201	\$1,744,099	\$2,680,908	\$ (161,390)	\$4,584,818

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

OHIO POWER COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

March 31, 2013 and December 31, 2012

(in thousands)

(Unaudited)

	March 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	\$ 1,027	\$ 3,640
Advances to Affiliates	10,342	116,422
Accounts Receivable:		
Customers	105,256	135,954
Affiliated Companies	157,242	176,590
Accrued Unbilled Revenues	55,389	57,887
Miscellaneous	8,895	9,327
Allowance for Uncollectible Accounts	(3,787)	(129)
Total Accounts Receivable	322,995	379,629
Fuel	329,858	328,840
Materials and Supplies	186,639	186,269
Risk Management Assets	33,481	44,313
Accrued Tax Benefits	3,070	17,785
Prepayments and Other Current Assets	26,604	26,807
TOTAL CURRENT ASSETS	914,016	1,103,705
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	8,727,339	8,673,296
Transmission	2,012,175	2,013,737
Distribution	3,737,356	3,722,745
Other Property, Plant and Equipment	585,825	571,154
Construction Work in Progress	348,366	354,497
Total Property, Plant and Equipment	15,411,061	15,335,429
Accumulated Depreciation and Amortization	5,311,018	5,242,805
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,100,043	10,092,624
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,462,357	1,420,966
Long-term Risk Management Assets	33,956	48,288
Deferred Charges and Other Noncurrent Assets	250,306	320,026
TOTAL OTHER NONCURRENT ASSETS	1,746,619	1,789,280
TOTAL ASSETS	\$ 12,760,678	\$ 12,985,609

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

OHIO POWER COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2013 and December 31, 2012
(Unaudited)

	March 31, 2013	December 31, 2012
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	\$ 172,211	\$ -
Accounts Payable:		
General	275,674	276,220
Affiliated Companies	102,678	153,222
Long-term Debt Due Within One Year – Nonaffiliated	581,000	856,000
Risk Management Liabilities	17,586	24,155
Accrued Taxes	361,287	467,309
Accrued Interest	62,504	63,560
Other Current Liabilities	231,202	263,638
TOTAL CURRENT LIABILITIES	1,804,142	2,104,104
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,579,628	2,804,440
Long-term Debt – Affiliated	400,000	200,000
Long-term Risk Management Liabilities	18,048	25,965
Deferred Income Taxes	2,402,498	2,345,850
Regulatory Liabilities and Deferred Investment Tax Credits	446,430	451,071
Deferred Credits and Other Noncurrent Liabilities	525,114	528,470
TOTAL NONCURRENT LIABILITIES	6,371,718	6,355,796
TOTAL LIABILITIES	8,175,860	8,459,900
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
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	1,744,099	1,744,099
Retained Earnings	2,680,908	2,626,134
Accumulated Other Comprehensive Income (Loss)	(161,390)	(165,725)
TOTAL COMMON SHAREHOLDER’S EQUITY	4,584,818	4,525,709
TOTAL LIABILITIES AND COMMON SHAREHOLDER’S EQUITY	\$ 12,760,678	\$ 12,985,609

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

OHIO POWER COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2013 and 2012
(in thousands)
(Unaudited)

	Three Months Ended March 31,	
	2013	2012
OPERATING ACTIVITIES		
Net Income	\$ 129,774	\$ 150,830
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	92,324	134,430
Deferred Income Taxes	55,328	47,668
Carrying Costs Income	(3,263)	(2,758)
Allowance for Equity Funds Used During Construction	(1,304)	(1,123)
Mark-to-Market of Risk Management Contracts	12,901	(8,566)
Property Taxes	55,246	53,973
Fuel Over/Under-Recovery, Net	9,191	21,222
Change in Other Noncurrent Assets	(34,964)	(1,649)
Change in Other Noncurrent Liabilities	1,730	(20,486)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	58,235	98,001
Fuel, Materials and Supplies	(1,388)	(40,200)
Accounts Payable	(42,749)	(98,502)
Accrued Taxes, Net	(91,308)	(76,603)
Other Current Assets	(705)	(2,041)
Other Current Liabilities	(21,374)	(10,538)
Net Cash Flows from Operating Activities	217,674	243,658
INVESTING ACTIVITIES		
Construction Expenditures	(131,590)	(148,956)
Change in Advances to Affiliates, Net	106,080	129,618
Proceeds from Sales of Assets	8,941	2,827
Other Investing Activities	819	(23)
Net Cash Flows Used for Investing Activities	(15,750)	(16,534)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Affiliated	200,000	-
Change in Advances from Affiliates, Net	172,211	-
Retirement of Long-term Debt – Nonaffiliated	(500,000)	(150,000)
Principal Payments for Capital Lease Obligations	(2,508)	(2,619)
Dividends Paid on Common Stock	(75,000)	(75,000)
Other Financing Activities	760	109
Net Cash Flows Used for Financing Activities	(204,537)	(227,510)
Net Decrease in Cash and Cash Equivalents	(2,613)	(386)

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Cash and Cash Equivalents at Beginning of Period		3,640		2,095
Cash and Cash Equivalents at End of Period	\$	1,027	\$	1,709

SUPPLEMENTARY INFORMATION

Cash Paid for Interest, Net of Capitalized Amounts	\$	50,327	\$	52,150
Net Cash Paid (Received) for Income Taxes		(2,390)		(7,359)
Noncash Acquisitions Under Capital Leases		1,811		819
Government Grants Included in Accounts Receivable as of March 31,		1,147		2,052
Construction Expenditures Included in Current Liabilities as of March 31,		69,152		28,330

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

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

The condensed notes to OPCo's condensed 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.

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PUBLIC SERVICE COMPANY OF OKLAHOMA

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PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Regulatory Activity

Oklahoma Environmental Compliance Plan

In September 2012, based upon an agreement with the Federal EPA, the State of Oklahoma and other parties, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES) Unit 4 in 2016 and additional environmental controls on NES Unit 3 to continue operations through 2026. The plan requested approval for (a) an estimated \$210 million of new environmental investment, excluding AFUDC and overheads of \$46 million, that will be incurred prior to 2016 at NES Unit 3, (b) accelerated recovery through 2026 of the net book value of NES Units 3 and 4 (combined net book value of the two units is \$232 million as of March 31, 2013), (c) an estimated \$83 million of new investment incurred through 2016 at various gas units and (d) a new 15-year purchase power agreement (PPA) with a nonaffiliated entity, effective in 2016, with cost recovery through a rider, including an annual earnings component of \$3 million. Although the environmental compliance plan does not seek to put any new costs into rates at this time, PSO anticipates seeking cost recovery when filing its next base rate case, which is expected to occur no later than 2014.

In January 2013, several parties filed testimony with various recommendations. In February 2013, the OCC staff requested a stay in this proceeding, which was granted by the OCC in March 2013. The stay will be in effect until the State Implementation Plan is approved by the Federal EPA, which could be as late as February 2014. If PSO is ultimately not permitted to fully recover its net book value of NES Units 3 and 4 and other environmental compliance costs, it could reduce future net income and cash flows and impact financial condition. See "Oklahoma Environmental Compliance Plan" section of Note 3.

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 predict the eventual resolution, timing or amount of any loss, fine or penalty. 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 2 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies in the 2012 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 133. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 187 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2013 2012 (in millions of KWhs)	
Retail:		
Residential	1,436	1,337
Commercial	1,079	1,101
Industrial	1,194	1,193
Miscellaneous	277	300
Total Retail	3,986	3,931
Wholesale	255	545
Total KWhs	4,241	4,476

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, 2013 2012 (in degree days)	
Actual - Heating (a)	1,089	676
Normal - Heating (b)	1,045	1,066
Actual - Cooling (c)	5	64
Normal - Cooling (b)	15	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 2013 Compared to First Quarter of 2012

Reconciliation of First Quarter of 2012 to First Quarter of 2013

Net Income

(in millions)

First Quarter of 2012	\$	13
Changes in Gross Margin:		
Retail Margins (a)		1
Transmission Revenues		1
Other Revenues		(1)
Total Change in Gross Margin		1
Changes in Expenses and Other:		
Other Operation and Maintenance		(1)
Taxes Other Than Income Taxes		1
Interest Expense		1
Total Change in Expenses and Other		1
Income Tax Expense		(1)
First Quarter of 2013	\$	14

(a) Includes firm wholesale sales to municipals and cooperatives.

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 electricity were as follows:

- Retail Margins increased \$1 million primarily due to the following:
 - A \$3 million increase in weather-related usage primarily due to a 61% increase in heating degree days.
 - A \$3 million increase primarily due to revenue increases from rate riders. This increase in retail margins has corresponding increases to riders/trackers recognized in other expense items below.
- These increases were partially offset by:
 - A \$4 million decrease primarily due to lower non-weather related usage.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased \$1 million primarily due to the following:
 - A \$3 million increase in transmission expenses primarily due to increased SPP transmission services.
- This increase was partially offset by:
 - A \$1 million decrease in employee benefit-related expenses.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” in the 2012 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” beginning on page 187 for a discussion of accounting pronouncements.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2013 and 2012
(in thousands)
(Unaudited)

	Three Months Ended March 31,	
	2013	2012
REVENUES		
Electric Generation, Transmission and Distribution	\$259,903	\$292,522
Sales to AEP Affiliates	1,834	7,105
Other Revenues	552	904
TOTAL REVENUES	262,289	300,531
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	43,310	125,425
Purchased Electricity for Resale	64,655	25,442
Purchased Electricity from AEP Affiliates	10,216	6,198
Other Operation	47,807	46,979
Maintenance	28,572	28,325
Depreciation and Amortization	24,180	23,533
Taxes Other Than Income Taxes	9,997	11,139
TOTAL EXPENSES	228,737	267,041
OPERATING INCOME	33,552	33,490
Other Income (Expense):		
Interest Income	928	935
Carrying Costs Income	207	613
Allowance for Equity Funds Used During Construction	980	422
Interest Expense	(13,340)	(14,711)
INCOME BEFORE INCOME TAX EXPENSE	22,327	20,749
Income Tax Expense	8,634	8,101
NET INCOME	\$13,693	\$12,648

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2013 and 2012
(in thousands)
(Unaudited)

	Three Months Ended March 31,	
	2013	2012
Net Income	\$13,693	\$12,648
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Cash Flow Hedges, Net of Tax of \$90 and \$29 in 2013 and 2012, Respectively	(167)	(53)
TOTAL COMPREHENSIVE INCOME	\$13,526	\$12,595

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2013 and 2012
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	\$157,230	\$364,037	\$364,389	\$ 7,149	\$892,805
Common Stock Dividends			(15,000)		(15,000)
Net Income			12,648		12,648
Other Comprehensive Loss				(53)	(53)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2012	\$157,230	\$364,037	\$362,037	\$ 7,096	\$890,400
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	\$157,230	\$364,037	\$388,530	\$ 6,481	\$916,278
Common Stock Dividends			(13,750)		(13,750)
Net Income			13,693		13,693
Other Comprehensive Loss				(167)	(167)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2013	\$157,230	\$364,037	\$388,473	\$ 6,314	\$916,054

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS

March 31, 2013 and December 31, 2012

(in thousands)

(Unaudited)

	March 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	\$ 474	\$ 1,367
Advances to Affiliates	-	10,558
Accounts Receivable:		
Customers	41,220	31,047
Affiliated Companies	16,335	24,751
Miscellaneous	2,594	6,216
Allowance for Uncollectible Accounts	(672)	(872)
Total Accounts Receivable	59,477	61,142
Fuel	21,597	22,085
Materials and Supplies	51,327	52,183
Risk Management Assets	712	509
Deferred Income Tax Benefits	2,780	7,183
Accrued Tax Benefits	26,168	11,812
Regulatory Asset for Under-Recovered Fuel Costs	9,867	-
Prepayments and Other Current Assets	5,956	7,633
TOTAL CURRENT ASSETS	178,358	174,472
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,351,151	1,346,530
Transmission	717,978	706,917
Distribution	1,878,736	1,859,557
Other Property, Plant and Equipment	212,771	210,549
Construction Work in Progress	99,494	95,170
Total Property, Plant and Equipment	4,260,130	4,218,723
Accumulated Depreciation and Amortization	1,292,967	1,278,941
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	2,967,163	2,939,782
OTHER NONCURRENT ASSETS		
Regulatory Assets	197,064	202,328
Long-term Risk Management Assets	4	31
Deferred Charges and Other Noncurrent Assets	37,158	8,560
TOTAL OTHER NONCURRENT ASSETS	234,226	210,919
TOTAL ASSETS	\$ 3,379,747	\$ 3,325,173

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2013 and December 31, 2012
(Unaudited)

	March 31, 2013	December 31, 2012
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	\$ 24,004	\$ -
Accounts Payable:		
General	73,334	87,050
Affiliated Companies	38,025	36,189
Long-term Debt Due Within One Year – Nonaffiliated	405	764
Risk Management Liabilities	3,006	5,848
Customer Deposits	46,703	46,533
Accrued Taxes	40,037	28,024
Accrued Interest	15,016	12,654
Regulatory Liability for Over-Recovered Fuel Costs	-	7,945
Other Current Liabilities	60,422	50,684
TOTAL CURRENT LIABILITIES	300,952	275,691
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	949,451	949,107
Long-term Risk Management Liabilities	-	31
Deferred Income Taxes	790,848	740,676
Regulatory Liabilities and Deferred Investment Tax Credits	350,199	344,817
Employee Benefits and Pension Obligations	34,517	34,906
Deferred Credits and Other Noncurrent Liabilities	37,726	63,667
TOTAL NONCURRENT LIABILITIES	2,162,741	2,133,204
TOTAL LIABILITIES	2,463,693	2,408,895
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – Par Value – \$15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157,230	157,230
Paid-in Capital	364,037	364,037
Retained Earnings	388,473	388,530
Accumulated Other Comprehensive Income (Loss)	6,314	6,481
TOTAL COMMON SHAREHOLDER’S EQUITY	916,054	916,278
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	\$ 3,379,747	\$ 3,325,173

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2013 and 2012
(in thousands)
(Unaudited)

	Three Months Ended March 31,	
	2013	2012
OPERATING ACTIVITIES		
Net Income	\$ 13,693	\$ 12,648
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	24,180	23,533
Deferred Income Taxes	20,242	9,307
Carrying Costs Income	(207)	(613)
Allowance for Equity Funds Used During Construction	(980)	(422)
Mark-to-Market of Risk Management Contracts	(3,013)	4,818
Property Taxes	(28,730)	(29,020)
Fuel Over/Under-Recovery, Net	(17,812)	62,075
Change in Other Noncurrent Assets	592	(3,567)
Change in Other Noncurrent Liabilities	4,620	(372)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	1,665	(15,757)
Fuel, Materials and Supplies	1,344	1,111
Accounts Payable	(5,827)	(10,655)
Accrued Taxes, Net	6,106	15,852
Other Current Assets	1,181	(564)
Other Current Liabilities	10,663	(3,542)
Net Cash Flows from Operating Activities	27,717	64,832
INVESTING ACTIVITIES		
Construction Expenditures	(54,298)	(62,696)
Change in Advances to Affiliates, Net	10,558	10,740
Other Investing Activities	5,196	290
Net Cash Flows Used for Investing Activities	(38,544)	(51,666)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	-	1,944
Change in Advances from Affiliates, Net	24,004	-
Retirement of Long-term Debt – Nonaffiliated	(99)	-
Principal Payments for Capital Lease Obligations	(754)	(841)
Dividends Paid on Common Stock	(13,750)	(15,000)
Other Financing Activities	533	106
Net Cash Flows from (Used for) Financing Activities	9,934	(13,791)
Net Decrease in Cash and Cash Equivalents	(893)	(625)
Cash and Cash Equivalents at Beginning of Period	1,367	1,413

Cash and Cash Equivalents at End of Period	\$	474	\$	788
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SUPPLEMENTARY INFORMATION

Cash Paid for Interest, Net of Capitalized Amounts	\$	10,519	\$	10,795
Net Cash Paid for Income Taxes		284		4,873
Noncash Acquisitions Under Capital Leases		1,015		437
Construction Expenditures Included in Current Liabilities as of March 31,		19,868		9,861

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to PSO's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to PSO.

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Regulatory Activity

Turk Plant

SWEP Co constructed the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the facility. As of March 31, 2013, excluding costs attributable to its joint owners and a \$62 million provision for a Texas capital cost cap, SWEPCo has capitalized approximately \$1.7 billion of expenditures, including AFUDC and capitalized interest of \$328 million and related transmission costs of \$120 million.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant (approximately 20%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to the Arkansas Supreme Court's decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This portion of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the SPP market. If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it could reduce future net income and cash flows and impact financial condition. See "Turk Plant" section of Note 3.

Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by \$83 million, primarily due to the Turk Plant, based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share (approximately 33%) of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates. In December 2012, several intervenors filed opposing testimony with various recommendations. A decision from the PUCT is expected in the second quarter of 2013. If the PUCT does not approve full cost recovery of SWEPCo's assets, it could reduce future net income and cash flows and impact financial condition. See "2012 Texas Base Rate Case" section of Note 3.

Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and approved by the LPSC. The settlement increased Louisiana total rates by approximately \$2 million annually, effective March 2013, which consisted of an increase in base rates of approximately \$85 million annually offset by a decrease in fuel and other rates of approximately \$83 million annually. The March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund based on the staff review of the cost of service and the prudence of the Turk Plant to be initiated by SWEPCo no later than May 2013. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover all non-fuel Turk Plant costs and a full weighted-average cost of capital return on the Turk Plant portion of rate base beginning, effective January 2013. If the LPSC orders refunds based upon the staff review

of the cost of service or prudence review of the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is \$408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant,

SWEPCo's portion of those costs is estimated at \$204 million. As of March 31, 2013, SWEPCo has incurred \$16 million related to this project, including AFUDC and company overheads. In March 2013, the APSC staff and the Arkansas Attorney General Office filed testimony that supported SWEPCo's petition. The Sierra Club continues to oppose SWEPCo's petition. Additional hearings were held in March 2013. If SWEPCo is not ultimately permitted to fully recover the net book value of the Flint Creek Plant and its incurred environmental costs in a future base rate proceeding, it could reduce future net income and cash flows and impact financial condition.

