AMERICAN ELECTRIC POWER CO INC
Form 10-Q
October 23, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended September 30, 2014
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)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215-2373	
	Telephone (614) 716-1000	

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes X No

Indicate by check mark whether 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.

Large accelerated filer X 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 October 23, 2014
American Electric Power Company, Inc.	489,240,481 ($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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September 30, 2014

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SIGNATURE 260

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., an electric 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.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Transmission Holdco	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	AEP Transmission Company, LLC, a subsidiary of AEP Transmission Holdco and an intermediate holding company that owns seven wholly-owned transmission companies.
AGR	AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation & Marketing segment.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	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 provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation 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 II LLC, DCC Fuel IV LLC, DCC Fuel V LLC and DCC Fuel VI 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.
ENEC	Expanded Net Energy Charge.
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP’s competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
ERCOT	Electric Reliability Council of Texas regional transmission organization.

ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.

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Term	Meaning
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
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, which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
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.
NO_x	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.

PIRR	Phase-In Recovery Rider.
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.

Term	Meaning
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 generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RPM	Reliability Pricing Model.
RSR	Retail Stability Rider.
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.
SIA	System Integration Agreement, effective June 15, 2000, as amended, 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 534 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.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC, 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 Legislation.
Transource Energy	Transource Energy, LLC, a consolidated variable interest entity formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Transource Missouri	A 100% wholly-owned subsidiary of Transource Energy.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant 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 2013 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 ref 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.
- Weather conditions, including storms and drought conditions, and our ability to recover significant storm restoration costs.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generation capacity and the performance of our generation plants.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generation 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.
- 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, cost recovery and/or profitability of our generation 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 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, alternative or distributed sources of generation.

Our ability to recover through rates or market prices any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.

- Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas.
- Changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP.
- The transition to market for generation in Ohio, including the implementation of ESPs.
- Our ability to successfully and profitably manage our separate competitive generation assets.
- 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 of such volatility 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 2013 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

Customer Demand

In comparison to 2013, heating degree days for the nine months ended September 30, 2014 were up 32% in our western region and 20% in our eastern region while cooling degree days were down 7% for the same period in both the eastern and western regions. Our weather-normalized retail sales volumes for the third quarter of 2014 increased by 0.1% from their levels for the third quarter of 2013 and increased by 0.4% for the first nine months of 2014 from their levels for the first nine months of 2013. In comparison to 2013, our industrial sales volume increased 1.2% for the three months ended September 30, 2014 and decreased 0.7% for the nine months ended September 30, 2014. The decrease in industrial sales volume is due mainly to the closure of Ormet, a large aluminum company. Excluding Ormet, our nine months ended September 30, 2014 industrial sales volumes increased 3.8% over the nine months ended September 30, 2013.

Ohio Electric Security Plan Filings

2009 - 2011 ESP

In August 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover OPCo's deferred fuel costs in rates beginning September 2012. As of September 30, 2014, OPCo's net deferred fuel balance was $395 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 balance up to the full amount.

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. This ruling was generally upheld in PUCO rehearing orders in January and March 2013.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the 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 OPCo RPM price collected from CRES providers, which includes reserve margins, was approximately $34/MW day through May 2014 and is $150/MW day from June 2014 through May 2015. 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 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and is currently collected at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In April and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order, including the RSR. As of September 30, 2014, OPCo's incurred deferred capacity costs balance was $409 million, including debt carrying costs.

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In November 2013, the PUCO issued an order approving OPCo’s competitive bid process with modifications. The modifications include the delay of the energy auctions that were originally ordered in the ESP order. In February 2014, OPCo conducted an energy-only auction for 10% of the SSO load with delivery beginning April 2014 through May 2015. In May and September 2014, OPCo conducted energy-only auctions for an additional 50% of the SSO load with delivery beginning November 2014 through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions 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. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit. In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC. In March 2014, the PUCO approved OPCo’s request to implement riders related to the unbundling of the FAC. In May 2014, an independent auditor was selected by the PUCO and an audit of the recovery of the fixed fuel costs began in June 2014. In October 2014, the independent auditor filed its report for the period August 2012 through May 2015 with the PUCO. If the PUCO ultimately concludes that a portion of the fixed fuel costs are also recovered through OPCo's $188.88 capacity charge, the independent auditor recommends a methodology for calculating a refund of a portion of certain fixed fuel costs. The retail share of these fixed fuel costs is approximately $90 million annually. A hearing related to this matter has not been scheduled. Management believes that no over-recovery of costs has occurred and intends to oppose the findings in the audit report.

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

Proposed June 2015 - May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that includes proposed rate adjustments and the continuation and modification of certain existing riders effective June 2015 through May 2018. The proposal includes a recommended auction schedule, a return on common equity of 10.65% on capital costs for certain riders and estimates an average decrease in rates of 9% over the three-year term of the plan for customers who receive their RPM capacity and energy auction-based generation through OPCo. The proposal also includes a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based purchase power agreement. In May 2014, intervenors and the PUCO staff filed testimony that provided various recommendations including the rejection and/or modification of various riders, including the Distribution Investment Rider and the proposed PPA. Hearings at the PUCO in the ESP case were held in June 2014. Additionally, in July 2014, OPCo submitted a separate application to continue the RSR established in the June 2012 - May 2015 ESP to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh until the balance of the capacity deferrals has been collected. In October 2014, OPCo filed a separate application with the PUCO to propose a new PPA for inclusion in the PPA rider, discussed above. The new PPA would include an additional 2,671 MW to be purchased from AGR over the life of the respective generating units.

If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, its deferred capacity cost and its proposed PPA rider, it could reduce future net income and cash flows and impact financial condition. See “Ohio Electric Security Plan Filings” section of Note 4.

2012 Texas Base Rate Case

Upon rehearing in January 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. The resulting annual base rate increase is approximately $52 million. In May 2014, intervenors filed appeals of the order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals and filed initial responses. If certain parts of the PUCT order are overturned it could reduce future net income and cash flows and impact financial condition. See the "2012 Texas Base Rate Case" section of Note 4.

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 of the Turk Plant. In February 2013, a settlement was approved by the LPSC that increased Louisiana total rates by approximately $2 million annually, effective March 2013. The March 2013 base rates are based upon a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. If the LPSC orders refunds based upon the pending staff review of the cost of service or the prudence review of the Turk Plant, it could reduce future net income and cash flows and impact financial condition. See the “2012 Louisiana Formula Rate Filing” section of Note 4.

2014 Oklahoma Base Rate Case

In January 2014, PSO filed a request with the OCC to increase annual base rates by $38 million, based upon a 10.5% return on common equity. This revenue increase includes a proposed increase in depreciation rates of $29 million. In addition, the filing proposed recovery of advanced metering costs through a separate rider over a three-year deployment period requesting $7 million of revenues in year one, increasing to $28 million in year three. The filing also proposed expansion of an existing transmission rider currently recovered in base rates to include additional transmission-related costs that are expected to increase over the next several years.

In June 2014, a non-unanimous stipulation agreement between PSO, the OCC staff and certain intervenors was filed with the OCC. The parties to the stipulation recommended no overall change to the transmission rider or to annual revenues, other than additional revenues through a separate rider related to advanced metering costs, and that the terms of the stipulation be effective November 2014. The advanced metering rider would provide $7 million of revenues in 2014 and increase to $27 million in 2016. New depreciation rates are recommended for advanced metering investments and existing meters, also to be effective November 2014. Additionally, the stipulation recommends recovery of regulatory assets for 2013 storms and regulatory case expenses. In July 2014, the Attorney General joined in the stipulation agreement. A hearing at the OCC was held in July 2014. An order is anticipated in the fourth quarter of 2014. If the OCC were to disallow any portion of this settlement agreement, it could reduce future net income and cash flows and impact financial condition. See the “2014 Oklahoma Base Rate Case” section of Note 4.

2014 Virginia Biennial Base Rate Case

In March 2014, APCo filed a biennial generation and distribution base rate case with the Virginia SCC. In accordance with a Virginia statute, APCo did not request an increase in base rates as its Virginia retail combined rate of return on common equity for 2012 and 2013 is within the statutory range of the approved return on common equity of 10.9%. The filing included a request to decrease generation depreciation rates, effective February 2015, primarily due to the change in the expected service life of certain plants. Additionally, the filing included a request to amortize $7 million annually for two years, beginning February 2015, related to IGCC and other deferred costs.

In August 2014, the Virginia SCC staff and intervenors filed testimony concluding that APCo's adjusted earned rate of return on common equity for 2012 and 2013, reflecting their recommended adjustments, was above the allowed threshold. Recommendations included (a) refunds to customers ranging from $15 million to $22 million, (b) the write-off of certain APCo assets, including IGCC pre-construction costs and previously approved 2009 storm costs, totaling $27 million and (c) $38 million in increased depreciation expense annually, retroactive to January 1, 2014, primarily related to accelerating depreciation on APCo generation assets to be retired in the second quarter of 2015. Hearings at the Virginia SCC were held in September 2014. A decision is expected in November 2014. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “2014 Virginia Biennial Base Rate Case” section of Note 4.

2014 West Virginia Base Rate Case

In June 2014, APCo filed a request with the WVPSC to increase annual base rates by $181 million, based upon a 10.62% return on common equity, to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates and requested recovery of $89 million over five years related to 2012 West Virginia storm costs, IGCC and other deferred costs. In addition to the base rate request, the filing also included a request to implement a rider of approximately $45 million annually to recover vegetation management costs, including a return on capital investment. In October 2014, the WVPSC approved APCo's motion to revise the procedural schedule which included the extension of the intervention period to November 2014 and a delay in the implementation of new rates from April 2015 to May 2015. Hearings at the WVPSC are scheduled for January 2015. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “2014 West Virginia Base Rate Case” section of Note 4.

Plant Transfer

APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a cost-of-service basis. West Virginia generally allows for timely recovery of fuel costs through an expanded net energy cost which trues-up to actual expenses. In March 2014, APCo and WPCo filed a request with the WVPSC for approval to transfer at net book value to WPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity presently owned by AGR. In April 2014, APCo and WPCo filed testimony that supported their request and proposed a base rate surcharge of $113 million, to be offset by an equal reduction in the ENEC revenues, to be effective upon the transfer of the Mitchell Plant to WPCo. In June 2014, the FERC issued an order approving AGR and WPCo's request to transfer AGR’s one-half interest in the Mitchell Plant to WPCo.

In October 2014, a stipulation agreement between APCo, WPCo, the WVPSC staff and intervenors in the case was filed with the WVPSC. The stipulation agreement recommended approval for WPCo to acquire, at net book value, the one-half interest in the Mitchell Plant, excluding $20 million of certain assets, which will be paid by WPCo and recovered as a regulatory asset over the life of the plant. Additionally, the agreement stated that 82.5% of the costs associated with the acquired interest will be reflected in rates effective from the date of the transfer via a surcharge with an offset in ENEC revenues. The remaining 17.5% of the costs associated with the acquired interest is to be included in rates by January 2020. The agreement also proposed that WPCo share the energy margins for 82.5% of the plant’s output with ratepayers and that WPCo retain all of the energy margins from sales into the wholesale market on the remaining 17.5%, to offset fixed costs associated with this portion, until the remaining portion is approved for inclusion in rates. Management anticipates an order related to the proposed plant transfer will be issued in the fourth quarter of 2014. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “Plant Transfer” section of APCo Rate Matters in Note 4.

Kentucky Fuel Adjustment Clause Review

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. An intervenor has requested and received a revised procedural schedule to determine if the allocation of fuel costs has been applied appropriately. In October 2014, intervenors filed testimony that recommended the KPSC direct KPCo to modify its fuel allocation methodology and order a refund to customers of approximately $13 million, plus carrying charges at a weighted average cost of capital, related to the period January 1, 2014 through April 30, 2014. A hearing at the KPSC is scheduled for November 2014. Management believes the methodology used to determine fuel costs is appropriate and intends to oppose the recommendations filed by intervenors. If the KPSC directs KPCo to modify its fuel allocation methodology, it could affect the allocation of costs for all periods beginning January 2014, and if any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “Kentucky Fuel Adjustment Clause Review” section of Note 4.

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PJM Capacity Market

AGR is required to offer all of its available generation capacity in the PJM RPM auction, which is conducted three years in advance of the actual delivery year. Therefore, the majority of AGR generation assets are subject to PJM capacity prices for periods after May 2015. Through May 2015, AGR will provide generation capacity to OPCo for both switched and non-switched OPCo generation customers. For switched customers, OPCo pays AGR $188.88/MW day for capacity. For non-switched OPCo generation customers, OPCo pays AGR its blended tariff rate for capacity consisting of $188.88/MW day for auctioned load and the non-fuel generation portion of its base rate for non-auctioned load. AGR's excess capacity is subject to the PJM RPM auction. Shown below are the current auction prices for capacity, as announced/settled by PJM:

PJM Auction Period	PJM Base Auction Price (per MW day)
June 2013 through May 2014	$ 27.73
June 2014 through May 2015	125.99
June 2015 through May 2016	136.00
June 2016 through May 2017	59.37
June 2017 through May 2018	120.00

We expect a significant decline in AGR capacity revenues after May 2015 when the Power Supply Agreement between AGR and OPCo ends. Additionally, we expect a decline in AGR capacity revenues from June 2016 through May 2017 based upon the decrease in the PJM base auction price.

In 2013, AEP formed a coalition with other utility companies to address mutual concerns related to the PJM capacity auction process. The advocacy work included: (a) assuring that capacity imports had firm transmission and could be dispatched by PJM as well as establishing more limiting criteria, (b) placing limits on the number of MWs of summer-only demand response to assure more year-round reliability, (c) modification and enforcement of the dispatch of demand response to better reflect real-time capacity requirements and (d) tightening of rules for incremental auctions in which speculative bidders sell resources in the base auction and buy back that capacity in an incremental auction, resulting in no additional capacity and artificially suppressing market prices.

PJM made four FERC filings related to these four issues beginning in the fall of 2013. FERC accepted the majority of the PJM recommendations in the first three filings. However, FERC rejected the fourth filing on incremental auctions, but set the docket for a technical conference for further discussion.

Welsh Plant, Units 1 and 3 - Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet mercury and air toxics standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of September 30, 2014, SWEPCo has incurred costs of $112 million and has contractual construction obligations of $84 million related to these projects. SWEPCo will seek to recover these project costs from customers through filings at the state commissions and FERC. These environmental projects could be adversely impacted by pending carbon emission regulations. See "CO_2 Regulation" section of "Environmental Issues" below. As of September 30, 2014, the net book value of Welsh Plant, Units 1 and 3 was $335 million, before cost of removal, including materials and supplies inventory and CWIP. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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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 4 - Rate Matters, Note 6 - Commitments, Guarantees and Contingencies and the "Litigation" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2013 Annual Report. Additionally, see Note 4 - Rate Matters and Note 5 - 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.

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court granted our motion to transfer this case to the U.S. District Court for the Southern District of Ohio. Our motion to dismiss the case, filed in October 2013, is pending. We will continue to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

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 SO_2, NO_x, PM and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, proposals governing the beneficial use and disposal of coal combustion products, proposed clean water rules and renewal permits for certain water discharges that are currently under appeal.

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 CO_2 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 2013 Annual Report. We will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. 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.

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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 September 30, 2014, 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 generating facilities. Based upon our estimates, investment to meet these requirements ranges from approximately $3 billion to $3.5 billion through 2020. Several proposed regulations issued during 2014, including CO_2 and the Clean Water Act, are currently under review and we cannot currently predict the impact these programs may have on future resource plans or our existing generating fleet; however, the costs may be substantial. These amounts include investments to convert some of our coal generation to natural gas. 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 (SIPs) or federal implementation plans (FIPs) 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. In addition, we are continuing to evaluate the economic feasibility of environmental investments on both regulated and nonregulated plants.

Subject to the factors listed above and based upon our continuing evaluation, we intend to retire the following plants or units of plants before or during 2016:

Company	Plant Name and Unit	Generating Capacity (in MWs)
AGR	Kammer Plant	630
AGR	Muskingum River Plant	1,440
AGR	Picway Plant	100
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/AGR	Sporn Plant	600
I&M	Tanners Creek Plant	995
KPCo	Big Sandy Plant, Unit 2	800
PSO	Northeastern Station, Unit 4	470
SWEPCo	Welsh Plant, Unit 2	528
Total		6,533

As of September 30, 2014, the net book value of the AGR units listed above was zero. The net book value before cost of removal, including related material and supplies inventory and CWIP balances, of the regulated plants in the table above was $973 million.

In addition, we are in the process of obtaining permits following the KPSC's approval for the conversion of KPCo's 278 MW Big Sandy Plant, Unit 1 to natural gas. As of September 30, 2014, the net book value before cost of removal, including related material and supplies inventory and CWIP balances, of Big Sandy Plant, Unit 1 was $99 million.

PSO received Federal EPA approval of the Oklahoma SIP, in February 2014, related to the environmental compliance plan for Northeastern Station, Unit 3.

Volatility in fuel prices, pending environmental rules and other market factors could also have an adverse impact on the accounting evaluation of the recoverability of the net book values of coal-fired units. For regulated plants that we may close early, we are seeking regulatory recovery of remaining net book values. 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 and impact financial condition.

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 the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. The U.S. Court of Appeals for the District of Columbia Circuit issued an order in 2011 staying the effective date of the rule pending judicial review. In 2012, a panel of the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. That decision was appealed to the U.S. Supreme Court, which reversed the decision in part and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit. Nearly all of the states in which our power plants are located are covered by CAIR. See "Cross-State Air Pollution Rule (CSAPR)" section below.

The Federal EPA issued the final maximum achievable control technology (MACT) standards for coal and oil-fired power plants in 2012. See "Mercury and Other Hazardous Air Pollutants (HAPs) Regulation" section below.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how 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 SIPs or, if SIPs are not adequate or are not developed on schedule, through FIPs. The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas. 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 CSAPR trading programs to use those programs in place of source-specific BART for SO_2 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.

In 2009, the Federal EPA issued a final mandatory reporting rule for CO_2 and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for greenhouse gas emissions from new motor vehicles in 2009. The Federal EPA determined that greenhouse gas emissions from stationary sources will be subject to regulation under the CAA beginning January 2011 and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, SIP calls and FIPs. The Federal EPA has proposed to include CO_2 emissions in standards that apply to new electric utility units and will consider whether such standards are appropriate for other source categories in the future. See "CO_2 Regulation" section below.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for PM, SO_2 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.

Cross-State Air Pollution Rule (CSAPR)

In 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in 2012. CSAPR relies on newly-created SO_2 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 is 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 SO_2 and NO_x in addition to the seasonal NO_x program. The annual SO_2 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 2011, the court granted the motions for stay. In 2012, the court issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the CAIR 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 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 petition for further review filed by the Federal EPA and other parties in the U.S. Supreme Court was granted in June 2013. In April 2014, the U.S. Supreme Court issued a decision reversing in part the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanding the case for further proceedings consistent with the opinion. The parties have filed motions to govern further proceedings. The Federal EPA has filed a motion to lift the stay and allow Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. Until the court acts on this motion, CAIR will remain in effect. Separate appeals of the Error Corrections Rule and the further revisions have been filed but no briefing schedules have been established. We cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 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 several nonmercury metals) 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. Petitions for administrative reconsideration and judicial review were 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. The Federal EPA issued revisions to the new source standards consistent with the proposed rule, except the start-up and shut down provisions in March 2013. The Federal EPA is still considering additional changes to the start-up and shut down provisions. In April 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the April 2012 final rule. Industry and environmental groups filed petitions for further review in the U.S. Supreme Court.

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. We have obtained a one-year administrative extension at several units to facilitate 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 remain concerned about the availability

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of compliance extensions, the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines and the lack of coordination among the Mercury and Air Toxics Standards schedule and other environmental requirements.

CO_2 Regulation

President Obama issued a memorandum to the Administrator of the Federal EPA directing the agency to develop and issue a new proposal regulating carbon emissions from new electric generating units. The new proposal was issued in September 2013 and requires new large natural gas units to meet 1,000 pounds of CO_2 per MWh of electricity generated and small natural gas units to meet 1,100 pounds of CO_2 per MWh. New coal-fired units are required to meet the 1,100 pounds of CO_2 per MWh limit, with the option to meet the tighter limits if they choose to average emissions over multiple years. The proposal was published in the Federal Register in January 2014.

The Federal EPA was also directed to develop and issue a separate proposal regulating carbon emissions from modified and reconstructed electric generating units (EGUs) and to issue guidelines for existing EGUs before June 2014, to finalize those standards by June 2015 and to require states to submit revisions to their implementation plans including such standards no later than June 2016. The President directed the Federal EPA, in developing this proposal, to directly engage states, leaders in the power sector, labor leaders and other stakeholders, to tailor the regulations to reduce costs, to develop market-based instruments and allow regulatory flexibilities and "assure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power." The guidelines use a "portfolio" approach to reducing emissions from existing sources that includes efficiency improvements at coal plants, displacing coal-fired generation with increased utilization of natural gas combined cycle units, expanding renewable resources and increasing customer energy efficiency. The Federal EPA issued proposed guidelines establishing state goals for CO_2 emissions from existing EGUs and comments are due December 1, 2014. The Federal EPA also issued proposed regulations governing emissions of CO_2 from modified and reconstructed EGUs in June 2014 and comments are due in October 2014. The standards for modified and reconstructed units include several options, including use of historic baselines or energy efficiency audits to establish source-specific CO_2 emission rates or to limit CO_2 emissions to no more than 1,900 pounds per MWh at larger coal units and 2,100 pounds per MWh at smaller coal units. These proposed regulations are currently under review. We cannot currently predict the impact these programs may have on future resource plans or our existing generating fleet, but the costs may be substantial.

In 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 CO_2 emissions from new motor vehicles and its plan to phase in regulation of CO_2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit denied a petition for rehearing. In June 2014, the U.S. Supreme Court determined that the Federal EPA was not compelled to regulate CO_2 emissions from stationary sources under the Title V or PSD programs as a result of its adoption of the motor vehicle standards, but that sources otherwise required to obtain a PSD permit may be required to perform a Best Available Control Technology analysis for CO_2 emissions if they exceed a reasonable level. The Federal EPA must undertake additional rulemaking to implement the court's decision and establish an appropriate level.

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 and also FGD gypsum generated at some coal-fired plants. 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 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. In 2013, the Federal EPA also issued a notice of data availability requesting comments on a narrow set of issues.

Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. The Federal EPA opposed the petition and sought additional time to coordinate the issuance of a final rule with the issuance of new effluent limitations under the Clean Water Act (CWA) for utility facilities. In October 2013, the U.S. District Court for the District of Columbia issued a final order partially ruling in favor of the Federal EPA for dismissal of two counts, ruling in favor of the environmental organizations on one count and directing the Federal EPA to provide the court with a proposed schedule for completion of the rulemaking. The court established December 19, 2014 as the Federal EPA’s deadline for publication of the rule.

In February 2014, the Federal EPA completed a risk evaluation of the beneficial uses of coal fly ash in concrete and FGD gypsum in wallboard and concluded that the Federal EPA supports these beneficial uses. 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. We 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. In 2012, the Federal EPA issued additional Notices of Data Availability and requested public comments. The final rule was released by the Federal EPA in May 2014 and affects all plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with the impingement standard and requires site-specific studies to determine appropriate entrainment compliance measures at facilities withdrawing more than 125 million gallons per day. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats. Facilities with existing closed cycle recirculating cooling systems, as defined in the rule, are not expected to require any technology changes. Facilities subject to both the impingement standard and site-specific entrainment studies will typically be given at least three years to conduct and submit the results of those studies to the permit agency. Compliance timeframes will then be established by the permit agency through each facility’s National Pollutant Discharge Elimination System (NPDES) permit for installation of any required technology changes, as those permits are renewed over the next five to eight years. Petitions for review of the final rule have been filed by industry and environmental groups and have been consolidated in the U.S. Court of Appeals for the Fourth Circuit.

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 September 2015. 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 continue to 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 submitted detailed comments to the Federal EPA in September 2013 and participated in comments filed by various organizations of which we are members.

In April 2014, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a proposed rule to clarify the scope of the regulatory definition of “waters of the United States” in light of recent U.S. Supreme Court cases and published the proposed rule in the Federal Register. The CWA provides for federal jurisdiction over “navigable waters” defined as “the waters of the United States.” This proposed jurisdictional definition will apply to all CWA programs, potentially impacting generation, transmission and distribution permitting and compliance requirements. Among those programs are: permits for wastewater and storm water discharges, permits for impacts to wetlands and water bodies and oil spill prevention planning. We agree that clarity and efficiency in the permitting process is needed. We are concerned that the proposed rule introduces new concepts and could subject more of our operations to CWA jurisdiction, thereby increasing the time and complexity of permitting. We will continue to evaluate the rule and its financial impact on the AEP System. We plan to submit comments and also participate in the preparation of comments to be filed by various organizations of which we are members. Comments are due in October 2014.

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 CO_2 emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing requirements of the CAA.

Several states have adopted programs that directly regulate CO_2 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.

Future federal and state legislation or regulations that mandate limits on the emission of CO_2 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 2013 Form 10-K under the headings entitled “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 Vertically Integrated Utilities 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.

During the fourth quarter of 2013, we changed the structure of our internal organization which resulted in a change in the composition of our reportable segments. In accordance with authoritative accounting guidance for segment reporting, prior period financial information has been recast in the financial statements and footnotes to be comparable to the current year presentation of reportable segments.

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

Vertically Integrated Utilities

- Generation, transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEGCo, APCo, I&M, KGPCo, KPCo, PSO, SWEPCo and WPCo.

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
- OPCo purchases energy to serve SSO customers and provides capacity for all connected load.

AEP Transmission Holdco

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

Generation & Marketing

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

AEP River Operations

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

The table below presents Earnings Attributable to AEP Common Shareholders by segment for the three and nine months ended September 30, 2014 and 2013.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Vertically Integrated Utilities	$219	$173	$651	$505
Transmission and Distribution Utilities	92	119	279	281
AEP Transmission Holdco	43	22	114	53
Generation & Marketing	117	112	378	188
AEP River Operations	11	(1)	17	(12)
Corporate and Other (a)	11	8	4	119
Earnings Attributable to AEP Common Shareholders	$493	$433	$1,443	$1,134

(a) While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

AEP CONSOLIDATED

Third Quarter of 2014 Compared to Third Quarter of 2013

Earnings Attributable to AEP Common Shareholders increased from $433 million in 2013 to $493 million in 2014 primarily due to:

- Impairments during the third quarter of 2013 related to the following:
- A decision by the PUCT determining that AFUDC on the Turk Plant was included in the Texas capital cost cap.
- A decision from the KPSC disallowing scrubber costs on KPCo's Big Sandy Plant.
- Successful rate proceedings in our various jurisdictions.
- An increase in transmission investment which resulted in higher revenues and income.

These increases were partially offset by:

- A decrease in weather-related usage.
- An increase in plant maintenance.
- An increase in vegetation management expenses.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

Earnings Attributable to AEP Common Shareholders increased from $1.1 billion in 2013 to $1.4 billion in 2014 primarily due to:

- Impairments during 2013 related to the following:
- Muskingum River Plant, Unit 5.
- A decision by the PUCT determining that AFUDC on the Turk Plant was included in the Texas capital cost cap.
- A decision from the KPSC disallowing scrubber costs on KPCo's Big Sandy Plant.
- Successful rate proceedings in our various jurisdictions.
- A net increase in weather-related usage.
- Higher market prices and increased sales volumes.
- An increase in transmission investment which resulted in higher revenues and income.

These increases were partially offset by:

- A favorable U.K. Windfall Tax decision by the U.S. Supreme Court in the second quarter of 2013.
- An increase in depreciation expense due to increased investments.
- An increase in vegetation management expenses.
- An increase in plant maintenance.