Litigation and Environmental Issues

In the ordinary course of business, SWEPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. 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 2 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies in the 2012 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 133. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

See the “Executive Overview” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” section beginning on page 187 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2013 2012 (in millions of KWhs)	
Retail:		
Residential	1,494	1,382
Commercial	1,279	1,311
Industrial	1,259	1,318
Miscellaneous	19	20
Total Retail	4,051	4,031
Wholesale	2,443	2,272
Total KWhs	6,494	6,303

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,
2013 2012

(in degree days)

Actual - Heating (a)	732	423
Normal - Heating (b)	728	746
Actual - Cooling (c)	16	114
Normal - Cooling (b)	33	30

(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 2013 Compared to First Quarter of 2012

Reconciliation of First Quarter of 2012 to First Quarter of 2013

Net Income

(in millions)

First Quarter of 2012	\$	36
Changes in Gross Margin:		
Retail Margins (a)		20
Off-system Sales		1
Transmission Revenues		2
Total Change in Gross Margin		23
Changes in Expenses and Other:		
Other Operation and Maintenance	(14)
Depreciation and Amortization	(11)
Taxes Other Than Income Taxes	(2)
Interest Income	(1)
Allowance for Equity Funds Used During Construction	(13)
Interest Expense	(12)
Total Change in Expenses and Other	(53)
Income Tax Expense		6
First Quarter of 2013	\$	12

(a) Includes firm wholesale sales to municipalities and cooperatives.

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 electricity were as follows:

- Retail Margins increased \$20 million primarily due to the following:
 - An \$18 million increase due to the Louisiana formula rate order related to the Turk Plant.
 - A \$7 million increase primarily due to 2012 fuel cost adjustments.
- These increases were partially offset by:
 - A \$6 million decrease in municipal and cooperative revenues due to prior year formula rate adjustments.
- Transmission Revenues increased \$2 million primarily due to higher rates in the SPP region.

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

- Other Operation and Maintenance expenses increased \$14 million primarily due to the following:
 - A \$6 million increase in generation plant operation and maintenance expenses primarily due to higher planned and unplanned plant outages in addition to Turk Plant operations.

- A \$3 million increase in transmission expenses primarily due to increased SPP transmission services.
- A \$2 million increase in employee benefit-related expenses.
- Depreciation and Amortization expenses increased \$11 million primarily due to the Turk Plant being placed in service in December 2012.
- Taxes Other Than Income Taxes increased \$2 million primarily due to higher property taxes related to the Turk Plant being placed in service in December 2012.
- Allowance for Equity Funds Used During Construction decreased \$13 million primarily due to completed construction of the Turk Plant in December 2012.
- Interest Expense increased \$12 million primarily due to a decrease in the debt component of AFUDC due to completed construction of the Turk Plant in December 2012.
- Income Tax Expense decreased \$6 million primarily due to a decrease in pretax book income, partially offset by other book/tax differences which are accounted for on a flow-through basis and the regulatory accounting treatment of state income taxes.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” in the 2012 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets and pension and other postretirement benefits.

See the “Accounting Pronouncements” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” beginning on page 187 for a discussion of accounting pronouncements.

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME**

For the Three Months Ended March 31, 2013 and 2012

(in thousands)

(Unaudited)

	Three Months Ended March 31,	
	2013	2012
REVENUES		
Electric Generation, Transmission and Distribution	\$381,277	\$339,703
Sales to AEP Affiliates	12,709	8,957
Other Revenues	331	326
TOTAL REVENUES	394,317	348,986
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	151,358	128,234
Purchased Electricity for Resale	39,760	35,467
Purchased Electricity from AEP Affiliates	1,017	6,255
Other Operation	59,448	51,593
Maintenance	27,791	21,262
Depreciation and Amortization	44,882	34,021
Taxes Other Than Income Taxes	19,422	16,786
TOTAL EXPENSES	343,678	293,618
OPERATING INCOME	50,639	55,368
Other Income (Expense):		
Interest Income	30	1,120
Allowance for Equity Funds Used During Construction	1,024	13,774
Interest Expense	(33,990)	(22,002)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	17,703	48,260
Income Tax Expense	6,796	12,472
Equity Earnings of Unconsolidated Subsidiary	641	607
NET INCOME	11,548	36,395
Net Income Attributable to Noncontrolling Interest	1,090	1,083
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	\$10,458	\$35,312

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

For the Three Months Ended March 31, 2013 and 2012

(in thousands)

(Unaudited)

	Three Months Ended March 31,	
	2013	2012
Net Income	\$11,548	\$36,395
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of \$321 and \$956 in 2013 and 2012, Respectively	596	(1,775)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of \$34 and \$89 in 2013 and 2012, Respectively	(63)	165
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	533	(1,610)
TOTAL COMPREHENSIVE INCOME	12,081	34,785
Total Comprehensive Income Attributable to Noncontrolling Interest	1,090	1,083
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	\$10,991	\$33,702

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY**

For the Three Months Ended March 31, 2013 and 2012

(in thousands)

(Unaudited)

SWEPCo Common Shareholder

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2011	\$ 135,660	\$ 674,606	\$ 1,029,915	\$ (26,815)	\$ 391	\$ 1,813,757
Common Stock Dividends – Nonaffiliated					(1,092)	(1,092)
Net Income			35,312		1,083	36,395
Other Comprehensive Loss				(1,610)		(1,610)
TOTAL EQUITY – MARCH 31, 2012	\$ 135,660	\$ 674,606	\$ 1,065,227	\$ (28,425)	\$ 382	\$ 1,847,450
TOTAL EQUITY – DECEMBER 31, 2012	\$ 135,660	\$ 674,606	\$ 1,228,806	\$ (17,860)	\$ 261	\$ 2,021,473
Common Stock Dividends			(31,250)			(31,250)
Common Stock Dividends – Nonaffiliated					(964)	(964)
Net Income			10,458		1,090	11,548
Other Comprehensive Income				533		533
TOTAL EQUITY – MARCH 31, 2013	\$ 135,660	\$ 674,606	\$ 1,208,014	\$ (17,327)	\$ 387	\$ 2,001,340

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

March 31, 2013 and December 31, 2012

(in thousands)

(Unaudited)

	March 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	\$ 7,143	\$ 2,036
Advances to Affiliates	26,885	153,829
Accounts Receivable:		
Customers	39,462	39,349
Affiliated Companies	29,608	26,288
Miscellaneous	20,753	35,514
Allowance for Uncollectible Accounts	(2,367)	(2,041)
Total Accounts Receivable	87,456	99,110
Fuel		
(March 31, 2013 and December 31, 2012 Amounts Include \$39,234 and \$42,084, Respectively, Related to Sabine)	128,901	134,234
Materials and Supplies	71,242	69,212
Risk Management Assets	727	695
Deferred Income Tax Benefits	102,757	101,403
Accrued Tax Benefits	19,810	9,616
Regulatory Asset for Under-Recovered Fuel Costs	8,939	8,527
Prepayments and Other Current Assets	17,955	16,489
TOTAL CURRENT ASSETS	471,815	595,151
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,902,714	3,888,230
Transmission	1,126,710	1,115,795
Distribution	1,772,135	1,758,988
Other Property, Plant and Equipment		
(March 31, 2013 and December 31, 2012 Amounts Include \$288,616 and \$287,032, Respectively, Related to Sabine)	693,621	688,254
Construction Work in Progress	130,614	99,783
Total Property, Plant and Equipment	7,625,794	7,551,050
Accumulated Depreciation and Amortization		
(March 31, 2013 and December 31, 2012 Amounts Include \$121,360 and \$116,597, Respectively, Related to Sabine)	2,317,046	2,284,258
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,308,748	5,266,792
OTHER NONCURRENT ASSETS		

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Regulatory Assets	406,339	403,278
Long-term Risk Management Assets	4	-
Deferred Charges and Other Noncurrent Assets	112,871	76,432
TOTAL OTHER NONCURRENT ASSETS	519,214	479,710
TOTAL ASSETS	\$ 6,299,777	\$ 6,341,653

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS

LIABILITIES AND EQUITY

March 31, 2013 and December 31, 2012

(Unaudited)

	March 31, 2013	December 31, 2012
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	\$ 115,135	\$ 126,768
Affiliated Companies	48,095	62,835
Short-term Debt – Nonaffiliated	-	2,603
Long-term Debt Due Within One Year – Nonaffiliated	3,250	3,250
Risk Management Liabilities	824	1,128
Customer Deposits	55,191	69,393
Accrued Taxes	69,720	31,532
Accrued Interest	18,712	43,950
Obligations Under Capital Leases	18,066	17,599
Regulatory Liability for Over-Recovered Fuel Costs	9,684	16,761
Other Current Liabilities	50,536	64,997
TOTAL CURRENT LIABILITIES	389,213	440,816
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,041,442	2,042,978
Deferred Income Taxes	1,104,268	1,075,551
Regulatory Liabilities and Deferred Investment Tax Credits	475,456	476,471
Asset Retirement Obligations	86,213	78,017
Employee Benefits and Pension Obligations	41,473	38,240
Obligations Under Capital Leases	111,820	114,161
Deferred Credits and Other Noncurrent Liabilities	48,552	53,946
TOTAL NONCURRENT LIABILITIES	3,909,224	3,879,364
TOTAL LIABILITIES	4,298,437	4,320,180
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
EQUITY		
Common Stock – Par Value – \$18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135,660	135,660
Paid-in Capital	674,606	674,606
Retained Earnings	1,208,014	1,228,806
Accumulated Other Comprehensive Income (Loss)	(17,327)	(17,860)
TOTAL COMMON SHAREHOLDER’S EQUITY	2,000,953	2,021,212
Noncontrolling Interest		
	387	261

TOTAL EQUITY	2,001,340	2,021,473
TOTAL LIABILITIES AND EQUITY	\$ 6,299,777	\$ 6,341,653

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Three Months Ended March 31, 2013 and 2012

(in thousands)

(Unaudited)

	Three Months Ended March 31,	
	2013	2012
OPERATING ACTIVITIES		
Net Income	\$ 11,548	\$ 36,395
Adjustments to Reconcile Net Income to Net Cash Flows from		
Operating Activities:		
Depreciation and Amortization	44,882	34,021
Deferred Income Taxes	25,583	82,540
Allowance for Equity Funds Used During Construction	(1,024)	(13,774)
Mark-to-Market of Risk Management Contracts	(293)	4,896
Property Taxes	(36,161)	(29,686)
Fuel Over/Under-Recovery, Net	(7,496)	(12,865)
Change in Other Noncurrent Assets	(1,245)	(4,400)
Change in Other Noncurrent Liabilities	4,953	(10,862)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	11,654	5,732
Fuel, Materials and Supplies	3,303	(183)
Accounts Payable	(12,658)	(7,399)
Customer Deposits	(14,202)	11,406
Accrued Taxes, Net	27,994	(42,370)
Accrued Interest	(25,447)	(20,801)
Other Current Assets	(638)	(8,557)
Other Current Liabilities	(13,551)	(11,533)
Net Cash Flows from Operating Activities	17,202	12,560
INVESTING ACTIVITIES		
Construction Expenditures	(97,786)	(130,344)
Change in Advances to Affiliates, Net	126,944	(27,651)
Other Investing Activities	(1,108)	(1,096)
Net Cash Flows from (Used for) Investing Activities	28,050	(159,091)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	-	336,664
Credit Facility Borrowings	17,091	20,701
Change in Advances from Affiliates, Net	-	(132,473)
Retirement of Long-term Debt – Nonaffiliated	(1,625)	(20,000)
Credit Facility Repayments	(19,694)	(37,717)
Principal Payments for Capital Lease Obligations	(4,225)	(3,726)
Dividends Paid on Common Stock	(31,250)	-
Dividends Paid on Common Stock – Nonaffiliated	(964)	(1,092)
Other Financing Activities	522	1,405
Net Cash Flows from (Used for) Financing Activities	(40,145)	163,762

Net Increase in Cash and Cash Equivalents	5,107	17,231
Cash and Cash Equivalents at Beginning of Period	2,036	801
Cash and Cash Equivalents at End of Period	\$ 7,143	\$ 18,032

SUPPLEMENTARY INFORMATION

Cash Paid for Interest, Net of Capitalized Amounts	\$ 55,626	\$ 39,581
Net Cash Paid (Received) for Income Taxes	(8,387)	1,168
Noncash Acquisitions Under Capital Leases	2,454	8,396
Construction Expenditures Included in Current Liabilities as of March 31,	40,990	95,570

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 133.

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

The condensed notes to SWEPCo's condensed financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to SWEPCo.

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The condensed notes to condensed financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

		Page Number
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Comprehensive Income	APCo, I&M, OPCo, PSO, SWEPCo	134
Rate Matters	APCo, I&M, OPCo, PSO, SWEPCo	141
Commitments, Guarantees and Contingencies	APCo, I&M, OPCo, PSO, SWEPCo	150
Disposition	OPCo	154
Benefit Plans	APCo, I&M, OPCo, PSO, SWEPCo	154
Business Segments	APCo, I&M, OPCo, PSO, SWEPCo	155
Derivatives and Hedging	APCo, I&M, OPCo, PSO, SWEPCo	156
Fair Value Measurements	APCo, I&M, OPCo, PSO, SWEPCo	168
Income Taxes	APCo, I&M, OPCo, PSO, SWEPCo	179
Financing Activities	APCo, I&M, OPCo, PSO, SWEPCo	180
Variable Interest Entities	APCo, I&M, OPCo, PSO, SWEPCo	183
Sustainable Cost Reductions	APCo, I&M, OPCo, PSO, SWEPCo	186

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed 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 interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods for each Registrant Subsidiary. Net income for the three months ended March 31, 2013 is not necessarily indicative of results that may be expected for the year ending December 31, 2013. The condensed financial statements are unaudited and should be read in conjunction with the audited 2012 financial statements and notes thereto, which are included in the Registrant Subsidiaries' Annual Reports on Form 10-K for the year ended December 31, 2012 as filed with the SEC on February 26, 2013.

2. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three months ended March 31, 2013. All amounts in the following tables are presented net of related income taxes.

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2013

	Commodity	Cash Flow Hedges Interest Rate and Foreign Currency (in thousands)	Pension and OPEB	Total
Balance in AOCI as of December 31, 2012	\$ (644)	\$ 2,077	\$ (31,331)	\$ (29,898)
Change in Fair Value Recognized in AOCI	794	(1)	-	793
Amounts Reclassified from AOCI	211	254	358	823
Net Current Period Other Comprehensive Income	1,005	253	358	1,616
Balance in AOCI as of March 31, 2013	\$ 361	\$ 2,330	\$ (30,973)	\$ (28,282)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2013

	Commodity	Cash Flow Hedges Interest Rate and Foreign Currency	Pension and OPEB	Total
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(in thousands)

Balance in AOCI as of December 31, 2012	\$	(446)	\$	(19,647)	\$	(8,790)	\$	(28,883)
Change in Fair Value Recognized in AOCI		532		2,249		-		2,781
Amounts Reclassified from AOCI		150		192		176		518
Net Current Period Other								
Comprehensive Income		682		2,441		176		3,299
Balance in AOCI as of March 31, 2013	\$	236	\$	(17,206)	\$	(8,614)	\$	(25,584)

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2013

	Commodity	Cash Flow Hedges Interest Rate and Foreign Currency (in thousands)	Pension and OPEB	Total
Balance in AOCI as of December 31, 2012	\$ (912)	\$ 8,095	\$ (172,908)	\$ (165,725)
Change in Fair Value Recognized in AOCI	1,102	-	-	1,102
Amounts Reclassified from AOCI	304	(340)	3,269	3,233
Net Current Period Other Comprehensive Income	1,406	(340)	3,269	4,335
Balance in AOCI as of March 31, 2013	\$ 494	\$ 7,755	\$ (169,639)	\$ (161,390)

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2013

	Commodity	Cash Flow Hedges Interest Rate and Foreign Currency (in thousands)	Total
Balance in AOCI as of December 31, 2012	\$ 21	\$ 6,460	\$ 6,481
Change in Fair Value Recognized in AOCI	36	-	36
Amounts Reclassified from AOCI	(13)	(190)	(203)
Net Current Period Other Comprehensive Income	23	(190)	(167)
Balance in AOCI as of March 31, 2013	\$ 44	\$ 6,270	\$ 6,314

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2013

	Commodity	Cash Flow Hedges Interest Rate and Foreign Currency (in thousands)	Pension and OPEB	Total
Balance in AOCI as of December 31, 2012	\$ 22	\$ (15,571)	\$ (2,311)	\$ (17,860)
Change in Fair Value Recognized in AOCI	44	-	-	44
Amounts Reclassified from AOCI	(15)	567	(63)	489
Net Current Period Other Comprehensive Income	29	567	(63)	533
Balance in AOCI as of March 31, 2013	\$ 51	\$ (15,004)	\$ (2,374)	\$ (17,327)

Reclassifications Out of Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three months ended March 31, 2013. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 for additional details.

APCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended March 31, 2013

		Amount of (Gain) Loss Reclassified from AOCI (in thousands)
Gains and Losses on Cash Flow Hedges		
Commodity:		
	Electric Generation, Transmission and Distribution Revenues	\$ 20
	Purchased Electricity for Resale	57
	Other Operation Expense	(11)
	Maintenance Expense	(16)
	Property, Plant and Equipment	(14)
	Regulatory Assets (a)	289
Subtotal - Commodity		325
Interest Rate and Foreign Currency:		
	Interest Expense	390
Subtotal - Interest Rate and Foreign Currency		390
Reclassifications from AOCI, before Income Tax (Expense) Credit		715
Income Tax (Expense) Credit		250
Reclassifications from AOCI, Net of Income Tax (Expense) Credit		465
Amortization of Pension and OPEB		
Prior Service Cost (Credit)		(1,282)
Actuarial (Gains)/Losses		1,833
Reclassifications from AOCI, before Income Tax (Expense) Credit		551
Income Tax (Expense) Credit		193
Reclassifications from AOCI, Net of Income Tax (Expense) Credit		358
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit		\$ 823

I&M

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended March 31, 2013

		Amount of (Gain) Loss Reclassified from AOCI (in thousands)
	Gains and Losses on Cash Flow Hedges	
Commodity:		
	Electric Generation, Transmission and Distribution Revenues	\$ 52
	Purchased Electricity for Resale	149
	Other Operation Expense	(7)
	Maintenance Expense	(7)
	Property, Plant and Equipment	(7)
	Regulatory Assets (a)	50
	Subtotal - Commodity	230
Interest Rate and Foreign Currency:		
	Interest Expense	296
	Subtotal - Interest Rate and Foreign Currency	296
	Reclassifications from AOCI, before Income Tax (Expense) Credit	526
	Income Tax (Expense) Credit	184
	Reclassifications from AOCI, Net of Income Tax (Expense) Credit	342
	Amortization of Pension and OPEB	
	Prior Service Cost (Credit)	(199)
	Actuarial (Gains)/Losses	469
	Reclassifications from AOCI, before Income Tax (Expense) Credit	270
	Income Tax (Expense) Credit	94
	Reclassifications from AOCI, Net of Income Tax (Expense) Credit	176
	Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	\$ 518

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OPCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended March 31, 2013

		Amount of (Gain) Loss Reclassified from AOCI (in thousands)
Gains and Losses on Cash Flow Hedges		
Commodity:		
	Electric Generation, Transmission and Distribution Revenues	\$ 134
	Purchased Electricity for Resale	382
	Other Operation Expense	(18)
	Maintenance Expense	(12)
	Property, Plant and Equipment	(19)
Subtotal - Commodity		467
Interest Rate and Foreign Currency:		
	Depreciation and Amortization Expense	2
	Interest Expense	(524)
Subtotal - Interest Rate and Foreign Currency		(522)
	Reclassifications from AOCI, before Income Tax (Expense) Credit	(55)
	Income Tax (Expense) Credit	(19)
	Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(36)
Amortization of Pension and OPEB		
	Prior Service Cost (Credit)	(1,468)
	Actuarial (Gains)/Losses	6,497
	Reclassifications from AOCI, before Income Tax (Expense) Credit	5,029
	Income Tax (Expense) Credit	1,760
	Reclassifications from AOCI, Net of Income Tax (Expense) Credit	3,269
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	\$	3,233

PSO

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended March 31, 2013

		Amount of (Gain) Loss Reclassified from AOCI (in thousands)
Gains and Losses on Cash Flow Hedges		
Commodity:		
	Other Operation Expense	\$ (9)
	Maintenance Expense	(4)
	Property, Plant and Equipment	(7)
Subtotal - Commodity		(20)

Interest Rate and Foreign Currency:

Interest Expense	(292)
Subtotal - Interest Rate and Foreign Currency	(292)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(312)
Income Tax (Expense) Credit	(109)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	\$ (203)

SWEPCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended March 31, 2013

	Amount of (Gain) Loss Reclassified from AOCI (in thousands)
Gains and Losses on Cash Flow Hedges	
Commodity:	
Other Operation Expense	\$ (10)
Maintenance Expense	(6)
Property, Plant and Equipment	(7)
Subtotal - Commodity	(23)
Interest Rate and Foreign Currency:	
Interest Expense	872
Subtotal - Interest Rate and Foreign Currency	872
Reclassifications from AOCI, before Income Tax (Expense) Credit	849
Income Tax (Expense) Credit	297
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	552
Amortization of Pension and OPEB	
Prior Service Cost (Credit)	(445)
Actuarial (Gains)/Losses	348
Reclassifications from AOCI, before Income Tax (Expense) Credit	(97)
Income Tax (Expense) Credit	(34)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(63)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	\$ 489

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

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The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2012. 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, 2012

Commodity Contracts	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Balance in AOCI as of December 31, 2011	\$ (1,309)	\$ (819)	\$ (1,748)	\$ (69)	\$ (62)
Changes in Fair Value Recognized in AOCI	(1,845)	(1,394)	(2,877)	139	132
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission, and Distribution Revenues	-	-	-	-	-
Purchased Electricity for Resale	219	567	1,486	-	-
Other Operation Expense	(2)	(2)	(5)	(2)	(2)
Maintenance Expense	(3)	(1)	(2)	-	(1)
Property, Plant and Equipment	(2)	(1)	(3)	(1)	(1)
Regulatory Assets (a)	825	142	-	-	-
Balance in AOCI as of March 31, 2012	\$ (2,117)	\$ (1,508)	\$ (3,149)	\$ 67	\$ 66

Interest Rate and Foreign Currency Contracts	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Balance in AOCI as of December 31, 2011	\$ 1,024	\$ (14,465)	\$ 9,454	\$ 7,218	\$ (15,462)
Changes in Fair Value Recognized in AOCI	-	2,996	-	-	(2,776)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Depreciation and Amortization Expense	-	-	1	-	-
Interest Expense	269	149	(341)	(189)	873
Balance in AOCI as of March 31, 2012	\$ 1,293	\$ (11,320)	\$ 9,114	\$ 7,029	\$ (17,365)

Total Contracts	APCo	I&M	OPCo	PSO	SWEPCo
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(in thousands)					
Balance in AOCI as of December 31, 2011	\$	(285)	\$	(15,284)	\$ 7,706 \$ 7,149 \$ (15,524)
Changes in Fair Value Recognized in AOCI		(1,845)		1,602	(2,877) 139 (2,644)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission, and Distribution Revenues		-		-	- - -
Purchased Electricity for Resale		219		567	1,486 - -
Other Operation Expense		(2)		(2)	(5) (2) (2)
Maintenance Expense		(3)		(1)	(2) - (1)
Depreciation and Amortization Expense		-		-	1 - -
Interest Expense		269		149	(341) (189) 873
Property, Plant and Equipment		(2)		(1)	(3) (1) (1)
Regulatory Assets (a)		825		142	- - -
Balance in AOCI as of March 31, 2012	\$	(824)	\$	(12,828)	\$ 5,965 \$ 7,096 \$ (17,299)

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

3. RATE MATTERS

As discussed in the 2012 Annual Report, the Registrant Subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2012 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 2013 and updates the 2012 Annual Report.

Regulatory Assets Not Yet Being Recovered

		APCo	
		March 31,	December 31,
		2013	2012
Noncurrent Regulatory Assets		(in thousands)	
Regulatory assets not yet being recovered pending future proceedings:			
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	\$	63,685	\$ 94,458
Virginia Environmental Rate Adjustment Clause		26,977	29,320
Mountaineer Carbon Capture and Storage			
Product Validation Facility		14,155	14,155
Dresden Plant Operating Costs		8,760	8,758
Medicare Part D		7,066	-
Deferred Wind Power Costs		5,112	5,143
Transmission Agreement Phase-In		3,129	2,992
Mountaineer Carbon Capture and Storage			
Commercial Scale Facility		1,287	1,287
Other Regulatory Assets Not Yet Being Recovered		2,646	1,447
Total Regulatory Assets Not Yet Being Recovered	\$	132,817	\$ 157,560

	I&M	
	March 31,	December 31,
	2013	2012
Noncurrent Regulatory Assets	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings:		
Regulatory Assets Currently Not Earning a Return		
Medicare Part D	\$ 12,242	\$ -
Litigation Settlement	-	11,098
Mountaineer Carbon Capture and Storage		
Commercial Scale Facility	-	1,380
Under-Recovered Capacity Costs	2,724	-
Other Regulatory Asset Not Yet Being Recovered	1,094	786
Total Regulatory Assets Not Yet Being Recovered	\$ 16,060	\$ 13,264

	OPCo	
	March 31,	December 31,
	2013	2012
Noncurrent Regulatory Assets	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings:		
Regulatory Assets Currently Earning a Return		
Economic Development Rider	\$ 13,373	\$ 13,213

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Regulatory Assets Currently Not Earning a Return

Storm Related Costs	59,758	61,828
Ormet Delayed Payment Arrangement	20,000	5,453
Medicare Part D	12,386	-
Other Regulatory Assets Not Yet Being Recovered	469	30
Total Regulatory Assets Not Yet Being Recovered	\$ 105,986	\$ 80,524

141

	PSO	
	March 31, 2013	December 31, 2012
Noncurrent Regulatory Assets	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings:		
Regulatory Assets Currently Not Earning a Return		
Medicare Part D	\$ 5,879	\$ -
Other Regulatory Assets Not Yet Being Recovered	703	423
Total Regulatory Assets Not Yet Being Recovered	\$ 6,582	\$ 423

		SWEPCo	
		March 31, 2013	December 31, 2012
Noncurrent Regulatory Assets		(in thousands)	
Regulatory assets not yet being recovered pending future proceedings:			
Regulatory Assets Currently Earning a Return			
Under-recovered Environmental Adjustment Clause	\$	20	\$ -
Regulatory Assets Currently Not Earning a Return			
Medicare Part D		6,400	-
Rate Case Expenses		5,758	4,517
Mountaineer Carbon Capture and Storage Commercial Scale Facility		2,295	2,295
Other Regulatory Assets Not Yet Being Recovered		2,276	2,188
Total Regulatory Assets Not Yet Being Recovered	\$	16,749	\$ 9,000

If these costs are ultimately determined not to be recoverable, it would reduce future net income and cash flows and impact financial condition.

OPCo Rate Matters

Ohio Electric Security Plan Filing

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018. The PUCO's March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers' Counsel and the IEU filed appeals of that order with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance. As of March 31, 2013, OPCo's net deferred fuel balance was \$501 million, excluding unrecognized equity carrying costs. A decision from the Supreme Court of Ohio is pending.

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off in 2010 and a subsequent refund to customers during 2011. The IEU and the Ohio Energy Group filed appeals with the Supreme Court of Ohio challenging the PUCO's SEET decision. In December 2012, the Supreme Court of Ohio issued an order which rejected all of the intervenors' challenges and affirmed the PUCO decision.

The 2009 SEET order gave consideration for a future commitment to invest \$20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend \$20 million on this solar project or another project by the end of 2013. Management continues to evaluate other investment alternatives.

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to \$62 million of 2010 earnings, which included off-system sales in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a \$23 million refund of 2010 earnings. OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO-ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's request to file the 2011 SEET one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo or in 2012 and 2013 for OPCo.

In August 2012, the PUCO issued an order in a separate proceeding which implemented a Phase-In Recovery Rider (PIRR) to recover deferred fuel costs in rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. In November 2012, OPCo filed an appeal at the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated 2009 – 2011 ESP order, which granted a weighted average cost of capital rate. The IEU and the Ohio Consumers' Counsel also filed appeals at the Supreme Court of Ohio in November 2012 arguing that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues and reduced carrying costs due to an accumulated deferred income tax credit. These appeals could reduce OPCo's net deferred fuel balance up to the total balance, which would reduce future net income and cash flows. A decision from the Supreme Court of Ohio is pending.

Management is unable to predict the outcome of the unresolved litigation discussed above. Depending on the rulings in these proceedings, it could reduce future net income and cash flows and impact financial condition.

June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that establishes base generation rates through May 2015.

As part of the ESP decision, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the SSO load with delivery beginning six months after the receipt of final orders in both the ESP and corporate separation cases and extending through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning June 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to \$188.88/MW day. The RPM price is approximately \$20/MW day through May 2013 then \$33/MW day through May 2014. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 PUCO ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is expected to provide approximately \$500 million over the ESP period and will be collected from customers at \$3.50/MWh through May 2014 and \$4.00/MWh for the period June 2014 through May

2015, with \$1.00/MWh applied to the recovery of deferred capacity costs. As of March 31, 2013, OPCo's incurred deferred capacity costs balance of \$116 million, including debt carrying costs, was recorded in Regulatory Assets on the balance sheet. In August 2012, the IEU filed an action with the Supreme Court of Ohio stating, among other things, that OPCo's collection of its capacity costs is illegal. In April 2013, the Supreme Court of Ohio dismissed the IEU's action. If OPCo is ultimately not permitted to fully collect its deferred capacity costs, it could reduce future net income and cash flows and impact financial condition.

In January and March 2013, the PUCO issued its Orders on Rehearing for the ESP which generally upheld its August 2012 order including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and costs would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket related to the competitive bidding process.

If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, it could reduce future net income and cash flows and impact financial condition.

Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets at net book value to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. In December 2012, the PUCO granted the IEU and the Ohio Consumers' Counsel requests for rehearing, which were denied by the PUCO in April 2013.

Also in October 2012, filings at the FERC were submitted related to corporate separation. If approved as filed, results of operations related to generation in Ohio will be largely determined by prevailing market conditions effective January 1, 2014. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters.

Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates. The SDRR seeks recovery of 2012 incremental storm distribution expenses over twelve months starting with the effective date of the SDRR as approved by the PUCO. OPCo requested approval of a weighted average cost of capital carrying charge, effective April 2013. As of March 31, 2013, OPCo recorded \$61 million in Regulatory Assets on the balance sheet related to 2012 storm damage. If OPCo is not ultimately permitted to recover these storm costs, it could reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

The PUCO selected an outside consultant to conduct an audit of OPCo's FAC for 2009. The outside consultant provided its audit report to the PUCO. In January 2012, the PUCO ordered that the remaining \$65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. OPCo recorded a \$30 million net favorable adjustment on the statement of income in the second quarter of 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of any future consultant recommendation regarding valuation of the coal reserve. If the PUCO ultimately determines that additional amounts should benefit ratepayers as a result of the consultant's review of the coal reserve valuation, it could reduce future net income and cash flows and impact financial condition.

In August 2012, intervenors filed an appeal with the Supreme Court of Ohio claiming the settlement credit ordered by the PUCO should have reflected the remaining gain not already flowed through the FAC with carrying charges, which, if ordered, would be \$35 million plus carrying charges. If the Supreme Court of Ohio ultimately determines that additional amounts should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audit reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes. As of March 31, 2013, the amount of OPCo's carrying costs that could potentially be reduced due to the accumulated income tax issue is estimated to be approximately \$35 million, including \$18 million of unrecognized equity carrying costs. These amounts include the

carrying costs exposure of the 2009 FAC audit, which has been appealed by an intervenor to the Supreme Court of Ohio. Decisions from the PUCO are pending. Management is unable to predict the outcome of these proceedings. If the PUCO orders result in a reduction to the FAC deferral, it could reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

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 filing and the FAC aspect of the ESP order was upheld by the Supreme Court of Ohio. The approval of the FAC as part of the ESP, together with the PUCO approval of the interim arrangement, provided the basis to record a regulatory asset for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, OPCo had \$64 million of deferred FAC costs related to the interim arrangement, excluding \$2 million of unrecognized equity carrying costs. In November 2009, OPCo requested that the PUCO approve recovery of the deferral under the interim agreement plus a weighted average cost of capital carrying charge. The deferral amount is included in OPCo's FAC phase-in deferral balance. In the 2009 – 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related regulatory asset and requested that the PUCO prevent OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request. The intervenors raised the issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement. This issue remains pending before the PUCO. If OPCo is not ultimately permitted to fully recover its requested deferrals under the interim arrangement, it could reduce future net income and cash flows and impact financial condition.

Special Rate Mechanism for Ormet

In October 2012, the PUCO issued an order approving a delayed payment plan for Ormet's October and November 2012 power billings totaling \$27 million to be paid in equal monthly installments over the period January 2014 to May 2015 without interest. In the event Ormet does not pay its \$27 million obligation, the PUCO permitted OPCo to recover the unpaid balance, up to \$20 million, in the economic development rider. To the extent unpaid amounts exceed \$20 million, it will reduce future net income and cash flows and impact financial condition.

In February 2013, Ormet filed Chapter 11 bankruptcy proceedings in the state of Delaware but is current on all payments due to OPCo. As of March 31, 2013, OPCo has a regulatory asset of \$20 million and a net receivable of \$6 million recorded related to the special rate mechanism for Ormet.

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. As of March 31, 2013, OPCo has collected \$24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions with the PUCO requesting all collected pre-construction costs be refunded to Ohio ratepayers with interest.

Management cannot predict the outcome of these proceedings concerning the Ohio IGCC plant or what effect, if any, these proceedings would have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

Turk Plant

SWEPCo constructed the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the facility. As of March 31, 2013, excluding costs attributable to its joint owners and a \$62 million provision for a Texas capital cost cap, SWEPCo has capitalized approximately \$1.7 billion of expenditures, including AFUDC and capitalized interest of \$328 million and related transmission costs of \$120 million.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant (approximately 20%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to the Arkansas Supreme Court's decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This portion of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the SPP market.

The PUCT approved 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 CO2 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 (TIEC) filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant should be revoked because the Turk Plant is unnecessary to serve retail customers. The Texas District Court and the Texas Court of Appeals affirmed the PUCT's order in all respects. In April 2012, SWEPCo and the TIEC filed petitions for review at the Supreme Court of Texas, which were denied in March 2013. In April 2013, SWEPCo and the TIEC filed motions for rehearing at the Supreme Court of Texas.

If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by \$83 million, primarily due to the Turk Plant, based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share (approximately 33%) of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. The filing also (a) increased depreciation expense due to the decrease in the average remaining life of the Welsh Plant to account for the change in the retirement date of the Welsh Plant Unit 2 from 2040 to 2016, (b) proposed increased vegetation management expenditures and (c) included a return on and of the Stall Unit as of December 2011 and associated operation and maintenance costs.