Our results of operations by operating segment are discussed below.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
	(in millions)			
Revenues	$2,450	$2,738	$7,288	$7,555
Fuel and Purchased Electricity	1,010	1,325	3,038	3,590
Gross Margin	1,440	1,413	4,250	3,965
Other Operation and Maintenance	615	524	1,809	1,653
Asset Impairments and Other Related Charges	—	144	—	144
Depreciation and Amortization	257	233	772	702
Taxes Other Than Income Taxes	95	93	278	277
Operating Income	473	419	1,391	1,189
Interest and Investment Income	2	—	3	7
Carrying Costs Income	1	5	2	10
Allowance for Equity Funds Used During Construction	12	9	33	27
Interest Expense	(133)	(136)	(396)	(408)
Income Before Income Tax Expense and Equity Earnings	355	297	1,033	825
Income Tax Expense	135	123	380	318
Equity Earnings of Unconsolidated Subsidiaries	—	—	1	1
Net Income	220	174	654	508
Net Income Attributable to Noncontrolling Interests	1	1	3	3
Earnings Attributable to AEP Common Shareholders	$219	$173	$651	$505

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended September 30, 2014	2013		Nine Months Ended September 30, 2014	2013	
	(in millions of KWhs)					
Retail:						
Residential	8,505	9,043		26,126	25,710	
Commercial	6,743	6,910		18,980	18,913	
Industrial	8,962	8,634		26,319	25,602	
Miscellaneous	608	602		1,740	1,717	
Total Retail	24,818	25,189		73,165	71,942	
Wholesale (a)	8,632	NM	(b)	27,418	NM	(b)

(a) Includes off-system sales, municipalities and cooperatives, unit power and other wholesale customers.
(b) 2014 is not comparable to 2013 due to the 2013 asset transfers related to corporate separation in Ohio on December 31, 2013 and the termination of the Interconnection Agreement effective January 1, 2014.
NM Not meaningful.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. 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 Vertically Integrated Utilities

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in degree days)			
Eastern Region				
Actual – Heating (a)	2	1	2,248	1,854
Normal – Heating (b)	5	6	1,736	1,741
Actual – Cooling (c)	559	657	921	1,007
Normal – Cooling (b)	733	733	1,062	1,062
Western Region				
Actual – Heating (a)	—	—	1,233	1,009
Normal – Heating (b)	1	2	921	923
Actual – Cooling (c)	1,246	1,387	1,926	2,070
Normal – Cooling (b)	1,399	1,396	2,109	2,106

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

Third Quarter of 2014 Compared to Third Quarter of 2013
Reconciliation of Third Quarter of 2013 to Third Quarter of 2014
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Third Quarter of 2013	$173
Changes in Gross Margin:	
Retail Margins	23
Off-system Sales	15
Transmission Revenues	1
Other Revenues	(12)
Total Change in Gross Margin	27
Changes in Expenses and Other:	
Other Operation and Maintenance	(91)
Asset Impairments and Other Related Charges	144
Depreciation and Amortization	(24)
Taxes Other Than Income Taxes	(2)
Interest and Investment Income	2
Carrying Costs Income	(4)
Allowance for Equity Funds Used During Construction	3
Interest Expense	3
Total Change in Expenses and Other	31
Income Tax Expense	(12)
Third Quarter of 2014	$219

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 $23 million primarily due to the following:
- The effect of successful rate proceedings in our service territories which include:
- APCo - $43 million.
- KPCo - $14 million.

For the rate increases described above, $35 million of these increases relate to riders/trackers which have corresponding increases in expense items below.
These increases were partially offset by:
- A $36 million decrease in weather-related usage primarily due to a decrease in cooling degree days.
- Margins from Off-system Sales increased $15 million primarily due to changes in margin sharing.
- Other Revenues decreased $12 million primarily due to a decrease in barging. This decrease in barging is a result of the River Transportation Division (RTD) no longer serving plants transferred from OPCo to AGR effective December 31, 2013 as a result of corporate separation in Ohio. This decrease in RTD revenue has a corresponding decrease in Other Operation and Maintenance expenses for barging as discussed below.

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

- Other Operation and Maintenance expenses increased $91 million primarily due to the following:
  - A $19 million increase in plant outage and maintenance expenses.
  - A $17 million increase in recoverable expenses, including PJM expenses, currently fully recovered in rate recovery riders/trackers partially offset by RTD expenses for barging activities.
  - A $17 million increase in employee-related expenses.
  - An $11 million increase in transmission and distribution expenses primarily due to storms and non-recoverable SPP services.
  - A $10 million increase in uncollectible accounts primarily due to the favorable resolution of contingencies related to pole attachments in the third quarter of 2013.
  - A $9 million increase in approved incremental vegetation management expenses.
  - An $8 million increase due to an accrual for expected environmental remediation costs.
- Asset Impairments and Other Related Charges decreased $144 million primarily due to the following:
  - A $111 million decrease due to the third quarter 2013 write-off of AFUDC on the Turk Plant.
  - A $33 million decrease due to KPCo's third quarter 2013 write-off of scrubber costs on the Big Sandy Plant and other generation in accordance with the KPSC's October 2013 order.
- Depreciation and Amortization expenses increased $24 million primarily due to overall higher depreciable base.
- Income Tax Expense increased $12 million primarily due to an increase in pretax book income partially offset by other book/tax differences which are accounted for on a flow-through basis.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013
Reconciliation of Nine Months Ended September 30, 2013 to Nine Months Ended September 30, 2014
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Nine Months Ended September 30, 2013	$505	
Changes in Gross Margin:		
Retail Margins	186	
Off-system Sales	121	
Transmission Revenues	17	
Other Revenues	(39	)
Total Change in Gross Margin	285	
Changes in Expenses and Other:		
Other Operation and Maintenance	(156	)
Asset Impairments and Other Related Charges	144	
Depreciation and Amortization	(70	)
Taxes Other Than Income Taxes	(1	)
Interest and Investment Income	(4	)
Carrying Costs Income	(8	)
Allowance for Equity Funds Used During Construction	6	
Interest Expense	12	
Total Change in Expenses and Other	(77	)
Income Tax Expense	(62	)
Nine Months Ended September 30, 2014	$651	

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 $186 million primarily due to the following:
- The effect of successful rate proceedings in our service territories which include:
- APCo - $114 million.
- KPCo - $41 million.
- SWEPCo - $28 million.
- I&M - $28 million.

For the rate increases described above, $87 million of these increases relate to riders/trackers which have corresponding increases in expense items below.
- A $16 million increase due to favorable weather conditions.

These increases were partially offset by:
- A $39 million increase in PJM expenses net of recovery or offsets.
- Margins from Off-system Sales increased $121 million primarily due to higher market prices.
- Transmission Revenues increased $17 million primarily due to increased investment in the PJM region.
- Other Revenues decreased $39 million primarily due to a decrease in barging. This decrease in barging is a result of the RTD no longer serving plants transferred from OPCo to AGR as of December 31, 2013 as a result of corporate separation in Ohio. This decrease in RTD revenue has a corresponding decrease in Other Operation and Maintenance expenses for barging as discussed below.

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

- Other Operation and Maintenance expenses increased $156 million primarily due to the following:
  - A $38 million increase in recoverable expenses, including PJM expenses, currently fully recovered in rate recovery riders/trackers partially offset by RTD expenses for barging activities.
  - A $38 million increase in transmission expenses primarily related to PJM and SPP services.
  - A $29 million increase in plant outage and maintenance expenses.
  - A $25 million increase due to an agreement reached to settle an insurance claim in the first quarter of 2013.
  - A $20 million increase in employee-related expenses.
  - A $14 million increase in distribution and transmission vegetation management expenses.

  These increases were partially offset by:
  - 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.
- Asset Impairments and Other Related Charges decreased $144 million primarily due to the following:
  - A $111 million decrease due to the third quarter 2013 write-off of AFUDC on the Turk Plant.
  - A $33 million decrease due to KPCo's third quarter 2013 write-off of scrubber costs on the Big Sandy Plant and other generation in accordance with the KPSC's October 2013 order.
- Depreciation and Amortization expenses increased $70 million primarily due to overall higher depreciable base.
- Carrying Cost Income decreased $8 million primarily due to the November 2013 securitization of the West Virginia ENEC deferral balance.
- Allowance for Equity Funds Used During Construction increased $6 million primarily due to an increase in environmental construction projects.
- Interest Expense decreased $12 million primarily due to the following:
  - A $5 million decrease due to the retirement of KPCo Senior Unsecured Notes in the third quarter of 2013.
  - A $4 million decrease due to rate approvals in Louisiana and Texas as well as an increase in the debt component of AFUDC due to increased transmission and environmental projects.
- Income Tax Expense increased $62 million primarily due to an increase in pretax book income.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
	(in millions)			
Revenues	$1,231	$1,195	$3,580	$3,393
Fuel and Purchased Electricity	377	406	1,123	1,260
Amortization of Generation Deferrals	27	—	83	—
Gross Margin	827	789	2,374	2,133
Other Operation and Maintenance	329	254	920	717
Depreciation and Amortization	182	165	499	449
Taxes Other Than Income Taxes	117	118	344	327
Operating Income	199	252	611	640
Interest and Investment Income	3	—	9	1
Carrying Costs Income	6	3	20	10
Allowance for Equity Funds Used During Construction	3	2	8	4
Interest Expense	(68)	(72)	(210)	(219)
Income Before Income Tax Expense	143	185	438	436
Income Tax Expense	51	66	159	155
Net Income	92	119	279	281
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$92	$119	$279	$281

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended September 30, 2014	2013		Nine Months Ended September 30, 2014	2013	
	(in millions of KWhs)					
Retail:						
Residential	7,194	7,371		20,280	19,589	
Commercial	6,796	6,827		19,012	18,693	
Industrial	5,489	5,648		16,262	17,277	
Miscellaneous	187	195		540	535	
Total Retail (a)	19,666	20,041		56,094	56,094	
Wholesale (b)	575	NM	(c)	1,727	NM	(c)

(a) Represents energy delivered to distribution customers.
(b) Ohio's contractually obligated purchases of OVEC power sold into PJM.
(c) 2014 is not comparable to 2013 due to the 2013 asset transfers related to corporate separation in Ohio on December 31, 2013 and the termination of the Interconnection Agreement effective January 1, 2014.
NM Not meaningful.

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Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. 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 Transmission and Distribution Utilities

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in degree days)			
Eastern Region				
Actual – Heating (a)	1	1	2,540	2,165
Normal – Heating (b)	7	8	2,074	2,083
Actual – Cooling (c)	581	645	943	991
Normal – Cooling (b)	663	660	946	940
Western Region				
Actual – Heating (a)	—	—	302	143
Normal – Heating (b)	—	—	200	205
Actual – Cooling (d)	1,367	1,387	2,309	2,464
Normal – Cooling (b)	1,346	1,339	2,358	2,346

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 70 degree temperature base.

Third Quarter of 2014 Compared to Third Quarter of 2013
Reconciliation of Third Quarter of 2013 to Third Quarter of 2014
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Third Quarter of 2013	$119
Changes in Gross Margin:	
Retail Margins	25
Transmission Revenues	12
Other Revenues	1
Total Change in Gross Margin	38
Changes in Expenses and Other:	
Other Operation and Maintenance	(75)
Depreciation and Amortization	(17)
Taxes Other Than Income Taxes	1
Interest and Investment Income	3
Carrying Costs Income	3
Allowance for Equity Funds Used During Construction	1
Interest Expense	4
Total Change in Expenses and Other	(80)
Income Tax Expense	15
Third Quarter of 2014	$92

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity and amortization of generation deferrals were as follows:

- Retail Margins increased $25 million primarily due to the following:
  - A $23 million increase in TCC and TNC revenues primarily due to increased transmission investment in Texas as well as increased usage.
  - A $2 million increase in revenues primarily associated with Ohio rate riders/trackers and PJM revenues, partially offset by regulatory provisions. These increases have corresponding increases in expense items discussed below.
- Transmission Revenues increased $12 million primarily due to increased transmission investment, increased transmission revenues from customers who have switched to alternative CRES providers and rate increases for customers in the PJM region. This increase in transmission revenues related to CRES providers primarily offsets lost revenues included in Retail Margins above.

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

- Other Operation and Maintenance expenses increased $75 million primarily due to the following:
  - A $74 million increase in expenses, including PJM expenses and the Ohio storm amortization, currently fully recovered in rate recovery riders/trackers.
  - A $9 million increase in employee-related expenses.

  These increases were partially offset by:
  - A $7 million decrease in transmission expenses primarily related to PJM services.
- Depreciation and Amortization expenses increased $17 million primarily due to the following:
  - A $9 million increase in amortization related to TCC and OPCo securitizations, which are offset in Retail Margins above.
  - An $8 million increase due to an increase in the depreciable base of transmission and distribution assets.
- Interest Expense decreased $4 million primarily due to reduced long-term debt outstanding.
- Income Tax Expense decreased $15 million primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013
Reconciliation of Nine Months Ended September 30, 2013 to Nine Months Ended September 30, 2014
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Nine Months Ended September 30, 2013	$281	
Changes in Gross Margin:		
Retail Margins	172	
Transmission Revenues	59	
Other Revenues	10	
Total Change in Gross Margin	241	
Changes in Expenses and Other:		
Other Operation and Maintenance	(203	)
Depreciation and Amortization	(50	)
Taxes Other Than Income Taxes	(17	)
Interest and Investment Income	8	
Carrying Costs Income	10	
Allowance for Equity Funds Used During Construction	4	
Interest Expense	9	
Total Change in Expenses and Other	(239	)
Income Tax Expense	(4	)
Nine Months Ended September 30, 2014	$279	

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity and amortization of generation deferrals were as follows:

- Retail Margins increased $172 million primarily due to the following:
  - A $101 million increase in revenues primarily associated with Ohio rate riders/trackers and PJM revenues, partially offset by regulatory provisions. These increases have corresponding increases in expense items discussed below.
  - A $71 million increase in TCC and TNC revenues primarily due to increased transmission investment in Texas as well as increased usage.
- Transmission Revenues increased $59 million primarily due to increased transmission investment, increased transmission revenues from customers who have switched to alternative CRES providers and rate increases for customers in the PJM region. This increase in transmission revenues related to CRES providers primarily offsets lost revenues included in Retail Margins above.
- Other Revenues increased $10 million primarily due to an increase in Texas securitization revenues which is offset in Depreciation and Amortization below. This increase is also partially offset by a $4 million demand side management bonus recorded in 2013.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $203 million primarily due to the following:
  - A $150 million increase in recoverable expenses, including PJM expenses and the Ohio storm amortization, currently fully recovered in rate recovery riders/trackers.
  - A $19 million increase in expenses related to various distribution services and vegetation management.
  - A $14 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 has corresponding increases in Retail Margins above.
  - An $11 million increase in employee-related expenses.
  - A $7 million increase in storm-related expenses primarily in OPCo's service territory.
- Depreciation and Amortization expenses increased $50 million primarily due to the following:
  - A $32 million increase in amortization related to TCC and OPCo securitizations, which are offset in Retail Margins.
  - An $18 million increase due to an increase in the depreciable base of transmission and distribution assets.
- Taxes Other Than Income Taxes increased $17 million primarily due to increased property taxes.
- Interest and Investment Income increased $8 million primarily due to interest on affiliated notes resulting from corporate separation.
- Carrying Costs Income increased $10 million primarily due to increased capacity deferral carrying charges.
- Interest Expense decreased $9 million primarily due to reduced long-term debt outstanding.

AEP TRANSMISSION HOLDCO

Third Quarter of 2014 Compared to Third Quarter of 2013

Earnings Attributable to AEP Common Shareholders from our AEP Transmission Holdco segment increased from $22 million in 2013 to $43 million in 2014 primarily due to an increase in investments by our wholly-owned transmission subsidiaries and ETT.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

Earnings Attributable to AEP Common Shareholders from our AEP Transmission Holdco segment increased from $53 million in 2013 to $114 million in 2014 primarily due to an increase in investments by our wholly-owned transmission subsidiaries and ETT. During this period, net plant increased from $1.3 billion to $2.4 billion.

GENERATION & MARKETING

	Three Months Ended September 30,		Nine Months Ended September 30,	
Generation & Marketing	2014	2013	2014	2013
	(in millions)			
Revenues	$901	$1,001	$3,065	$2,813
Fuel, Purchased Electricity and Other	529	648	1,894	1,764
Gross Margin	372	353	1,171	1,049
Other Operation and Maintenance	122	106	363	342
Asset Impairments and Other Related Charges	—	—	—	154
Depreciation and Amortization	56	57	169	180
Taxes Other Than Income Taxes	12	11	37	44
Operating Income	182	179	602	329
Interest and Investment Income	2	—	4	2
Interest Expense	(12)	(10)	(35)	(44)
Income Before Income Tax Expense	172	169	571	287
Income Tax Expense	55	57	193	99
Net Income	117	112	378	188
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$117	$112	$378	$188

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions of MWhs)			
Fuel Type:				
Coal	16	10	37	29
Natural Gas	2	2	6	5
Total MWhs	18	12	43	34

Third Quarter of 2014 Compared to Third Quarter of 2013
Reconciliation of Third Quarter of 2013 to Third Quarter of 2014
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Third Quarter of 2013	$112	
Changes in Gross Margin:		
Generation	19	
Total Change in Gross Margin	19	
Changes in Expenses and Other:		
Other Operation and Maintenance	(16	)
Depreciation and Amortization	1	
Taxes Other Than Income Taxes	(1	)
Interest and Investment Income	2	
Interest Expense	(2	)
Total Change in Expenses and Other	(16	)
Income Tax Expense	2	
Third Quarter of 2014	$117	

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:

- Gross Margin increased $19 million primarily due to lower fuel expenses.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $16 million primarily due to an increase in plant maintenance.

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Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013
Reconciliation of Nine Months Ended September 30, 2013 to Nine Months Ended September 30, 2014
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Nine Months Ended September 30, 2013	$188	
Changes in Gross Margin:		
Generation	118	
Retail, Trading and Marketing	4	
Total Change in Gross Margin	122	
Changes in Expenses and Other:		
Other Operation and Maintenance	(21	)
Asset Impairments and Other Related Charges	154	
Depreciation and Amortization	11	
Taxes Other Than Income Taxes	7	
Interest and Investment Income	2	
Interest Expense	9	
Total Change in Expenses and Other	162	
Income Tax Expense	(94	)
Nine Months Ended September 30, 2014	$378	

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

- Generation increased $118 million primarily due to increased demand and market prices driven by cold temperatures in the first quarter of 2014.

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

- Other Operation and Maintenance expenses increased $21 million primarily due to increased plant maintenance.
- Asset Impairments and Other Related Charges decreased by $154 million primarily due to the 2013 impairment of Muskingum River Plant, Unit 5.
- Depreciation and Amortization expenses decreased $11 million primarily due to the 2013 impairment of Muskingum River Plant, Unit 5.
- Taxes Other Than Income Taxes decreased $7 million primarily due to a decrease in property taxes related to the 2012 and 2013 plant impairments.
- Interest Expense decreased $9 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- Income Tax Expense increased $94 million primarily due to an increase in pretax book income.

AEP RIVER OPERATIONS

Third Quarter of 2014 Compared to Third Quarter of 2013

Earnings Attributable to AEP Common Shareholders from our AEP River Operations segment increased from a loss of $1 million in 2013 to income of $11 million in 2014 due to a 20% increase in barge freight revenue for the third quarter of 2014 compared to the third quarter of 2013. The increase in freight revenue is primarily due to improvements in barge freight demand.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

Earnings Attributable to AEP Common Shareholders from our AEP River Operations segment increased from a loss of $12 million in 2013 to income of $17 million in 2014 due to a 30% increase in barge freight revenue for 2014 compared to 2013. The additional revenue resulted from improvements in river conditions and increased barge freight demand.

CORPORATE AND OTHER

Third Quarter of 2014 Compared to Third Quarter of 2013

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from $8 million in 2013 to $11 million in 2014 primarily due to the recording of federal and state income tax adjustments in the third quarter of 2014.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from $119 million in 2013 to $4 million in 2014 primarily due to a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in the second quarter of 2013.

AEP SYSTEM INCOME TAXES

Third Quarter of 2014 Compared to Third Quarter of 2013

Income Tax Expense increased $12 million primarily due to an increase in pretax book income, partially offset by the recording of federal and state income tax adjustments in the third quarter of 2014.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

Income Tax Expense increased $271 million primarily due to an increase in pretax book income and by a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in the second quarter of 2013.

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

	September 30, 2014			December 31, 2013		
	(dollars in millions)					
Long-term Debt, including amounts due within one year	$18,058	49.9	%	$18,377	52.2	%
Short-term Debt	1,282	3.5		757	2.1	
Total Debt	19,340	53.4		19,134	54.3	
AEP Common Equity	16,868	46.6		16,085	45.7	
Noncontrolling Interests	4	—		1	—	
Total Debt and Equity Capitalization	$36,212	100.0	%	$35,220	100.0	%

Our ratio of debt-to-total capital improved from 54.3% as of December 31, 2013 to 53.4% as of September 30, 2014 primarily due to an increase in our common equity from 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 September 30, 2014, we had $3.5 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.

Commercial Paper Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. As of September 30, 2014, our available liquidity was approximately $3.1 billion as illustrated in the table below:

		Amount	Maturity
		(in millions)	
Commercial Paper Backup:			
	Revolving Credit Facility	$1,750	June 2016
	Revolving Credit Facility	1,750	July 2017
Total		3,500	
Cash and Cash Equivalents		194	
Total Liquidity Sources		3,694	
Less:	AEP Commercial Paper Outstanding	532	
	Letters of Credit Issued	76	
Net Available Liquidity		$3,086	

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

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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 nine months of 2014 was $877 million. The weighted-average interest rate for our commercial paper during 2014 was 0.26%.

Other Credit Facilities

In January 2014, we issued letters of credit under an $85 million uncommitted facility signed in October 2013. As of September 30, 2014, the maximum future payment for letters of credit issued under the uncommitted facility was $78 million with maturity dates through January 2015. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

Securitized Accounts Receivable

Our receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement was increased from $700 million and expires in June 2016.

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 credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of September 30, 2014, this contractually-defined percentage was 49.9%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of September 30, 2014, 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. This condition also applies in a majority of our non-exchange traded commodity contracts and would similarly allow 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 credit agreements.

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

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. As of September 30, 2014, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.53 per share in October 2014. 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 primarily 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.

	Nine Months Ended September 30,	
	2014	2013
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$118	$279
Net Cash Flows from Operating Activities	3,725	3,040
Net Cash Flows Used for Investing Activities	(3,081)	(2,520)
Net Cash Flows Used for Financing Activities	(568)	(652)
Net Increase (Decrease) in Cash and Cash Equivalents	76	(132)
Cash and Cash Equivalents at End of Period	$194	$147

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

Operating Activities

	Nine Months Ended September 30,	
	2014	2013
	(in millions)	
Net Income	$1,446	$1,137
Depreciation and Amortization	1,441	1,310
Other	838	593
Net Cash Flows from Operating Activities	$3,725	$3,040

Net Cash Flows from Operating Activities were $3.7 billion in 2014 consisting primarily of Net Income of $1.4 billion and $1.4 billion of noncash Depreciation and Amortization partially offset by $106 million of Ohio capacity deferrals as a result of the PUCO's July 2012 approval of a capacity deferral mechanism. 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. Deferred Income Taxes increased primarily due to provisions in the Taxpayer Relief Act of 2012 and an increase in tax/book temporary differences from operations. The reduction in Fuel, Material and Supplies balances reflects a decrease in fuel inventory due to the cold winter weather and increased generation.

Net Cash Flows from Operating Activities were $3 billion in 2013 consisting primarily of Net Income of $1.1 billion, and $1.3 billion of noncash Depreciation and Amortization and $298 million of Asset Impairments related to Muskingum River Plant, Unit 5, Turk and Big Sandy Plants, partially offset by $157 million of Ohio capacity deferrals as a result of the PUCO's July 2012 approval of a capacity deferral mechanism. 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. Deferred Income Taxes increased primarily due to provisions in the Taxpayer Relief Act of 2012 and an increase in tax/book temporary differences from operations. Net cash flows for Accrued Taxes were a result of recording the estimated federal tax loss associated with tax/book temporary differences and the recognition of the tax benefit related to the U.K. Windfall Tax.

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Investing Activities

	Nine Months Ended September 30,	
	2014	2013
	(in millions)	
Construction Expenditures	$(2,899)	$(2,481)
Acquisitions of Nuclear Fuel	(109)	(110)
Acquisitions of Assets/Businesses	(45)	(6)
Insurance Proceeds Related to Cook Plant Fire	—	72
Proceeds from Sales of Assets	2	14
Other	(30)	(9)
Net Cash Flows Used for Investing Activities	$(3,081)	$(2,520)

Net Cash Flows Used for Investing Activities were $3.1 billion in 2014 primarily due to Construction Expenditures for environmental, distribution and transmission investments. We also purchased transmission assets for $38 million.

Net Cash Flows Used for Investing Activities were $2.5 billion in 2013 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Financing Activities

	Nine Months Ended September 30,	
	2014	2013
	(in millions)	
Issuance of Common Stock, Net	$63	$61
Issuance of Debt, Net	193	43
Dividends Paid on Common Stock	(736)	(709)
Other	(88)	(47)
Net Cash Flows Used for Financing Activities	$(568)	$(652)

Net Cash Flows Used for Financing Activities in 2014 were $568 million. Our net debt issuances were $193 million. The net issuances included issuances of $650 million of senior unsecured notes, $343 million of pollution control bonds and $224 million of other debt notes and an increase in short-term borrowing of $525 million offset by retirements of $953 million of senior unsecured and other debt notes, $312 million of pollution control bonds and $273 million of securitization bonds. We paid common stock dividends of $736 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows Used for Financing Activities in 2013 were $652 million. Our net debt issuances were $43 million. The net issuances included issuances of $475 million of senior unsecured notes, $800 million draws on a $1 billion term credit facility, $305 million of pollution control bonds, $267 million of securitization bonds, $251 million of notes payable and other debt and an increase in short-term borrowing of $237 million offset by retirements of $1.8 billion of senior unsecured and other debt notes, $211 million of securitization bonds and $281 million of pollution control bonds. We paid common stock dividends of $709 million.

In October 2014, APCo remarketed $100 million of Pollution Control Bonds due in 2018 at 1.625%.

In October 2014, I&M retired $5 million of Notes Payable related to DCC Fuel.

BUDGETED CONSTRUCTION EXPENDITURES

In 2014, we increased our forecast for construction expenditures by $350 million to approximately $4.2 billion for 2014. The increase is primarily for transmission investment in the AEP Transmission Holdco, Vertically Integrated Utilities and Transmission and Distribution Utilities segments.

OFF-BALANCE SHEET ARRANGEMENTS

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:

	September 30, 2014	December 31, 2013
	(in millions)	
Rockport Plant, Unit 2 Future Minimum Lease Payments	$ 1,256	$ 1,330
Railcars Maximum Potential Loss from Lease Agreement	19	19

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 2013 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of our contractual obligations is included in our 2013 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 2013 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

Pronouncements Effective in the Future

The FASB issued ASU 2014-08 “Presentation of Financial Statements and Property, Plant and Equipment” changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity’s operations and financial results when the component meets the criteria to be classified as held-for-sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014 with early adoption permitted.

The FASB issued ASU 2014-09 "Revenue from Contracts with Customers" clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. We plan to adopt ASU 2014-09 effective January 1, 2017.

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 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 Vertically Integrated Utilities segment is exposed to certain market risks as a major power producer and through its transactions in power, coal, natural gas 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 Transmission and Distribution Utilities segment is exposed to FTR price risk as it relates to congestion during the June 2012 - May 2015 Ohio ESP period. Additional risk includes interest rate risk.

Our Generation & 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. In addition, our Generation & Marketing segment is also exposed to certain market risks as a major power producer and through its transactions in wholesale electricity, natural gas and coal trading and marketing contracts.

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, natural gas and, to a lesser extent, heating oil, gasoline 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, Energy Supply, 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 (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, and Chief Risk Officer in addition to Energy Supply's President and Vice President. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the respective committee.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2013:
MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2014

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
	(in millions)			
Total MTM Derivative Contract Net Assets as of December 31, 2013	$32	$3	$157	$192
Gain from Contracts Realized/Settled During the Period and Entered in a Prior Period	(7)	(3)	(32)	(42)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	9	9
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	21	21
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	12	8	—	20
Total MTM Derivative Contract Net Assets as of September 30, 2014	$37	$8	$155	$200
Commodity Cash Flow Hedge Contracts				6
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(1)
Fair Value Hedge Contracts				(8)
Collateral Deposits				(14)
Total MTM Derivative Contract Net Assets as of September 30, 2014				$183

(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 9 – Derivatives and Hedging and Note 10 – 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.

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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 September 30, 2014, our credit exposure net of collateral to sub investment grade counterparties was approximately 9.3%, 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 September 30, 2014, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$482	$1	$481	2	$245
Split Rating	14	—	14	1	13
Noninvestment Grade	2	1	1	2	1
No External Ratings:					
Internal Investment Grade	71	—	71	4	44
Internal Noninvestment Grade	71	14	57	1	29
Total as of September 30, 2014	$640	$16	$624	10	$332
Total as of December 31, 2013	$787	$18	$769	9	$381

In addition, we are exposed to credit risk related to our participation in RTOs. For each of the RTOs in which we participate, this risk is generally determined based on our proportionate share of member gross activity over a specified period of time.

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 September 30, 2014, 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

Nine Months Ended September 30, 2014				Twelve Months Ended December 31, 2013			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$—	$3	$1	$—	$—	$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 several 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, Regulated Risk Committee, or Competitive Risk Committee 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 September 30, 2014 and December 31, 2013, the estimated EaR on our debt portfolio for the following twelve months was $42 million and $32 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2014 and 2013
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
REVENUES				
Vertically Integrated Utilities	$2,432	$2,543	$7,217	$7,075
Transmission and Distribution Utilities	1,163	1,139	3,388	3,248
Generation & Marketing	538	359	1,932	915
Other Revenues	169	135	457	346
TOTAL REVENUES	4,302	4,176	12,994	11,584
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	1,080	1,168	3,291	3,107
Purchased Electricity for Resale	449	373	1,560	1,103
Other Operation	787	677	2,327	2,079
Maintenance	321	261	953	839
Asset Impairments and Other Related Charges	—	144	—	298
Depreciation and Amortization	507	447	1,441	1,310
Taxes Other Than Income Taxes	233	231	689	671
TOTAL EXPENSES	3,377	3,301	10,261	9,407
OPERATING INCOME	925	875	2,733	2,177
Other Income (Expense):				
Interest and Investment Income	1	3	5	55
Carrying Costs Income	7	8	22	20
Allowance for Equity Funds Used During Construction	27	19	74	51
Interest Expense	(221)	(225)	(662)	(685)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	739	680	2,172	1,618
Income Tax Expense	269	257	791	520
Equity Earnings of Unconsolidated Subsidiaries	24	11	65	39
NET INCOME	494	434	1,446	1,137
Net Income Attributable to Noncontrolling Interests	1	1	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$493	$433	$1,443	$1,134
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	488,912,892	486,932,747	488,361,017	486,353,876

TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.01	$ 0.89	$ 2.95	$ 2.33
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	488,970,647	487,258,905	488,597,178	486,792,914
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.01	$ 0.89	$ 2.95	$ 2.33
CASH DIVIDENDS DECLARED PER SHARE	$ 0.50	$ 0.49	$ 1.50	$ 1.45

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 46.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2014 and 2013
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net Income	$494	$434	$1,446	$1,137
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $1 and $1 for the Three Months Ended September 30, 2014 and 2013, Respectively, and $3 and $7 for the Nine Months Ended September 30, 2014 and 2013, Respectively	(2)	(1)	6	13
Securities Available for Sale, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2014 and 2013, Respectively, and $0 and $1 for the Nine Months Ended September 30, 2014 and 2013, Respectively	—	1	1	2
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1 and $4 for the Three Months Ended September 30, 2014 and 2013, Respectively, and $2 and $9 for the Nine Months Ended September 30, 2014 and 2013, Respectively	1	7	3	16
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(1)	7	10	31
TOTAL COMPREHENSIVE INCOME	493	441	1,456	1,168
Total Comprehensive Income Attributable to Noncontrolling Interests	1	1	3	3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$492	$440	$1,453	$1,165

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 46.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2014 and 2013
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY - DECEMBER 31, 2012	506	$3,289	$6,049	$6,236	$(337)	$—	$15,237
Issuance of Common Stock	2	10	51				61
Common Stock Dividends				(706)		(3)	(709)
Other Changes in Equity			5			1	6
Net Income				1,134		3	1,137
Other Comprehensive Income					31		31
TOTAL EQUITY - SEPTEMBER 30, 2013	508	$3,299	$6,105	$6,664	$(306)	$1	$15,763
TOTAL EQUITY - DECEMBER 31, 2013	508	$3,303	$6,131	$6,766	$(115)	$1	$16,086
Issuance of Common Stock	2	9	54				63
Common Stock Dividends				(733)		(3)	(736)
Other Changes in Equity			6	(6)		3	3
Net Income				1,443		3	1,446
Other Comprehensive Income					10		10
TOTAL EQUITY - SEPTEMBER 30, 2014	510	$3,312	$6,191	$7,470	$(105)	$4	$16,872

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 46.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2014 and December 31, 2013
(in millions)
(Unaudited)

	September 30, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$194	$118
Other Temporary Investments (September 30, 2014 and December 31, 2013 Amounts Include $304 and $335, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and EIS)	318	353
Accounts Receivable:		
Customers	671	746
Accrued Unbilled Revenues	107	157
Pledged Accounts Receivable – AEP Credit	1,013	945
Miscellaneous	83	72
Allowance for Uncollectible Accounts	(19)	(60)
Total Accounts Receivable	1,855	1,860
Fuel	472	701
Materials and Supplies	733	722
Risk Management Assets	135	160
Regulatory Asset for Under-Recovered Fuel Costs	145	80
Margin Deposits	82	70
Prepayments and Other Current Assets	177	246
TOTAL CURRENT ASSETS	4,111	4,310
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	25,565	25,074
Transmission	11,649	10,893
Distribution	16,938	16,377
Other Property, Plant and Equipment (Including Plant to be Retired, Coal Mining and Nuclear Fuel)	5,688	5,470
Construction Work in Progress	3,283	2,471
Total Property, Plant and Equipment	63,123	60,285
Accumulated Depreciation and Amortization	20,059	19,288
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	43,064	40,997
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,308	4,376
Securitized Assets	2,159	2,373
Spent Nuclear Fuel and Decommissioning Trusts	2,020	1,932
Goodwill	91	91
Long-term Risk Management Assets	228	297
Deferred Charges and Other Noncurrent Assets	1,944	2,038
TOTAL OTHER NONCURRENT ASSETS	10,750	11,107

TOTAL ASSETS	$57,925	$56,414

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 46.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2014 and December 31, 2013
(dollars in millions)
(Unaudited)

	September 30, 2014	December 31, 2013
CURRENT LIABILITIES		
Accounts Payable	$1,259	$1,266
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	750	700
Other Short-term Debt	532	57
Total Short-term Debt	1,282	757
Long-term Debt Due Within One Year (September 30, 2014 and December 31, 2013 Amounts Include $409 and $416, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	2,381	1,549
Risk Management Liabilities	60	90
Customer Deposits	315	299
Accrued Taxes	769	822
Accrued Interest	219	245
Regulatory Liability for Over-Recovered Fuel Costs	53	119
Other Current Liabilities	1,119	965
TOTAL CURRENT LIABILITIES	7,457	6,112
NONCURRENT LIABILITIES		
Long-term Debt (September 30, 2014 and December 31, 2013 Amounts Include $2,230 and $2,532, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy and Sabine)	15,677	16,828
Long-term Risk Management Liabilities	120	177
Deferred Income Taxes	10,506	10,300
Regulatory Liabilities and Deferred Investment Tax Credits	3,837	3,694
Asset Retirement Obligations	1,923	1,835
Employee Benefits and Pension Obligations	414	415
Deferred Credits and Other Noncurrent Liabilities	1,119	967
TOTAL NONCURRENT LIABILITIES	33,596	34,216
TOTAL LIABILITIES	41,053	40,328
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2014	2013

Shares Authorized	600,000,000	600,000,000		
Shares Issued	509,563,446	508,113,964		
(20,336,592 Shares were Held in Treasury as of September 30, 2014 and December 31, 2013)			3,312	3,303
Paid-in Capital			6,191	6,131
Retained Earnings			7,470	6,766
Accumulated Other Comprehensive Income (Loss)			(105)	(115)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			16,868	16,085
Noncontrolling Interests			4	1
TOTAL EQUITY			16,872	16,086
TOTAL LIABILITIES AND EQUITY			$57,925	$56,414

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 46.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2014 and 2013
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2014	2013
OPERATING ACTIVITIES		
Net Income	$1,446	$1,137
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,441	1,310
Deferred Income Taxes	383	582
Asset Impairments and Other Related Charges	—	298
Carrying Costs Income	(22)	(20)
Allowance for Equity Funds Used During Construction	(74)	(51)
Mark-to-Market of Risk Management Contracts	15	29
Amortization of Nuclear Fuel	114	101
Pension Contributions to Qualified Plan Trust	(71)	—
Property Taxes	220	191
Fuel Over/Under-Recovery, Net	(77)	38
Deferral of Ohio Capacity Costs, Net	(106)	(157)
Change in Other Noncurrent Assets	(54)	(35)
Change in Other Noncurrent Liabilities	272	16
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	—	4
Fuel, Materials and Supplies	222	72
Accounts Payable	(43)	(28)
Accrued Taxes, Net	32	(278)
Other Current Assets	(12)	(5)
Other Current Liabilities	39	(164)
Net Cash Flows from Operating Activities	3,725	3,040
INVESTING ACTIVITIES		
Construction Expenditures	(2,899)	(2,481)
Change in Other Temporary Investments, Net	37	53
Purchases of Investment Securities	(791)	(693)
Sales of Investment Securities	746	635
Acquisitions of Nuclear Fuel	(109)	(110)
Acquisitions of Assets/Businesses	(45)	(6)
Insurance Proceeds Related to Cook Plant Fire	—	72
Proceeds from Sales of Assets	2	14
Other Investing Activities	(22)	(4)
Net Cash Flows Used for Investing Activities	(3,081)	(2,520)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	63	61
Issuance of Long-term Debt	1,206	2,087
Commercial Paper and Credit Facility Borrowings	—	17

Change in Short-term Debt, Net	525	240
Retirement of Long-term Debt	(1,538)	(2,281)
Commercial Paper and Credit Facility Repayments	—	(20)
Principal Payments for Capital Lease Obligations	(91)	(53)
Dividends Paid on Common Stock	(736)	(709)
Other Financing Activities	3	6
Net Cash Flows Used for Financing Activities	(568)	(652)
Net Increase (Decrease) in Cash and Cash Equivalents	76	(132)
Cash and Cash Equivalents at Beginning of Period	118	279
Cash and Cash Equivalents at End of Period	$194	$147
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$649	$702
Net Cash Paid (Received) for Income Taxes	109	(64)
Noncash Acquisitions Under Capital Leases	80	53
Construction Expenditures Included in Current Liabilities as of September 30,	515	363

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 46.

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 and nine months ended September 30, 2014 is not necessarily indicative of results that may be expected for the year ending December 31, 2014. The condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2013 consolidated financial statements and notes thereto, which are included in our Form 10-K as filed with the SEC on February 25, 2014.

Revenue Recognition

Electricity Supply and Delivery Activities - Transactions with PJM

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. For regulated and nonregulated operations, we recognize the revenues on the statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts.

APCo, I&M and KPCo sell power produced at their generation plants to PJM and purchase power from PJM to supply their retail load. These power sales and purchases for each subsidiary’s retail load are netted hourly for financial reporting purposes. On an hourly net basis, each subsidiary records sales of power to PJM in excess of purchases of power from PJM as revenue on the statements of income. Also, on an hourly net basis, each subsidiary records purchases of power from PJM to serve retail load in excess of sales of power to PJM as Purchased Electricity for Resale on the statements of income. Upon termination of the Interconnection Agreement in 2014, each subsidiary manages and accounts for its purchases and sales with PJM individually based on market prices.

AEP’s nonregulated subsidiaries also purchase power from PJM and sell power to PJM. With the exception of certain dedicated load bilateral power supply contracts, these transactions are reported as gross purchases and sales.

SPP Integrated Power Market

In March 2014, SPP changed from an energy imbalance service market to a fully integrated power market. In the past, PSO and SWEPCo would satisfy their load requirements with their own generation resources or through the Operating Agreement. In the new integrated power market, PSO and SWEPCo operate as standalone entities by offering their respective generation into the SPP power market, which then economically dispatches the resources. This change further enables retail customers to obtain low cost power through either internal generation or power purchases from the SPP market. The new integrated power market now operates in a similar manner as the PJM power market for the AEP East Companies. No significant impact on results of operations is expected due to this change.

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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 tables present our basic and diluted EPS calculations included on our condensed statements of income:

	Three Months Ended September 30,			
	2014		2013	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$493		$433	
Weighted Average Number of Basic Shares Outstanding	488.9	$1.01	486.9	$0.89
Weighted Average Dilutive Effect of Restricted Stock Units	0.1	—	0.4	—
Weighted Average Number of Diluted Shares Outstanding	489.0	$1.01	487.3	$0.89

	Nine Months Ended September 30,			
	2014		2013	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$1,443		$1,134	
Weighted Average Number of Basic Shares Outstanding	488.4	$2.95	486.4	$2.33
Weighted Average Dilutive Effect of Restricted Stock Units	0.2	—	0.4	—
Weighted Average Number of Diluted Shares Outstanding	488.6	$2.95	486.8	$2.33

There were no antidilutive shares outstanding as of September 30, 2014 and 2013.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, we review the new accounting literature to determine its relevance, if any, to our business. The following final pronouncements will impact our financial statements.

ASU 2014-08 “Presentation of Financial Statements and Property, Plant and Equipment” (ASU 2014-08)

In April 2014, the FASB issued ASU 2014-08 changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity’s operations and financial results when the component meets the criteria to be classified as held-for-sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. This standard must be prospectively applied to all reporting periods presented in financial reports issued after the effective date. Early adoption is permitted for disposals that have not been reported in financial statements previously issued or available for issuance.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014 with early adoption permitted. If applicable, this standard will change the presentation of our financial statements but will not affect the calculation of net income, comprehensive income or earnings per share.

ASU 2014-09 “Revenue from Contracts with Customers” (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts. This standard must be retrospectively applied to all reporting periods presented in financial reports issued after the effective date.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016. Early adoption is not permitted. As applicable, this standard may change the amount of revenue recognized in the income statements in each reporting period. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. We plan to adopt ASU 2014-09 effective January 1, 2017.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three and nine months ended September 30, 2014 and 2013. All amounts in the following tables are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2014

	Cash Flow Hedges				
	Commodity	Interest Rate and Foreign Currency	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of June 30, 2014	$6	$(21)	$8	$(97)	$(104)
Change in Fair Value Recognized in AOCI	3	—	—	—	3
Amounts Reclassified from AOCI	(6)	1	—	1	(4)
Net Current Period Other Comprehensive Income	(3)	1	—	1	(1)
Balance in AOCI as of September 30, 2014	$3	$(20)	$8	$(96)	$(105)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2013

	Cash Flow Hedges				
	Commodity	Interest Rate and Foreign Currency	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of June 30, 2013	$1	$(25)	$5	$(294)	$(313)
Change in Fair Value Recognized in AOCI	1	—	1	—	2
Amounts Reclassified from AOCI	(3)	1	—	7	5
Net Current Period Other Comprehensive Income	(2)	1	1	7	7
Balance in AOCI as of September 30, 2013	$(1)	$(24)	$6	$(287)	$(306)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2014

	Cash Flow Hedges				
	Commodity	Interest Rate and Foreign Currency	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of December 31, 2013	$—	$(23)	$7	$(99)	$(115)
	(8)	—	1	—	(7)

Change in Fair Value Recognized in AOCI					
Amounts Reclassified from AOCI	11	3	—	3	17
Net Current Period Other Comprehensive Income	3	3	1	3	10
Balance in AOCI as of September 30, 2014	$3	$(20)	$8	$(96)	$(105)

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Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2013

	Cash Flow Hedges				
	Commodity	Interest Rate and Foreign Currency	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of December 31, 2012	$(8)	$(30)	$4	$(303)	$(337)
Change in Fair Value Recognized in AOCI	11	2	2	—	15
Amounts Reclassified from AOCI	(4)	4	—	16	16
Net Current Period Other Comprehensive Income	7	6	2	16	31
Balance in AOCI as of September 30, 2013	$(1)	$(24)	$6	$(287)	$(306)

Reclassifications from Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and nine months ended September 30, 2014 and 2013. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended September 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in millions)	
Commodity:		
Vertically Integrated Utilities Revenues	$—	$(1)
Generation & Marketing Revenues	—	(3)
Purchased Electricity for Resale	(9)	(1)
Subtotal – Commodity	(9)	(5)
Interest Rate and Foreign Currency:		
Interest Expense	2	2
Subtotal – Interest Rate and Foreign Currency	2	2
Reclassifications from AOCI, before Income Tax (Expense) Credit	(7)	(3)
Income Tax (Expense) Credit	(2)	(1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(5)	(2)
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(5)	(7)
Amortization of Actuarial (Gains)/Losses	7	18
Reclassifications from AOCI, before Income Tax (Expense) Credit	2	11
Income Tax (Expense) Credit	1	4

Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1	7
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(4)	$5

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Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI Nine Months Ended September 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in millions)	
Commodity:		
Vertically Integrated Utilities Revenues	$—	$(1)
Generation & Marketing Revenues	—	(8)
Purchased Electricity for Resale	20	3
Regulatory Assets/(Liabilities), Net (a)	(3)	—
Subtotal – Commodity	17	(6)
Interest Rate and Foreign Currency:		
Interest Expense	6	6
Subtotal – Interest Rate and Foreign Currency	6	6
Reclassifications from AOCI, before Income Tax (Expense) Credit	23	—
Income Tax (Expense) Credit	9	—
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	14	—
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(15)	(16)
Amortization of Actuarial (Gains)/Losses	21	41
Reclassifications from AOCI, before Income Tax (Expense) Credit	6	25
Income Tax (Expense) Credit	3	9
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	3	16
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$17	$16

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

4. RATE MATTERS

As discussed in the 2013 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2013 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 2014 and updates the 2013 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	September 30, 2014 (in millions)	December 31, 2013
Regulatory Assets Currently Earning a Return		
Storm Related Costs	$21	$22
West Virginia Vegetation Management Program	17	—
Ohio Economic Development Rider	—	14
Other Regulatory Assets Pending Final Regulatory Approval	—	4
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	103	161
IGCC Pre-Construction Costs	21	—
Mountaineer Carbon Capture and Storage Product Validation Facility	13	13
Ormet Special Rate Recovery Mechanism	10	36
Expanded Net Energy Charge – Coal Inventory	9	21
Indiana Under-Recovered Capacity Costs	—	22
Other Regulatory Assets Pending Final Regulatory Approval	37	37
Total Regulatory Assets Pending Final Regulatory Approval	$231	$330

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

OPCo Rate Matters

Ohio Electric Security Plan Filings

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 (OCC) 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. In February 2014, the Supreme Court of Ohio affirmed the PUCO's decision and rejected all appeals filed by the OCC and the IEU.

In August 2012, the PUCO issued an order in a separate proceeding which implemented a 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 related to the PUCO decision in the PIRR proceeding claiming a long-term debt rate modified the previously adjudicated 2009 - 2011 ESP order, which granted a weighted average cost of capital rate. In November 2012, the IEU and the OCC filed appeals regarding the PUCO decision in the PIRR proceeding. These appeals principally argued that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues which could reduce OPCo's net deferred fuel balance up to the full amount. These intervenors' appeals also argued that carrying costs should be reduced due to an accumulated deferred income tax credit which, as of September 30, 2014, could reduce carrying costs by $28 million including $14 million of unrecognized equity carrying costs. As of September 30, 2014, OPCo's net deferred fuel balance was $395 million, excluding unrecognized equity carrying costs. 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. This ruling was generally upheld in rehearing orders in January and March 2013.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the 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 OPCo RPM price collected from CRES providers, which includes reserve margins, was approximately $34/MW day through May 2014 and is $150/MW day from June 2014 through May 2015. 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 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and is currently collected at $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 September 30, 2014, OPCo's incurred deferred capacity costs balance of $409 million, including debt carrying costs, was recorded in regulatory assets on the condensed balance sheet.

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 expenses 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 bid process (CBP). In April and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order, including the RSR.

In November 2013, the PUCO issued an order approving OPCo's CBP with modifications which included the delay of the energy auctions that were originally ordered in the ESP order. As ordered, in February 2014, OPCo conducted an energy-only auction for 10% of the SSO load with delivery beginning April 2014 through May 2015. Also as ordered, in May 2014 and September 2014, OPCo conducted energy-only auctions for an additional 50% of the SSO load with delivery beginning November 2014 through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions 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. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit. In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC. In March 2014, the PUCO approved OPCo's request to implement riders related to the unbundling of the FAC. In May 2014, an independent auditor was selected by the PUCO and an audit of the recovery of the fixed fuel costs began in June 2014. In October 2014, the independent auditor filed its report for the period August 2012 through May 2015 with the PUCO. If the PUCO ultimately concludes that a portion of the fixed fuel costs are also recovered through OPCo's $188.88 capacity charge, the independent auditor recommends a methodology for calculating a refund of a portion of certain fixed fuel costs. The retail share of these fixed fuel costs is approximately $90 million annually. A hearing related to this matter has not been scheduled. Management believes that no over-recovery of costs has occurred and intends to oppose the findings in the audit report.

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

Proposed June 2015 - May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that includes proposed rate adjustments and the continuation and modification of certain existing riders, including the Distribution Investment Rider (DIR), effective June 2015 through May 2018. The proposal includes a recommended auction schedule, a return on common equity of 10.65% on capital costs for certain riders and estimates an average decrease in rates of 9% over the three-year term of the plan for customers who receive their RPM capacity and energy auction-based generation through OPCo. The proposal also includes a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based purchase power agreement. The PPA would initially be based upon the OVEC contractual entitlement and could, upon further approval, be expanded to include other contracts involving other Ohio legacy generation assets. In May 2014, intervenors and the PUCO staff filed testimony that provided various recommendations including the rejection and/or modification of various riders, including the DIR and the proposed PPA. Hearings at the PUCO in the ESP case were held in June 2014. Additionally, in July 2014, OPCo submitted a separate application to continue the RSR established in the June 2012 - May 2015 ESP to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh, until the balance of the capacity deferrals has been collected. In October 2014, OPCo filed a separate application with the PUCO to propose a new PPA for inclusion in the PPA rider, discussed above. The new PPA would include an additional 2,671 MW to be purchased from AGR over the life of the respective generating units.

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

Significantly Excessive Earnings Test Filings

In January 2011, the PUCO issued an order on the 2009 SEET filing. The 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. In September 2013, a proposed second phase of OPCo’s gridSMART® program was filed with the PUCO which included a proposed project to satisfy this PUCO directive. A decision from the PUCO is pending.

In March 2014, the PUCO approved a stipulation agreement between OPCo and the PUCO staff that there were no significantly excessive earnings in 2011 for CSPCo or OPCo. In May 2014, the PUCO approved a stipulation agreement between OPCo and the PUCO staff that there were no significantly excessive earnings in 2012 for OPCo. In May 2014, OPCo filed its 2013 SEET filing with the PUCO. In October 2014, OPCo entered into a stipulation agreement with the PUCO staff in which both parties agree that there were no significantly excessive earnings in 2013 for OPCo. A hearing at the PUCO related to the 2013 SEET filing is scheduled for November 2014.

Management believes its financial statements adequately address the impact of SEET requirements.

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 and associated generation liabilities at net book value to AGR. In June 2013, the IEU filed an appeal with the Supreme Court of Ohio claiming the PUCO order approving the corporate separation was unlawful. A decision from the Supreme Court of Ohio is pending. In December 2013, corporate separation of OPCo’s generation assets was completed. If any part of the PUCO order is overturned, it could reduce future net income and cash flows and impact financial condition.

Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates to recover 2012 incremental storm distribution expenses. In April 2014, the PUCO approved a stipulation agreement between OPCo, the PUCO staff and all intervenors, except the Ohio Consumers’ Counsel, to recover $55 million over a 12-month period. The agreement also provided that carrying charges using a long-term debt rate will be assessed from April 2013 until recovery begins, but no additional carrying charges will accrue during the actual recovery period. Compliance tariffs were filed with the PUCO and new rates were implemented in April 2014. In May 2014, the PUCO upheld the settlement agreement on rehearing.

2009 Fuel Adjustment Clause Audit

In January 2012, the PUCO issued an order in OPCo’s 2009 FAC 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. As a result, OPCo recorded a $30 million net favorable adjustment on the statement of income in 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.

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. In September 2014, the Supreme Court of Ohio upheld the PUCO order. A review of the coal reserve valuation by an outside consultant is still pending. 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.

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 with the use of a weighted average cost of capital (WACC). The PUCO subsequently ruled in the PIRR proceeding that the fuel clause for these years was approved with a WACC carrying cost and that the carrying costs on the balance should not be net of accumulated income taxes. See the 2009 - 2011 ESP section of “Ohio Electric Security Plan Filings” above for a discussion of the PUCO order in the PIRR proceeding. In May 2014, the PUCO issued an order that generally approved OPCo's 2010-2011 fuel costs and rejected the auditor recommendation to adjust the WACC carrying charges related to accumulated deferred income taxes. Additionally, the PUCO requested further review related to an affiliate barging agreement and the modification of certain fuel procurement processes and practices. Further, the order provided for the auditor to address any remaining concerns in their next audit report, as they deem necessary. In July 2014, the PUCO issued an order that denied all requests for rehearing.

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2012 and 2013 Fuel Adjustment Clause Audits

In May 2014, the PUCO-selected outside consultant provided its final report related to its 2012 and 2013 FAC audit which included certain unfavorable recommendations related to the FAC recovery for 2012 and 2013. These recommendations are opposed by OPCo. In addition, the PUCO will consider the results of the final audit of the recovery of fixed fuel costs that was issued in October 2014. See the "June 2012 – May 2015 ESP Including Capacity Charge" section above. If the PUCO orders a reduction to the FAC deferral or a refund to customers, it could reduce future net income and cash flows and impact financial condition.

Ormet

Ormet, a large aluminum company, had a contract to purchase power from OPCo through 2018. In February 2013, Ormet filed Chapter 11 bankruptcy proceedings in the state of Delaware and subsequently shut down operations in October 2013. Based upon previous PUCO rulings providing rate assistance to Ormet, the PUCO is expected to permit OPCo to recover unpaid Ormet amounts through the Economic Development Rider (EDR), except where recovery from ratepayers is limited to $20 million related to previously deferred payments from Ormet’s October and November 2012 power bills. In February 2014, a stipulation agreement between OPCo and Ormet was filed with the PUCO. The stipulation recommended approval of OPCo’s right to fully recover approximately $49 million of foregone revenues through the EDR. Also in February 2014, intervenor comments were filed objecting to full recovery of these foregone revenues. In March 2014, the PUCO issued an order in OPCo’s EDR filing allowing OPCo to include $39 million of Ormet-related foregone revenues in the EDR effective April 2014. The order stated that if the stipulation agreement between OPCo and Ormet is subsequently adopted by the PUCO, OPCo could file an application to modify the EDR rate for the remainder of the period requesting recovery of the remaining $10 million of Ormet deferrals which, as of September 30, 2014, is recorded in regulatory assets on the condensed balance sheet. In April 2014, an intervenor filed testimony objecting to $5 million of the remaining foregone revenues. A hearing at the PUCO related to the stipulation agreement was held in May 2014.

In addition, in the 2009 - 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related revenues under a previous interim arrangement (effective from January 2009 through September 2009) and requested that the PUCO prevent OPCo from collecting Ormet-related revenues in the future. 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. The PUCO did not take any action on this request. The intervenors raised this issue again in response to OPCo’s November 2009 filing to approve recovery of the deferral under the interim agreement.

To the extent amounts discussed above are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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 September 30, 2014, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions and comments with the PUCO requesting that OPCo refund all collected pre-construction costs to Ohio ratepayers with interest. A hearing at the PUCO is scheduled for December 2014.

Management cannot predict the outcome of this proceeding or what effect, if any, this proceeding could 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.