In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates.

In December 2012, several intervenors, including the PUCT staff, filed testimony that recommended an annual base rate increase between \$16 million and \$51 million based upon a return on common equity between 9% and 9.55%. In addition, two intervenors recommended that the Turk Plant be excluded from rate base. A decision from the PUCT is expected in the second quarter of 2013. If the PUCT does not approve full cost recovery of SWEPCo's assets, it could reduce future net income and cash flows and impact financial condition.

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and approved by the LPSC. The settlement increased Louisiana total rates by approximately \$2 million annually, effective March 2013, which consisted of an increase in base rates of approximately \$85 million annually offset by a decrease in fuel and other rates of approximately \$83 million annually. The March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to

refund based on the staff review of the cost of service and the prudence of the Turk Plant to be initiated by SWEPCo no later than May 2013. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover all non-fuel Turk Plant costs and a full weighted-average cost of capital return on the Turk Plant portion of rate base, effective January 2013. If the LPSC orders refunds based upon the staff review of the cost of service or prudence review of the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is \$408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at \$204 million. As of March 31, 2013, SWEPCo has incurred \$16 million related to this project, including AFUDC and company overheads. In March 2013, the APSC staff and the Arkansas Attorney General Office filed testimony that supported SWEPCo's petition. The Sierra Club continues to oppose SWEPCo's petition. Additional hearings were held in March 2013. If SWEPCo is not ultimately permitted to fully recover the net book value of the Flint Creek Plant and its incurred environmental costs in a future base rate proceeding, it could reduce future net income and cash flows and impact financial condition.

APCo Rate Matters

Plant Transfers

In October 2012, the AEP East Companies submitted several filings with the FERC regarding the transfer of certain generation plants within the AEP System. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters. In December 2012, APCo and WPCo filed requests with the Virginia SCC and the WVPSC for approval to transfer at net book value to APCo a two-thirds interest in Amos Plant Unit 3 and a one-half interest in the Mitchell Plant, comprising 1,647 MW of average annual generating capacity presently owned by OPCo. In April 2013, several intervenors filed testimony with the Virginia SCC and made recommendations relating to APCo's proposed asset transfers including the issuance of a Request for Proposal for APCo's resource needs. Hearings at the Virginia SCC and the WVPSC are scheduled for June 2013 and July 2013, respectively. If the transfers are approved, APCo and WPCo anticipate seeking cost recovery in upcoming rate proceedings. If APCo and WPCo are not ultimately permitted to recover their incurred costs, it could reduce future net income and cash flows and impact financial condition.

APCo IGCC Plant

As of March 31, 2013, 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 \$10 million applicable to its Virginia jurisdiction. If the costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Environmental Rate Adjustment Clause (Environmental RAC)

In March 2013, APCo filed with the Virginia SCC for approval of an environmental RAC to recover \$39 million related to 2012 and 2011 environmental compliance costs effective February 2014 over a one-year period. In March 2013, the environmental RAC surcharge expired related to the collection of 2009 and 2010 environmental compliance costs. APCo has deferred \$28 million as of March 31, 2013 for the Virginia portion of unrecovered environmental RAC costs incurred in 2012 and 2011, excluding \$11 million of unrecognized equity carrying costs. If the Virginia SCC were to disallow any portion of the environmental RAC, it could reduce future net income and cash flows.

Generation Rate Adjustment Clause (Generation RAC)

In March 2013, APCo filed with the Virginia SCC for an increase in its generation RAC revenues of \$12 million for a total of \$38 million annually to collect costs related to the Dresden Plant. The generation RAC increase is expected to be effective in March 2014. APCo has deferred \$4 million as of March 31, 2013 for the Virginia portion of unrecovered costs of the Dresden Plant, excluding \$3 million of unrecognized equity carrying costs. If the Virginia

SCC were to disallow any portion of the generation RAC, it could reduce future net income and cash flows.

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

In March 2012, West Virginia passed securitization legislation which allows the WVPSC to establish a regulatory framework for electric utilities to securitize certain deferred ENEC balances and other ENEC-related assets. In August 2012, APCo and WPCo filed a request with the WVPSC for a financing order to securitize a total of \$422 million related to the December 2011 under-recovered ENEC deferral balance including other ENEC-related assets of \$13 million and related future financing costs of \$7 million. Upon completion of the securitization, APCo would offset its current ENEC rates by an amount to recover the securitized balance over the securitization period. In March 2013, APCo, WPCo and intervenors filed a settlement agreement with the WVPSC which recommended the WVPSC authorize APCo to securitize \$376 million plus upfront financing costs. As of March 31, 2013, APCo's ENEC under-recovery balance of \$287 million, net of 2012 and 2013 over-recovery, was recorded in Regulatory Assets on the balance sheet, excluding \$4 million of unrecognized equity carrying costs and \$14 million of other ENEC-related assets.

In April 2013, APCo and WPCo filed to keep total rates unchanged with a portion of the ENEC to be specifically identified for the amount to be securitized in accordance with the proposed securitization settlement agreement. The remaining ENEC rate is proposed to include (a) the proposed transfer of certain generation facilities from OPCo and the APCo/WPCo merger, (b) construction surcharges and (c) ongoing ENEC costs. Decisions on these issues are pending with the WVPSC.

Virginia Storm Costs

In March 2013, due to the 2013 enactment of a Virginia law, APCo wrote off \$30 million of previously deferred 2012 Virginia storm costs. The change in law affected the test years to be included in APCo's next biennial Virginia base rate filing in March 2014 and the determination of how these costs are treated in the Virginia jurisdictional biennial earnings test for 2012 actual results and 2013 estimated results. The 2013 earnings component will be reviewed quarterly to determine if any storm costs can be deferred. If this quarterly test allows APCo to recover previously expensed storm costs, it could increase future net income and cash flows.

WPCo Merger with APCo

In December 2011, APCo and WPCo filed an application with the WVPSC requesting approval to merge WPCo into APCo. In December 2012, APCo and WPCo filed merger applications with the Virginia SCC and the FERC. A hearing at the Virginia SCC is scheduled for June 2013. No hearing date has been scheduled in West Virginia.

PSO Rate Matters

Oklahoma Environmental Compliance Plan

In September 2012, based upon an agreement with the Federal EPA, the State of Oklahoma and other parties, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES) Unit 4 in 2016 and additional environmental controls on NES Unit 3 to continue operations through 2026. The plan requested approval for (a) an estimated \$210 million of new environmental investment, excluding AFUDC and overheads of \$46 million, that will be incurred prior to 2016 at NES Unit 3, (b) accelerated recovery through 2026 of the net book value of NES Units 3 and 4 (combined net book value of the two units is \$232 million as of March 31, 2013), (c) an estimated \$83 million of new investment incurred through 2016 at various gas units and (d) a new 15-year purchase power agreement (PPA) with a nonaffiliated entity, effective in 2016, with cost recovery through a rider, including an annual earnings component of \$3 million. Although the environmental compliance plan does not seek to put any new costs into rates at this time, PSO anticipates seeking cost recovery when filing its next base rate case, which is expected to occur no later than 2014.

In January 2013, testimony filed by the OCC staff and the Oklahoma Office of the Attorney General (OOAG) recommended no earnings component on the PPA and to delay final decisions until 2020 on parts of the plan including cost recovery of the net book value of NES Unit 3 and any increases in fuel costs due to reductions in the output of energy from NES Unit 3 beginning in 2021. The testimony recommended that cost recovery could extend past 2026 on parts of the plan and recommended a \$175 million cost cap on NES Unit 3 environmental investment excluding AFUDC and overheads.

In March 2013, the OCC staff and the OOAG filed additional testimony revising the recommended cost cap on NES Unit 3 to \$210 million, excluding AFUDC and overheads, and recommended conditional approval of the planned NES Unit 3 retirement subject to OCC approval in 2020 provided the planned retirement is consistent with environmental rules at that time.

Also, an intervenor representing some of PSO's large industrial users opposed the majority of PSO's plan, including recommending no cost recovery of NES Units 3 and 4 book value amounts not recovered at the time of their retirement and no recovery of the PPA costs, including earnings on the PPA. In February 2013, the OCC staff requested a stay in this proceeding, which was granted by the OCC in March 2013. The stay will be in effect until the State Implementation Plan is approved by the Federal EPA, which could be as late as February 2014.

If PSO is ultimately not permitted to fully recover its net book value of NES Units 3 and 4 and other environmental compliance costs, it could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters

2011 Indiana Base Rate Case

In February 2013, the IURC issued an order that granted an \$85 million annual increase in base rates based upon a return on common equity of 10.2%. In a March 2013 order, the IURC approved an adjustment which increased the authorized annual increase in base rates from \$85 million to \$92 million. In March 2013, the Indiana Office of Utility Consumer Counselor (OUCC) filed a request for reconsideration with the IURC, which was denied. Also in March 2013, the OUCC filed an appeal of the order with the Indiana Court of Appeals. If the order is overturned by the Indiana Court of Appeals, it could reduce future net income and cash flows.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its extended licensed life. The estimated cost of the LCM Project is \$1.2 billion to be incurred through 2018, excluding AFUDC. As of March 31, 2013, I&M has incurred \$197 million related to the LCM Project, including AFUDC.

In April 2012, I&M filed a petition with the IURC for recovery of project costs, including interest, through a new rider. In August 2012, intervenors filed testimony in Indiana. The Indiana Michigan Power Company Industrial Group recommended that I&M recover \$229 million in a rider with the remaining costs to be requested in future base rate cases. The Indiana Office of Utility Consumer Counselor (OUCC) recommended a maximum of \$408 million of LCM Project costs be recovered in a rider, and a maximum of \$299 million for projects the OUCC believes are not related to the LCM Project to be recovered in future base rates. The IURC held a hearing in January 2013 and an order is pending.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project. In April 2013, an intervenor filed an appeal with the Michigan Court of Appeals objecting to the issuance of the CON as well as the amount of the CON related to the LCM Project. If I&M is not ultimately permitted to recover its LCM Project costs, it could reduce future net income and cash flows and impact financial condition.

Rockport Plant Clean Coal Technology Project (CCT Project)

In April 2013, I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit both of its units at the Rockport Plant with a Dry Sorbent Injection system. The

estimated cost of the CCT Project is \$285 million, excluding AFUDC, of which I&M's ownership share is \$142 million. The application requested deferral treatment of any unrecovered carrying costs incurred during construction and incremental post in-service depreciation expense and operation and maintenance expenses until such costs are recognized and recovered in a rider. If I&M receives approval of a CPCN, I&M will file for cost recovery associated with the retrofit using the Clean Coal Technology Rider recovery mechanism. As of March 31, 2013, I&M has incurred \$31 million related to the CCT Project, including AFUDC. If I&M is not ultimately permitted to recover its incurred costs, it could reduce future net income and cash flows.

FERC Rate Matters

Corporate Separation and Termination of Interconnection Agreement – Affecting APCo, I&M and OPGCo

In October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPGCo's generation assets from its distribution and transmission operations. The filings requested approval to transfer at net book value approximately 9,200 MW of OPGCo-owned generation assets to a new wholly-owned company, AEPGenCo. The AEP East Companies also requested FERC approval to transfer at net book value OPGCo's current two-thirds ownership (867 MW) in Amos Plant Unit 3 to APCo and transfer at net book value OPGCo's Mitchell Plant to APCo and KPGCo in equal one-half interests (780 MW each). These transfers are proposed to be effective no later than December 31, 2013. Additionally, the AEP East Companies asked the FERC, effective January 1, 2014, to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPGCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, APCo and I&M would be individually responsible for planning their respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo and I&M to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities. Intervenors have opposed several of these filings. The AEP East Companies responded to intervenor comments and filed a revised PCA at the FERC in March 2013. The revised PCA included certain clarifying wording changes that have been agreed upon by intervenors. A decision from the FERC is expected in the second quarter of 2013. Similar asset transfer filings have been made at the Virginia SCC and the WVPSC. See the "Plant Transfers" section of APCo Rate Matters.

If APCo and/or I&M experience decreases in revenues or increases in expenses as a result of changes to their relationship with affiliates 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.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The Registrant Subsidiaries are subject to certain claims and legal actions arising in their ordinary course of business. In addition, their business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation 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 effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2012 Annual Report should be read in conjunction with this report.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit – Affecting APCo, I&M, OPGCo and SWEPCo

Certain Registrant Subsidiaries enter into standby letters of credit with third parties. These letters of credit are issued in the ordinary course of business and cover items such as insurance programs, security deposits and debt service reserves.

AEP has two credit facilities totaling \$3.5 billion, under which up to \$1.2 billion may be issued as letters of credit. As of March 31, 2013, the maximum future payments for letters of credit issued under the credit facilities were as

follows:

Company	Amount (in thousands)	Maturity
I&M	\$ 150	March 2014
OPCo	2,102	June 2013
SWEPCo	4,448	March 2014

150

The Registrant Subsidiaries have \$357 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for \$361 million as follows:

Company	Pollution Control Bonds (in thousands)	Bilateral Letters of Credit	Maturity of Bilateral Letters of Credit
APCo	\$ 229,650	\$ 232,293	March 2014 to March 2015
I&M	77,000	77,886	March 2015
OPCo	50,000	50,575	July 2014

Guarantees of Third-Party Obligations – Affecting 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 \$115 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. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, it is estimated the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately \$58 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of March 31, 2013, SWEPCo has collected approximately \$60 million through a rider for final mine closure and reclamation costs, of which \$11 million is recorded in Deferred Credits and Other Noncurrent Liabilities and \$49 million is recorded in Asset Retirement Obligations on SWEPCo's condensed 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 – Affecting APCo, I&M, OPCo, PSO and SWEPCo

Contracts

The Registrant Subsidiaries enter into certain 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, exposure generally does not exceed the sale price. As of March 31, 2013, there were no material liabilities recorded for any indemnifications.

APCo, I&M and OPCo are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East Companies related to power purchase and sale activity pursuant to the SIA. PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of PSO and SWEPCo related to power purchase and sale activity pursuant to the SIA.

Master Lease Agreements

The Registrant Subsidiaries lease certain equipment under master lease agreements. Under the 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, the Registrant Subsidiaries are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of March 31, 2013, the maximum potential loss by Registrant Subsidiary for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was as follows:

Company	Maximum Potential Loss (in thousands)
APCo	\$ 3,441
I&M	2,469
OPCo	4,245
PSO	1,180
SWEPCo	2,414

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 assignments are 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 \$14 million and \$15 million for I&M and SWEPCo, respectively, for the remaining railcars as of March 31, 2013.

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. The maximum potential losses related to the guarantee are approximately \$12 million and \$13 million for I&M and SWEPCo, respectively, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair value would produce a sufficient sales price to avoid any loss.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance Claims – Affecting APCo, I&M, OPCo, PSO and SWEPCo

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. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. In March 2012, the court granted the defendants' motion for dismissal on several grounds, including the doctrine of collateral estoppel and the applicable statute of limitations. Plaintiffs appealed the decision to the Fifth Circuit Court of Appeals. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims – Affecting APCo, I&M, OPCo, PSO and SWEPCo

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 CO₂ 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. In September 2012, the Ninth Circuit Court of Appeals affirmed the trial court's decision, holding that the CAA displaced Kivalina's claims for damages. Plaintiffs filed seeking further review in the U.S. Supreme Court. Management believes the action is without merit and will continue to defend against the claims. Management is 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 – Affecting I&M

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, the generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. The Registrant Subsidiaries 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 reserve is approximately \$10 million. As the remediation work is completed, I&M's cost may change 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. Management cannot predict the amount of additional cost, if any.

NUCLEAR CONTINGENCIES – AFFECTING I&M

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission. I&M has 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.

Nuclear Incident Insurance

Prior to April 2013, I&M carried insurance coverage for a nuclear or nonnuclear incident at the Cook Plant for property damage, decommissioning and decontamination in the amount of \$2.8 billion. Effective April 2013, insurance coverage for a nonnuclear incident at the Cook Plant was reduced to \$1.7 billion. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

5. DISPOSITION

2013

Conesville Coal Preparation Plant – Affecting OPCo

In April 2013, OPCo closed on the sale of its Conesville Coal Preparation Plant. This sale did not have a significant impact on OPCo's financial statements.