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SWEPCo Rate Matters

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In October 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo's recovery of AFUDC in addition to limits on its recovery of cash construction costs. Additionally, the PUCT deferred consideration of the requested increase in depreciation expense related to the change in the 2016 retirement date of the Welsh Plant, Unit 2. As of September 30, 2014, the net book value of Welsh Plant, Unit 2 was $85 million, before cost of removal, including materials and supplies inventory and CWIP.

Upon rehearing in January 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. The resulting annual base rate increase is approximately $52 million. In March 2014, the PUCT issued an order related to the January 2014 PUCT ruling and in April 2014, this order became final. In May 2014, intervenors filed appeals of that order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals and filed initial responses.

If certain parts of the PUCT order are overturned or if SWEPCo cannot ultimately recover its Texas jurisdictional share of the Turk Plant investment, including AFUDC, or its retirement-related costs of Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition.

Texas Transmission Cost Recovery Factor Filing

In May 2014, SWEPCo filed an application with the PUCT to implement its transmission cost recovery factor (TCRF) requesting additional annual revenue of $15 million. The TCRF is designed to recover increases from the amounts included in SWEPCo's Texas retail base rates for transmission infrastructure improvement costs and wholesale transmission charges under a tariff approved by the FERC. SWEPCo's application included Turk Plant transmission-related costs. In July 2014, intervenors filed testimony with recommendations that included revenue increases ranging from $1 million to $10 million. Hearings at the PUCT were held in August 2014. In October 2014, the Administrative Law Judge issued a proposal for decision that recommended approval of SWEPCo's application with an increase in annual revenue of $14 million. An order is anticipated in the fourth quarter of 2014. If the PUCT were to disallow any portion of the TCRF, 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. The rates are subject to refund based on the staff review of the cost of service and the prudency review of the Turk Plant. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. If the LPSC orders refunds based upon the pending staff review of the cost of service or the prudence review of the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

2014 Louisiana Formula Rate Filing

In April 2014, SWEPCo filed its annual formula rate plan for test year 2013 with the LPSC. The filing included a $5 million annual increase, which was effective August 2014, subject to refund. SWEPCo also proposed to increase rates by an additional $15 million annually, effective January 2015, for a total annual increase of $20 million. This additional increase reflects the cost of incremental generation to be used to serve Louisiana customers in 2015 due to the expiration of a purchase power agreement attributable to Louisiana customers. These increases are subject to LPSC staff review. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Welsh Plant, Units 1 and 3 - Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet mercury and air toxics standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of September 30, 2014, SWEPCo has incurred costs of $112 million and has contractual construction obligations of $84 million related to these projects. SWEPCo will seek to recover these project costs from customers through filings at the state commissions and FERC. These environmental projects could be adversely impacted by pending carbon emission regulations. As of September 30, 2014, the net book value of Welsh Plant, Units 1 and 3 was $335 million, before cost of removal, including materials and supplies inventory and CWIP. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

APCo and WPCo Rate Matters

Plant Transfer

APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a cost-of-service basis. West Virginia generally allows for timely recovery of fuel costs through an expanded net energy cost which trues-up to actual expenses. In March 2014, APCo and WPCo filed a request with the WVPSC for approval to transfer at net book value to WPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity presently owned by AGR. In April 2014, APCo and WPCo filed testimony that supported their request and proposed a base rate surcharge of $113 million, to be offset by an equal reduction in the ENEC revenues, to be effective upon the transfer of the Mitchell Plant to WPCo until APCo's West Virginia base rates are updated. See the "2014 West Virginia Base Rate Case" below. In April 2014, AGR and WPCo filed a request with the FERC for approval to transfer AGR’s one-half interest in the Mitchell Plant to WPCo. In June 2014, the FERC issued an order approving this request.

In August 2014, intervenors filed testimony with the WVPSC with recommendations that ranged from transferring only a portion of the one-half interest in the Mitchell Plant to denial of the transfer in its entirety. Additionally, recommendations included reducing the net book value of the one-half interest in the Mitchell Plant and reducing the base rate surcharge to $87 million. Intervenors also expressed concerns related to the amount of liability assumed by WPCo should the transfer be approved. In October 2014, a stipulation agreement between APCo, WPCo, the WVPSC staff and intervenors in the case was filed with the WVPSC. The stipulation agreement recommended approval for WPCo to acquire, at net book value, the one-half interest in the Mitchell Plant, excluding $20 million of certain assets, which will be paid by WPCo and recovered as a regulatory asset over the life of the plant. Additionally, the agreement stated that 82.5% of the costs associated with the acquired interest will be reflected in rates effective from the date of the transfer via a surcharge with an offset in ENEC revenues. The remaining 17.5% of the costs associated with the acquired interest is to be included in rates by January 2020. The agreement also proposed that WPCo share the energy margins for 82.5% of the plant's output with ratepayers and that WPCo retain all of the energy margins from sales into the wholesale market on the remaining 17.5%, to offset fixed costs associated with this portion, until the remaining portion is approved for inclusion in rates. Management anticipates an order related to the proposed transfer will be issued in the fourth quarter of 2014. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

APCo IGCC Plant

As of September 30, 2014, 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. In March 2014, APCo submitted a request to the Virginia SCC as part of the 2014 Virginia Biennial Base Rate Case to amortize the Virginia jurisdictional share of these costs over two years. In June 2014, APCo submitted a request to the WVPSC as part of the 2014 West Virginia Base Rate Case to amortize the West Virginia jurisdictional share of these costs over five years. In August 2014, intervenors filed testimony with the Virginia SCC that recommended APCo write-off the entire $10 million applicable to the Virginia jurisdiction. Hearings at the Virginia SCC were held in September 2014. A decision is expected in November 2014. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2013 Virginia Transmission Rate Adjustment Clause (transmission RAC)

In December 2013, APCo filed with the Virginia SCC to increase its transmission RAC revenues by $50 million annually to be effective May 2014. In March 2014, the Virginia SCC issued an order approving a stipulation agreement between APCo and the Virginia SCC staff increasing the transmission RAC revenues by $49 million annually, subject to true-up, effective May 2014. Pursuant to the order, the Virginia SCC staff will audit APCo's transmission RAC under-recoveries and report its findings and recommendations in testimony in APCo's next transmission RAC proceeding in 2015.

2014 Virginia Biennial Base Rate Case

In March 2014, APCo filed a biennial generation and distribution base rate case with the Virginia SCC. In accordance with a Virginia statute, APCo did not request a change in base rates as its Virginia retail combined rate of return on common equity for 2012 and 2013 is within the statutory range of the approved return on common equity of 10.9%. The filing included a request to decrease generation depreciation rates, effective February 2015, primarily due to changes in the expected service lives of various generating units and the extended recovery through 2040 of the net book value of certain planned 2015 plant retirements. Additionally, the filing included a request to amortize $7 million annually for two years, beginning February 2015, related to IGCC and other deferred costs.

In August 2014, the Virginia SCC staff and intervenors filed testimony concluding that APCo's adjusted earned rate of return on common equity for 2012 and 2013, reflecting their recommended adjustments, was above the allowed threshold. Recommendations included (a) refunds to customers ranging from $15 million to $22 million, (b) the write-off of certain APCo assets, including IGCC pre-construction costs and previously approved 2009 storm costs, totaling $27 million and (c) $38 million in increased depreciation expense annually, retroactive to January 1, 2014, primarily related to accelerating depreciation on APCo generation assets to be retired in the second quarter of 2015. Hearings at the Virginia SCC were held in September 2014. A decision is expected in November 2014. If any of these costs are not recoverable, or if refunds are ordered, it could reduce future net income and cash flows and impact financial condition.

2014 West Virginia Base Rate Case

In June 2014, APCo filed a request with the WVPSC to increase annual base rates by $181 million, based upon a 10.62% return on common equity, to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates primarily due to the increase in plant investment and changes in the expected service lives of various generating units. The filing also requested recovery of $89 million over five years related to 2012 West Virginia storm costs, IGCC and other deferred costs. In addition to the base rate request, the filing also included a request to implement a rider of approximately $45 million annually to recover vegetation management costs, including a return on capital investment. In October 2014, the WVPSC approved APCo's motion to revise the procedural schedule which included the extension of the intervention period to November 2014 and a delay in the implementation of new rates from April 2015 to May 2015. Hearings at the WVPSC are scheduled for January 2015. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters

2014 Oklahoma Base Rate Case

In January 2014, PSO filed a request with the OCC to increase annual base rates by $38 million, based upon a 10.5% return on common equity. This revenue increase includes a proposed increase in depreciation rates of $29 million. In addition, the filing proposed recovery of advanced metering costs through a separate rider over a three-year deployment period requesting $7 million of revenues in year one, increasing to $28 million in year three. The filing also proposed expansion of an existing transmission rider currently recovered in base rates to include additional transmission-related costs that are expected to increase over the next several years.

In April and May 2014, testimony was filed by the OCC staff and intervenors with recommendations that included adjustments to annual base rates ranging from an increase of $16 million to a reduction of $22 million, primarily based upon the determination of depreciation rates and a return on common equity between 9.18% and 9.5%. Additionally, the recommendations did not support the advanced metering rider or the expansion of the transmission rider. In May 2014, PSO filed rebuttal testimony that included an updated annual base rate increase request of $42 million to reflect certain updated costs.

In June 2014, a non-unanimous stipulation agreement between PSO, the OCC staff and certain intervenors was filed with the OCC. The parties to the stipulation recommended no overall change to the transmission rider or to annual revenues, other than additional revenues through a separate rider related to advanced metering costs, and that the terms of the stipulation be effective November 2014. The advanced metering rider would provide $7 million of revenues in 2014 and increase to $27 million in 2016. New depreciation rates are recommended for advanced metering investments and existing meters, also to be effective November 2014. Further, the stipulation recommends a return on common equity of 9.85% to be used only in the formula to calculate AFUDC, factoring of customer receivables and for riders with an equity component. Additionally, the stipulation recommends recovery of regulatory assets for 2013 storms and regulatory case expenses. In July 2014, the Attorney General joined in the stipulation agreement. A hearing at the OCC was held in July 2014. An order is anticipated in the fourth quarter of 2014. If the OCC were to disallow any portion of this settlement agreement, 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% and adjusted the authorized annual increase in base rates to $92 million in March 2013. In April 2014, the Indiana Office of Utility Consumer Counselor (OUCC) filed an appeal to the Indiana Supreme Court related to the inclusion of a prepaid pension asset in rate base, which is approximately $7 million in annual revenues. In August 2014, the Indiana Supreme Court denied the appeal filed by the OUCC.

Cook Plant Life Cycle Management Project (LCM Project)

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the LCM Project, which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life (2034 for Unit 1 and 2037 for Unit 2). The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. As of September 30, 2014, I&M has incurred costs of $492 million related to the LCM Project, including AFUDC.

In July 2013, the IURC approved I&M's proposed project with the exception of an estimated $23 million related to certain items that might accommodate a future potential power uprate which the IURC stated I&M could seek recovery of in a subsequent base rate case. I&M will recover approved costs through an LCM rider which will be determined in semi-annual proceedings. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in rates. In May 2014, the IURC issued a final order approving the LCM rider rates that were implemented in January 2014.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project and authorized deferral accounting for costs incurred related to the approved projects effective January 2013 until these costs are included in rates. In February 2013, intervenors filed appeals 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. In October 2014, the Michigan Court of Appeals issued an order that affirmed the MPSC decision in part, but reversed the portion of the MPSC decision related to certain costs. The order indicated that I&M could recover those costs in a future Michigan base case if they can show that the costs were reasonable and prudent.

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.

Tanners Creek Plant

In 2011, I&M announced that it would retire Tanners Creek Plant, Units 1-3 by June 2015 to comply with proposed environmental regulations. In September 2013, I&M announced that Tanners Creek Plant, Unit 4 would also be retired in mid-2015 rather than being converted from coal to natural gas. I&M is currently recovering depreciation and a return on the net book value of the Tanners Creek Plant in base rates and plans to seek recovery of all of the plant’s retirement related costs in its next Indiana and Michigan base rate cases.

In December 2013, I&M filed an application with the MPSC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and the Tanners Creek Plant due to the retirement of the Tanners Creek Plant in 2015. Upon the retirement of the Tanners Creek Plant, I&M proposed that, for purposes of determining its depreciation rates, the net book value of the Tanners Creek Plant be recovered over the remaining life of the Rockport Plant.

In September 2014, a settlement agreement was approved by the MPSC that included the authorization for I&M to implement revised depreciation rates for Rockport Plant, Unit 1, effective upon the retirement date of the Tanners Creek Plant. Upon implementation of the revised depreciation rates, I&M is authorized to reduce customer rates through a credit rider until the revised rates for Rockport Plant, Unit 1 are included in base rates.

Transmission, Distribution and Storage System Improvement Charge (TDSIC)

In October 2014, I&M filed petitions with the IURC for approval of a TDSIC Rider and approval of I&M’s seven-year TDSIC Plan, from 2015 through 2021, for eligible transmission, distribution and storage system improvements. The initial estimated cost of the capital improvements and associated operation and maintenance expenses included in the TDSIC Plan of $787 million will be updated annually. The TDSIC Plan included distribution investments specific to the Indiana jurisdiction. The TDSIC Rider will allow the periodic adjustment of I&M's rates to provide for timely recovery of 80% of approved TDSIC Plan costs. I&M will defer the remaining 20% of approved TDSIC Plan costs to be recovered in I&M's next general rate case. I&M is not seeking a rate adjustment in this proceeding but is seeking approval of a TDSIC Rider rate adjustment mechanism for subsequent proceedings. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

KPCo Rate Matters

Plant Transfer

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. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of September 30, 2014, the net book value of Big Sandy Plant, Unit 2 was $273 million, before cost of removal, including materials and supplies inventory and CWIP.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. The WVPSC order was subsequently issued in December 2013, but the WVPSC deferred a decision on the transfer of the one-half interest in the Mitchell Plant to APCo. See the "Plant Transfer" disclosure above within the APCo and WPCo Rate Matters section. The modified settlement agreement approved by the KPSC also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set in the next base rate case (no earlier than June 2015), but rejected KPCo’s request to defer FGD project costs for Big Sandy Plant, Unit 2. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed.

In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In May 2014, KPCo's motion to dismiss the appeal was denied. In May 2014, KPCo filed motions for reconsideration and clarification with the Franklin County Circuit Court. In June 2014, the motion for reconsideration was denied but the motion to clarify was granted, thereby limiting the appeal to the issues of law presented in the Attorney General's appeal. If any part of the KPSC order is overturned, or if the WVPSC approves a lower net book value for the Mitchell Plant transfer, it could reduce future net income and cash flows and impact financial condition.

Kentucky Fuel Adjustment Clause Review

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. An intervenor has requested and received a revised procedural schedule to determine if the allocation of fuel costs has been applied appropriately. In October 2014, intervenors filed testimony that recommended the KPSC direct KPCo to modify its fuel allocation methodology and order a refund to customers of approximately $13 million, plus carrying charges at a weighted average cost of capital, related to the period January 1, 2014 through April 30, 2014. A hearing at the KPSC is scheduled for November 2014. Management believes the methodology used to determine fuel costs is appropriate and intends to oppose the recommendations filed by intervenors. If the KPSC directs KPCo to modify its fuel allocation methodology, it could affect the allocation of costs for all periods beginning January 2014, and if any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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5. 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 2013 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 revolving credit facilities totaling $3.5 billion, under which we may issue up to $1.2 billion as letters of credit. As of September 30, 2014, the maximum future payments for letters of credit issued under the revolving credit facilities were $76 million with maturities ranging from October 2014 to June 2015.

In January 2014, we issued letters of credit under an $85 million uncommitted facility signed in October 2013. As of September 30, 2014, the maximum future payments for letters of credit issued under the uncommitted facility were $78 million with maturities ranging from October 2014 to January 2015. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

We have $477 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $483 million. The letters of credit have maturities ranging from March 2015 to July 2017.

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 September 30, 2014, SWEPCo has collected approximately $63 million through a rider for final mine closure and reclamation costs, of which $16 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $47 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 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, our exposure generally does not exceed the sale price. As of September 30, 2014, 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 September 30, 2014, the maximum potential loss for these lease agreements was approximately $24 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 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 $12 million and $14 million for I&M and SWEPCo, respectively, for the remaining railcars as of September 30, 2014.

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 83% 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 $9 million and $10 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

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 generation 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 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. In September 2014, I&M

recorded an accrual for remediation at certain additional sites in Michigan. As of September 30, 2014, I&M’s accrual for all of these sites is approximately $17 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 sites or changes in the scope of remediation. 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 generation 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.

OPERATIONAL CONTINGENCIES

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants’ actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court granted our motion to transfer this case to the U.S. District Court for the Southern District of Ohio. Our motion to dismiss the case, filed in October 2013, is pending. We will continue to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

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. Defendants in these cases, including AEP, previously filed a petition seeking further review with the U.S. Supreme Court on the preemption issue. In June 2014, AEP filed a petition with the U.S. Supreme Court seeking review of the personal jurisdiction issue. In July 2014, the U.S. Supreme Court granted the defendants' previously filed petition for further review with the U.S. Supreme Court on the preemption issue. We will continue to defend the cases. We believe the provision we have is adequate. We are unable to determine the amount of potential additional losses that are reasonably possible of occurring.

Wage and Hours Lawsuit

In August 2013, PSO received an amended complaint filed in the U.S. District Court for the Northern District of Oklahoma by 36 current and former line and warehouse employees alleging that they have been denied overtime pay in violation of the Fair Labor Standards Act. Plaintiffs claim that they are entitled to overtime pay for “on call” time. They allege that restrictions placed on them during on call hours are burdensome enough that they are entitled to compensation for these hours as hours worked. Plaintiffs also filed a motion to conditionally certify this action as a class action, claiming there are an additional 70 individuals similarly situated to plaintiffs. Plaintiffs seek damages in the amount of unpaid overtime over a three-year period and liquidated damages in the same amount.

In March 2014, the federal court granted plaintiffs’ motion to conditionally certify the action as a class action. Notice was given to all potential class members and an additional 43 individuals opted in to the class, bringing the plaintiff class to 79 current and former employees. We will continue to defend the case. We are unable to determine a range of potential losses that are reasonably possible of occurring.

National Do Not Call Registry Lawsuit

In May 2014, AEP Energy was served with a complaint filed in the U.S. District Court for the Northern District of Illinois, alleging violations of the Telephone Consumer Protection Act (TCPA). The plaintiff alleges that he received telemarketing calls on behalf of AEP Energy despite having registered his telephone number on the National Do Not Call Registry. Plaintiff seeks to represent a class of persons who allegedly received such calls. Plaintiff seeks statutory damages under the TCPA on behalf of himself and the alleged class as well as injunctive relief. We will continue to defend this case. We believe the provision we have is adequate. We are unable to determine the amount of potential additional losses that are reasonably possible of occurring.

Gavin Landfill Litigation

In August 2014, a complaint was filed in the Mason County, West Virginia Circuit Court against AEP, AEPSC, OPCo and an individual supervisor alleging wrongful death and personal injury/illness claims arising out of purported exposure to coal combustion by-product waste at the Gavin Plant landfill. The lawsuit was filed on behalf of 77 plaintiffs, consisting of 39 current and former contractors of the landfill and 38 family members of those contractors. Eleven of the family members are pursuing personal injury/illness claims and the remainder are pursuing loss of consortium claims. The plaintiffs seek compensatory and punitive damages, as well as medical monitoring. In September 2014, we filed a motion to dismiss the complaint, contending the case should be filed in Ohio. That motion is pending. We will continue to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

6. IMPAIRMENTS

2013

Turk Plant (Vertically Integrated Utilities segment)

In the third quarter of 2013, SWEPCo recorded a pretax write-off of $111 million in Asset Impairments and Other Related Charges on the statement of income related to AFUDC on the Turk Plant that was included in the Texas capital cost cap. See the "2012 Texas Base Rate Case" section of Note 4.

Big Sandy Plant, Unit 2 FGD Project (Vertically Integrated Utilities segment)

In the third quarter of 2013, KPCo recorded a pretax write-off of $33 million in Asset Impairments and Other Related Charges on the statement of income primarily related to the Big Sandy Plant, Unit 2 FGD project. See the "Plant Transfer" section of KPCo Rate Matters in Note 4.

Muskingum River Plant, Unit 5 (Generation & Marketing segment)

In May 2013, the U.S. District Court for the Southern District of Ohio approved a modification to the consent decree, which was initially entered into in 2007, requiring certain types of pollution control equipment to be installed at certain AEP plants, including the 600 MW Muskingum River Plant, Unit 5 (MR5) coal-fired generation plant. Under the modification to the consent decree, we have the option to cease burning coal and retire MR5 in 2015 or to cease burning coal in 2015 and complete a natural gas refueling project no later than June 2017. In the second quarter of 2013, based on the approval of the modified consent decree and changes in other market factors, we re-evaluated potential courses of action with respect to the planned operation of MR5 and concluded that completion of a refueling project, which would have extended the useful life of MR5, is remote. As a result, management completed an impairment analysis and concluded that MR5 was impaired. Under a market-based value approach, using level 3 unobservable inputs, management determined that the fair value of this generating unit was zero based on the lack of installed environmental control equipment and the nature and condition of this generating unit. In the second quarter of 2013, we recorded a pretax impairment of $154 million in Asset Impairments and Other Related Charges on the statement of income which includes a $6 million pretax impairment of related material and supplies inventory. Management will retire the plant in 2015.

7. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following tables provide the components of our net periodic benefit cost (credit) for the plans for the three and nine months ended September 30, 2014 and 2013:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Service Cost	$18	$17	$4	$5
Interest Cost	55	51	16	18
Expected Return on Plan Assets	(65)	(69)	(28)	(27)
Amortization of Prior Service Cost (Credit)	1	1	(18)	(17)
Amortization of Net Actuarial Loss	31	45	6	16
Net Periodic Benefit Cost (Credit)	$40	$45	$(20)	$(5)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Service Cost	$54	$52	$11	$17
Interest Cost	166	152	50	53
Expected Return on Plan Assets	(196)	(208)	(84)	(80)
Amortization of Prior Service Cost (Credit)	2	2	(52)	(52)
Amortization of Net Actuarial Loss	93	137	17	48
Net Periodic Benefit Cost (Credit)	$119	$135	$(58)	$(14)

8. BUSINESS SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. Within our Vertically Integrated Utilities 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.

During the fourth quarter of 2013, we changed the structure of our internal organization which resulted in a change in the composition of our reportable segments. In accordance with authoritative accounting guidance for segment reporting, prior period financial information has been recast in the financial statements and footnotes to be comparable to the current year presentation of reportable segments.

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

Vertically Integrated Utilities

- Generation, transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEGCo, APCo, I&M, KGPCo, KPCo, PSO, SWEPCo and WPCo.

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
- OPCo purchases energy to serve standard service offer customers, and provides capacity for all connected load.

AEP Transmission Holdco

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

Generation & Marketing

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

AEP River Operations

- Commercial barging operations that transports liquids, coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

The remainder of our activities is presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

The tables below present our reportable segment income statement information for the three and nine months ended September 30, 2014 and 2013 and reportable segment balance sheet information as of September 30, 2014 and December 31, 2013. These amounts include certain estimates and allocations where necessary.

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)							
Three Months Ended September 30, 2014								
Revenues from:								
External Customers	$2,432 (b)	$ 1,163	$ 21	$ 538 (b)	$ 141	$7	$ — (c)	$ 4,302
Other Operating Segments	18 (b)	68	34	363 (b)	14	19	(516)	—
Total Revenues	$2,450	$ 1,231	$ 55	$ 901	$ 155	$26	$ (516)	$ 4,302
Net Income	$220	$ 92	$ 43	$ 117	$ 11	$11	$ —	$ 494

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)							
Three Months Ended September 30, 2013								
Revenues from:								
External Customers	$2,543	$ 1,139	$ 9	$ 359	$ 126	$12	$ (12) (c)	$ 4,176
Other Operating Segments	195	56	17	642	4	16	(930)	—
Total Revenues	$2,738	$ 1,195	$ 26	$ 1,001	$ 130	$28	$ (942)	$ 4,176
Net Income (Loss)	$174	$ 119	$ 22	$ 112	$ (1)	$8	$ —	$ 434

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)							
Nine Months Ended September 30, 2014								
Revenues from:								
External Customers	$7,217 (b)	$ 3,388	$ 54	$ 1,932 (b)	$ 435	$19	$ (51) (c)	$ 12,994
Other Operating Segments	71 (b)	192	86	1,133 (b)	45	55	(1,582)	—
Total Revenues	$7,288	$ 3,580	$ 140	$ 3,065	$ 480	$74	$ (1,633)	$ 12,994
Net Income	$654	$ 279	$ 114	$ 378	$ 17	$4	$ —	$ 1,446

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)							
Nine Months Ended September 30, 2013								
Revenues from:								
External Customers	$7,075	$ 3,248	$ 18	$ 915	$ 365	$26	$ (63) (c)	$ 11,584
Other Operating Segments	480	145	35	1,898	15	41	(2,614)	—
Total Revenues	$7,555	$ 3,393	$ 53	$ 2,813	$ 380	$67	$ (2,677)	$ 11,584
Net Income (Loss)	$508	$ 281	$ 53	$ 188	$ (12)	$119	$ —	$ 1,137

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	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments		Consolidated
	(in millions)								
September 30, 2014									
Total Property, Plant and Equipment	$38,857	$ 12,792	$ 2,378	$ 8,363	$ 673	$331	$ (271	) (d)	$ 63,123
Accumulated Depreciation and Amortization	12,728	3,447	20	3,563	212	183	(94	) (d)	20,059
Total Property Plant and Equipment - Net	$26,129	$ 9,345	$ 2,358	$ 4,800	$ 461	$148	$ (177	) (d)	$ 43,064
Total Assets	$33,072	$ 13,822	$ 3,000	$ 6,280	$ 686	$20,706	$ (19,641	) (d) (e)	$ 57,925
Long-term Debt Due Within One Year:									
Affiliated	$131	$ —	$ —	$ 86	$ —	$—	$ (217	)	$ —
Non-Affiliated	1,309	405	—	661	3	3	—		2,381
Long-term Debt:									
Affiliated	20	—	—	32	—	—	(52	)	—
Non-Affiliated	8,574	5,189	699	297	81	837	—		15,677
Total Long-term Debt	$10,034	$ 5,594	$ 699	$ 1,076	$ 84	$840	$ (269	)	$ 18,058

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	AEP River Operations	Corporate and Other (a)	Reconciling Adjustments		Consolidated
	(in millions)								
December 31, 2013									
Total Property, Plant and Equipment	$37,545	$ 12,143	$ 1,636	$ 8,277	$ 638	$315	$ (269	) (d)	$ 60,285
Accumulated Depreciation and	12,250	3,342	10	3,409	189	173	(85	) (d)	19,288

Amortization								
Total Property Plant and Equipment - Net	$25,295	$ 8,801	$ 1,626	$ 4,868	$ 449	$142	$ (184) (d)	$ 40,997
Total Assets	$32,791	$ 14,165	$ 2,245	$ 6,426	$ 673	$19,645	$ (19,531) (d) (e)	$ 56,414
Long-term Debt Due Within One Year:								
Affiliated	$—	$ —	$ —	$ 179	$ 5	$—	$ (184)	$ —
Non-Affiliated	720	697	—	126	2	4	—	1,549
Long-term Debt:								
Affiliated	151	—	—	118	10	—	(279)	—
Non-Affiliated	9,265	5,360	620	664	83	836	—	16,828
Total Long-term Debt	$10,136	$ 6,057	$ 620	$ 1,087	$ 100	$840	$ (463)	$ 18,377

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

(b) Includes the impact of the corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013, as well as the impact of the termination of the Interconnection Agreement effective January 1, 2014.

(c) Reconciling Adjustments for External Customers primarily include eliminations as a result of corporate separation in Ohio.

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

(e) 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.

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9. 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, natural gas, 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 extent, heating oil, gasoline 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 September 30, 2014 and December 31, 2013:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume September 30, 2014 (in millions)	December 31, 2013	Unit of Measure
Commodity:			
Power	348	406	MWhs
Coal	2	4	Tons
Natural Gas	112	127	MMBtus
Heating Oil and Gasoline	5	6	Gallons
Interest Rate	$162	$191	USD
Interest Rate and Foreign Currency	$815	$820	USD

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Fair Value Hedging Strategies

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

Cash Flow Hedging Strategies

We enter into and designate as cash flow hedges certain derivative transactions for the purchase and sale of power and natural gas ("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. We discontinued cash flow hedge accounting for these derivative contracts effective March 31, 2014. During the three and nine months ended September 30, 2013, we designated financial heating oil and gasoline derivatives as cash flow hedges. For disclosure purposes, these contracts were included with other hedging activities as "Commodity" as of December 31, 2013. In March 2014, these contracts were grouped as "Commodity" with other risk management activities. 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 September 30, 2014 and December 31, 2013 condensed balance sheets, we netted $20 million and $4 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $6 million and $13 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 September 30, 2014 and December 31, 2013:

Fair Value of Derivative Instruments
September 30, 2014

	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in millions)					
Current Risk Management Assets	$340	$17	$4	$361	$(226)	$ 135
Long-term Risk Management Assets	300	4	—	304	(76)	228
Total Assets	640	21	4	665	(302)	363
Current Risk Management Liabilities	262	12	1	275	(215)	60
Long-term Risk Management Liabilities	180	3	12	195	(75)	120
Total Liabilities	442	15	13	470	(290)	180
Total MTM Derivative Contract Net Assets (Liabilities)	$198	$6	$(9)	$195	$(12)	$ 183

Fair Value of Derivative Instruments
December 31, 2013

	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk	Gross Amounts Offset in	Net Amounts of Assets/Liabilities Presented in the

Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Management Assets/ Liabilities Recognized	the Statement of Financial Position (b)	Statement of Financial Position (c)
	(in millions)					
Current Risk Management Assets	$347	$12	$4	$363	$(203)	$ 160
Long-term Risk Management Assets	368	3	—	371	(74)	297
Total Assets	715	15	4	734	(277)	457
Current Risk Management Liabilities	292	11	1	304	(214)	90
Long-term Risk Management Liabilities	237	3	15	255	(78)	177
Total Liabilities	529	14	16	559	(292)	267
Total MTM Derivative Contract Net Assets (Liabilities)	$186	$1	$(12)	$175	$15	$ 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 and nine months ended September 30, 2014 and 2013:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three and Nine Months Ended September 30, 2014 and 2013

	Three Months Ended September 30,		Nine Months Ended September 30,	
Location of Gain (Loss)	2014	2013	2014	2013
	(in millions)			
Vertically Integrated Utilities Revenues	$7	$3	$29	$13
Generation & Marketing Revenues	21	10	69	43
Regulatory Assets (a)	(6)	(1)	(6)	(3)
Regulatory Liabilities (a)	(7)	(4)	111	(10)
Total Gain on Risk Management Contracts	$15	$8	$203	$43

(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 and nine months ended September 30, 2014, we recognized losses of $2 million and gains of $2 million, respectively, on our hedging instruments and offsetting gains of $2 million and losses of $2 million, respectively, on our long-term debt. During the three and nine months ended September 30, 2013, we recognized gains of $4 million and losses of $8 million, respectively, on our hedging instruments and offsetting losses of $4 million and gains of $8 million, respectively, on our long-term debt. During the three and nine months ended September 30, 2014 and 2013, hedge ineffectiveness was immaterial.

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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 and nine months ended September 30, 2014 and 2013, 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 and nine months ended September 30, 2013, we designated heating oil and gasoline derivatives as cash flow hedges. We discontinued cash flow hedge accounting for these derivative contracts effective March 31, 2014.

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 and nine months ended September 30, 2014 and 2013, 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 and nine months ended September 30, 2014 and 2013, we did not designate any foreign currency derivatives as cash flow hedges.

During the three and nine months ended September 30, 2014 and 2013, 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 and nine months ended September 30, 2014 and 2013, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets as of September 30, 2014 and December 31, 2013 were:
Impact of Cash Flow Hedges on the Condensed Balance Sheet
September 30, 2014

	Commodity	Interest Rate and Foreign Currency	Total
	(in millions)		
Hedging Assets (a)	$9	$—	$9
Hedging Liabilities (a)	3	1	4
AOCI Gain (Loss) Net of Tax	3	(20)	(17)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	2	(3)	(1)

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

	Commodity	Interest Rate and Foreign Currency	Total
	(in millions)		
Hedging Assets (a)	$7	$—	$7
Hedging Liabilities (a)	6	2	8
AOCI Loss Net of Tax	—	(23)	(23)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	—	(4)	(4)

(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 September 30, 2014, 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 was 63 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, these agreements 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), a limited number of derivative and non-derivative contracts primarily related to our competitive retail auction loads, and guaranties for contractual obligations, we are obligated to post an additional amount of collateral if our credit ratings decline below a specified rating threshold. 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 a specified rating threshold that would require the posting of additional collateral. 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 and guaranties for contractual obligations if our credit ratings had declined below a specified rating threshold and (c) how much was attributable to RTO and ISO activities as of September 30, 2014 and December 31, 2013:

	September 30, 2014	December 31, 2013
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$1	$3
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	144	33
Amount Attributable to RTO and ISO Activities	35	28

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 September 30, 2014 and December 31, 2013:

	September 30, 2014	December 31, 2013
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$189	$293
Amount of Cash Collateral Posted	—	1
Additional Settlement Liability if Cross Default Provision is Triggered	147	235

10. 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 amount of risk taken is determined by the Commercial Operations, Energy Supply 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 (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer and Chief Risk Officer in addition to Energy Supply's President and Vice President.

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

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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 September 30, 2014 and December 31, 2013 are summarized in the following table:

	September 30, 2014		December 31, 2013	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$18,058	$20,237	$18,377	$19,672

Fair Value Measurements of Other Temporary Investments

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds and Securities Available for Sale, including 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:

	September 30, 2014			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$213	$—	$—	$213
Fixed Income Securities – Mutual Funds	80	—	—	80
Equity Securities – Mutual Funds	13	12	—	25
Total Other Temporary Investments	$306	$12	$—	$318

	December 31, 2013			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$250	$—	$—	$250
Fixed Income Securities – Mutual Funds	80	—	—	80
Equity Securities – Mutual Funds	12	11	—	23
Total Other Temporary Investments	$342	$11	$—	$353

(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 and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Proceeds from Investment Sales	$—	$—	$—	$—
Purchases of Investments	—	6	1	17
Gross Realized Gains on Investment Sales	—	—	—	—
Gross Realized Losses on Investment Sales	—	—	—	—

As of September 30, 2014 and December 31, 2013, we had no Other Temporary Investments with an unrealized loss position. As of September 30, 2014, fixed income securities were primarily debt based mutual funds with short and intermediate maturities. Mutual funds may be sold and do not contain maturity dates.

For details of the reasons for changes in Securities Available for Sale included in Accumulated Other Comprehensive Income (Loss) for the three and nine months ended September 30, 2014 and 2013, see Note 3.

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 September 30, 2014 and December 31, 2013:

	September 30, 2014			December 31, 2013		
	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	$13	$—	$—	$19	$—	$—
Fixed Income Securities:						
United States Government	609	35	(3)	609	26	(4)
Corporate Debt	46	4	(1)	37	2	(1)
State and Local Government	286	1	—	255	1	—
Subtotal Fixed Income Securities	941	40	(4)	901	29	(5)
Equity Securities – Domestic	1,066	545	(80)	1,012	506	(82)
Spent Nuclear Fuel and Decommissioning Trusts	$2,020	$585	$(84)	$1,932	$535	$(87)

The following table provides the securities activity within the decommissioning and SNF trusts for the three and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Proceeds from Investment Sales	$263	$250	$746	$635
Purchases of Investments	281	264	790	676
Gross Realized Gains on Investment Sales	8	4	25	16
Gross Realized Losses on Investment Sales	1	2	10	12

The adjusted cost of fixed income securities was $901 million and $872 million as of September 30, 2014 and December 31, 2013, respectively. The adjusted cost of equity securities was $521 million and $506 million as of September 30, 2014 and December 31, 2013, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2014 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$103
1 year – 5 years	377
5 years – 10 years	198
After 10 years	263
Total	$941

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 September 30, 2014 and December 31, 2013. 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
September 30, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$22	$1	$—	$171	$194
Other Temporary Investments					
Restricted Cash (a)	196	8	—	9	213
Fixed Income Securities - Mutual Funds	80	—	—	—	80
Equity Securities – Mutual Funds (b)	25	—	—	—	25
Total Other Temporary Investments	301	8	—	9	318
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	13	441	155	(261)	348
Cash Flow Hedges:					
Commodity Hedges (c)	—	16	4	(11)	9
Fair Value Hedges	—	1	—	3	4
De-designated Risk Management Contracts (e)	—	—	—	2	2
Total Risk Management Assets	13	458	159	(267)	363
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	4	—	—	9	13
Fixed Income Securities:					
United States Government	—	609	—	—	609
Corporate Debt	—	46	—	—	46
State and Local Government	—	286	—	—	286
Subtotal Fixed Income Securities	—	941	—	—	941
Equity Securities – Domestic (b)	1,066	—	—	—	1,066
Total Spent Nuclear Fuel and Decommissioning Trusts	1,070	941	—	9	2,020
Total Assets	$1,406	$1,408	$159	$(78)	$2,895
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$26	$355	$30	$(247)	$164
Cash Flow Hedges:					
Commodity Hedges (c)	—	14	—	(11)	3

Interest Rate/Foreign Currency Hedges	—	1	—	—	1
Fair Value Hedges	—	9	—	3	12
Total Risk Management Liabilities	$26	$379	$30	$(255)	$180

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

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$16	$1	$—	$101	$118
Other Temporary Investments					
Restricted Cash (a)	231	8	—	11	250
Fixed Income Securities - Mutual Funds	80	—	—	—	80
Equity Securities – Mutual Funds (b)	23	—	—	—	23
Total Other Temporary Investments	334	8	—	11	353
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	22	549	142	(273)	440
Cash Flow Hedges:					
Commodity Hedges (c)	—	15	—	(8)	7
Fair Value Hedges	—	1	—	3	4
De-designated Risk Management Contracts (e)	—	—	—	6	6
Total Risk Management Assets	22	565	142	(272)	457
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	8	—	—	11	19
Fixed Income Securities:					
United States Government	—	609	—	—	609
Corporate Debt	—	37	—	—	37
State and Local Government	—	255	—	—	255
Subtotal Fixed Income Securities	—	901	—	—	901
Equity Securities – Domestic (b)	1,012	—	—	—	1,012
Total Spent Nuclear Fuel and Decommissioning Trusts	1,020	901	—	11	1,932
Total Assets	$1,392	$1,475	$142	$(149)	$2,860
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$30	$475	$22	$(282)	$245
Cash Flow Hedges:					
Commodity Hedges (c)	—	11	3	(8)	6
Interest Rate/Foreign Currency Hedges	—	2	—	—	2
Fair Value Hedges	—	11	—	3	14
Total Risk Management Liabilities	$30	$499	$25	$(287)	$267

(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 September 30, 2014 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($12) million in periods 2015-2017 and ($1) million in periods 2018-2019; Level 2 matures $6 million in 2014, $67 million in periods 2015-2017, $9 million in periods 2018-2019 and $4 million in periods 2020-2030; Level 3 matures $38 million in 2014, $46 million in periods 2015-2017, $16 million in periods 2018-2019 and $25 million in periods 2020-2030. 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. Level 1 amounts primarily represent investments in money market funds.

(g) The December 31, 2013 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $4 million in 2014, ($11) million in periods 2015-2017 and ($1) million in periods 2018-2019; Level 2 matures $25 million in 2014, $37 million in periods 2015-2017, $7 million in periods 2018-2019 and $5 million in periods 2020-2030; Level 3 matures $27 million in 2014, $60 million in periods 2015-2017, $14 million in periods 2018-2019 and $19 million in periods 2020-2030. Risk management commodity contracts are substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the three and nine months ended September 30, 2014 and 2013.

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 September 30, 2014	Net Risk Management Assets (Liabilities) (in millions)	
Balance as of June 30, 2014	$132	
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(9	)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	10	
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(3	)
Purchases, Issuances and Settlements (c)	(5	)
Transfers into Level 3 (d) (e)	(9	)
Transfers out of Level 3 (e) (f)	(1	)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	14	
Balance as of September 30, 2014	$129	

Three Months Ended September 30, 2013	Net Risk Management Assets (Liabilities) (in millions)	
Balance as of June 30, 2013	$122	
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(2	)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	13	
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(3	)
Purchases, Issuances and Settlements (c)	(8	)
Transfers out of Level 3 (e) (f)	(2	)
Balance as of September 30, 2013	$120	

Nine Months Ended September 30, 2014	Net Risk Management Assets (Liabilities) (in millions)	
Balance as of December 31, 2013	$117	
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	91	
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	12	
Purchases, Issuances and Settlements (c)	(103	)
Transfers into Level 3 (d) (e)	(9	)
Transfers out of Level 3 (e) (f)	(8	)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	32	
Balance as of September 30, 2014	$129	

Nine Months Ended September 30, 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)	(9)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	32
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(3)
Purchases, Issuances and Settlements (c)	(7)
Transfers into Level 3 (d) (e)	18
Transfers out of Level 3 (e) (f)	(1)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	4
Balance as of September 30, 2013	$120

(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 our Level 3 positions as of September 30, 2014 and December 31, 2013:

Significant Unobservable Inputs
September 30, 2014

	Fair Value Assets (in millions)	Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	High	Weighted Average
Energy Contracts	$124	$29	Discounted Cash Flow	Forward Market Price (a)	$9.93	$103.05	$47.87
				Counterparty Credit Risk (b)	301		
FTRs	35	1	Discounted Cash Flow	Forward Market Price (a)	(14.63)	15.47	1.31
Total	$159	$30					

Significant Unobservable Inputs
December 31, 2013

	Fair Value Assets (in millions)	Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	High
Energy Contracts	$132	$22	Discounted Cash Flow	Forward Market Price (a)	$11.42	$120.72
				Counterparty Credit Risk (b)	316	
FTRs	10	3	Discounted Cash Flow	Forward Market Price (a)	(5.10)	10.44
Total	$142	$25				

(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.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of September 30, 2014:

Sensitivity of Fair Value Measurements
September 30, 2014

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)
Counterparty Credit Risk	Loss	Increase (Decrease)	Higher (Lower)
Counterparty Credit Risk	Gain	Increase (Decrease)	Lower (Higher)

11. 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 and was completed in the second quarter of 2013. The IRS examination of years 2011 and 2012 started in April 2014. 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. We are currently under examination in several state and local jurisdictions. However, it is possible 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 that the ultimate resolution of these audits will not materially impact net income. We are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2009.

12. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding as of September 30, 2014 and December 31, 2013:

Type of Debt	September 30, 2014	December 31, 2013
	(in millions)	
Senior Unsecured Notes	$12,017	$11,799
Pollution Control Bonds	1,963	1,932
Notes Payable	277	369
Securitization Bonds	2,413	2,686
Spent Nuclear Fuel Obligation (a)	265	265
Other Long-term Debt	1,155	1,360
Fair Value of Interest Rate Hedges	(7)	(9)
Unamortized Discount, Net	(25)	(25)
Total Long-term Debt Outstanding	18,058	18,377
Long-term Debt Due Within One Year	2,381	1,549
Long-term Debt	$15,677	$16,828

(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 $309 million as of September 30, 2014 and December 31, 2013, 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 nine months of 2014 are shown in the tables below:

Company	Type of Debt	Principal Amount		Interest Rate	Due Date
Issuances:		(in millions)		(%)	
APCo	Senior Unsecured Notes	$300		4.40	2044
I&M	Pollution Control Bonds	100		1.75	2018
PSO	Other Long-term Debt	75		Variable	2016
SWEPCo	Other Long-term Debt	100		Variable	2017
Non-Registrant:					
AEPTCo	Senior Unsecured Notes	30		5.42	2044
AGR	Pollution Control Bonds	39		Variable	2015
AGR	Pollution Control Bonds	79		Variable	2015
AGR	Pollution Control Bonds	60	(a)	Variable	2038
KPCo	Pollution Control Bonds	65	(a)	Variable	2036
KPCo	Senior Unsecured Notes	120		4.18	2026
TCC	Senior Unsecured Notes	50		2.61	2019
TCC	Senior Unsecured Notes	50		3.81	2026
TCC	Senior Unsecured Notes	100		4.67	2044
Transource Missouri	Other Long-term Debt	49		Variable	2018
Total Issuances		$1,217	(b)		

(a)

Pollution Control Bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year.

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

Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Total Retirements and Principal Payments:		(in millions)	(%)	
APCo	Other Long-term Debt	$300	Variable	2015
APCo	Securitization Bonds	13	2.01	2024
APCo	Senior Unsecured Notes	200	4.95	2015
I&M	Notes Payable	29	Variable	2017
I&M	Notes Payable	22	Variable	2016
I&M	Notes Payable	11	2.12	2016
I&M	Notes Payable	15	Variable	2016
I&M	Notes Payable	4	4.00	2014
I&M	Other Long-term Debt	8	Variable	2015
I&M	Other Long-term Debt	1	6.00	2025
I&M	Pollution Control Bonds	100	6.25	2014
OPCo	Pollution Control Bonds	39	2.875	2014
OPCo	Pollution Control Bonds	79	3.25	2014
OPCo	Pollution Control Bonds	60	3.875	2014
OPCo	Senior Unsecured Notes	225	4.85	2014
OPCo	Securitization Bonds	35	0.958	2018
PSO	Pollution Control Bonds	34	5.25	2014
SWEPCo	Notes Payable	3	4.58	2032
Non-Registrant:				
AEGCo	Senior Unsecured Notes	7	6.33	2037
AEP Subsidiaries	Notes Payable	2	8.03	2026
AEP Subsidiaries	Notes Payable	1	7.59	2026
AEP Subsidiaries	Notes Payable	5	Variable	2017
KPCo	Other Long-term Debt	120	Variable	2015
TCC	Securitization Bonds	127	5.09	2015
TCC	Securitization Bonds	72	6.25	2016
TCC	Securitization Bonds	26	0.88	2017
Total Retirements and Principal Payments		$1,538		

In December 2013, AGR assigned KPCo $200 million of Other Long-term Debt due in May 2015. In September 2014, KPCo refinanced $120 million of the original assignment as Senior Unsecured Notes (see issuances and retirements tables above). Also in September 2014, KPCo signed an agreement to refinance the remaining $80 million in December 2014 as 4.33% Senior Unsecured Notes due in 2026. Consequently and as of September 30, 2014, the remaining $80 million was excluded from current liabilities and was instead classified as Long-term Debt on the balance sheet.

In October 2014, APCo remarketed $100 million of 1.625% Pollution Control Bonds due in 2018.

In October 2014, I&M retired $5 million of Notes Payable related to DCC Fuel.

As of September 30, 2014, trustees held on our behalf, $435 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 primarily 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:

	September 30, 2014			December 31, 2013		
Type of Debt	Outstanding Amount (in millions)	Interest Rate (a)		Outstanding Amount (in millions)	Interest Rate (a)	
Securitized Debt for Receivables (b)	$750	0.22	%	$700	0.23	%
Commercial Paper	532	0.28	%	57	0.29	%
Total Short-term Debt	$1,282			$757		

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

Credit Facilities

For an additional discussion of credit facilities, see "Letters of Credit" section of Note 5.

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.

Our receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement was increased in June 2014 from $700 million and expires in June 2016.

Accounts receivable information for AEP Credit is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	0.21 %	0.23 %	0.22 %	0.23 %
Net Uncollectible Accounts Receivable Written Off	$16	$12	$32	$26

	September 30, 2014	December 31, 2013
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$1,000	$929
Total Principal Outstanding	750	700
Delinquent Securitized Accounts Receivable	57	45
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	13	16
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	269	331

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.

13. 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, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, a protected cell of EIS and Transource Energy. In addition, we have not provided material financial or other support to any of these entities that was not previously contractually required. We hold a significant variable interest in DHLC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine’s only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo’s total billings from Sabine for the three months ended September 30, 2014 and 2013 were $41 million and $41 million, respectively, and for the nine months ended September 30, 2014 and 2013 were $121 million and $125 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 II LLC, DCC Fuel IV LLC, DCC Fuel V LLC and DCC Fuel VI 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 September 30, 2014 and 2013 were $28 million and $32 million, respectively, and for the nine months ended September 30, 2014 and 2013 were $84 million and $96 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. In October 2013, the lease agreements ended for DCC Fuel LLC and DCC Fuel III LLC. 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 concluded that we are the primary beneficiary and are required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the condensed balance sheets. See "Securitized Accounts Receivable – AEP Credit" section of Note 12.

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 $1.8 billion and $2 billion as of September 30, 2014 and December 31, 2013, respectively. Transition Funding has securitized transition assets of $1.7 billion and $1.9 billion as of September 30, 2014 and December 31, 2013, respectively. 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.

Ohio Phase-in-Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to phase-in recovery property. Management has concluded that OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding because OPCo has the power to direct the most significant activities of the VIE and OPCo's equity interest could potentially be significant. Therefore, OPCo is required to consolidate Ohio Phase-in-Recovery Funding. The securitized bonds totaled $232 million and $267 million as of September 30, 2014 and December 31, 2013, respectively. Ohio Phase-in-Recovery Funding has securitized assets of $116 million and $132 million as of September 30, 2014 and December 31, 2013, respectively. The phase-in recovery property represents the right to impose and collect Ohio deferred distribution charges from customers receiving electric transmission and distribution service from OPCo under a recovery mechanism approved by the PUCO. In August 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to OPCo or any other AEP entity. OPCo acts as the servicer for Ohio Phase-in-Recovery Funding's securitized assets and remits all related amounts collected from customers to Ohio Phase-in-Recovery Funding for interest and principal payments on the securitization bonds and related costs. See the table below for the classification of Ohio Phase-in-Recovery Funding's assets and liabilities on the condensed balance sheets.

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. The securitized bonds totaled $368 million and $380 million as of September 30, 2014 and December 31, 2013, respectively. Appalachian Consumer Rate Relief Funding has securitized assets of $356 million and $369 million as of September 30, 2014 and December 31, 2013, respectively. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on the condensed balance sheets.

The securitized bonds of Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding are included in current and long-term debt on the condensed balance sheets. The securitized assets of Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding are included in securitized assets 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 EIS. Our insurance premium expense to the protected cell for the three months ended September 30, 2014 and 2013 were $16 million and $15 million, respectively, and for the nine months ended September 30, 2014 and 2013 were $33 million and $30 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.

Transource Energy was formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates. AEP has equity and voting ownership of 86.5% with the other owner having 13.5% interest. Management has concluded that Transource Energy is a VIE and that AEP is the primary beneficiary because AEP has the power to direct the most significant activities of the entity. Therefore, AEP is required to consolidate Transource Energy. AEP's equity interest could potentially be significant. In January 2014, Transource Missouri acquired transmission assets from the non-controlling owner and issued debt and received a capital contribution to fund the acquisition. The majority of Transource Energy's activity resulted from the asset acquisition, debt issuance and capital contribution. See the tables below for the classification of Transource Energy's assets and liabilities on the condensed balance sheets.

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
September 30, 2014
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	AEP Credit	TCC Transition Funding		OPCo Ohio Phase-in-Recovery Funding		APCo Appalachian Consumer Rate Relief Funding		Protected Cell of EIS	Transource Energy
ASSETS											
Current Assets	$62	$69	$1,006	$ 198		$ 22		$ 10		$ 158	$ 3
Net Property, Plant and Equipment	148	73	—	—		—		—		—	82
Other Noncurrent Assets	51	27	—	1,730	(a)	221	(b)	364	(c)	3	4
Total Assets	$261	$169	$1,006	$ 1,928		$ 243		$ 374		$ 161	$ 89
LIABILITIES AND EQUITY											
Current Liabilities	$31	$65	$910	$ 313		$ 47		$ 24		$ 50	$ 11
Noncurrent Liabilities	230	104	—	1,597		195		348		70	49
Equity	—	—	96	18		1		2		41	29
Total Liabilities and Equity	$261	$169	$1,006	$ 1,928		$ 243		$ 374		$ 161	$ 89

(a) Includes an intercompany item eliminated in consolidation of $77 million.
(b) Includes an intercompany item eliminated in consolidation of $102 million.
(c) Includes an intercompany item eliminated in consolidation of $4 million.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2013
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	AEP Credit	TCC Transition Funding		OPCo Ohio Phase-in-Recovery Funding		APCo Appalachian Consumer Rate Relief Funding		Protected Cell of EIS
ASSETS										
Current Assets	$67	$118	$935	$232		$23		$6		$143
Net Property, Plant and Equipment	157	157	—	—		—		—		—
Other Noncurrent Assets	51	60	1	1,918	(a)	252	(b)	378	(c)	3
Total Assets	$275	$335	$936	$2,150		$275		$384		$146
LIABILITIES AND EQUITY										
Current Liabilities	$33	$108	$827	$312		$37		$14		$39
Noncurrent Liabilities	242	227	1	1,820		237		368		66
Equity	—	—	108	18		1		2		41
Total Liabilities and Equity	$275	$335	$936	$2,150		$275		$384		$146

(a) Includes an intercompany item eliminated in consolidation of $82 million.
(b) Includes an intercompany item eliminated in consolidation of $116 million.
(c) Includes an intercompany item eliminated in consolidation of $4 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 September 30, 2014 and 2013 were $24 million and $21 million, respectively, and for the nine months ended September 30, 2014 and 2013 were $31 million and $53 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:

	September 30, 2014		December 31, 2013	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$8	$8	$8	$8
Retained Earnings	3	3	1	1
SWEPCo's Guarantee of Debt	—	113	—	61
Total Investment in DHLC	$11	$124	$9	$70

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, the transmission project that PATH was intended to develop, and removed it from the 2012 Regional Transmission Expansion Plan. In September 2012, the PATH Project companies submitted an application to the FERC requesting authority to recover prudently-incurred costs associated with the PATH Project. In November 2012, the FERC issued an order accepting the PATH Project's abandonment cost recovery application, subject to settlement procedures and hearing. The parties to the case have been unable to reach a settlement agreement and in March 2014, settlement judge procedures were terminated. A hearing at the FERC is scheduled for March 2015.

Our investment in PATH-WV was:

	September 30, 2014		December 31, 2013	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$19	$19	$19	$19
Retained Earnings	6	6	6	6
Total Investment in PATH-WV	$25	$25	$25	$25

As of September 30, 2014, our $25 million investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the condensed balance sheet. If we cannot ultimately recover our investment related to PATH-WV, it could reduce future net income and cash flows.

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 Transfer

APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a cost-of-service basis. West Virginia generally allows for timely recovery of fuel costs through an expanded net energy cost which trues-up to actual expenses. In March 2014, APCo and WPCo filed a request with the WVPSC for approval to transfer at net book value to WPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity presently owned by AGR. In April 2014, APCo and WPCo filed testimony that supported their request and proposed a base rate surcharge of $113 million, to be offset by an equal reduction in the ENEC revenues, to be effective upon the transfer of the Mitchell Plant to WPCo. In June 2014, the FERC issued an order approving AGR and WPCo's request to transfer AGR’s one-half interest in the Mitchell Plant to WPCo.

In October 2014, a stipulation agreement between APCo, WPCo, the WVPSC staff and intervenors in the case was filed with the WVPSC. The stipulation agreement recommended approval for WPCo to acquire, at net book value, the one-half interest in the Mitchell Plant, excluding $20 million of certain assets, which will be paid by WPCo and recovered as a regulatory asset over the life of the plant. Additionally, the agreement stated that 82.5% of the costs associated with the acquired interest will be reflected in rates effective from the date of the transfer via a surcharge with an offset in ENEC revenues. The remaining 17.5% of the costs associated with the acquired interest is to be included in rates by January 2020. The agreement also proposed that WPCo share the energy margins for 82.5% of the plant’s output with ratepayers and that WPCo retain all of the energy margins from sales into the wholesale market on the remaining 17.5%, to offset fixed costs associated with this portion, until the remaining portion is approved for inclusion in rates. Management anticipates an order related to the proposed plant transfer will be issued in the fourth quarter of 2014. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “Plant Transfer” section of APCo Rate Matters in Note 4.