6. BENEFIT PLANS

The Registrant Subsidiaries participate in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. Substantially all employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. The Registrant Subsidiaries also participate in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost (credit) by Registrant Subsidiary for the plans for the three months ended March 31, 2013 and 2012:

APCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2013	2012	2013	2012
	(in thousands)			
Service Cost	\$ 1,543	\$ 1,891	\$ 641	\$ 1,347
Interest Cost	6,916	7,553	3,363	4,616
Expected Return on Plan Assets	(9,260)	(10,486)	(4,536)	(4,188)
Amortization of Transition Obligation	-	-	-	200
Amortization of Prior Service Cost (Credit)	49	119	(2,512)	(716)
Amortization of Net Actuarial Loss	6,256	5,085	3,062	2,631
Net Periodic Benefit Cost	\$ 5,504	\$ 4,162	\$ 18	\$ 3,890

I&M

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2013	2012	2013	2012
	(in thousands)			
Service Cost	\$ 2,184	\$ 2,477	\$ 805	\$ 1,655
Interest Cost	6,025	6,561	2,055	3,196
Expected Return on Plan Assets	(8,207)	(9,391)	(3,296)	(3,211)
	-	-	-	33

Amortization of Transition
Obligation

Amortization of Prior Service Cost (Credit)	49	102	(2,355)	(596)
Amortization of Net Actuarial Loss	5,422	4,392	1,882	1,762
Net Periodic Benefit Cost (Credit)	\$ 5,473	\$ 4,141	\$ (909)	\$ 2,839

OPCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2013	2012	2013	2012
	(in thousands)			
Service Cost	\$ 2,372	\$ 2,751	\$ 1,300	\$ 2,187
Interest Cost	10,292	11,298	4,447	6,047
Expected Return on Plan Assets	(15,141)	(17,100)	(6,238)	(5,639)
Amortization of Transition Obligation	-	-	-	26
Amortization of Prior Service Cost (Credit)	71	186	(3,231)	(968)
Amortization of Net Actuarial Loss	9,309	7,610	4,041	3,417
Net Periodic Benefit Cost	\$ 6,903	\$ 4,745	\$ 319	\$ 5,070

PSO

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2013	2012	2013	2012
	(in thousands)			
Service Cost	\$ 1,391	\$ 1,488	\$ 343	\$ 709
Interest Cost	2,748	3,075	948	1,449
Expected Return on Plan Assets	(3,918)	(4,504)	(1,522)	(1,480)
Amortization of Prior Service Cost (Credit)	74	(237)	(1,072)	(270)
Amortization of Net Actuarial Loss	2,461	2,052	869	797
Net Periodic Benefit Cost (Credit)	\$ 2,756	\$ 1,874	\$ (434)	\$ 1,205

SWEPCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2013	2012	2013	2012
	(in thousands)			
Service Cost	\$ 1,753	\$ 1,775	\$ 423	\$ 831
Interest Cost	2,864	3,134	1,075	1,668
Expected Return on Plan Assets	(4,127)	(4,717)	(1,720)	(1,699)
Amortization of Prior Service Cost (Credit)	87	(198)	(1,288)	(233)
Amortization of Net Actuarial Loss	2,553	2,083	982	915
	\$ 3,130	\$ 2,077	\$ (528)	\$ 1,482

Net Periodic Benefit Cost
(Credit)

7. BUSINESS SEGMENTS

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business. The Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

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8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

The Registrant Subsidiaries are exposed to certain market risks as major power producers and marketers 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 the Registrant Subsidiaries due to changes in the underlying market prices or rates. AEPSC, on behalf of the Registrant Subsidiaries, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of the Registrant Subsidiaries. To accomplish these objectives, AEPSC, on behalf of the Registrant Subsidiaries, primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. 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.

AEPSC, on behalf of the Registrant Subsidiaries, enters 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 the energy business. AEPSC, on behalf of the Registrant Subsidiaries, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with the Registrant Subsidiaries’ commodity portfolio. For disclosure purposes, such risks are grouped as “Commodity,” as these risks are related to energy risk management activities. AEPSC, on behalf of the Registrant Subsidiaries, also engages 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 established risk management policies as approved by the Finance Committee of AEP’s Board of Directors.

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The following tables represent the gross notional volume of the Registrant Subsidiaries' outstanding derivative contracts as of March 31, 2013 and December 31, 2012:

Notional Volume of Derivative Instruments
March 31, 2013

Primary Risk Exposure	Unit of Measure	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Commodity:						
Power	MWhs	62,679	43,390	88,625	8	9
Coal	Tons	932	2,175	2,213	1,489	789
Natural Gas	MMBtus	8,213	5,676	11,613	-	-
Heating Oil and Gasoline	Gallons	1,177	580	1,386	589	724
Interest Rate	USD	\$ 22,108	\$ 15,278	\$ 31,259	\$ -	\$ -
Interest Rate and Foreign Currency	USD	\$ -	\$ -	\$ -	\$ -	\$ -

Notional Volume of Derivative Instruments
December 31, 2012

Primary Risk Exposure	Unit of Measure	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Commodity:						
Power	MWhs	94,059	64,791	132,188	-	-
Coal	Tons	1,401	2,711	3,033	1,980	1,312
Natural Gas	MMBtus	10,077	6,922	14,163	-	-
Heating Oil and Gasoline	Gallons	1,050	532	1,260	616	585
Interest Rate	USD	\$ 24,146	\$ 16,584	\$ 33,934	\$ -	\$ -
Interest Rate and Foreign Currency	USD	\$ -	\$ 200,000	\$ -	\$ -	\$ -

Fair Value Hedging Strategies

AEPC, on behalf of the Registrant Subsidiaries, enters 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 an exposure to interest rate risk by converting a portion of 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

AEPC, on behalf of the Registrant Subsidiaries, enters into and designates 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. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions

to protect profit margins for a portion of future electricity sales and fuel or energy purchases. The Registrant Subsidiaries do not hedge all commodity price risk.

The Registrant Subsidiaries' vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of the Registrant Subsidiaries, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activities as "Commodity." The Registrant Subsidiaries do not hedge all fuel price risk.

AEPSC, on behalf of the Registrant Subsidiaries, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of the Registrant Subsidiaries, also enters into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The forecasted 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. The Registrant Subsidiaries do not hedge all interest rate exposure.

At times, the Registrant Subsidiaries are exposed to foreign currency exchange rate risks primarily when some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of the Registrant Subsidiaries, 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. The Registrant Subsidiaries do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the condensed 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 the derivative instruments, the Registrant Subsidiaries 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 management's 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 risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," the Registrant Subsidiaries reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrant Subsidiaries are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2013 and December 31, 2012 condensed balance sheets, the Registrant Subsidiaries netted cash collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

	March 31, 2013		December 31, 2012	
	Cash Collateral Received Netted Against	Cash Collateral Paid Netted Against	Cash Collateral Received Netted Against	Cash Collateral Paid Netted Against Risk Management
Company	Risk Management Assets	Risk Management Liabilities	Risk Management Assets	Liabilities
(in thousands)				

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APCo	\$	1,837	\$	4,888	\$	1,262	\$	11,029
I&M		1,270		3,378		867		7,576
OPCo		2,598		6,912		1,774		15,500
PSO		-		1		-		-
SWEPCo		-		2		-		-

The following tables represent the gross fair value of the Registrant Subsidiaries' derivative activity on the condensed balance sheets as of March 31, 2013 and December 31, 2012:

APCo

Fair Value of Derivative Instruments
March 31, 2013

Balance Sheet Location	Risk Management			Gross Amounts of Risk		Net Amounts of Assets/Liabilities Presented in the	
	Contracts	Hedging Contracts	Interest Rate and Foreign Currency	Management Assets/ Liabilities Recognized	Offset in the Statement of Financial Position (b)	Statement of Financial Position (c)	
	(a)	(a)	(a)	(in thousands)			
Current Risk Management Assets	\$ 86,551	\$ 1,189	\$ -	\$ 87,740	\$ (64,613)	\$ 23,127	
Long-term Risk Management Assets	39,728	131	-	39,859	(15,843)	24,016	
Total Assets	126,279	1,320	-	127,599	(80,456)	47,143	
Current Risk Management Liabilities	78,306	651	-	78,957	(66,909)	12,048	
Long-term Risk Management Liabilities	29,230	132	-	29,362	(16,598)	12,764	
Total Liabilities	107,536	783	-	108,319	(83,507)	24,812	
Total MTM Derivative Contract Net Assets (Liabilities)	\$ 18,743	\$ 537	\$ -	\$ 19,280	\$ 3,051	\$ 22,331	

APCo

Fair Value of Derivative Instruments
December 31, 2012

Risk Management	Gross Amounts of Risk		Net Amounts of Assets/Liabilities Presented in the	
	Contracts	Hedging Contracts	Management Assets/ Liabilities	Offset in the Statement of Financial Position
		Interest Rate and Foreign		

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Balance Sheet Location	Commodity (a)	Commodity (a)	Currency (a)	Recognized (in thousands)	Position (b)	Position (c)
Current Risk						
Management Assets	\$ 127,645	\$ 338	\$ -	\$ 127,983	\$ (97,023)	\$ 30,960
Long-term Risk						
Management Assets	60,498	215	-	60,713	(26,353)	34,360
Total Assets	188,143	553	-	188,696	(123,376)	65,320
Current Risk						
Management Liabilities	119,430	1,182	-	120,612	(103,914)	16,698
Long-term Risk						
Management Liabilities	47,281	424	-	47,705	(29,229)	18,476
Total Liabilities	166,711	1,606	-	168,317	(133,143)	35,174
Total MTM Derivative Contract Net						
Assets						
(Liabilities)	\$ 21,432	\$ (1,053)	\$ -	\$ 20,379	\$ 9,767	\$ 30,146

I&M

Fair Value of Derivative Instruments
March 31, 2013

Balance Sheet Location	Risk Management			Gross Amounts of Risk		Gross Amounts Offset in the Statement of Financial	Net Amounts of Assets/Liabilities Presented in the Statement of Financial
	Contracts	Hedging	Contracts	Management			
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Assets/Liabilities Recognized	Position (b)		Position (c)
(in thousands)							
Current Risk Management Assets	\$ 61,736	\$ 800	\$ -	\$ 62,536	\$ (44,450)		\$ 18,086
Long-term Risk Management Assets	27,454	89	-	27,543	(10,948)		16,595
Total Assets	89,190	889	-	90,079	(55,398)		34,681
Current Risk Management Liabilities	54,278	450	-	54,728	(46,037)		8,691
Long-term Risk Management Liabilities	20,876	90	-	20,966	(11,469)		9,497
Total Liabilities	75,154	540	-	75,694	(57,506)		18,188
Total MTM Derivative Contract Net Assets (Liabilities)	\$ 14,036	\$ 349	\$ -	\$ 14,385	\$ 2,108		\$ 16,493

I&M

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management			Gross Amounts of Risk		Gross Amounts Offset in the Statement of Financial	Net Amounts of Assets/Liabilities Presented in the Statement of Financial
	Contracts	Hedging	Contracts	Management			
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Assets/Liabilities Recognized	Position (b)		Position (c)
(in thousands)							
Current Risk Management Assets	\$ 93,268	\$ 220	\$ -	\$ 93,488	\$ (66,514)		\$ 26,974

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Long-term Risk							
Management Assets	41,553	148	-	41,701	(18,132)	23,569	
Total Assets	134,821	368	-	135,189	(84,646)	50,543	
Current Risk							
Management Liabilities	82,433	807	19,524	102,764	(71,247)	31,517	
Long-term Risk							
Management Liabilities	33,714	292	-	34,006	(20,108)	13,898	
Total Liabilities	116,147	1,099	19,524	136,770	(91,355)	45,415	
Total MTM Derivative							
Contract Net							
Assets							
(Liabilities)	\$ 18,674	\$ (731)	\$ (19,524)	\$ (1,581)	\$ 6,709	\$ 5,128	

OPCo

Fair Value of Derivative Instruments
March 31, 2013

Balance Sheet Location	Risk Management			Gross Amounts of Risk	Gross Amounts	Net Amounts of Assets/Liabilities Presented in the
	Contracts	Hedging Contracts	Interest Rate and Foreign Currency	Management	Offset in the	Statement of
	Commodity (a)	Commodity (a)	(a)	Assets/Liabilities Recognized	Financial Position (b)	Financial Position (c)
(in thousands)						
Current Risk Management Assets	\$ 126,082	\$ 1,657	\$ -	\$ 127,739	\$ (94,258)	\$ 33,481
Long-term Risk Management Assets	56,173	184	-	56,357	(22,401)	33,956
Total Assets	182,255	1,841	-	184,096	(116,659)	67,437
Current Risk Management Liabilities	114,172	919	-	115,091	(97,505)	17,586
Long-term Risk Management Liabilities	41,330	186	-	41,516	(23,468)	18,048
Total Liabilities	155,502	1,105	-	156,607	(120,973)	35,634
Total MTM Derivative Contract Net Assets (Liabilities)	\$ 26,753	\$ 736	\$ -	\$ 27,489	\$ 4,314	\$ 31,803

OPCo

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management			Gross Amounts of Risk	Gross Amounts	Net Amounts of Assets/Liabilities Presented in the
	Contracts	Hedging Contracts	Interest Rate and Foreign Currency	Management	Offset in the	Statement of
	Commodity (a)	Commodity (a)	(a)	Assets/Liabilities Recognized	Financial Position (b)	Financial Position (c)
(in thousands)						

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Current Risk							
Management Assets	\$	183,064	\$	464	\$	-	\$ 183,528 \$ (139,215) \$ 44,313
Long-term Risk							
Management Assets		85,023		303		-	85,326 (37,038) 48,288
Total Assets		268,087		767		-	268,854 (176,253) 92,601

Current Risk							
Management Liabilities		171,397		1,658		-	173,055 (148,900) 24,155
Long-term Risk							
Management Liabilities		66,448		596		-	67,044 (41,079) 25,965
Total Liabilities		237,845		2,254		-	240,099 (189,979) 50,120

Total MTM Derivative							
Contract Net							
Assets							
(Liabilities)	\$	30,242	\$	(1,487)	\$	-	\$ 28,755 \$ 13,726 \$ 42,481

PSO

Fair Value of Derivative Instruments
March 31, 2013

Balance Sheet Location	Risk Management		Hedging Contracts		Gross Amounts of Risk	Gross Amounts Offset in the Statement of	Net Amounts of Assets/Liabilities Presented in the
	Contracts	Commodity	Commodity	Interest Rate and Foreign Currency	Management Assets/ Liabilities Recognized	the Statement of Financial Position (b)	Statement of Financial Position (c)
	(a)	(a)	(a)	(a)	(in thousands)		
Current Risk Management Assets	\$ 1,723	\$ 57	\$ -	\$ -	\$ 1,780	\$ (1,068)	\$ 712
Long-term Risk Management Assets	-	4	-	-	4	-	4
Total Assets	1,723	61	-	-	1,784	(1,068)	716
Current Risk Management Liabilities	4,074	-	-	-	4,074	(1,068)	3,006
Long-term Risk Management Liabilities	-	1	-	-	1	(1)	-
Total Liabilities	4,074	1	-	-	4,075	(1,069)	3,006
Total MTM Derivative Contract Net							
Assets (Liabilities)	\$ (2,351)	\$ 60	\$ -	\$ -	\$ (2,291)	\$ 1	\$ (2,290)

PSO

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management		Hedging Contracts		Gross Amounts of Risk	Gross Amounts Offset in the Statement of	Net Amounts of Assets/Liabilities Presented in the
	Contracts	Commodity	Commodity	Interest Rate and Foreign Currency	Management Assets/ Liabilities Recognized	the Statement of Financial Position (b)	Statement of Financial Position (c)
	(a)	(a)	(a)	(a)	(in thousands)		

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Current Risk Management										
Assets	\$	1,657	\$	42	\$	-	\$	1,699	\$ (1,190) \$	509
Long-term Risk										
Management Assets		-		-		-		-	31	31
Total Assets		1,657		42		-		1,699	(1,159)	540
Current Risk Management										
Liabilities		7,021		17		-		7,038	(1,190)	5,848
Long-term Risk										
Management Liabilities		-		-		-		-	31	31
Total Liabilities		7,021		17		-		7,038	(1,159)	5,879
Total MTM Derivative										
Contract Net										
Assets (Liabilities)	\$	(5,364)	\$	25	\$	-	\$	(5,339)	\$ - \$	(5,339)

SWEPCo

Fair Value of Derivative Instruments
March 31, 2013

Balance Sheet Location	Risk Management		Hedging Contracts		Gross Amounts of Risk	Gross Amounts Offset in the Statement of	Net Amounts of Assets/Liabilities Presented in the Statement of
	Contracts		Interest Rate and Foreign Currency		Management Assets/Liabilities	Financial	Financial
	Commodity (a)	Commodity (a)	(a)		Recognized	Position (b)	Position (c)
(in thousands)							
Current Risk Management Assets	\$ 2,765	\$ 69	\$ -		\$ 2,834	\$ (2,107)	\$ 727
Long-term Risk Management Assets	-	4	-		4	-	4
Total Assets	2,765	73	-		2,838	(2,107)	731
Current Risk Management Liabilities	2,931	-	-		2,931	(2,107)	824
Long-term Risk Management Liabilities	-	2	-		2	(2)	-
Total Liabilities	2,931	2	-		2,933	(2,109)	824
Total MTM Derivative Contract Net							
Assets (Liabilities)	\$ (166)	\$ 71	\$ -		\$ (95)	\$ 2	\$ (93)

SWEPCo

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management		Hedging Contracts		Gross Amounts of Risk	Gross Amounts Offset in the Statement of	Net Amounts of Assets/Liabilities Presented in the Statement of
	Contracts		Interest Rate and Foreign Currency		Management Assets/Liabilities	Financial	Financial
	Commodity (a)	Commodity (a)	(a)		Recognized	Position (b)	Position (c)

(in thousands)

Current Risk Management Assets	\$	2,804	\$	41	\$	-	\$	2,845	\$	(2,150)	\$	695
Long-term Risk Management Assets		-		-		-		-		-		-
Total Assets		2,804		41		-		2,845		(2,150)		695
Current Risk Management Liabilities		3,261		17		-		3,278		(2,150)		1,128
Long-term Risk Management Liabilities		-		-		-		-		-		-
Total Liabilities		3,261		17		-		3,278		(2,150)		1,128
Total MTM Derivative Contract Net												
Assets (Liabilities)	\$	(457)	\$	24	\$	-	\$	(433)	\$	-	\$	(433)

- (a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed 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."
- (c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The tables below present the Registrant Subsidiaries' activity of derivative risk management contracts for the three months ended March 31, 2013 and 2012:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2013

Location of Gain (Loss)	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Electric Generation, Transmission and					
Distribution Revenues	\$ 679	\$ 4,947	\$ 1,714	\$ 47	\$ 28
Sales to AEP Affiliates	-	-	-	-	-
Fuel and Other Consumables Used for					
Electric Generation	-	-	-	-	-
Regulatory Assets (a)	-	486	(1,205)	2,010	271
Regulatory Liabilities (a)	(466)	(5,182)	-	1	96
Total Gain (Loss) on Risk Management Contracts	\$ 213	\$ 251	\$ 509	\$ 2,058	\$ 395

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2012

Location of Gain (Loss)	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Electric Generation, Transmission and					
Distribution Revenues	\$ (327)	\$ 2,813	\$ 8,493	\$ (5)	\$ (51)
Sales to AEP Affiliates	-	-	-	-	-
Fuel and Other Consumables Used for					
Electric Generation	-	-	-	-	-
Regulatory Assets (a)	(3,481)	(3,110)	(3,131)	(5,201)	(6,727)
Regulatory Liabilities (a)	6,409	6,726	-	27	21
Total Gain (Loss) on Risk Management Contracts	\$ 2,601	\$ 6,429	\$ 5,362	\$ (5,179)	\$ (6,757)

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

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 statements of income on an accrual basis.