WPCo Merger with APCo

In December 2011, APCo and WPCo filed an application with the WVPSC requesting authority to merge WPCo into APCo. In December 2012, APCo and WPCo filed merger applications with the Virginia SCC and the FERC. In April 2013, the FERC approved the merger. Also 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. In July 2013, the Virginia SCC approved the merger of WPCo into APCo and the transfer of the two-thirds interest in the Amos Plant, Unit 3 to APCo but denied the proposed transfer of the one-half interest in the Mitchell Plant to APCo. In December 2013, the WVPSC issued an order that deferred ruling on the merger of WPCo into APCo. The feasibility of the merger remains under review. See the “WPCo Merger with APCo” section of APCo Rate Matters in Note 4.

2014 Virginia Biennial Base Rate Case

In March 2014, APCo filed a biennial generation and distribution base rate case with the Virginia SCC. In accordance with a Virginia statute, APCo did not request an increase in base rates as its Virginia retail combined rate of return on common equity for 2012 and 2013 is within the statutory range of the approved return on common equity of 10.9%.

The filing included a request to decrease generation depreciation rates, effective February 2015, primarily due to the change in the expected service life of certain plants. Additionally, the filing included a request to amortize $7 million annually for two years, beginning February 2015, related to IGCC and other deferred costs.

In August 2014, the Virginia SCC staff and intervenors filed testimony concluding that APCo's adjusted earned rate of return on common equity for 2012 and 2013, reflecting their recommended adjustments, was above the allowed threshold. Recommendations included (a) refunds to customers ranging from $15 million to $22 million, (b) the write-off of certain APCo assets, including IGCC pre-construction costs and previously approved 2009 storm costs, totaling $27 million and (c) $38 million in increased depreciation expense annually, retroactive to January 1, 2014, primarily related to accelerating depreciation on APCo generation assets to be retired in the second quarter of 2015. Hearings at the Virginia SCC were held in September 2014. A decision is expected in November 2014. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “2014 Virginia Biennial Base Rate Case” section of APCo Rate Matters in Note 4.

2014 West Virginia Base Rate Case

In June 2014, APCo filed a request with the WVPSC to increase annual base rates by $156 million, based upon a 10.62% return on common equity, to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates and requested recovery of $77 million over five years related to 2012 West Virginia storm costs, IGCC and other deferred costs. In addition to the base rate request, the filing also included a request to implement a rider of approximately $38 million annually to recover vegetation management costs, including a return on capital investment. In October 2014, the WVPSC approved APCo's motion to revise the procedural schedule which included the extension of the intervention period to November 2014 and a delay in the implementation of new rates from April 2015 to May 2015. Hearings at the WVPSC are scheduled for January 2015. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “2014 West Virginia Base Rate Case” section of APCo Rate Matters in Note 4.

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 3 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies in the 2013 Annual Report. Also, see Note 4 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 170. 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 249 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions of KWhs)			
Retail:				
Residential	2,503	2,613	9,131	8,870
Commercial	1,726	1,788	5,150	5,147
Industrial	2,600	2,522	7,665	7,765
Miscellaneous	205	203	636	618
Total Retail	7,034	7,126	22,582	22,400
Wholesale	563	3,132	2,507	7,201
Total KWhs	7,597	10,258	25,089	29,601

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in degree days)			
Actual - Heating (a)	—	—	1,776	1,497
Normal - Heating (b)	2	3	1,405	1,408
Actual - Cooling (c)	639	727	1,041	1,115
Normal - Cooling (b)	816	815	1,183	1,182

(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.

Third Quarter of 2014 Compared to Third Quarter of 2013
Reconciliation of Third Quarter of 2013 to Third Quarter of 2014
Net Income
(in millions)

Third Quarter of 2013	$63
Changes in Gross Margin:	
Retail Margins	53
Off-system Sales	(3)
Transmission Revenues	2
Other Revenues	4
Total Change in Gross Margin	56
Changes in Expenses and Other:	
Other Operation and Maintenance	(54)
Depreciation and Amortization	(16)
Taxes Other Than Income Taxes	(4)
Carrying Costs Income	(2)
Other Income	1
Interest Expense	(5)
Total Change in Expenses and Other	(80)
Income Tax Expense	10
Third Quarter of 2014	$49

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 $53 million primarily due to the following:
  - A $43 million increase primarily due to increases in rates in Virginia and West Virginia. Of these increases, $32 million relate to riders/trackers which have corresponding increases in other expense items below.
  - A $21 million decrease in capacity settlement expenses, net of West Virginia recovery, due to the termination of the Interconnection Agreement.

  These increases were partially offset by:
  - A $9 million decrease in weather-related usage primarily due to a 12% decrease in cooling degree days.

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

- Other Operation and Maintenance expenses increased $54 million primarily due to the following:
  - An $11 million increase in transmission expenses primarily due to PJM services.
  - A $10 million increase in steam and electric plant maintenance expenses primarily at Amos Plant, primarily driven by APCo's increased ownership of the plant. This increase is partially offset by an increase in Retail Margins detailed above.
  - A $9 million increase in uncollectible accounts expense as a result of the favorable resolution of contingencies related to pole attachments in the third quarter of 2013.
  - A $5 million increase associated with the deferral of transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause effective May 2014 as allowed by the Virginia SCC.
  - A $3 million increase associated with the Distribution and the Transmission Vegetation Management Programs in West Virginia in 2014.
  - A $2 million increase in employee-related expenses.
- Depreciation and Amortization expenses increased $16 million primarily due to an increase in depreciable base including the increased ownership in Amos Plant.
- Taxes Other Than Income Taxes increased $4 million primarily due to an increase in state business occupation tax and state minimum tax expense.
- Interest Expense increased $5 million primarily due to the November 2013 issuance of securitization bonds and the assumption of debt related to APCo's increased ownership of Amos Plant in December 2013. This increase is partially offset by an increase in Retail Margins detailed above.
- Income Tax Expense decreased $10 million primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013
Reconciliation of Nine Months Ended September 30, 2013 to Nine Months Ended September 30, 2014
Net Income
(in millions)

Nine Months Ended September 30, 2013	$163
Changes in Gross Margin:	
Retail Margins	168
Off-system Sales	(3)
Transmission Revenues	3
Other Revenues	3
Total Change in Gross Margin	171
Changes in Expenses and Other:	
Other Operation and Maintenance	(60)
Depreciation and Amortization	(44)
Taxes Other Than Income Taxes	(10)
Carrying Costs Income	(7)
Other Income	1
Interest Expense	(14)
Total Change in Expenses and Other	(134)
Income Tax Expense	(13)
Nine Months Ended September 30, 2014	$187

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 $168 million primarily due to the following:
  - A $114 million increase primarily due to increases in rates in West Virginia and Virginia. Of these increases, $72 million relate to riders/trackers which have corresponding increases in other expense items below.
  - A $59 million decrease in capacity settlement expenses, net of West Virginia recovery, due to the termination of the Interconnection Agreement.
  - An $18 million increase in weather-related usage primarily due to a 19% increase in heating degree days.

  These increases were partially offset by:
  - A $13 million increase in PJM expenses.

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

- Other Operation and Maintenance expenses increased $60 million primarily due to the following:
  - A $27 million increase in steam operation and maintenance expenses primarily at Amos Plant, primarily driven by APCo's increased ownership of the plant. This increase is partially offset by an increase in Retail Margins detailed above.
  - A $21 million increase in transmission expenses due to increased investment in the PJM region.
  - An $18 million increase in transmission expenses primarily due to PJM services.
  - A $7 million increase due to the Distribution and the Transmission Vegetation Management Programs in West Virginia in 2014.
  - A $6 million increase in employee-related expenses.
  - A $5 million increase in other generation mainly due to higher miscellaneous power supply and hydro expenses.
  - A $4 million increase associated with the deferral of transmission costs in accordance with Virginia Transmission Rate Adjustment Clause effective May 2014 as allowed by the Virginia SCC.
  - A $4 million increase in uncollectible accounts expense primarily as a result of the favorable resolution of contingencies related to pole attachments in the third quarter of 2013.

  These increases were partially offset by:
  - A $30 million write-off in the first quarter of 2013 of previously deferred Virginia storm costs resulting from the 2013 enactment of a Virginia law.
  - A $20 million decrease in distribution maintenance expense due to $25 million of Virginia storm expenses in January and June 2013 partially offset by $5 million of West Virginia storm expenses in June 2014.
- Depreciation and Amortization expenses increased $44 million primarily due to the following:
  - A $32 million increase due to an increase in depreciable base including the increased ownership in Amos Plant.
  - A $6 million increase due to amortization of Virginia environmental deferrals. This increase in expense is offset within Retail Margins above.
- Taxes Other Than Income Taxes increased $10 million primarily due to the following:
  - A $5 million increase in state business occupation tax and state minimum tax expense.
  - A $4 million increase in amortization of real and personal property taxes.
- Carrying Costs Income decreased $7 million primarily due to the November 2013 securitization of the West Virginia ENEC deferral balance.
- Interest Expense increased $14 million primarily due to the November 2013 issuance of securitization bonds and the assumption of debt related to APCo's increased ownership of Amos Plant in December 2013. This increase is partially offset by an increase in Retail Margins detailed above.
- Income Tax Expense increased $13 million primarily due to an increase in pretax book income.

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 2013 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 249 for a discussion of accounting pronouncements.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
REVENUES				
Electric Generation, Transmission and Distribution	$672,459	$756,606	$2,202,967	$2,299,587
Sales to AEP Affiliates	35,455	90,558	108,439	241,311
Other Revenues	1,970	2,569	6,537	6,833
TOTAL REVENUES	709,884	849,733	2,317,943	2,547,731
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	194,303	207,442	627,943	575,902
Purchased Electricity for Resale	85,656	47,391	340,680	172,334
Purchased Electricity from AEP Affiliates	—	220,736	4,662	625,534
Other Operation	103,835	64,508	297,269	223,180
Maintenance	64,333	49,924	193,907	207,870
Depreciation and Amortization	99,889	84,513	300,125	255,656
Taxes Other Than Income Taxes	31,632	27,527	92,434	82,931
TOTAL EXPENSES	579,648	702,041	1,857,020	2,143,407
OPERATING INCOME	130,236	147,692	460,923	404,324
Other Income (Expense):				
Interest Income	521	334	1,311	2,134
Carrying Costs Income (Expense)	482	2,793	(1,130)	6,029
Allowance for Equity Funds Used During Construction	1,665	826	4,525	2,809
Interest Expense	(52,738)	(47,375)	(157,540)	(143,707)
INCOME BEFORE INCOME TAX EXPENSE	80,166	104,270	308,089	271,589
Income Tax Expense	31,408	41,645	121,233	108,554
NET INCOME	$48,758	$62,625	$186,856	$163,035

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net Income	$48,758	$62,625	$186,856	$163,035
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $92 and $12 for the Three Months Ended September 30, 2014 and 2013, Respectively, and $314 and $737 for the Nine Months Ended September 30, 2014 and 2013, Respectively	170	22	582	1,369
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $179 and $193 for the Three Months Ended September 30, 2014 and 2013, Respectively, and $538 and $579 for the Nine Months Ended September 30, 2014 and 2013, Respectively	(333)	359	(999)	1,075
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(163)	381	(417)	2,444
TOTAL COMPREHENSIVE INCOME	$48,595	$63,006	$186,439	$165,479

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2012	$260,458	$1,573,752	$1,248,250	$(29,898)	$3,052,562
Common Stock Dividends			(130,000)		(130,000)
Net Income			163,035		163,035
Other Comprehensive Income				2,444	2,444
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2013	$260,458	$1,573,752	$1,281,285	$(27,454)	$3,088,041
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$260,458	$1,809,562	$1,156,461	$2,951	$3,229,432
Common Stock Dividends			(60,000)		(60,000)
Net Income			186,856		186,856
Other Comprehensive Loss				(417)	(417)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2014	$260,458	$1,809,562	$1,283,317	$2,534	$3,355,871

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2014 and December 31, 2013
(in thousands)
(Unaudited)

	September 30, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$2,701	$2,745
Advances to Affiliates	70,090	92,485
Accounts Receivable:		
Customers	95,688	142,010
Affiliated Companies	60,436	113,793
Accrued Unbilled Revenues	38,861	55,930
Miscellaneous	778	412
Allowance for Uncollectible Accounts	(1,945)	(2,443)
Total Accounts Receivable	193,818	309,702
Fuel	111,120	191,811
Materials and Supplies	130,557	128,843
Risk Management Assets	21,819	21,171
Regulatory Asset for Under-Recovered Fuel Costs	68,782	39,811
Prepayments and Other Current Assets	25,048	16,472
TOTAL CURRENT ASSETS	623,935	803,040
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,828,543	6,745,172
Transmission	2,200,241	2,160,660
Distribution	3,218,405	3,139,150
Other Property, Plant and Equipment	374,940	357,517
Construction Work in Progress	253,928	184,701
Total Property, Plant and Equipment	12,876,057	12,587,200
Accumulated Depreciation and Amortization	3,797,663	3,617,990
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	9,078,394	8,969,210
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,003,018	1,003,890
Securitized Assets	355,561	369,355
Long-term Risk Management Assets	6,501	16,948
Deferred Charges and Other Noncurrent Assets	133,058	148,205
TOTAL OTHER NONCURRENT ASSETS	1,498,138	1,538,398
TOTAL ASSETS	$11,200,467	$11,310,648

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2014 and December 31, 2013
(Unaudited)

	September 30, 2014	December 31, 2013
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$159,067	$169,184
Affiliated Companies	71,302	120,789
Long-term Debt Due Within One Year – Nonaffiliated	652,211	342,360
Long-term Debt Due Within One Year – Affiliated	86,000	—
Risk Management Liabilities	6,371	8,892
Customer Deposits	66,923	66,040
Deferred Income Taxes	40,072	6,899
Accrued Taxes	61,316	114,699
Accrued Interest	63,519	51,899
Regulatory Liability for Over-Recovered Fuel Costs	13,696	107,048
Other Current Liabilities	94,732	97,566
TOTAL CURRENT LIABILITIES	1,315,209	1,085,376
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,241,896	3,765,997
Long-term Debt – Affiliated	—	86,000
Long-term Risk Management Liabilities	3,293	10,241
Deferred Income Taxes	2,334,399	2,232,441
Regulatory Liabilities and Deferred Investment Tax Credits	676,480	631,225
Employee Benefits and Pension Obligations	101,613	82,264
Deferred Credits and Other Noncurrent Liabilities	171,706	187,672
TOTAL NONCURRENT LIABILITIES	6,529,387	6,995,840
TOTAL LIABILITIES	7,844,596	8,081,216
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
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	1,809,562	1,809,562
Retained Earnings	1,283,317	1,156,461
Accumulated Other Comprehensive Income (Loss)	2,534	2,951
TOTAL COMMON SHAREHOLDER’S EQUITY	3,355,871	3,229,432
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$11,200,467	$11,310,648

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2014	2013
OPERATING ACTIVITIES		
Net Income	$186,856	$163,035
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	300,125	255,656
Deferred Income Taxes	114,778	89,501
Carrying Costs Income	1,130	(6,029)
Deferral of Storm Costs	5,112	34,364
Allowance for Equity Funds Used During Construction	(4,525)	(2,809)
Mark-to-Market of Risk Management Contracts	255	9,409
Pension Contributions to Qualified Plan Trust	(8,963)	—
Property Taxes	25,856	21,940
Fuel Over/Under-Recovery, Net	(114,022)	46,009
Change in Other Noncurrent Assets	(24,290)	(19,784)
Change in Other Noncurrent Liabilities	29,312	10,199
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	114,387	62,363
Fuel, Materials and Supplies	78,977	5,094
Accounts Payable	(65,358)	(76,665)
Accrued Taxes, Net	(43,092)	(726)
Other Current Assets	(3,748)	1,970
Other Current Liabilities	9,085	(14,820)
Net Cash Flows from Operating Activities	601,875	578,707
INVESTING ACTIVITIES		
Construction Expenditures	(342,291)	(272,433)
Change in Advances to Affiliates, Net	22,395	(400)
Other Investing Activities	(1,114)	103
Net Cash Flows Used for Investing Activities	(321,010)	(272,730)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	295,039	69,346
Change in Advances from Affiliates, Net	—	102,811
Retirement of Long-term Debt – Nonaffiliated	(512,702)	(345,021)
Principal Payments for Capital Lease Obligations	(4,255)	(4,049)
Dividends Paid on Common Stock	(60,000)	(130,000)
Other Financing Activities	1,009	1,490
Net Cash Flows Used for Financing Activities	(280,909)	(305,423)
Net Increase (Decrease) in Cash and Cash Equivalents	(44)	554
Cash and Cash Equivalents at Beginning of Period	2,745	3,576
Cash and Cash Equivalents at End of Period	$2,701	$4,130

SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$136,919	$131,600
Net Cash Paid (Received) for Income Taxes	22,148	(3,746)
Noncash Acquisitions Under Capital Leases	3,451	3,440
Construction Expenditures Included in Current Liabilities as of September 30,	54,463	43,802

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

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
AND SUBSIDIARIES

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

EXECUTIVE OVERVIEW

Regulatory Activity

Transmission, Distribution and Storage System Improvement Charge (TDSIC)

In October 2014, I&M filed petitions with the IURC for approval of a TDSIC Rider and TDSIC Plan for eligible transmission, distribution and storage system improvements. The initial estimated cost of the capital improvements and associated operation and maintenance expenses included in the TDSIC Plan of $787 million will be updated annually. The TDSIC Rider will allow the periodic adjustment of I&M's rates to provide for timely recovery of 80% of approved TDSIC Plan costs. I&M will defer the remaining 20% of approved TDSIC Plan costs to be recovered in I&M's next general rate case. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “Transmission, Distribution and Storage System Improvement Charge (TDSIC)” section of I&M Rate Matters in Note 4.

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 3 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies in the 2013 Annual Report. Also, see Note 4 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 170. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants’ actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court granted the motion to transfer this case to the U.S. District Court for the Southern District of Ohio. AEGCo’s and I&M’s motion to dismiss the case, filed in October 2013, remains pending. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

See the “Executive Overview” section of “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries” section beginning on page 249 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions of KWhs)			
Retail:				
Residential	1,347	1,487	4,413	4,365
Commercial	1,264	1,335	3,681	3,720
Industrial	1,933	1,914	5,701	5,611
Miscellaneous	15	16	50	51
Total Retail	4,559	4,752	13,845	13,747
Wholesale	3,985	3,198	13,151	8,029
Total KWhs	8,544	7,950	26,996	21,776

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in degree days)			
Actual - Heating (a)	6	2	3,222	2,552
Normal - Heating (b)	11	11	2,388	2,396
Actual - Cooling (c)	410	523	712	801
Normal - Cooling (b)	581	584	843	846

(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.

Third Quarter of 2014 Compared to Third Quarter of 2013
Reconciliation of Third Quarter of 2013 to Third Quarter of 2014
Net Income
(in millions)

Third Quarter of 2013	$58
Changes in Gross Margin:	
Retail Margins	(2)
FERC Municipals and Cooperatives	(2)
Off-system Sales	3
Transmission Revenues	1
Other Revenues	(10)
Total Change in Gross Margin	(10)
Changes in Expenses and Other:	
Other Operation and Maintenance	(23)
Depreciation and Amortization	(5)
Taxes Other Than Income Taxes	(1)
Interest Expense	1
Total Change in Expenses and Other	(28)
Income Tax Expense	7
Third Quarter of 2014	$27

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 decreased $2 million primarily due to the following:
  - An $8 million decrease due to lower Indiana recovery of energy efficiency program costs. The decrease in revenue was partially offset by a corresponding decrease in energy efficiency expense items discussed below.
  - A $7 million decrease in weather related usage primarily due to a 22% decrease in cooling days.
  - A $4 million decrease due to increased costs for power acquired under a unit power agreement.

  These decreases were partially offset by:
  - A $9 million increase due to rate recovery primarily due to a return on assets under the Cook Plant Life Cycle Management Project rider effective January 2014.
  - An $8 million increase due to an Indiana Capacity Tracker Rider effective August 2014.
- Margins from Off-system Sales increased $3 million due to increased sales volumes.
- Other Revenues decreased $10 million primarily due to the following:
  - A $6 million decrease in barging. This decrease in barging is a result of River Transportation Division (RTD) no longer serving plants transferred to AGR as a result of corporate separation in Ohio. The decrease in RTD revenue was offset by a corresponding decrease in Other Operation and Maintenance expenses for barging discussed below.
  - A $4 million decrease due to an MPSC order disallowing 2012 to 2014 lost revenue related to Demand Side Management (DSM).

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

- Other Operation and Maintenance expenses increased $23 million primarily due to the following:
  - An $8 million increase due to a third quarter 2014 accrual for expected environmental remediation costs.
  - A $6 million increase in maintenance of overhead lines.
  - A $5 million increase in nuclear expenses.
  - A $5 million increase in PJM expenses.
  - A $5 million increase in administrative and general expenses.

  These increases were partially offset by:
  - A $5 million decrease in customer services expense related to energy efficiency. The decrease in expenses was offset by a corresponding decrease in Retail Margins discussed above.
  - A $5 million decrease in RTD expenses for barging activities. The decrease in RTD expenses was offset by a corresponding decrease in Other Revenues from barging activities discussed above.
- Depreciation and Amortization expenses increased $5 million primarily due to higher depreciable base and a change in the life of Tanner Creek Plant.
- Income Tax Expense decreased $7 million primarily due to a decrease in pretax book income partially offset by recording of federal and state income tax return adjustments in 2014.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013
Reconciliation of Nine Months Ended September 30, 2013 to Nine Months Ended September 30, 2014
Net Income
(in millions)

Nine Months Ended September 30, 2013	$142
Changes in Gross Margin:	
Retail Margins	21
FERC Municipals and Cooperatives	(1)
Off-system Sales	58
Transmission Revenues	10
Other Revenues	(26)
Total Change in Gross Margin	62
Changes in Expenses and Other:	
Other Operation and Maintenance	(40)
Depreciation and Amortization	(18)
Taxes Other Than Income Taxes	1
Other Income	(4)
Total Change in Expenses and Other	(61)
Income Tax Expense	(2)
Nine Months Ended September 30, 2014	$141

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 $21 million primarily due to the following:
  - A $22 million increase due to rate recovery primarily due to a return on assets under the Cook Plant Life Cycle Management Project rider effective January 2014.
  - A $14 million increase due to a rate increase in Indiana effective March 2013.
  - An $8 million increase due to an Indiana Capacity Tracker Rider effective August 2014.
  - An $8 million increase in weather related usage primarily due to a 26% increase in heating degree days partially offset by a decrease in cooling degree days.

  These increases were partially offset by:
  - A $22 million decrease due to lower Indiana recovery of energy efficiency program costs. The decrease in revenue was partially offset by a corresponding decrease in energy efficiency expense items discussed below.
  - A $7 million decrease in certain cost recovery revenues, including fuel and PJM costs.
- Margins from Off-system Sales increased $58 million due to higher market prices and increased sales volumes.
- Transmission Revenues increased $10 million primarily due to increased investment in the PJM region.
- Other Revenues decreased $26 million primarily due to the following:
  - A $22 million decrease in barging. This decrease in barging is a result of River Transportation Division (RTD) no longer serving plants transferred to AGR as a result of corporate separation in Ohio. The decrease in RTD revenue was offset by a corresponding decrease in Other Operation and Maintenance expenses for barging discussed below.
  - A $4 million decrease due to an MPSC order disallowing 2012 to 2014 lost revenue related to DSM.

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Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $40 million primarily due to the following:
  - A $24 million increase in transmission expenses primarily due to increased PJM expenses.
  - A $19 million increase in nuclear expenses primarily due to a prior year deferral of $8 million in expenses, as regulatory assets, for future recovery as approved by the IURC effective March 2013 and $7 million of increased refueling amortization.
  - A $10 million increase in distribution expenses primarily due to metering expenses and maintenance of overhead lines.
  - A $10 million increase in administrative and general expenses.
  - An $8 million increase due to a third quarter 2014 accrual for expected environmental remediation costs.

  These increases were partially offset by:
  - A $20 million decrease in RTD expenses for barging activities. The decrease in RTD expenses was offset by a corresponding decrease in Other Revenues from barging activities as discussed above.
  - A $14 million decrease in customer services expense related to energy efficiency. The decrease in expenses was offset by a corresponding decrease in Retail Margins discussed above.
- Depreciation and Amortization expenses increased $18 million primarily due to higher depreciable base and a change in the life of Tanner Creek Plant.