The 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, management designates 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 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 statements of income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses in regulated jurisdictions (APCo, I&M, PSO and SWEPCo) 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.

The Registrant Subsidiaries 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 the condensed statements of income. During the three months ended March 31, 2013 and 2012, the Registrant Subsidiaries did not designate any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrant Subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets until the period the hedged item affects Net Income. The Registrant Subsidiaries 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 and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on the condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on the condensed balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2013 and 2012, APCo, I&M and OPCo designated power, coal and natural gas derivatives as cash flow hedges.

The Registrant Subsidiaries reclassify gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. During the three months ended March 31, 2013 and 2012, the Registrant Subsidiaries designated heating oil and gasoline derivatives as cash flow hedges.

The Registrant Subsidiaries reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets into Interest Expense on the condensed statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2013, I&M designated interest rate derivatives as cash flow hedges. During the three months ended March 31, 2012, I&M and SWEPCo designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets into Depreciation and Amortization expense on the condensed 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, 2013, the Registrant Subsidiaries did not designate any foreign currency derivatives as cash flow hedges. During the three months ended March 31, 2012, SWEPCo designated foreign currency derivatives as cash flow hedges.

During the three months ended March 31, 2013 and 2012, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2013 and 2012, see Note 2.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets as of March 31, 2013 and December 31, 2012 were:

Impact of Cash Flow Hedges on the Registrant Subsidiaries'
Condensed Balance Sheets
March 31, 2013

Company	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
			(in thousands)			
APCo	\$ 987	\$ -	\$ 450	\$ -	\$ 361	\$ 2,330
I&M	660	-	311	-	236	(17,206)
OPCo	1,372	-	636	-	494	7,755
PSO	61	-	1	-	44	6,270
SWEPCo	73	-	2	-	51	(15,004)

Expected to be Reclassified
to
Net Income During the
Next
Twelve Months

Company	Interest Rate and Foreign Currency		Maximum Term for Exposure to Variability of Future Cash Flows (in months)
	Commodity	Currency	
	(in thousands)		
APCo	\$ 363	\$ (1,013)	21
I&M	235	(1,640)	21
OPCo	495	1,359	21
PSO	41	759	21
SWEPCo	49	(2,267)	21

Impact of Cash Flow Hedges on the Registrant Subsidiaries'
Condensed Balance Sheets
December 31, 2012

Company	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
			(in thousands)			

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APCo	\$	302	\$	-	\$	1,355	\$	-	\$	(644)	\$	2,077
I&M		200		-		931		19,524		(446)		(19,647)
OPCo		416		-		1,903		-		(912)		8,095
PSO		25		-		-		-		21		6,460
SWEPCo		24		-		-		-		22		(15,571)

Expected to be
Reclassified to
Net Income During the
Next
Twelve Months

Company	Commodity	Interest Rate and Foreign Currency (in thousands)
APCo	\$ (507)	\$ (1,013)
I&M	(355)	(1,600)
OPCo	(720)	1,359
PSO	21	759
SWEPCo	22	(2,267)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the condensed balance sheets.

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

AEPSC, on behalf of the Registrant Subsidiaries, limits credit risk in their 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. AEPSC, on behalf of the Registrant Subsidiaries, uses 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.

When AEPSC, on behalf of the Registrant Subsidiaries, uses standardized master agreements, AEPSC 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 the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's 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 competitive retail auction loads, the Registrant Subsidiaries are obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. The Registrant Subsidiaries have not experienced a downgrade below investment grade. The following tables represent: (a) the Registrant Subsidiaries' fair values of such derivative contracts, (b) the amount of collateral the Registrant Subsidiaries would have been required to post for all derivative and non-derivative contracts if credit ratings of the Registrant Subsidiaries had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of March 31, 2013 and December 31, 2012:

Company	Liabilities for Derivative Contracts with Credit Downgrade Triggers	March 31, 2013	
		Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post (in thousands)	Amount Attributable to RTO and ISO Activities
APCo	\$ 1,377	\$ 3,635	\$ 3,531
I&M	951	2,512	2,440
OPCo	1,946	5,140	4,992
PSO	-	625	562
SWEPCo	-	736	662

Company	Liabilities for Derivative Contracts with Credit Downgrade Triggers	December 31, 2012	
		Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities

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(in thousands)

APCo	\$	2,159	\$	3,699	\$	3,510
I&M		1,483		2,540		2,411
OPCo		3,034		5,198		4,933
PSO		-		1,509		1,429
SWEPCo		-		1,778		1,683

In addition, a majority of the Registrant Subsidiaries' 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, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following tables represent: (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 posted by the Registrant Subsidiaries and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering the Registrant Subsidiaries' contractual netting arrangements as of March 31, 2013 and December 31, 2012:

Company	March 31, 2013		
	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted (in thousands)	Additional Settlement Liability if Cross Default Provision is Triggered
APCo	\$ 32,626	\$ -	\$ 20,446
I&M	22,546	-	14,129
OPCo	46,131	-	28,909
PSO	11	-	9
SWEPCo	12	-	11

Company	December 31, 2012		
	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted (in thousands)	Additional Settlement Liability if Cross Default Provision is Triggered
APCo	\$ 49,465	\$ 1,822	\$ 30,160
I&M	53,499	1,252	40,240
OPCo	69,516	2,561	42,386
PSO	-	-	-
SWEPCo	-	-	-

9. 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. The AEP System's market risk oversight staff independently monitors its valuation policies and procedures and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and monthly reports, regarding compliance with policies and procedures. The CORC consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Energy Supply, Senior Vice President of Commercial Operations and Chief Risk Officer.

For 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. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included 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. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of the contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A significant portion of the Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

AEP utilizes its trustee's external pricing service in its estimate of the fair value of the underlying investments held in the nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the 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, Other Cash Deposits and Cash and Cash Equivalents 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. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalents funds. Fixed income securities do not trade on an exchange and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. 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.

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 classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt for the Registrant Subsidiaries as of March 31, 2013 and December 31, 2012 are summarized in the following table:

Company	March 31, 2013		December 31, 2012	
	Book Value	Fair Value	Book Value	Fair Value
(in thousands)				

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APCo	\$	3,702,599	\$	4,507,266	\$	3,702,442	\$	4,555,143
I&M		2,282,580		2,584,356		2,057,666		2,372,017
OPCo		3,560,628		4,170,595		3,860,440		4,560,337
PSO		949,856		1,154,618		949,871		1,175,759
SWEPCo		2,044,692		2,386,875		2,046,228		2,400,509

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 I&M 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.

I&M maintains 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 fixed income 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 fixed income investments held in these trusts and generally intends to sell fixed income 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 these 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 as of March 31, 2013 and December 31, 2012:

	March 31, 2013			December 31, 2012		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than- Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than- Temporary Impairments
	(in thousands)					
Cash and Cash Equivalents	\$ 13,320	\$ -	\$ -	\$ 16,783	\$ -	\$ -
Fixed Income Securities:						
United States						
Government	641,780	53,220	(907)	647,918	58,268	(747)
Corporate Debt	37,267	4,522	(1,353)	35,399	4,903	(1,352)
State and Local						
Government	279,027	(12)	(1,667)	270,090	1,006	(863)
Subtotal Fixed Income						
Securities	958,074	57,730	(3,927)	953,407	64,177	(2,962)
Equity Securities -						
Domestic	816,135	360,386	(80,949)	735,582	284,599	(76,557)
Spent Nuclear Fuel and						

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Decommissioning Trusts \$ 1,787,529 \$ 418,116 \$ (84,876) \$ 1,705,772 \$ 348,776 \$ (79,519)

The following table provides the securities activity within the decommissioning and SNF trusts for the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Proceeds from Investment Sales	\$ 167,670	\$ 334,400
Purchases of Investments	184,299	352,877
Gross Realized Gains on Investment Sales	3,323	1,552
Gross Realized Losses on Investment Sales	2,315	1,416

The adjusted cost of fixed income securities was \$900 million and \$889 million as of March 31, 2013 and December 31, 2012, respectively. The adjusted cost of equity securities was \$456 million and \$451 million as of March 31, 2013 and December 31, 2012, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of March 31, 2013 was as follows:

	Fair Value of Fixed Income Securities
	(in thousands)
Within 1 year	\$ 95,390
1 year – 5 years	355,812
5 years – 10 years	273,653
After 10 years	233,219
Total	\$ 958,074

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, the Registrant Subsidiaries' financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2013 and December 31, 2012. 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. Management's 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 management's valuation techniques.

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2013

	Level 1	Level 2	Level 3 (in thousands)	Other	Total
Assets:					
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	\$ 3,184	\$ 108,817	\$ 13,220	\$ (79,065)	\$ 46,156
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,306	-	(319)	987
Total Risk Management Assets	\$ 3,184	\$ 110,123	\$ 13,220	\$ (79,384)	\$ 47,143
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	\$ 1,541	\$ 100,473	\$ 4,464	\$ (82,116)	\$ 24,362
Cash Flow Hedges:					
Commodity Hedges (a)	-	769	-	(319)	450
Total Risk Management Liabilities	\$ 1,541	\$ 101,242	\$ 4,464	\$ (82,435)	\$ 24,812

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

	Level 1	Level 2	Level 3 (in thousands)	Other	Total
Assets:					
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	\$ 4,161	\$ 166,916	\$ 17,058	\$ (123,117)	\$ 65,018
Cash Flow Hedges:					
Commodity Hedges (a)	-	498	-	(196)	302
Total Risk Management Assets	\$ 4,161	\$ 167,414	\$ 17,058	\$ (123,313)	\$ 65,320
Liabilities:					
Risk Management Liabilities					

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Risk Management Commodity										
Contracts (a) (b)	\$	1,959	\$	158,665	\$	6,079	\$	(132,884)	\$	33,819
Cash Flow Hedges:										
Commodity Hedges (a)		-		1,551		-		(196)		1,355
Total Risk Management Liabilities	\$	1,959	\$	160,216	\$	6,079	\$	(133,080)	\$	35,174

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I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2013

	Level 1	Level 2	Level 3	Other	Total
(in thousands)					
Assets:					
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	\$ 2,200	\$ 77,123	\$ 9,136	\$ (54,438)	\$ 34,021
Cash Flow Hedges:					
Commodity Hedges (a)	-	880	-	(220)	660
Total Risk Management Assets	2,200	78,003	9,136	(54,658)	34,681
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (c)	4,896	-	-	8,424	13,320
Fixed Income Securities:					
United States Government	-	641,780	-	-	641,780
Corporate Debt	-	37,267	-	-	37,267
State and Local Government	-	279,027	-	-	279,027
Subtotal Fixed Income Securities	-	958,074	-	-	958,074
Equity Securities - Domestic (d)	816,135	-	-	-	816,135
Total Spent Nuclear Fuel and Decommissioning Trusts	821,031	958,074	-	8,424	1,787,529
Total Assets	\$ 823,231	\$ 1,036,077	\$ 9,136	\$ (46,234)	\$ 1,822,210
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	\$ 1,065	\$ 70,273	\$ 3,085	\$ (56,546)	\$ 17,877
Cash Flow Hedges:					
Commodity Hedges (a)	-	531	-	(220)	311
Total Risk Management Liabilities	\$ 1,065	\$ 70,804	\$ 3,085	\$ (56,766)	\$ 18,188

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

	Level 1	Level 2	Level 3 (in thousands)	Other	Total
Assets:					
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	\$ 2,858	\$ 120,242	\$ 11,717	\$ (84,474)	\$ 50,343
Cash Flow Hedges:					
Commodity Hedges (a)	-	330	-	(130)	200
Total Risk Management Assets	2,858	120,572	11,717	(84,604)	50,543
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (c)	6,508	-	-	10,275	16,783
Fixed Income Securities:					
United States Government	-	647,918	-	-	647,918
Corporate Debt	-	35,399	-	-	35,399
State and Local Government	-	270,090	-	-	270,090
Subtotal Fixed Income Securities	-	953,407	-	-	953,407
Equity Securities - Domestic (d)	735,582	-	-	-	735,582
Total Spent Nuclear Fuel and Decommissioning Trusts	742,090	953,407	-	10,275	1,705,772
Total Assets	\$ 744,948	\$ 1,073,979	\$ 11,717	\$ (74,329)	\$ 1,756,315
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	\$ 1,346	\$ 110,621	\$ 4,176	\$ (91,183)	\$ 24,960
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,061	-	(130)	931
Interest Rate/Foreign Currency Hedges	-	19,524	-	-	19,524
Total Risk Management Liabilities	\$ 1,346	\$ 131,206	\$ 4,176	\$ (91,313)	\$ 45,415

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2013

	Level 1	Level 2	Level 3 (in thousands)	Other	Total
Assets:					
Other Cash Deposits (e)	\$ -	\$ 26	\$ -	\$ 39	\$ 65
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	4,501	157,565	18,693	(114,694)	66,065
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,823	-	(451)	1,372
Total Risk Management Assets	4,501	159,388	18,693	(115,145)	67,437
Total Assets	\$ 4,501	\$ 159,414	\$ 18,693	\$ (115,106)	\$ 67,502
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	\$ 2,178	\$ 145,516	\$ 6,312	\$ (119,008)	\$ 34,998
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,087	-	(451)	636
Total Risk Management Liabilities	\$ 2,178	\$ 146,603	\$ 6,312	\$ (119,459)	\$ 35,634

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

	Level 1	Level 2	Level 3 (in thousands)	Other	Total
Assets:					
Other Cash Deposits (e)	\$ -	\$ 26	\$ -	\$ 39	\$ 65
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	5,848	238,254	23,973	(175,890)	92,185
Cash Flow Hedges:					
Commodity Hedges (a)	-	688	-	(272)	416
Total Risk Management Assets	5,848	238,942	23,973	(176,162)	92,601
Total Assets	\$ 5,848	\$ 238,968	\$ 23,973	\$ (176,123)	\$ 92,666
Liabilities:					
Risk Management Liabilities					

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Risk Management Commodity

Contracts (a) (b)	\$	2,753	\$	226,536	\$	8,544	\$	(189,616)	\$	48,217
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Cash Flow Hedges:

Commodity Hedges (a)	-	2,175	-	(272)	1,903
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Total Risk Management Liabilities	\$	2,753	\$	228,711	\$	8,544	\$	(189,888)	\$	50,120
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PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts					
(a) (b)	\$ -	\$ 1,722	\$ -	\$ (1,067)	\$ 655
Cash Flow Hedges:					
Commodity Hedges	-	61	-	-	61
Total Risk Management Assets	\$ -	\$ 1,783	\$ -	\$ (1,067)	\$ 716

Risk Management Liabilities					
Risk Management Commodity Contracts					
(a) (b)	\$ -	\$ 4,074	\$ -	\$ (1,069)	\$ 3,005
Cash Flow Hedges:					
Commodity Hedges	-	1	-	-	1
Total Risk Management Liabilities	\$ -	\$ 4,075	\$ -	\$ (1,069)	\$ 3,006

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts					
(a) (b)	\$ -	\$ 1,657	\$ -	\$ (1,142)	\$ 515
Cash Flow Hedges:					
Commodity Hedges (a)	-	42	-	(17)	25
Total Risk Management Assets	\$ -	\$ 1,699	\$ -	\$ (1,159)	\$ 540

Liabilities:

Risk Management Liabilities					
Risk Management Commodity Contracts					
(a) (b)	\$ -	\$ 7,021	\$ -	\$ (1,142)	\$ 5,879
Cash Flow Hedges:					
Commodity Hedges (a)	-	17	-	(17)	-
Total Risk Management Liabilities	\$ -	\$ 7,038	\$ -	\$ (1,159)	\$ 5,879

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2013

	Level 1	Level 2	Level 3 (in thousands)	Other	Total
Assets:					
Cash and Cash Equivalents (e)	\$ 6,160	\$ -	\$ -	\$ 983	\$ 7,143
Risk Management Assets					
Risk Management Commodity Contracts					
(a) (b)	-	2,764	-	(2,106)	658
Cash Flow Hedges:					
Commodity Hedges (a)	-	72	-	1	73
Total Risk Management Assets	-	2,836	-	(2,105)	731
Total Assets	\$ 6,160	\$ 2,836	\$ -	\$ (1,122)	\$ 7,874
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts					
(a) (b)	\$ -	\$ 2,930	\$ -	\$ (2,108)	\$ 822
Cash Flow Hedges:					
Commodity Hedges (a)	-	1	-	1	2
Total Risk Management Liabilities	\$ -	\$ 2,931	\$ -	\$ (2,107)	\$ 824

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

	Level 1	Level 2	Level 3 (in thousands)	Other	Total
Assets:					
Risk Management Assets					
Risk Management Commodity Contracts					
(a) (b)	\$ -	\$ 2,804	\$ -	\$ (2,133)	\$ 671
Cash Flow Hedges:					
Commodity Hedges (a)	-	41	-	(17)	24
Total Risk Management Assets	\$ -	\$ 2,845	\$ -	\$ (2,150)	\$ 695
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts					
(a) (b)	\$ -	\$ 3,261	\$ -	\$ (2,133)	\$ 1,128
Cash Flow Hedges:					
Commodity Hedges (a)	-	17	-	(17)	-

Total Risk Management Liabilities	\$	-	\$	3,278	\$	-	\$	(2,150)	\$	1,128
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- (a) 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."
- (b) Substantially comprised of power contracts for APCo, I&M and OPCo and coal contracts for PSO and SWEPCo.
- (c) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.
- (d) Amounts represent publicly traded equity securities and equity-based mutual funds.
- (e) Amounts in "Other" column primarily represent cash deposits with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2013 and 2012.

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

Three Months Ended March 31, 2013	APCo	I&M (in thousands)	OPCo
Balance as of December 31, 2012	\$ 10,979	\$ 7,541	\$ 15,429
Realized Gain (Loss) Included in Net Income			
(or Changes in Net Assets)			
(a) (b)	(1,456)	(1,005)	(2,055)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	-	(1,988)
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (c)	257	179	366
Transfers into Level 3 (d) (e)	632	434	888
Transfers out of Level 3 (e) (f)	(533)	(366)	(749)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(1,123)	(732)	490
Balance as of March 31, 2013	\$ 8,756	\$ 6,051	\$ 12,381
Three Months Ended March 31, 2012	APCo	I&M (in thousands)	OPCo
Balance as of December 31, 2011	\$ 1,971	\$ 1,263	\$ 2,666
Realized Gain (Loss) Included in Net Income			
(or Changes in Net Assets)			
(a) (b)	(3,580)	(2,411)	(5,056)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	-	6,509
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	49	31	66
Purchases, Issuances and Settlements (c)	5,948	4,043	8,477
Transfers into Level 3 (d) (e)	2,508	1,764	3,699
Transfers out of Level 3 (e) (f)	(4,001)	(2,814)	(5,900)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	5,086	3,738	1,306
Balance as of March 31, 2012	\$ 7,981	\$ 5,614	\$ 11,767

(a) Included in revenues on the condensed 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) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
- (f) Represents existing assets or liabilities that were previously categorized as Level 3.
- (g) Relates to the net gains (losses) of those contracts that are not reflected on the condensed statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of March 31, 2013:

APCo

	Fair Value		Valuation Technique	Significant Unobservable Input (a)	Forward Price Range	
	Assets (in thousands)	Liabilities			Low	High
Energy Contracts	\$ 12,347	\$ 3,082	Discounted Cash Flow	Forward Market Price	\$ 11.59	\$ 75.95
FTRs	873	1,382	Discounted Cash Flow	Forward Market Price	(4.47)	9.67
Total	\$ 13,220	\$ 4,464				

I&M

	Fair Value		Valuation Technique	Significant Unobservable Input (a)	Forward Price Range	
	Assets (in thousands)	Liabilities			Low	High
Energy Contracts	\$ 8,533	\$ 2,130	Discounted Cash Flow	Forward Market Price	\$ 11.59	\$ 75.95
FTRs	603	955	Discounted Cash Flow	Forward Market Price	(4.47)	9.67
Total	\$ 9,136	\$ 3,085				

OPCo

	Fair Value		Valuation Technique	Significant Unobservable Input (a)	Forward Price Range	
	Assets (in thousands)	Liabilities			Low	High
Energy Contracts	\$ 17,459	\$ 4,359	Discounted Cash Flow	Forward Market Price	\$ 11.59	\$ 75.95
FTRs	1,234	1,953	Discounted Cash Flow	Forward Market Price	(4.47)	9.67
Total	\$ 18,693	\$ 6,312				

(a) Represents market prices in dollars per MWh.

10. INCOME TAXES

AEP System Tax Allocation Agreement

The Registrant Subsidiaries join in the filing of a consolidated federal income tax return with their affiliates in the AEP System. 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 its 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.

Federal and State Income Tax Audit Status

The IRS examination of years 2009 and 2010 started in October 2011. 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, the Registrant Subsidiaries accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

The Registrant Subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and the Registrant Subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. With few exceptions, the Registrant Subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2008.

11. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2013 are shown in the tables below:

Company	Type of Debt	Principal Amount (a) (in thousands)	Interest Rate (%)	Due Date
Issuances:				
I&M	Senior Unsecured Notes	\$ 250,000	3.20	2023
OPCo	Long-term Debt - Affiliated	200,000 (b)	Variable	2015

(a) Amounts indicated on the statements of cash flows are net of issuance costs and premium or discount and will not tie to the issuance amounts.

(b) Intercompany issuance from AEP consisting of a draw on a \$1 billion term credit facility due in May 2015 to fund certain OPCo maturities on an interim basis and to facilitate the corporate separation of generation assets from transmission and distribution.

Company	Type of Debt	Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	Land Note	\$ 7	13.718	2026
I&M	Notes Payable	4,040	Variable	2015
I&M	Notes Payable	5,953	Variable	2016
I&M	Notes Payable	4,123	2.12	2016
I&M	Notes Payable	10,542	Variable	2016
I&M	Other Long-term Debt	206	6.00	2025
OPCo	Senior Unsecured Notes	250,000	5.50	2013
OPCo	Senior Unsecured Notes	250,000	5.50	2013
PSO	Notes Payable	99	3.00	2027
SWEPCo	Notes Payable	1,625	4.58	2032

In April 2013, I&M retired \$28 million of Notes Payable related to DCC Fuel.

In April 2013, I&M reacquired \$40 million of 5.25% Pollution Control Bonds due in 2025. The variable rate bonds are held by a trustee on behalf of I&M.

As of March 31, 2013, trustees held, on behalf of OPCo, \$413 million of its reacquired Pollution Control Bonds.

Dividend Restrictions

The Registrant Subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the Registrant Subsidiaries to transfer funds to Parent in the form of dividends.

Federal Power Act

The Federal Power Act prohibits each of the Registrant 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 book value of the common stock.

Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generating plants. Because of their respective ownership of such plants, this reserve applies to APCo, I&M and OPCo.

None of these restrictions limit the ability of the Registrant Subsidiaries to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, APCo, I&M and OPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of the subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with FERC. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of March 31, 2013 and December 31, 2012 is included in Advances to/from Affiliates on each of the Registrant Subsidiaries' condensed balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits for the three months ended March 31, 2013 are described in the following table:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Net Loans (Borrowings) to/from Utility Money Pool as of March 31, 2013	Authorized Short-term Borrowing Limit
(in thousands)						
APCo	\$ 217,174	\$ 23,509	\$ 114,102	\$ 23,313	\$ (73,448)	\$ 600,000
I&M	23,135	337,330	8,308	99,150	321,985	500,000
OPCo	410,456	169,284	207,014	53,482	(161,869)	600,000
PSO	24,004	25,343	11,929	11,527	(24,004)	300,000
SWEPco	-	153,830	-	78,892	26,885	350,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Three Months Ended March 31,	
	2013	2012
Maximum Interest Rate	0.43 %	0.56 %
Minimum Interest Rate	0.35 %	0.45 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the three months ended March 31, 2013 and 2012 are summarized for all Registrant Subsidiaries in the following table:

Company	Average Interest Rate for Funds Borrowed from Utility Money Pool for Three Months Ended March 31,		Average Interest Rate for Funds Loaned to Utility Money Pool for Three Months Ended March 31,	
	2013	2012	2013	2012
APCo	0.38 %	0.51 %	0.37 %	0.51 %
I&M	0.36 %	- %	0.37 %	0.51 %
OPCo	0.36 %	0.47 %	0.37 %	0.52 %

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PSO	0.36 %	- %	0.38 %	0.51 %
SWEPCo	- %	0.53 %	0.38 %	0.51 %

Short-term Debt

The Registrant Subsidiaries' outstanding short-term debt was as follows:

Company	Type of Debt	March 31, 2013		December 31, 2012	
		Outstanding Amount (in thousands)	Interest Rate (a)	Outstanding Amount (in thousands)	Interest Rate (a)
SWEPCo	Line of Credit – Sabine	\$ -	- %	\$ 2,603	1.82 %

(a) Weighted average rate.

Credit Facilities

For a discussion of credit facilities, see “Letters of Credit” section of Note 4.

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiary's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' condensed statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable sold.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement for each Registrant Subsidiary as of March 31, 2013 and December 31, 2012 was as follows:

Company	March 31, 2013		December 31, 2012	
	(in thousands)		(in thousands)	
APCo	\$	163,474	\$	153,719
I&M		134,377		123,447
OPCo		319,682		300,675
PSO		84,456		85,530
SWEPCo		121,202		132,449

The fees paid by the Registrant Subsidiaries to AEP Credit for customer accounts receivable sold were:

Company	Three Months Ended March 31, 2013		Three Months Ended March 31, 2012	
	(in thousands)		(in thousands)	
APCo	\$	1,556	\$	2,130
I&M		1,452		1,543
OPCo		4,669		5,916
PSO		1,414		1,732
SWEPCo		1,380		1,386

The Registrant Subsidiaries' proceeds on the sale of receivables to AEP Credit were:

Company	Three Months Ended March 31,	
	2013	2012
	(in thousands)	
APCo	\$ 398,193	\$ 346,526
I&M	351,830	339,581
OPCo	696,958	837,897
PSO	240,275	272,795
SWEPCo	331,936	321,608

12. 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 they are the primary beneficiary of a VIE, management considers for each Registrant Subsidiary factors such as equity at risk, the amount of the VIE’s variability the Registrant Subsidiary absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. The Registrant Subsidiaries have not provided financial or other support to any VIE that was not previously contractually required.

SWEP Co is the primary beneficiary of Sabine. I&M is the primary beneficiary of DCC Fuel. SWEP Co holds a significant variable interest in DHL Co. APCo, I&M, OPCo, PSO and SWEP Co each hold a significant variable interest in AEPSC. I&M and OPCo each hold a significant variable interest in AEGCo.

Sabine is a mining operator providing mining services to SWEP Co. SWEP Co has no equity investment in Sabine but is Sabine’s only customer. SWEP Co 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 SWEP Co. The creditors of Sabine have no recourse to any AEP entity other than SWEP Co. Under the provisions of the mining agreement, SWEP Co 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, SWEP Co determines how much coal will be mined each year. Based on these facts, management concluded that SWEP Co is the primary beneficiary and is required to consolidate Sabine. SWEP Co’s total billings from Sabine for the three months ended March 31, 2013 and 2012 were \$44 million and \$55 million, respectively. See the tables below for the classification of Sabine’s assets and liabilities on SWEP Co’s condensed balance sheets.

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

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITIES
March 31, 2013 and December 31, 2012
(in thousands)

	Sabine	
ASSETS	2013	2012
Current Assets	\$ 64,194	\$ 56,535
Net Property, Plant and Equipment	167,256	170,436
Other Noncurrent Assets	65,847	55,076
Total Assets	\$ 297,297	\$ 282,047
LIABILITIES AND EQUITY		
Current Liabilities	\$ 30,681	\$ 31,446
Noncurrent Liabilities	266,229	250,340
Equity	387	261
Total Liabilities and Equity	\$ 297,297	\$ 282,047

I&M has nuclear fuel lease agreements with DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC and DCC Fuel V 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. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the three months ended March 31, 2013 and 2012 were \$26 million and \$17 million, respectively. 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 respective lease terms, which do not exceed 54 months. Based on

I&M's control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the table below for the classification of DCC Fuel's assets and liabilities on I&M's condensed balance sheets.

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

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

VARIABLE INTEREST ENTITIES

March 31, 2013 and December 31, 2012

(in thousands)

ASSETS	DCC Fuel	
	2013	2012
Current Assets	\$ 128,450	\$ 132,886
Net Property, Plant and Equipment	146,271	176,065
Other Noncurrent Assets	72,589	92,473
Total Assets	\$ 347,310	\$ 401,424
LIABILITIES AND EQUITY		
Current Liabilities	\$ 112,209	\$ 120,873
Noncurrent Liabilities	235,101	280,551
Equity	-	-
Total Liabilities and Equity	\$ 347,310	\$ 401,424

DHLC is a mining operator which sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and voting rights equally. Each entity guarantees 50% 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, 2013 and 2012 were \$18 million and \$14 million, respectively. SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although SWEPCo holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's condensed balance sheets.

SWEPCo's investment in DHLC was:

	March 31, 2013		December 31, 2012	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
(in thousands)				
Capital Contribution from SWEPCo	\$ 7,643	\$ 7,643	\$ 7,643	\$ 7,643
Retained Earnings	912	912	946	946
SWEPCo's Guarantee of Debt	-	39,968	-	49,564
Total Investment in DHLC	\$ 8,555	\$ 48,523	\$ 8,589	\$ 58,153

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided

financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

Company	Three Months Ended March 31,	
	2013	2012
	(in thousands)	
APCo	\$ 39,040	\$ 38,546
I&M	27,498	26,107
OPCo	54,069	53,445
PSO	18,161	17,596
SWEPCo	27,480	26,720

The carrying amount and classification of variable interest in AEPSC's accounts payable are as follows:

Company	March 31, 2013		December 31, 2012	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in thousands)			
APCo	\$ 14,324	\$ 14,324	\$ 29,819	\$ 29,819
I&M	7,902	7,902	17,911	17,911
OPCo	20,051	20,051	39,323	39,323
PSO	6,772	6,772	13,381	13,381
SWEPCo	9,048	9,048	19,669	19,669

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEGCo leases the Lawrenceburg Generating Station to OPCo. AEP guarantees all the debt obligations of AEGCo. I&M and OPCo are considered to have a significant interest in AEGCo due to these transactions. I&M and OPCo are exposed to losses to the extent they cannot recover the costs of AEGCo through their normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M, OPCo and KPCo, this financing would be provided by AEP. For additional information regarding AEGCo's lease, see "Rockport Lease" section of Note 11 in the 2012 Annual Report.

Total billings from AEGCo were as follows:

Company	Three Months Ended March 31,	
	2013	2012
	(in thousands)	
I&M	\$ 58,535	\$ 58,822
OPCo	38,711	58,417

The carrying amount and classification of variable interest in AEGCo's accounts payable are as follows:

March 31, 2013

December 31, 2012

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Company	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
		(in thousands)		
I&M	\$ 18,543	\$ 18,543	\$ 25,498	\$ 25,498
OPCo	12,889	12,889	16,302	16,302

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13. SUSTAINABLE COST REDUCTIONS

In April 2012, management initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. Management selected a consulting firm to facilitate an organizational and process evaluation and a second firm to evaluate current employee benefit programs. The process resulted in involuntary severances and was completed by the end of the first quarter of 2013. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

The Registrant Subsidiaries recorded charges to Other Operation expense in 2012 primarily related to severance benefits as a result of the sustainable cost reductions initiative. The total amount incurred in 2012 by Registrant Subsidiary was as follows:

Company	Total Cost Incurred (in thousands)
APCo	\$ 8,472
I&M	5,678
OPCo	13,498
PSO	3,675
SWEPCo	5,709

The Registrant Subsidiaries' sustainable cost reduction activity for the three months ended March 31, 2013 is described in the following table:

Company	Balance as of December 31, 2012	Expense Allocation from AEPSC	Incurred for Registrant Subsidiaries (in thousands)	Settled	Adjustments	Remaining Balance as of March 31, 2013
APCo	\$ 1,321	\$ 1,266	\$ -	\$ (1,825)	\$ (538)	\$ 224
I&M	1,357	891	-	(2,047)	(143)	58
OPCo	3,450	1,709	6,114	(3,163)	(1,918)	6,192
PSO	652	444	-	(598)	(472)	26
SWEPCo	627	803	-	(1,695)	405	140

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the condensed statements of income. The remaining liability is included in Other Current Liabilities on the condensed balance sheets. Management does not expect additional costs to be incurred related to this initiative.

COMBINED MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the Registrant Subsidiaries' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and net income and is meant to be read with (a) Management's Narrative Discussion and Analysis of Results of Operations, (b) financial statements, (c) footnotes and (d) the schedules of each individual registrant. The Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries section of the 2012 Annual Report should also be read in conjunction with this report.

EXECUTIVE OVERVIEW

Customer Demand

In comparison to 2012, heating degree days in 2013 were up 59% in AEP's western region and 44% in AEP's eastern region. Weather-normalized retail sales across the AEP System were down 1.5% compared to 2012. OPCo's weather-normalized industrial sales declined 13.6% partially due to Ormet, a large aluminum company that lowered their production in the third quarter of 2012 by one-third and is currently in bankruptcy proceedings.

In 2013, management anticipates slight increases in retail sales in AEP's service territories primarily driven by oil and gas related projects, including shale gas. Management also anticipates decreases in OPCo's industrial demand related to Ormet's lower production levels discussed above.

ENVIRONMENTAL ISSUES

The Registrant Subsidiaries are implementing a substantial capital investment program and incurring additional operational costs to comply with environmental control requirements. The Registrant Subsidiaries 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, NO_x, PM and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, new proposals governing the beneficial use and disposal of coal combustion products and proposed clean water rules.

The Registrant Subsidiaries 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 I&M's nuclear units. AEP, along with various industry groups, affected states and other parties have challenged some of the Federal EPA requirements in court. Management is 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. Management believes that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

See a complete discussion of these matters in the "Environmental Issues" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" in the 2012 Annual Report. Management will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Recovery in Ohio will be dependent upon prevailing market conditions. Environmental rules could result in accelerated depreciation, impairment of assets or regulatory disallowances. If the costs of environmental compliance are not recovered, it would reduce future net income and cash flows and impact financial condition.

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. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of March 31, 2013, the AEP System had a total generating capacity of 37,600 MWs, of which 23,700 MWs are coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on the coal-fired generating facilities. For the Registrant Subsidiaries, management's current ranges of estimates of environmental investments to comply with these proposed requirements are listed below:

Company	Through 2020 Estimated Environmental Investment	
	Low	High
	(in millions)	
APCo	\$ 330	\$ 440
I&M	510	610
OPCo	840	1,080
PSO	310	380
SWEPCo	1,430	1,750

For APCo, I&M and OPCo, the projected environmental investments above include the conversion of 470 MWs, 500 MWs and 600 MWs, respectively, of coal generation to natural gas capacity. If natural gas conversion is not completed, the units could be closed sooner than planned.