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 2013 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 249 for a discussion of accounting pronouncements.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
REVENUES				
Electric Generation, Transmission and Distribution	$520,881	$537,453	$1,642,721	$1,518,357
Sales to AEP Affiliates	401	73,576	3,753	159,888
Other Revenues – Affiliated	20,832	27,322	70,821	89,962
Other Revenues – Nonaffiliated	749	514	1,298	3,552
TOTAL REVENUES	542,863	638,865	1,718,593	1,771,759
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	117,414	140,193	387,757	330,088
Purchased Electricity for Resale	20,019	32,976	52,467	111,602
Purchased Electricity from AEP Affiliates	66,561	116,511	203,807	317,434
Other Operation	144,331	136,702	431,953	414,418
Maintenance	59,043	43,448	161,854	139,200
Depreciation and Amortization	50,585	45,393	150,062	131,991
Taxes Other Than Income Taxes	22,059	21,278	64,685	65,899
TOTAL EXPENSES	480,012	536,501	1,452,585	1,510,632
OPERATING INCOME	62,851	102,364	266,008	261,127
Other Income (Expense):				
Interest Income	1,450	2,360	4,228	7,077
Allowance for Equity Funds Used During Construction	5,596	5,041	14,364	15,568
Interest Expense	(22,617)	(23,932)	(71,955)	(72,579)
INCOME BEFORE INCOME TAX EXPENSE	47,280	85,833	212,645	211,193
Income Tax Expense	20,654	27,953	71,596	69,102
NET INCOME	$26,626	$57,880	$141,049	$142,091

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net Income	$26,626	$57,880	$141,049	$142,091
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $220 and $132 for the Three Months Ended September 30, 2014 and 2013, Respectively, and $638 and $1,986 for the Nine Months Ended September 30, 2014 and 2013, Respectively	410	244	1,185	3,688
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $22 and $94 for the Three Months Ended September 30, 2014 and 2013, Respectively, and $68 and $283 for the Nine Months Ended September 30, 2014 and 2013, Respectively	42	174	128	525
TOTAL OTHER COMPREHENSIVE INCOME	452	418	1,313	4,213
TOTAL COMPREHENSIVE INCOME	$27,078	$58,298	$142,362	$146,304

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2012	$56,584	$980,896	$795,178	$(28,883)	$1,803,775
Common Stock Dividends			(47,500)		(47,500)
Net Income			142,091		142,091
Other Comprehensive Income				4,213	4,213
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2013	$56,584	$980,896	$889,769	$(24,670)	$1,902,579
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$56,584	$980,896	$900,182	$(15,509)	$1,922,153
Common Stock Dividends			(100,000)		(100,000)
Net Income			141,049		141,049
Other Comprehensive Income				1,313	1,313
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2014	$56,584	$980,896	$941,231	$(14,196)	$1,964,515

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2014 and December 31, 2013
(in thousands)
(Unaudited)

	September 30, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$1,418	$1,317
Advances to Affiliates	13,499	55,863
Accounts Receivable:		
Customers	40,579	63,011
Affiliated Companies	60,313	78,282
Accrued Unbilled Revenues	1,536	17,293
Miscellaneous	1,483	5,064
Allowance for Uncollectible Accounts	(91)	(184)
Total Accounts Receivable	103,820	163,466
Fuel	45,891	53,807
Materials and Supplies	201,692	209,718
Risk Management Assets	16,330	15,388
Accrued Tax Benefits	7,460	48,832
Prepayments and Other Current Assets	25,404	38,103
TOTAL CURRENT ASSETS	415,514	586,494
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,655,966	3,577,906
Transmission	1,332,551	1,304,225
Distribution	1,676,964	1,625,057
Other Property, Plant and Equipment (Including Plant to be Retired, Coal Mining and Nuclear Fuel)	1,441,401	1,421,361
Construction Work in Progress	561,440	427,164
Total Property, Plant and Equipment	8,668,322	8,355,713
Accumulated Depreciation, Depletion and Amortization	3,403,540	3,299,349
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,264,782	5,056,364
OTHER NONCURRENT ASSETS		
Regulatory Assets	513,387	524,114
Spent Nuclear Fuel and Decommissioning Trusts	2,020,248	1,931,610
Long-term Risk Management Assets	4,409	11,495
Deferred Charges and Other Noncurrent Assets	111,641	143,657
TOTAL OTHER NONCURRENT ASSETS	2,649,685	2,610,876
TOTAL ASSETS	$8,329,981	$8,253,734

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2014 and December 31, 2013
(dollars in thousands)
(Unaudited)

	September 30, 2014	December 31, 2013
CURRENT LIABILITIES		
Advances from Affiliates	$95,899	$—
Accounts Payable:		
General	146,361	142,219
Affiliated Companies	65,270	93,773
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2014 and December 31, 2013 Amounts Include $64,434 and $107,143, Respectively, Related to DCC Fuel)	238,698	294,845
Risk Management Liabilities	3,625	7,029
Customer Deposits	34,263	31,103
Accrued Taxes	58,676	73,292
Accrued Interest	12,992	27,686
Obligations Under Capital Leases	42,500	46,210
Other Current Liabilities	167,754	139,088
TOTAL CURRENT LIABILITIES	866,038	855,245
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,710,233	1,744,171
Long-term Risk Management Liabilities	2,032	6,946
Deferred Income Taxes	1,195,401	1,183,350
Regulatory Liabilities and Deferred Investment Tax Credits	1,145,699	1,112,645
Asset Retirement Obligations	1,299,178	1,255,184
Deferred Credits and Other Noncurrent Liabilities	146,885	174,040
TOTAL NONCURRENT LIABILITIES	5,499,428	5,476,336
TOTAL LIABILITIES	6,365,466	6,331,581
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
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	941,231	900,182
Accumulated Other Comprehensive Income (Loss)	(14,196)	(15,509)
TOTAL COMMON SHAREHOLDER'S EQUITY	1,964,515	1,922,153
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$8,329,981	$8,253,734

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Nine Months Ended September 30,	
	2014	2013
OPERATING ACTIVITIES		
Net Income	$141,049	$142,091
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	150,062	131,991
Deferred Income Taxes	15,792	84,067
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	23,951	(15,450)
Allowance for Equity Funds Used During Construction	(14,364)	(15,568)
Mark-to-Market of Risk Management Contracts	(2,196)	12,995
Amortization of Nuclear Fuel	114,238	101,316
Fuel Over/Under-Recovery, Net	18,931	6,459
Change in Other Noncurrent Assets	(36,596)	(718)
Change in Other Noncurrent Liabilities	66,502	25,249
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	59,646	23,111
Fuel, Materials and Supplies	14,884	(9,859)
Accounts Payable	(12,052)	(35,517)
Accrued Taxes, Net	30,719	(8,987)
Other Current Assets	11,741	18,948
Other Current Liabilities	(8,201)	(4,130)
Net Cash Flows from Operating Activities	574,106	455,998
INVESTING ACTIVITIES		
Construction Expenditures	(345,369)	(360,668)
Change in Advances to Affiliates, Net	42,364	(205,499)
Purchases of Investment Securities	(789,461)	(675,727)
Sales of Investment Securities	746,272	635,256
Acquisitions of Nuclear Fuel	(109,224)	(109,598)
Insurance Proceeds Related to Cook Plant Fire	—	72,000
Other Investing Activities	11,773	27,888
Net Cash Flows Used for Investing Activities	(443,645)	(616,348)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	99,323	348,892
Change in Advances from Affiliates, Net	95,899	—
Retirement of Long-term Debt – Nonaffiliated	(190,550)	(137,544)
Principal Payments for Capital Lease Obligations	(35,660)	(4,112)
Dividends Paid on Common Stock	(100,000)	(47,500)
Other Financing Activities	628	850
Net Cash Flows from (Used for) Financing Activities	(130,360)	160,586

Net Increase in Cash and Cash Equivalents	101	236
Cash and Cash Equivalents at Beginning of Period	1,317	1,562
Cash and Cash Equivalents at End of Period	$1,418	$1,798
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$75,789	$76,468
Net Cash Paid (Received) for Income Taxes	(1,475)	(35,307)
Noncash Acquisitions Under Capital Leases	5,015	2,858
Construction Expenditures Included in Current Liabilities as of September 30,	69,241	54,082
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	11	279
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	3,208	19

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

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 SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Company Overview

As a public utility, OPCo engages in the transmission and distribution of power to 1,464,000 retail customers in the northwestern, central, eastern and southern sections of Ohio. OPCo purchases energy and capacity to serve its remaining generation service customers. Prior to January 1, 2014, OPCo also engaged in the generation of electric power and the subsequent sale of that power to customers. On December 31, 2013, based on FERC and PUCO orders which approved corporate separation of generation assets and associated liabilities, OPCo transferred its generation assets and related generation liabilities at net book value to AGR. In accordance with the PUCO's corporate separation order, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. Effective January 1, 2014, OPCo purchases power from both affiliated and nonaffiliated entities, subject to auction requirements and PUCO approval, to meet the energy and capacity needs of customers.

Regulatory Activity

Ohio Electric Security Plan Filings

2009 - 2011 ESP

In August 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover OPCo's deferred fuel costs in rates beginning September 2012. As of September 30, 2014, OPCo's net deferred fuel balance was $395 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 balance up to the full amount.

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. This ruling was generally upheld in PUCO rehearing orders in January and March 2013.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the 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 OPCo RPM price collected from CRES providers, which includes reserve margins, was approximately $34/MW day through May 2014 and is $150/MW day from June 2014 through May 2015. 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 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and is currently collected at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In April and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order, including the RSR. As of September 30, 2014, OPCo's incurred deferred capacity costs balance was $409 million, including debt carrying costs.

In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. The modifications include the delay of the energy auctions that were originally ordered in the ESP order. In February 2014, OPCo conducted an energy-only auction for 10% of the SSO load with delivery beginning April 2014 through May 2015. In May and September 2014, OPCo conducted energy-only auctions for an additional 50% of the SSO load with delivery beginning November 2014 through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions 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. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit. In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC. In March 2014, the PUCO approved OPCo’s request to implement riders related to the unbundling of the FAC. In May 2014, an independent auditor was selected by the PUCO and an audit of the recovery of the fixed fuel costs began in June 2014. In October 2014, the independent auditor filed its report for the period August 2012 through May 2015 with the PUCO. If the PUCO ultimately concludes that a portion of the fixed fuel costs are also recovered through OPCo's $188.88 capacity charge, the independent auditor recommends a methodology for calculating a refund of a portion of certain fixed fuel costs. The retail share of these fixed fuel costs is approximately $90 million annually. A hearing related to this matter has not been scheduled. Management believes that no over-recovery of costs has occurred and intends to oppose the findings in the audit report.

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

Proposed June 2015 - May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that includes proposed rate adjustments and the continuation and modification of certain existing riders effective June 2015 through May 2018. The proposal includes a recommended auction schedule, a return on common equity of 10.65% on capital costs for certain riders and estimates an average decrease in rates of 9% over the three-year term of the plan for customers who receive their RPM capacity and energy auction-based generation through OPCo. The proposal also includes a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based purchase power agreement. In May 2014, intervenors and the PUCO staff filed testimony that provided various recommendations including the rejection and/or modification of various riders, including the Distribution Investment Rider and the proposed PPA. Hearings at the PUCO in the ESP case were held in June 2014. Additionally, in July 2014, OPCo submitted a separate application to continue the RSR established in the June 2012 - May 2015 ESP to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh until the balance of the capacity deferrals has been collected. In October 2014, OPCo filed a separate application with the PUCO to propose a new PPA for inclusion in the PPA rider, discussed above. The new PPA would include an additional 2,671 MW to be purchased from AGR over the life of the respective generating units.

If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, its deferred capacity cost and its proposed PPA rider, it could reduce future net income and cash flows and impact financial condition. See “Ohio Electric Security Plan Filings” section of OPCo Rate Matters in Note 4.

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 3 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies in the 2013 Annual Report. Also, see Note 4 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 170. 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 249 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions of KWhs)			
Retail:				
Residential	3,513	3,742	11,189	11,006
Commercial	3,714	3,820	10,838	10,712
Industrial	3,647	4,012	10,822	12,297
Miscellaneous	26	29	88	91
Total Retail (a)	10,900	11,603	32,937	34,106
Wholesale	575	(b) 4,222	1,727	(b) 9,683
Total KWhs	11,475	15,825	34,664	43,789

(a) Represents energy delivered to distribution customers.
(b) Ohio's contractually obligated purchases of OVEC power sold into PJM.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in degree days)			
Actual - Heating (a)	1	1	2,540	2,165
Normal - Heating (b)	7	8	2,074	2,083
Actual - Cooling (c)	581	646	943	991
Normal - Cooling (b)	663	660	946	940

(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.

Third Quarter of 2014 Compared to Third Quarter of 2013
Reconciliation of Third Quarter of 2013 to Third Quarter of 2014
Net Income
(in millions)

Third Quarter of 2013	$179
Changes in Gross Margin:	
Retail Margins	(256)
Off-system Sales	(39)
Transmission Revenues	10
Other Revenues	(11)
Total Change in Gross Margin	(296)
Changes in Expenses and Other:	
Other Operation and Maintenance	33
Depreciation and Amortization	40
Taxes Other Than Income Taxes	16
Other Income	1
Carrying Costs Income	3
Interest Expense	14
Total Change in Expenses and Other	107
Income Tax Expense	64
Third Quarter of 2014	$54

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, purchased electricity and amortization of generation deferrals were as follows:

- Retail Margins decreased $256 million primarily due to the following:
  - A $229 million decrease due to the impacts of corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013 and regulatory provisions. In addition, this decrease includes customers switching to alternative CRES providers, which is partially offset by an increase in Transmission Revenues detailed below.

  These decreases were partially offset by:
  - A $17 million increase in revenues primarily associated with the Distribution Investment Rider and Universal Service Fund (USF) surcharge. Of these increases, including the USF, $6 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $14 million increase in revenues associated with the Storm Damage Recovery Rider. This increase in Retail Margins is primarily offset by an increase in Other Operation and Maintenance below.
- Margins from Off-system Sales decreased $39 million due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.
- Transmission Revenues increased $10 million primarily due to increased transmission revenues due to customers who have switched to alternative CRES providers, rate increases for customers in the PJM region and increased transmission investment. The increase in transmission revenues related to CRES providers primarily offsets lost revenues included in Retail Margins above.
-

Other Revenues decreased $11 million primarily due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.

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

- Other Operation and Maintenance expenses decreased $33 million primarily due to the following:
  - An $82 million decrease due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.

  This decrease was partially offset by:
  - A $36 million increase in PJM expenses. This increase was partially offset by a corresponding increase in Gross Margin above.
  - A $13 million increase due to the amortization of 2012 deferred storm expenses. This increase was offset by a corresponding increase in Retail Margins above.
- Depreciation and Amortization expenses decreased $40 million primarily due to the following:
  - A $53 million decrease due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.

  This decrease was partially offset by:
  - A $9 million increase in amortization of securitized assets being recovered through the Deferred Asset Phase-In Rider. This increase was offset by a corresponding increase in Retail Margins above.
- Taxes Other Than Income Taxes decreased $16 million primarily due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.
- Interest Expense decreased $14 million primarily due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.
- Income Tax Expense decreased $64 million primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013
Reconciliation of Nine Months Ended September 30, 2013 to Nine Months Ended September 30, 2014
Net Income
(In Millions)

Nine Months Ended September 30, 2013	$330	
Changes in Gross Margin:		
Retail Margins	(684	)
Off-system Sales	(94	)
Transmission Revenues	60	
Other Revenues	(34	)
Total Change in Gross Margin	(752	)
Changes in Expenses and Other:		
Other Operation and Maintenance	135	
Asset Impairments and Other Related Charges	154	
Depreciation and Amortization	124	
Taxes Other Than Income Taxes	42	
Other Income	6	
Carrying Costs Income	10	
Interest Expense	46	
Total Change in Expenses and Other	517	
Income Tax Expense	76	
Nine Months Ended September 30, 2014	$171	

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, purchased electricity and amortization of generation deferrals were as follows:

- Retail Margins decreased $684 million primarily due to the following:
- A $621 million decrease due to the impacts of corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013 and regulatory provisions. In addition, this decrease includes customers switching to alternative CRES providers, which is partially offset by an increase in Transmission Revenues detailed below.
These decreases were partially offset by:
- A $45 million increase in revenues primarily associated with the Distribution Investment Rider and Universal Service Fund (USF) surcharge. Of these increases, including the USF, $18 million relates to riders/trackers which have corresponding increases in other expense items below.
- A $28 million increase in revenues associated with the Storm Damage Recovery Rider. This increase in Retail Margins is primarily offset by an increase in Other Operation and Maintenance expenses below.
- Margins from Off-system Sales decreased $94 million due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.
- Transmission Revenues increased $60 million primarily due to increased transmission revenues due to customers who have switched to alternative CRES providers, rate increases for customers in the PJM region and increased transmission investment. The increase in transmission revenues related to CRES providers primarily offsets lost revenues included in Retail Margins above.
-

Other Revenues decreased $34 million due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013. This decrease in Other Revenues has a corresponding decrease in Other Operation and Maintenance expenses below.

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

- Other Operation and Maintenance expenses decreased $135 million primarily due to the following:
- A $291 million decrease due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.

This decrease was partially offset by:

- A $90 million increase in PJM expenses. This increase was partially offset by a corresponding increase in Gross Margin above.
- A $26 million increase due to the amortization of 2012 deferred storm expenses. This increase was offset by a corresponding increase in Retail Margins above.
- A $14 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.
- Asset Impairments and Other Related Charges decreased $154 million primarily due to the 2013 impairment of Muskingum River Plant, Unit 5.
- Depreciation and Amortization expenses decreased $124 million primarily due to the following:
- A $154 million decrease due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.

This decrease was partially offset by:

- A $19 million increase in amortization of securitized assets being recovered through the Deferred Asset Phase-In Rider. This increase was offset by a corresponding increase in Retail Margins above.
- An $8 million increase due to an increase in depreciable base of transmission and distribution assets.
- Taxes Other Than Income Taxes decreased $42 million due to the following:
- A $51 million decrease due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.

This decrease was partially offset by:

- A $7 million increase in property taxes due to increased investment in transmission and distribution assets and increased tax rates.
- Other Income increased $6 million due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.
- Carrying Costs Income increased $10 million primarily due to increased capacity deferral carrying charges.
- Interest Expense decreased $46 million primarily due to corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013.
- Income Tax Expense decreased $76 million primarily due to a decrease in pretax book income.

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 2013 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 249 for a discussion of accounting pronouncements.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
REVENUES				
Electric Generation, Transmission and Distribution	$793,900	$959,816	$2,380,768	$2,710,990
Sales to AEP Affiliates	43,733	313,818	120,154	873,850
Other Revenues – Affiliated	—	2,715	—	18,138
Other Revenues – Nonaffiliated	1,564	2,827	4,628	12,982
TOTAL REVENUES	839,197	1,279,176	2,505,550	3,615,960
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	—	396,437	—	1,158,389
Purchased Electricity for Resale	48,541	34,568	191,730	114,911
Purchased Electricity from AEP Affiliates	315,903	103,869	897,658	257,540
Amortization of Generation Deferrals	26,655	—	82,818	—
Other Operation	145,163	159,965	428,074	481,417
Maintenance	53,724	71,670	136,965	218,962
Asset Impairments and Other Related Charges	—	—	—	154,304
Depreciation and Amortization	54,968	94,802	165,152	289,472
Taxes Other Than Income Taxes	89,564	105,070	268,734	310,285
TOTAL EXPENSES	734,518	966,381	2,171,131	2,985,280
OPERATING INCOME	104,679	312,795	334,419	630,680
Other Income (Expense):				
Interest Income	1,986	476	8,159	3,165
Carrying Costs Income	5,606	2,813	19,594	9,833
Allowance for Equity Funds Used During Construction	1,825	1,028	4,893	2,853
Interest Expense	(31,171)	(45,070)	(96,937)	(142,487)
INCOME BEFORE INCOME TAX EXPENSE	82,925	272,042	270,128	504,044
Income Tax Expense	28,865	93,141	98,759	174,313
NET INCOME	$54,060	$178,901	$171,369	$329,731

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net Income	$54,060	$178,901	$171,369	$329,731
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $185 and $363 for the Three Months Ended September 30, 2014 and 2013, Respectively, and $611 and $83 for the Nine Months Ended September 30, 2014 and 2013, Respectively	(343)	(675)	(1,134)	(154)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,607 and $5,128 for the Three and Nine Months Ended in 2013, Respectively	—	2,985	—	9,524
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(343)	2,310	(1,134)	9,370
TOTAL COMPREHENSIVE INCOME	$53,717	$181,211	$170,235	$339,101

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2012	$321,201	$1,744,099	$2,626,134	$(165,725)	$4,525,709
Distribution of Cook Coal Terminal to Parent			(22,303)	19,652	(2,651)
Common Stock Dividends			(275,000)		(275,000)
Net Income			329,731		329,731
Other Comprehensive Income				9,370	9,370
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2013	$321,201	$1,744,099	$2,658,562	$(136,703)	$4,587,159
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$321,201	$663,782	$633,203	$7,079	$1,625,265
Common Stock Dividends			(35,000)		(35,000)
Net Income			171,369		171,369
Other Comprehensive Loss				(1,134)	(1,134)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2014	$321,201	$663,782	$769,572	$5,945	$1,760,500

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2014 and December 31, 2013
(in thousands)
(Unaudited)

	September 30, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$3,889	$3,004
Restricted Cash for Securitized Funding	17,734	19,387
Advances to Affiliates	23,745	339,070
Accounts Receivable:		
Customers	47,423	67,054
Affiliated Companies	85,462	74,771
Accrued Unbilled Revenues	31,181	36,353
Miscellaneous	959	1,559
Allowance for Uncollectible Accounts	(179)	(34,984)
Total Accounts Receivable	164,846	144,753
Notes Receivable Due Within One Year – Affiliated	86,000	178,580
Materials and Supplies	54,958	53,711
Risk Management Assets	7,917	3,082
Deferred Income Tax Benefits	19,387	36,105
Accrued Tax Benefits	1,888	7,109
Prepayments and Other Current Assets	6,449	22,312
TOTAL CURRENT ASSETS	386,813	807,113
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,064,599	2,011,289
Distribution	3,995,070	3,877,532
Other Property, Plant and Equipment	389,392	364,573
Construction Work in Progress	238,195	185,428
Total Property, Plant and Equipment	6,687,256	6,438,822
Accumulated Depreciation and Amortization	2,011,530	1,973,042
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,675,726	4,465,780
OTHER NONCURRENT ASSETS		
Notes Receivable – Affiliated	32,245	118,245
Regulatory Assets	1,370,561	1,378,697
Securitized Assets	115,806	131,582
Long-term Risk Management Assets	5	—
Deferred Charges and Other Noncurrent Assets	113,477	260,141
TOTAL OTHER NONCURRENT ASSETS	1,632,094	1,888,665
TOTAL ASSETS	$6,694,633	$7,161,558

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2014 and December 31, 2013
(dollars in thousands)
(Unaudited)

	September 30, 2014	December 31, 2013
CURRENT LIABILITIES		
Accounts Payable:		
General	$128,400	$146,307
Affiliated Companies	142,052	222,889
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2014 and December 31, 2013 Amounts Include $45,427 and $34,936, Respectively, Related to Ohio Phase-in-Recovery Funding)	131,496	438,595
Customer Deposits	52,113	49,140
Accrued Taxes	238,481	429,260
Accrued Interest	45,895	40,853
Other Current Liabilities	143,091	95,194
TOTAL CURRENT LIABILITIES	881,528	1,422,238
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (September 30, 2014 and December 31, 2013 Amounts Include $187,040 and $232,466, Respectively, Related to Ohio Phase-in-Recovery Funding)	2,165,508	2,296,580
Deferred Income Taxes	1,357,930	1,330,711
Regulatory Liabilities and Deferred Investment Tax Credits	479,704	435,499
Employee Benefits and Pension Obligations	23,958	28,329
Deferred Credits and Other Noncurrent Liabilities	25,505	22,936
TOTAL NONCURRENT LIABILITIES	4,052,605	4,114,055
TOTAL LIABILITIES	4,934,133	5,536,293
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
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	663,782	663,782
Retained Earnings	769,572	633,203
Accumulated Other Comprehensive Income (Loss)	5,945	7,079
TOTAL COMMON SHAREHOLDER’S EQUITY	1,760,500	1,625,265
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$6,694,633	$7,161,558

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Nine Months Ended September 30,	
	2014	2013
OPERATING ACTIVITIES		
Net Income	$171,369	$329,731
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	165,152	289,472
Amortization of Generation Deferrals	82,818	—
Deferred Income Taxes	27,990	111,850
Asset Impairments and Other Related Charges	—	154,304
Carrying Costs Income	(19,594)	(9,833)
Allowance for Equity Funds Used During Construction	(4,893)	(2,853)
Mark-to-Market of Risk Management Contracts	(5,003)	14,037
Pension Contributions to Qualified Plan Trust	(6,547)	—
Property Taxes	148,124	166,607
Fuel Over/Under-Recovery, Net	37,326	21,271
Deferral of Ohio Capacity Costs, Net	(138,737)	(156,952)
Change in Other Noncurrent Assets	35,962	(29,012)
Change in Other Noncurrent Liabilities	59,081	(11,664)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(20,395)	123,893
Fuel, Materials and Supplies	(1,247)	79,028
Accounts Payable	(83,029)	(67,487)
Customer Deposits	2,973	(2,275)
Accrued Taxes, Net	(173,470)	(187,677)
Other Current Assets	(947)	3,246
Other Current Liabilities	26,039	(36,976)
Net Cash Flows from Operating Activities	302,972	788,710
INVESTING ACTIVITIES		
Construction Expenditures	(327,972)	(445,189)
Change in Restricted Cash for Securitized Funding	1,653	—
Change in Advances to Affiliates, Net	315,325	101,616
Proceeds from Sales of Assets	886	13,059
Proceeds from Notes Receivable – Affiliated	178,580	—
Other Investing Activities	5,921	(8,586)
Net Cash Flows from (Used for) Investing Activities	174,393	(339,100)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	977,002
Issuance of Long-term Debt – Affiliated	—	200,000
Change in Advances from Affiliates, Net	—	1,063
Retirement of Long-term Debt – Nonaffiliated	(438,583)	(1,146,000)

Retirement of Long-term Debt – Affiliated	—	(200,000)
Principal Payments for Capital Lease Obligations	(3,912)	(7,920)
Dividends Paid on Common Stock	(35,000)	(275,000)
Other Financing Activities	1,015	1,946
Net Cash Flows Used for Financing Activities	(476,480)	(448,909)
Net Increase in Cash and Cash Equivalents	885	701
Cash and Cash Equivalents at Beginning of Period	3,004	3,640
Cash and Cash Equivalents at End of Period	$3,889	$4,341
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$90,188	$145,817
Net Cash Paid for Income Taxes	15,523	38,446
Noncash Acquisitions Under Capital Leases	4,505	5,756
Government Grants Included in Accounts Receivable as of September 30,	—	377
Construction Expenditures Included in Current Liabilities as of September 30,	45,691	68,481
Noncash Distribution of Cook Coal Terminal to Parent	—	(22,303)

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

OHIO POWER COMPANY AND SUBSIDIARIES
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

2014 Oklahoma Base Rate Case

In January 2014, PSO filed a request with the OCC to increase annual base rates by $38 million, based upon a 10.5% return on common equity. This revenue increase includes a proposed increase in depreciation rates of $29 million. In addition, the filing proposed recovery of advanced metering costs through a separate rider over a three-year deployment period requesting $7 million of revenues in year one, increasing to $28 million in year three. The filing also proposed expansion of an existing transmission rider currently recovered in base rates to include additional transmission-related costs that are expected to increase over the next several years.

In June 2014, a non-unanimous stipulation agreement between PSO, the OCC staff and certain intervenors was filed with the OCC. The parties to the stipulation recommended no overall change to the transmission rider or to annual revenues, other than additional revenues through a separate rider related to advanced metering costs, and that the terms of the stipulation be effective November 2014. The advanced metering rider would provide $7 million of revenues in 2014 and increase to $27 million in 2016. New depreciation rates are recommended for advanced metering investments and existing meters, also to be effective November 2014. Additionally, the stipulation recommends recovery of regulatory assets for 2013 storms and regulatory case expenses. In July 2014, the Attorney General joined in the stipulation agreement. A hearing at the OCC was held in July 2014. An order is anticipated in the fourth quarter of 2014. If the OCC were to disallow any portion of this settlement agreement, it could reduce future net income and cash flows and impact financial condition. See the "2014 Oklahoma Base Rate Case" section of PSO Rate Matters in Note 4.

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 3 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies in the 2013 Annual Report. Also, see Note 4 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 170. 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 249 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions of KWhs)			
Retail:				
Residential	1,981	2,100	4,978	4,906
Commercial	1,455	1,475	3,905	3,829
Industrial	1,407	1,344	3,939	3,829
Miscellaneous	356	353	956	951
Total Retail	5,199	5,272	13,778	13,515
Wholesale	42	330	318	852
Total KWhs	5,241	5,602	14,096	14,367

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in degree days)			
Actual - Heating (a)	—	—	1,417	1,208
Normal - Heating (b)	1	2	1,086	1,084
Actual - Cooling (c)	1,259	1,357	1,935	2,006
Normal - Cooling (b)	1,394	1,395	2,058	2,059

(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.

Third Quarter of 2014 Compared to Third Quarter of 2013
Reconciliation of Third Quarter of 2013 to Third Quarter of 2014
Net Income
(in millions)

Third Quarter of 2013	$51
Changes in Gross Margin:	
Retail Margins (a)	1
Other Revenues	(3)
Total Change in Gross Margin	(2)
Changes in Expenses and Other:	
Other Operation and Maintenance	(8)
Taxes Other Than Income Taxes	2
Other Income	(1)
Total Change in Expenses and Other	(7)
Income Tax Expense	3
Third Quarter of 2014	$45

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

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 $5 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.

  This increase was partially offset by:
  - A $5 million decrease in weather-related usage primarily due to a 7% decrease in cooling degree days.
- Other Revenues decreased $3 million primarily due a 2013 sale of fuel inventory.

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

- Other Operation and Maintenance expenses increased $8 million primarily due to the following:
  - A $5 million increase in general and administrative expenses.
  - A $4 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $3 million increase in energy efficiency program expenses.

  These increases were partially offset by:
  - A $3 million decrease in distribution expenses primarily related to the amortization of the 2007 and 2010 storm deferrals which were fully recovered in 2013.
- Income Tax Expense decreased $3 million primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013
Reconciliation of Nine Months Ended September 30, 2013 to Nine Months Ended September 30, 2014
Net Income
(in millions)

Nine Months Ended September 30, 2013	$93	
Changes in Gross Margin:		
Retail Margins (a)	1	
Off-system Sales	1	
Other Revenues	(4	)
Total Change in Gross Margin	(2	)
Changes in Expenses and Other:		
Other Operation and Maintenance	(29	)
Depreciation and Amortization	(1	)
Taxes Other Than Income Taxes	6	
Other Income	(2	)
Interest Expense	(1	)
Total Change in Expenses and Other	(27	)
Income Tax Expense	12	
Nine Months Ended September 30, 2014	$76	

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

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 $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.

  This increase was partially offset by:
  - A $3 million net decrease in weather-related usage primarily due to a 4% decrease in cooling degree days, partially offset by an increase in heating degree.
- Other Revenues decreased $4 million primarily due a 2013 sale of fuel inventory.

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

- Other Operation and Maintenance expenses increased $29 million primarily due to the following:
  - A $16 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $10 million increase in generation plant operation and maintenance expenses.
  - A $5 million increase in general and administrative expenses.
  - A $5 million increase in energy efficiency program expenses.

  These increases were partially offset by:
  - A $9 million decrease in distribution expenses primarily related to amortization of the 2007 and 2010 storm deferrals which were fully recovered in 2013.

- Taxes Other Than Income Taxes decreased $6 million primarily due to a 2014 property tax reduction resulting from a change in Oklahoma tax law.
- Income Tax Expense decreased $12 million primarily due to a decrease in pretax book income.

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 2013 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 249 for a discussion of accounting pronouncements.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
REVENUES				
Electric Generation, Transmission and Distribution	$415,193	$408,803	$1,028,427	$986,008
Sales to AEP Affiliates	789	1,659	6,240	9,186
Other Revenues	1,009	621	2,524	2,865
TOTAL REVENUES	416,991	411,083	1,037,191	998,059
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	85,018	124,763	192,567	254,314
Purchased Electricity for Resale	117,521	55,915	301,816	179,405
Purchased Electricity from AEP Affiliates	—	13,129	11,024	30,168
Other Operation	71,605	60,566	193,101	162,032
Maintenance	21,800	25,071	76,223	78,396
Depreciation and Amortization	24,496	24,191	73,085	72,449
Taxes Other Than Income Taxes	9,137	11,616	27,757	33,440
TOTAL EXPENSES	329,577	315,251	875,573	810,204
OPERATING INCOME	87,414	95,832	161,618	187,855
Other Income (Expense):				
Interest Income	137	25	138	1,146
Carrying Costs Income	—	21	—	338
Allowance for Equity Funds Used During Construction	194	852	2,215	2,676
Interest Expense	(13,913)	(13,417)	(41,009)	(40,016)
INCOME BEFORE INCOME TAX EXPENSE	73,832	83,313	122,962	151,999
Income Tax Expense	28,746	32,217	46,979	58,778
NET INCOME	$45,086	$51,096	$75,983	$93,221

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net Income	$45,086	$51,096	$75,983	$93,221
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $102 and $92 for the Three Months Ended September 30, 2014 and 2013, Respectively, and $337 and $319 for the Nine Months Ended September 30, 2014 and 2013, Respectively	(190)	(172)	(626)	(593)
TOTAL COMPREHENSIVE INCOME	$44,896	$50,924	$75,357	$92,628

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2012	$157,230	$364,037	$388,530	$ 6,481	$916,278
Common Stock Dividends			(41,250)		(41,250)
Net Income			93,221		93,221
Other Comprehensive Loss				(593)	(593)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2013	$157,230	$364,037	$440,501	$ 5,888	$967,656
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$157,230	$364,037	$415,076	$ 5,758	$942,101
Net Income			75,983		75,983
Other Comprehensive Loss				(626)	(626)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2014	$157,230	$364,037	$491,059	$ 5,132	$1,017,458

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2014 and December 31, 2013
(in thousands)
(Unaudited)

	September 30, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$1,828	$1,277
Accounts Receivable:		
Customers	32,464	32,314
Affiliated Companies	26,770	30,392
Miscellaneous	5,907	3,102
Allowance for Uncollectible Accounts	(128)	(462)
Total Accounts Receivable	65,013	65,346
Fuel	10,524	15,191
Materials and Supplies	51,619	52,707
Risk Management Assets	563	1,167
Deferred Income Tax Benefits	—	7,333
Accrued Tax Benefits	12,298	21,665
Regulatory Asset for Under-Recovered Fuel Costs	36,544	3,298
Prepayments and Other Current Assets	9,226	6,194
TOTAL CURRENT ASSETS	187,615	174,178
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,248,341	1,203,221
Transmission	770,613	731,312
Distribution	2,062,942	1,986,032
Other Property, Plant and Equipment (Including Plant to be Retired)	426,221	393,026
Construction Work in Progress	158,716	175,890
Total Property, Plant and Equipment	4,666,833	4,489,481
Accumulated Depreciation and Amortization	1,333,626	1,323,522
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,333,207	3,165,959
OTHER NONCURRENT ASSETS		
Regulatory Assets	143,123	156,690
Long-term Risk Management Assets	3	—
Employee Benefits and Pension Assets	27,272	22,629
Deferred Charges and Other Noncurrent Assets	15,184	7,238
TOTAL OTHER NONCURRENT ASSETS	185,582	186,557
TOTAL ASSETS	$3,706,404	$3,526,694

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2014 and December 31, 2013
(Unaudited)

	September 30, 2014	December 31, 2013
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$100,867	$36,772
Accounts Payable:		
General	98,911	150,184
Affiliated Companies	40,599	45,427
Long-term Debt Due Within One Year – Nonaffiliated	424	34,115
Risk Management Liabilities	—	85
Customer Deposits	48,126	45,379
Accrued Taxes	45,850	23,442
Accrued Interest	14,904	12,646
Other Current Liabilities	50,342	58,992
TOTAL CURRENT LIABILITIES	400,023	407,042
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,040,632	965,695
Deferred Income Taxes	853,893	836,556
Regulatory Liabilities and Deferred Investment Tax Credits	326,048	327,673
Employee Benefits and Pension Obligations	10,772	10,561
Deferred Credits and Other Noncurrent Liabilities	57,578	37,066
TOTAL NONCURRENT LIABILITIES	2,288,923	2,177,551
TOTAL LIABILITIES	2,688,946	2,584,593
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
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	491,059	415,076
Accumulated Other Comprehensive Income (Loss)	5,132	5,758
TOTAL COMMON SHAREHOLDER’S EQUITY	1,017,458	942,101
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$3,706,404	$3,526,694

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2014	2013
OPERATING ACTIVITIES		
Net Income	$75,983	$93,221
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	73,085	72,449
Deferred Income Taxes	27,327	39,665
Allowance for Equity Funds Used During Construction	(2,215)	(2,676)
Mark-to-Market of Risk Management Contracts	432	(4,984)
Pension Contributions to Qualified Plan Trust	(4,439)	—
Property Taxes	(7,970)	(10,177)
Fuel Over/Under-Recovery, Net	(33,246)	(9,201)
Change in Other Noncurrent Assets	2,035	(3,513)
Change in Other Noncurrent Liabilities	(2,015)	(13,094)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	333	6,454
Fuel, Materials and Supplies	5,755	3,876
Accounts Payable	(28,643)	8,783
Accrued Taxes, Net	32,131	37,739
Other Current Assets	(4,034)	216
Other Current Liabilities	17,024	(3,780)
Net Cash Flows from Operating Activities	151,543	214,978
INVESTING ACTIVITIES		
Construction Expenditures	(256,741)	(172,602)
Change in Advances to Affiliates, Net	—	(8,884)
Other Investing Activities	2,881	10,657
Net Cash Flows Used for Investing Activities	(253,860)	(170,829)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	74,973	—
Change in Advances from Affiliates, Net	64,095	—
Retirement of Long-term Debt – Nonaffiliated	(34,010)	(301)
Principal Payments for Capital Lease Obligations	(2,785)	(2,558)
Dividends Paid on Common Stock	—	(41,250)
Other Financing Activities	595	593
Net Cash Flows from (Used for) Financing Activities	102,868	(43,516)
Net Increase in Cash and Cash Equivalents	551	633
Cash and Cash Equivalents at Beginning of Period	1,277	1,367
Cash and Cash Equivalents at End of Period	$1,828	$2,000

SUPPLEMENTARY INFORMATION

Cash Paid for Interest, Net of Capitalized Amounts	$37,458	$36,054
Net Cash Paid (Received) for Income Taxes	(416)	2,026
Noncash Acquisitions Under Capital Leases	2,098	4,068
Construction Expenditures Included in Current Liabilities as of September 30,	33,527	33,820

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

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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

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

EXECUTIVE OVERVIEW

Regulatory Activity

2012 Texas Base Rate Case

Upon rehearing in January 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. The resulting annual base rate increase is approximately $52 million. In May 2014, intervenors filed appeals of the order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals and filed initial responses. If certain parts of the PUCT order are overturned it could reduce future net income and cash flows and impact financial condition. See the "2012 Texas Base Rate Case" section of SWEPCo Rate Matters in Note 4.

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 of the Turk Plant. In February 2013, a settlement was approved by the LPSC that increased Louisiana total rates by approximately $2 million annually, effective March 2013. The March 2013 base rates are based upon a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. If the LPSC orders refunds based upon the pending staff review of the cost of service or the prudence review of the Turk Plant, it could reduce future net income and cash flows and impact financial condition. See the "2012 Louisiana Formula Rate Filing" section of SWEPCo Rate Matters in Note 4.

2014 Louisiana Formula Rate Filing

In April 2014, SWEPCo filed its annual formula rate plan for test year 2013 with the LPSC. The filing included a $5 million annual increase, which was effective August 2014, subject to refund. SWEPCo also proposed to increase rates by an additional $15 million annually, effective January 2015, for a total annual increase of $20 million. This additional increase reflects the cost of incremental generation to be used to serve Louisiana customers in 2015 due to the expiration of a purchase power agreement attributable to Louisiana customers. These increases are subject to LPSC staff review. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Welsh Plant, Units 1 and 3 - Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet mercury and air toxics standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of September 30, 2014, SWEPCo has incurred costs of $112 million and has contractual construction obligations of $84 million related to these projects. SWEPCo will seek to recover these project costs from customers through filings at the state commissions and FERC. These environmental projects could be adversely impacted by pending carbon emission regulations. See "CO_2 Regulation" section of “Environmental Issues” within “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries”. As of September 30, 2014, the net book value of Welsh Plant, Units 1 and 3 was $335 million, before cost of removal, including materials and supplies inventory and CWIP. If any of these costs are not recoverable, 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 3 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies in the 2013 Annual Report. Also, see Note 4 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 170. 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 249 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions of KWhs)			
Retail:				
Residential	1,949	2,081	4,974	5,021
Commercial	1,744	1,745	4,583	4,580
Industrial	1,511	1,443	4,453	4,167
Miscellaneous	20	19	60	60
Total Retail	5,224	5,288	14,070	13,828
Wholesale	2,458	2,479	7,022	7,053
Total KWhs	7,682	7,767	21,092	20,881

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in degree days)			
Actual - Heating (a)	—	—	1,039	800
Normal - Heating (b)	1	1	748	754
Actual - Cooling (c)	1,232	1,418	1,917	2,137
Normal - Cooling (b)	1,404	1,397	2,162	2,155

(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.

Third Quarter of 2014 Compared to Third Quarter of 2013
Reconciliation of Third Quarter of 2013 to Third Quarter of 2014
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Third Quarter of 2013	$7	
Changes in Gross Margin:		
Retail Margins (a)	(13	)
Off-system Sales	2	
Transmission Revenues	(2	)
Other Revenues	1	
Total Change in Gross Margin	(12	)
Changes in Expenses and Other:		
Other Operation and Maintenance	(12	)
Asset Impairments and Other Related Charges	111	
Depreciation and Amortization	(5	)
Taxes Other Than Income Taxes	(1	)
Interest Expense	1	
Total Change in Expenses and Other	94	
Income Tax Expense	(16	)
Third Quarter of 2014	$73	

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

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 decreased $13 million primarily due to the following:
  - A $13 million decrease primarily due to a favorable Texas rate order adjustment in the third quarter of 2013 related to the Turk Plant.
  - A $13 million decrease in weather-related usage primarily due to a 13% decrease in cooling degree days.

  These decreases were partially offset by:
  - An $11 million increase due to higher weather-normalized retail sales.
  - A $2 million increase in municipal and cooperative revenues due to formula rate adjustments.

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

- Other Operation and Maintenance expenses increased $12 million primarily due to the following:
  - A $5 million increase in general and administrative expenses.
  - A $5 million increase in distribution expenses primarily due to overhead line maintenance expenses.
- Asset Impairments and Other Related Charges decreased $111 million due to the third quarter 2013 write-off of AFUDC on the Turk Plant.
- Depreciation and Amortization expenses increased $5 million primarily due to a greater depreciable base.
-

Income Tax Expense increased $16 million primarily due to an increase in pretax book income, partially offset by the recording of federal and state income tax return adjustments and other book/tax differences which are accounted for on a flow-through basis.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013
Reconciliation of Nine Months Ended September 30, 2013 to Nine Months Ended September 30, 2014
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Nine Months Ended September 30, 2013	$46	
Changes in Gross Margin:		
Retail Margins (a)	23	
Off-system Sales	7	
Transmission Revenues	(4	)
Other Revenues	2	
Total Change in Gross Margin	28	
Changes in Expenses and Other:		
Other Operation and Maintenance	(33	)
Asset Impairments and Other Related Charges	111	
Depreciation and Amortization	(6	)
Taxes Other Than Income Taxes	(4	)
Other Income	3	
Interest Expense	5	
Total Change in Expenses and Other	76	
Income Tax Expense	(23	)
Nine Months Ended September 30, 2014	$127	

(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 $23 million primarily due to the following:
  - A $17 million net increase due to the Texas and Louisiana rate orders related to the Turk Plant.
  - A $15 million increase in municipal and cooperative revenues due to formula rate adjustments.

  These increases were partially offset by:
  - A $9 million net decrease in weather-related usage primarily due to a 10% decrease in cooling degree days, partially offset by an increase in heating degree days.
- Margins from Off-system Sales increased $7 million primarily due to increased market prices and higher physical sales margins.
- Transmission Revenues decreased $4 million primarily due to lower SPP margins.

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

- Other Operation and Maintenance expenses increased $33 million primarily due to the following:
  - A $13 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $6 million increase in general and administrative expenses.
  - A $5 million increase in distribution expenses primarily due to overhead line maintenance expenses.
  - A $5 million increase in generation plant operation and maintenance expenses.

- Asset Impairments and Other Related Charges decreased $111 million due to the third quarter 2013 write-off of AFUDC on the Turk Plant.
- Depreciation and Amortization expenses increased $6 million primarily due to a greater depreciable base.
- Taxes Other Than Income Taxes increased $4 million primarily due to higher property taxes.

- Other Income increased $3 million primarily due to an increase in AFUDC as a result of environmental and transmission projects.
- Interest Expense decreased $5 million primarily due to rate approvals in Louisiana and Texas and an increase in the debt component of AFUDC due to increased environmental and transmission projects.
- Income Tax Expense increased $23 million primarily due to an increase in pretax book income, partially offset by the recording of federal and state income tax return adjustments in the third quarter of 2014 and other book/tax differences which are accounted for on a flow-through basis.

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 2013 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 249 for a discussion of accounting pronouncements.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
REVENUES				
Electric Generation, Transmission and Distribution	$526,047	$534,196	$1,397,326	$1,324,325
Sales to AEP Affiliates	5,203	18,296	22,748	41,935
Other Revenues	521	441	1,570	1,163
TOTAL REVENUES	531,771	552,933	1,421,644	1,367,423
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	194,175	202,024	500,878	490,447
Purchased Electricity for Resale	36,960	37,505	138,380	120,273
Purchased Electricity from AEP Affiliates	—	815	3,766	6,757
Other Operation	68,601	62,108	206,442	182,351
Maintenance	29,867	24,654	93,946	84,725
Asset Impairments and Other Related Charges	—	110,850	—	110,850
Depreciation and Amortization	46,791	41,846	138,316	132,460
Taxes Other Than Income Taxes	22,246	20,772	63,272	59,530
TOTAL EXPENSES	398,640	500,574	1,145,000	1,187,393
OPERATING INCOME	133,131	52,359	276,644	180,030
Other Income (Expense):				
Other Income	3,367	2,457	7,737	5,048
Interest Expense	(31,644)	(32,614)	(95,258)	(100,151)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	104,854	22,202	189,123	84,927
Income Tax Expense	31,042	14,935	60,252	37,057
Equity Earnings of Unconsolidated Subsidiary	735	653	1,461	1,825
NET INCOME	74,547	7,920	130,332	49,695
Net Income Attributable to Noncontrolling Interest	1,109	1,058	3,337	3,204
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$73,438	$6,862	$126,995	$46,491

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net Income	$74,547	$7,920	$130,332	$49,695
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $305 and $317 for the Three Months Ended September 30, 2014 and 2013, Respectively, and $881 and $902 for the Nine Months Ended September 30, 2014 and 2013, Respectively	567	589	1,636	1,675
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $126 and $35 for the Three Months Ended September 30, 2014 and 2013, Respectively, and $379 and $103 for the Nine Months Ended September 30, 2014 and 2013, Respectively	(235)	(64)	(704)	(191)
TOTAL OTHER COMPREHENSIVE INCOME	332	525	932	1,484
TOTAL COMPREHENSIVE INCOME	74,879	8,445	131,264	51,179
Total Comprehensive Income Attributable to Noncontrolling Interest	1,109	1,058	3,337	3,204
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$73,770	$7,387	$127,927	$47,975

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2014 and 2013
(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, 2012	$135,660	$674,606	$1,228,806	$(17,860)	$261	$2,021,473
Common Stock Dividends			(93,750)			(93,750)
Common Stock Dividends – Nonaffiliated					(3,142)	(3,142)
Net Income			46,491		3,204	49,695
Other Comprehensive Income				1,484		1,484
TOTAL EQUITY - SEPTEMBER 30, 2013	$135,660	$674,606	$1,181,547	$(16,376)	$323	$1,975,760
TOTAL EQUITY - DECEMBER 31, 2013	$135,660	$674,606	$1,253,617	$(8,444)	$478	$2,055,917
Common Stock Dividends			(75,000)			(75,000)
Common Stock Dividends – Nonaffiliated					(3,483)	(3,483)
Net Income			126,995		3,337	130,332
Other Comprehensive Income				932		932
TOTAL EQUITY - SEPTEMBER 30, 2014	$135,660	$674,606	$1,305,612	$(7,512)	$332	$2,108,698

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2014 and December 31, 2013
(in thousands)
(Unaudited)

	September 30, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents		
(September 30, 2014 and December 31, 2013 Amounts Include $21,649 and $15,827, Respectively, Related to Sabine)	$23,986	$17,241
Accounts Receivable:		
Customers	38,932	86,263
Affiliated Companies	28,296	22,389
Miscellaneous	30,855	27,175
Allowance for Uncollectible Accounts	(296)	(1,418)
Total Accounts Receivable	97,787	134,409
Fuel		
(September 30, 2014 and December 31, 2013 Amounts Include $31,320 and $37,518, Respectively, Related to Sabine)	100,176	122,026
Materials and Supplies	74,212	74,862
Risk Management Assets	408	1,179
Deferred Income Tax Benefits	4,729	177,297
Accrued Tax Benefits	106,744	158
Regulatory Asset for Under-Recovered Fuel Costs	30,221	17,949
Prepayments and Other Current Assets	26,020	20,931
TOTAL CURRENT ASSETS	464,283	566,052
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,844,042	3,764,429
Transmission	1,265,646	1,165,167
Distribution	1,887,635	1,843,912
Other Property, Plant and Equipment (Including Plant to be Retired)		
(September 30, 2014 and December 31, 2013 Amounts Include $286,792 and $291,556, Respectively, Related to Sabine)	876,552	869,230
Construction Work in Progress	395,740	281,849
Total Property, Plant and Equipment	8,269,615	7,924,587
Accumulated Depreciation and Amortization		
(September 30, 2014 and December 31, 2013 Amounts Include $138,776 and $134,282, Respectively, Related to Sabine)	2,485,292	2,391,652
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,784,323	5,532,935
OTHER NONCURRENT ASSETS		
Regulatory Assets	364,968	369,905
Long-term Risk Management Assets	3	—
Deferred Charges and Other Noncurrent Assets	110,552	92,890
TOTAL OTHER NONCURRENT ASSETS	475,523	462,795

TOTAL ASSETS	$6,724,129	$6,561,782

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2014 and December 31, 2013
(Unaudited)

	September 30, 2014	December 31, 2013
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$6,329	$9,180
Accounts Payable:		
General	175,572	152,653
Affiliated Companies	44,666	56,923
Long-term Debt Due Within One Year – Nonaffiliated	306,750	3,250
Risk Management Liabilities	131	—
Customer Deposits	58,595	56,375
Accrued Taxes	70,222	41,508
Accrued Interest	19,589	43,996
Obligations Under Capital Leases	18,006	17,899
Regulatory Liability for Over-Recovered Fuel Costs	—	7,275
Other Current Liabilities	76,030	79,622
TOTAL CURRENT LIABILITIES	775,890	468,681
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,833,598	2,040,082
Deferred Income Taxes	1,285,125	1,271,478
Regulatory Liabilities and Deferred Investment Tax Credits	470,748	472,128
Asset Retirement Obligations	90,929	87,630
Employee Benefits and Pension Obligations	17,319	14,602
Obligations Under Capital Leases	95,036	105,086
Deferred Credits and Other Noncurrent Liabilities	46,786	46,178
TOTAL NONCURRENT LIABILITIES	3,839,541	4,037,184
TOTAL LIABILITIES	4,615,431	4,505,865
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
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	1,305,612	1,253,617
Accumulated Other Comprehensive Income (Loss)	(7,512)	(8,444)
TOTAL COMMON SHAREHOLDER’S EQUITY	2,108,366	2,055,439
Noncontrolling Interest	332	478

TOTAL EQUITY	2,108,698	2,055,917
TOTAL LIABILITIES AND EQUITY	$6,724,129	$6,561,782

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2014	2013
OPERATING ACTIVITIES		
Net Income	$130,332	$49,695
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	138,316	132,460
Deferred Income Taxes	181,482	27,736
Asset Impairments and Other Related Charges	—	110,850
Allowance for Equity Funds Used During Construction	(7,415)	(4,872)
Mark-to-Market of Risk Management Contracts	802	(591)
Pension Contributions to Qualified Plan Trust	(3,832)	—
Property Taxes	(12,503)	(11,804)
Fuel Over/Under-Recovery, Net	(19,547)	(24,110)
Change in Other Noncurrent Assets	11,926	21,935
Change in Other Noncurrent Liabilities	39	(10,203)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	36,622	(7,384)
Fuel, Materials and Supplies	22,500	8,638
Accounts Payable	(15,046)	(7,626)
Accrued Taxes, Net	(76,982)	36,127
Accrued Interest	(24,406)	(24,752)
Other Current Assets	(7,448)	(1,483)
Other Current Liabilities	(2,983)	(13,770)
Net Cash Flows from Operating Activities	351,857	280,846
INVESTING ACTIVITIES		
Construction Expenditures	(351,666)	(284,650)
Change in Advances to Affiliates, Net	—	135,195
Other Investing Activities	4,334	(383)
Net Cash Flows Used for Investing Activities	(347,332)	(149,838)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	99,633	—
Credit Facility Borrowings	—	17,091
Change in Advances from Affiliates, Net	(2,851)	—
Retirement of Long-term Debt – Nonaffiliated	(3,250)	(3,250)
Credit Facility Repayments	—	(19,694)
Principal Payments for Capital Lease Obligations	(13,673)	(13,394)
Dividends Paid on Common Stock	(75,000)	(93,750)
Dividends Paid on Common Stock – Nonaffiliated	(3,483)	(3,142)
Other Financing Activities	844	746
Net Cash Flows from (Used for) Financing Activities	2,220	(115,393)

Net Increase in Cash and Cash Equivalents	6,745	15,615
Cash and Cash Equivalents at Beginning of Period	17,241	2,036
Cash and Cash Equivalents at End of Period	$23,986	$17,651
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$113,137	$115,627
Net Cash Paid (Received) for Income Taxes	(13,820)	265
Noncash Acquisitions Under Capital Leases	3,923	3,848
Construction Expenditures Included in Current Liabilities as of September 30,	88,291	44,815

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 170.

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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.

	Page Number
Significant Accounting Matters	171
New Accounting Pronouncements	172
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Commitments, Guarantees and Contingencies	203
Disposition and Impairments	207
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INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

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
Significant Accounting Matters	APCo, I&M, OPCo, PSO, SWEPCo	171
New Accounting Pronouncements	APCo, I&M, OPCo, PSO, SWEPCo	172
Comprehensive Income	APCo, I&M, OPCo, PSO, SWEPCo	173
Rate Matters	APCo, I&M, OPCo, PSO, SWEPCo	192
Commitments, Guarantees and Contingencies	APCo, I&M, OPCo, PSO, SWEPCo	203
Disposition and Impairments	OPCo, SWEPCo	207
Benefit Plans	APCo, I&M, OPCo, PSO, SWEPCo	208
Business Segments	APCo, I&M, OPCo, PSO, SWEPCo	211
Derivatives and Hedging	APCo, I&M, OPCo, PSO, SWEPCo	212
Fair Value Measurements	APCo, I&M, OPCo, PSO, SWEPCo	226
Income Taxes	APCo, I&M, OPCo, PSO, SWEPCo	239
Financing Activities	APCo, I&M, OPCo, PSO, SWEPCo	240
Variable Interest Entities	APCo, I&M, OPCo, PSO, SWEPCo	244

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 and nine months ended September 30, 2014 is not necessarily indicative of results that may be expected for the year ending December 31, 2014. The condensed financial statements are unaudited and should be read in conjunction with the audited 2013 financial statements and notes thereto, which are included in the Registrant Subsidiaries' Annual Reports on Form 10-K as filed with the SEC on February 25, 2014.

Revenue Recognition

Electricity Supply and Delivery Activities - Transactions with PJM

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. The Registrant Subsidiaries recognize the revenues on the statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts.

APCo and I&M sell power produced at their generation plants to PJM and purchase power from PJM to supply their retail load. These power sales and purchases for each subsidiary's retail load are netted hourly for financial reporting purposes. On an hourly net basis, each subsidiary records sales of power to PJM in excess of purchases of power from PJM as revenues on the statements of income. Also, on an hourly net basis, each subsidiary records purchases of power from PJM to serve retail load in excess of sales of power to PJM as Purchased Electricity for Resale on the statements of income. Upon termination of the Interconnection Agreement in 2014, each subsidiary manages and accounts for its purchases and sales with PJM individually based on market prices.

SPP Integrated Power Market

In March 2014, SPP changed from an energy imbalance service market to a fully integrated power market. In the past, PSO and SWEPCo would satisfy their load requirements with their own generation resources or through the Operating Agreement. In the new integrated power market, PSO and SWEPCo operate as standalone entities by offering their respective generation into the SPP power market, which then economically dispatches the resources. This change further enables retail customers to obtain low cost power through either internal generation or power purchases from the SPP market. The new integrated power market now operates in a similar manner as the PJM power market for the AEP East Companies. No significant impact on results of operations is expected due to this change.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to the Registrant Subsidiaries' business. The following final pronouncements will impact the financial statements.

ASU 2014-08 "Presentation of Financial Statements and Property, Plant and Equipment" (ASU 2014-08)

In April 2014, the FASB issued ASU 2014-08 changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component meets the criteria to be classified as held-for-sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. This standard must be prospectively applied to all reporting periods presented in financial reports issued after the effective date. Early adoption is permitted for disposals that have not been reported in financial statements previously issued or available for issuance.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014 with early adoption permitted. If applicable, this standard will change the presentation of financial statements but will not affect the calculation of net income, comprehensive income or earnings per share.

ASU 2014-09 "Revenue from Contracts with Customers" (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts. This standard must be retrospectively applied to all reporting periods presented in financial reports issued after the effective date.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016. Early adoption is not permitted. As applicable, this standard may change the amount of revenue recognized in the income statements in each reporting period. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2017.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three and nine months ended September 30, 2014 and 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 September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of June 30, 2014	$—	$3,596	$(899)	$2,697
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	170	(333)	(163)
Net Current Period Other Comprehensive Income	—	170	(333)	(163)
Balance in AOCI as of September 30, 2014	$—	$3,766	$(1,232)	$2,534

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of June 30, 2013	$197	$2,583	$(30,615)	$(27,835)
Change in Fair Value Recognized in AOCI	(47)	—	—	(47)
Amounts Reclassified from AOCI	(184)	253	359	428
Net Current Period Other Comprehensive Income	(231)	253	359	381
Balance in AOCI as of September 30, 2013	$(34)	$2,836	$(30,256)	$(27,454)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2013	$94	$3,090	$(233)	$2,951
Change in Fair Value Recognized in AOCI	1,686	—	—	1,686
Amounts Reclassified from AOCI	(1,780)	676	(999)	(2,103)
Net Current Period