The preceding discussion of environmental investments and plans for future years reflects the ownership of plants as of March 31, 2013. The AEP East Companies have filed with the FERC to terminate the Interconnection Agreement and for OPCo to transfer facilities to APCo, KPCo and AEPGenCo. Management expects the transfers will be effective December 31, 2013.

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 for each Registrant Subsidiary 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 more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on the 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.

Subject to the factors listed above and based upon continuing evaluation, management has given notice to the applicable RTOs of the intent to retire the following plants or units of plants before or during 2016:

Company	Plant Name and Unit	Generating Capacity (in MWs)
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
	Philip Sporn Plant, Units	
APCo/OPCo	1-4	600
	Tanners Creek Plant,	
I&M	Units 1-3	495

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OPCo	Kammer Plant	630
OPCo	Muskingum River Plant, Units 1-4	840
OPCo	Picway Plant	100
SWEPCo	Welsh Plant, Unit 2	528

Duke Energy Corporation, the operator of W. C. Beckjord Generating Station, has announced its intent to close the facility in 2015. OPCo owns 12.5% (53 MWs) of one unit at that station. In December 2012, OPCo retired the 165 MW Conesville Plant, Unit 3.

A decline in natural gas prices, pending environmental rules and the proposed termination of the Interconnection Agreement had an adverse impact on the recoverability of the net book values of certain coal-fired units. In 2012, OPCo recorded a \$287 million pretax impairment charge for the net book value of certain plants totaling 1,870 MWs in the table above and the Beckjord and Conesville plants discussed above. As of March 31, 2013, the net book value of the impaired plants is zero.

As of March 31, 2013, the net book value of the regulated plants in the table above was \$383 million. This amount does not include related inventory or CWIP balances.

Management is in the process of obtaining permits and other necessary regulatory approvals for either the conversion of some coal units to natural gas or installing emission control equipment on certain units. Management is also evaluating closure of certain units based on changes in emission requirements and demand for power. The following table lists the plants or units that are either awaiting regulatory approval or are still being evaluated:

Company	Plant Name and Unit	Generating Capacity (in MWs)
APCo	Clinch River Plant, Units 1-2	470
I&M/AEGCo/KPCo	Rockport Plant, Units 1-2	2,620
I&M	Tanners Creek Plant, Unit 4	500
OPCo	Muskingum River Plant, Unit 5	600
PSO	Northeastern Station, Units 3-4	930
SWEPCo	Flint Creek Plant	264

As of March 31, 2013, the net book values of the regulated plants and nonregulated plant (Muskingum River) in the table above were \$1.1 billion and \$168 million, respectively. These amounts do not include related inventory or CWIP balances.

The rules and regulatory actions that may impact the evaluation of specific units are discussed in the following sections. Clinch River and Tanners Creek units are being considered for gas conversion. Muskingum River Plant, Unit 5 will have options to cease burning coal and retire in 2015 or cease burning coal in 2015 and complete a refueling project no later than June 2017. Natural gas prices and pending environmental rules could also have an adverse impact on the accounting evaluation of the recoverability of the net book values of certain coal-fired units. To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially reduce future net income and cash flows.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing the CAA's requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of

certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual state implementation plans (SIPs) or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas and Oklahoma. The Federal EPA finalized a FIP for Oklahoma that contains more stringent control requirements for SO₂ emissions from affected units in that state. The Arkansas SIP was disapproved and the state is developing a revised submittal. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the Cross-State Air Pollution Rule (CSAPR) trading programs to use those programs in place of source-specific BART for SO₂ and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the U.S. Court of Appeals for the District of Columbia Circuit and its fate is uncertain given developments in the CSAPR litigation.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for PM, SO₂, NO_x and lead, and is currently reviewing the NAAQS for ozone. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for facilities as a result of those evaluations. Management cannot currently predict the nature, stringency or timing of those requirements.

Notable developments in significant CAA regulatory requirements affecting the Registrant Subsidiaries' operations are discussed in the following sections.

Cross-State Air Pollution Rule (CSAPR)

In August 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in March 2012. CSAPR relies on newly-created SO₂ and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units in 28 states. Interstate trading of allowances was allowed on a restricted sub-regional basis. Arkansas and Louisiana are subject only to the seasonal NO_x program in the rule. Texas is subject to the annual programs for SO₂ and NO_x in addition to the seasonal NO_x program. The annual SO₂ allowance budgets in Indiana, Ohio and West Virginia were reduced significantly in the rule. A supplemental rule includes Oklahoma in the seasonal NO_x program. The supplemental rule was finalized in December 2011 with an increased NO_x emission budget for the 2012 compliance year. The Federal EPA issued a final Error Corrections Rule and further CSAPR revisions in 2012 to make corrections to state budgets and unit allocations and to remove the restrictions on interstate trading in the first phase of CSAPR.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U. S. Court of Appeals for the District of Columbia Circuit. Several of the petitioners filed motions to stay the implementation of the rule pending judicial review. In December 2011, the court granted the motions for stay. In August 2012, the panel issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the Clean Air Interstate Rule until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to "overcontrol" emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. The Federal EPA and other respondents have filed petitions for rehearing but in January 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied all petitions for rehearing. The Federal EPA and other parties have filed a petition for further review at the U.S. Supreme Court. Separate appeals of the supplemental rule, the Error Corrections Rule and the further revisions have been filed, but are being held in abeyance.

The time frames and stringency of the required 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 its electric utility customers. Management cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In February 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metal) and hydrogen chloride (as a surrogate for acid gases) for units burning coal, 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. The effective date of the final rule was April 16, 2012 and compliance is required within three years. The AEP System is participating through various organizations in the petitions for administrative reconsideration and judicial review that have been filed. In 2012, the Federal EPA published a notice announcing that it would accept comments on its reconsideration of certain issues related to the new source standards, including clarification of the requirements that apply during periods of start-up and shut down, measurement issues and the application of variability factors that may have an impact on the level of the standards. Revisions to the new

source standards consistent with the proposed rule were issued by the Federal EPA in March 2013.

The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and allows operators to exclude periods of startup and shutdown from the emissions averaging periods. The compliance time frame remains a serious concern. A one-year administrative extension may be available if the extension is necessary for the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. Management is concerned about the availability of compliance extensions and the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines. The AEP System is participating in petitions for review filed in the U.S. Court of Appeals for the District of Columbia Circuit by several organizations in which the Registrant Subsidiaries are members. Certain issues related to the standards for new coal-fired units have been severed from the main case and are being held in abeyance pending completion of the Federal EPA's reconsideration proceeding. The case is proceeding on the remaining issues and briefing was completed in April 2013.

Regional Haze – Affecting PSO

In 2011, the Federal EPA proposed to approve in part and disapprove in part the regional haze SIP submitted by the State of Oklahoma through the Department of Environmental Quality. The Federal EPA proposed 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 proposed a FIP that would require these units to install technology capable of reducing SO2 emissions to 0.06 pounds per million British thermal units within three years of the effective date of the FIP. The Federal EPA finalized the FIP in December 2011 that mirrored the proposed rule but established a five-year compliance schedule. PSO filed a petition for review of the FIP in the Tenth Circuit Court of Appeals and engaged in settlement discussions with the Federal EPA, the State of Oklahoma and other parties. In November 2012, PSO notified the court that the parties had reached agreement on a settlement that would provide for submission of a revised Regional Haze SIP requiring the retirement of one coal-fired unit of PSO's Northeastern Station no later than 2016, installation of emission controls on the second coal-fired Northeastern unit in 2016 and retirement of the second unit no later than 2026. The Tenth Circuit Court of Appeals is holding the appeal in abeyance pending implementation of the settlement. A revised regional haze SIP was proposed by the State of Oklahoma and submitted to the Federal EPA for review.

CO2 Regulation

In March 2012, the Federal EPA issued a proposal to regulate CO2 emissions from new fossil fuel-fired electricity generating units. The proposed rule establishes a new source performance standard of 1,000 pounds of CO2 per megawatt hour of electricity generated, a rate that most natural gas combined cycle units can meet, but that is substantially below the emission rate of a new pulverized coal generator or an integrated gas combined cycle unit that uses coal for fuel. As proposed, the rule does not apply to new gas-fired stationary combustion turbines used as peaking units, does not apply to existing, modified or reconstructed sources, and does not apply to units whose CO2 emission rate increases as a result of the addition of pollution control equipment to control criteria pollutant emissions or HAPs. The rule is not anticipated to have a significant immediate impact on the AEP System since it does not apply to existing units or units that have already commenced construction. New source performance standards affect units that have not yet received permits. The proposed standards were challenged in the U. S. Court of Appeals for the District of Columbia Circuit. That case was dismissed because the court determined that no final agency action had yet been taken. The Federal EPA is expected to finalize these standards in 2013.

In June 2012, the U. S. Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA's endangerment finding, its regulatory program for CO2 emissions from new motor vehicles and its plan to phase in regulation of CO2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. A petition for rehearing was filed which the court denied in December 2012. Petitioners filed petitions for further review in the U.S. Supreme Court.

The Federal EPA also finalized a rule in June 2012 that retains the current thresholds for permitting stationary sources under the PSD and Title V operating permit programs at 100,000 tons per year for new sources and 75,000 tons per year for modified sources. The Federal EPA also confirmed that it will re-evaluate these thresholds during its five-year review in 2016. The AEP System's generating units are large sources of CO2 emissions and management will continue to evaluate the permitting obligations in light of these thresholds.

Coal Combustion Residual Rule

In 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 coal-fired electric generating units. The rule contains two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another 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. In 2011, the Federal EPA issued a notice of data availability requesting comments on a number of technical reports and other data received during the comment period for the original proposal and requesting comments on potential modeling analyses to update its risk assessment. The Federal EPA has also announced its intention to complete a risk assessment of various beneficial uses of coal ash. Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. The Federal EPA opposed the petition and is seeking additional time to coordinate the issuance of a final rule with the issuance of new effluent limitations under the Clean Water Act for utility facilities.

Currently, approximately 40% of the coal ash and other residual products from the AEP System's 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, surface impoundments and landfills to manage these materials are currently used at the generating facilities. The Registrant Subsidiaries will incur significant costs to upgrade or close and replace their existing facilities under the proposed solid waste management alternative. Regulation of these materials as hazardous wastes would significantly increase these costs. As the rule is not final, management is unable to determine a range of potential costs that are reasonably possible of occurring but expect the costs to be significant.

Clean Water Act Regulations

In 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a 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 for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. The proposed entrainment standard for new units at existing facilities requires either intake flows commensurate with closed cycle cooling or achieving entrainment reductions equivalent to 90% or greater of the reductions that could be achieved with closed cycle cooling. 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. Management is evaluating the proposal and engaged in the collection of additional information regarding the feasibility of implementing this proposal at the AEP System's facilities. In June 2012, the Federal EPA issued additional Notices of Data Availability and requested public comments. Management submitted comments in July 2012. Issuance of a final rule is not expected until June 2013. Management is preparing to begin activities to implement the rule following its issuance and an analysis of the final requirements.

In addition, the Federal EPA issued an information collection request and is developing revised effluent limitation guidelines for electricity generating facilities. A proposed rule was signed in April 2013 with a final rule expected in 2014. The Federal EPA proposed eight options of increasing stringency and cost for fly ash and bottom ash transport water, scrubber wastewater, leachate from coal combustion byproduct landfills and impoundments and other

wastewaters associated with coal-fired generating units, with four labeled preferred options. Certain of the Federal EPA's preferred options have already been implemented or are part of the AEP System's long-term plans. Management will review the proposal in detail to evaluate whether the plants are currently meeting the proposed limitations, what technologies have been incorporated into the long-range plans and what additional costs might be incurred if the Federal EPA's most stringent options were adopted. Management plans to submit detailed comments to the Federal EPA.

Climate Change

National public policy makers and regulators in the 10 states the Registrant Subsidiaries serve have diverse views on climate change. Management is currently focused on responding to these emerging views with prudent actions, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies and evaluating assets across a range of plausible scenarios and outcomes. Management is also active participants in a variety of public policy discussions at state and federal levels to assure that proposed new requirements are feasible and the economies of the states served are not placed at a competitive disadvantage.

While comprehensive economy-wide regulation of CO₂ emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO₂ emissions under the existing requirements of the CAA.

Several states have adopted programs that directly regulate CO₂ emissions from power plants. The majority of the states where the Registrant Subsidiaries have generating facilities passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. Management is taking steps to comply with these requirements.

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

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

For additional information on climate change, other environmental issues and the actions management is taking to address potential impacts, see Part I of the 2012 Form 10-K under the headings entitled “Business – General – Environmental and Other Matters” and “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries.”

ACCOUNTING PRONOUNCEMENTS

Future Accounting Changes

The FASB’s standard-setting process is ongoing and until new standards have been finalized and issued, management cannot determine the impact on the reporting of the Registrant Subsidiaries’ operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, financial instruments, leases, insurance, hedge accounting and consolidation policy. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

Item 4. Controls and Procedures

During the first quarter of 2013, management, including the principal executive officer and principal financial officer of each of AEP, APCo, I&M, OPCo, PSO and SWEPCo (collectively, the Registrants), evaluated the Registrants’

disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of March 31, 2013, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the first quarter of 2013 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see "Commitments, Guarantees and Contingencies," of Note 4 incorporated herein by reference.

Item 1A. Risk Factors

The Annual Report on Form 10-K for the year ended December 31, 2012 includes a detailed discussion of risk factors. The information presented below amends certain of those risk factors that have been updated and should be read in conjunction with the risk factors and information disclosed in the 2012 Annual Report on Form 10-K.

GENERAL RISKS OF OUR REGULATED OPERATIONS

We may not fully recover all of the investment in and expenses related to the Turk Plant – Affecting AEP and SWEPCo

In December 2012, SWEPCo placed the Turk Plant in Arkansas into commercial operation. SWEPCo holds a 73% ownership interest in the 600 MW coal-fired generating facility. SWEPCo had originally intended that the Arkansas jurisdictional share of the Turk Plant (approximately 20%) would become part of the rate base for its retail customers in Arkansas. Following a proceeding at the Arkansas Supreme Court, the APSC issued an order which reversed and set aside a previously granted Certificate of Environmental Compatibility and Public Need. This portion of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the SPP market. SWEPCo has included a request to recover a portion of the costs of the Turk Plant in its base rate case filed in Texas. In addition, in February 2013, the LPSC granted recovery for a portion of the Turk Plant costs in a formula rate filing, subject to refund based on the staff review of the cost of service and prudence review of the Turk Plant. If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant either through retail rates or sales into the SPP market, it could reduce future net income and cash flows and impact financial condition.

We may not fully recover all of the investment in and expenses related to extending the useful life of the Cook Plant – Affecting AEP and I&M

In April 2012, I&M filed a petition with the IURC for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects for Cook Plant Units 1 and 2 intended to ensure the safe and reliable operation of the plant through its licensed life. The estimated cost of the LCM Project is \$1.2 billion to be incurred through 2018, excluding AFUDC. As of March 31, 2013, I&M has incurred \$197 million related to the LCM Project, including AFUDC. In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project. In April 2013, an intervenor filed an appeal with the Michigan Court of Appeals objecting to the issuance of the CON as well as the amount of the CON related to the LCM Project. If I&M is not ultimately permitted to recover its LCM Project costs, it would reduce future net income and cash flows and impact financial condition.

Request for rate recovery in Texas may not be approved in its entirety. – Affecting AEP and SWEPCo

In July 2012, SWEPCo filed a request with the PUCT for an annual increase in Texas base rates. A portion of the increase seeks recovery for costs associated with the construction and operation of the Texas jurisdictional share (approximately 33%) of the Turk Plant. If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it would reduce future net income and cash flows and impact financial condition.

Request for rate recovery in Indiana may be overturned on appeal. – Affecting AEP and I&M

In February 2013, the IURC issued an order granting an annual increase in base rates. In March 2013, the Indiana Office of Utility Consumer Counselor filed an appeal of the order with the Indiana Court of Appeals. If the order is overturned by the Indiana Court of Appeals, it could reduce future net income and cash flows.

RISKS RELATING TO STATE RESTRUCTURING

Customers are choosing alternative electric generation service providers, as allowed by Ohio law and regulation. – Affecting AEP and OPCo

Under current Ohio law, electric generation is sold in a competitive market in Ohio and native load customers in Ohio have the ability to switch to alternative suppliers for their electric generation service. CRES providers are targeting retail customers by offering alternative generation service. If customer switching in Ohio continues, it could reduce future net income and cash flows and impact financial condition.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None

Item 4. Mine Safety Disclosures

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, and OPCo, through its ownership of Conesville Coal Preparation Company (CCPC) and 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 and its related regulations require companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. Exhibit 95 contains the notices of violation and proposed assessments received by DHLC, CCPC and Conner Run under the Mine Act for the quarter ended March 31, 2013.

Item 5. Other Information

None

Item 6. Exhibits

12 – Computation of Consolidated Ratio of Earnings to Fixed Charges

31(a) – Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

31(b) – Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

32(a) – Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

32(b) – Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

95 – Mine Safety Disclosures

101.INS – XBRL Instance Document
101.SCH – XBRL Taxonomy Extension Schema
101.CAL – XBRL Taxonomy Extension Calculation Linkbase
101.DEF – XBRL Taxonomy Extension Definition Linkbase
101.LAB – XBRL Taxonomy Extension Label Linkbase
101.PRE – XBRL Taxonomy Extension Presentation Linkbase

SIGNATURE

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

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

APPALACHIAN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: April 26, 2013

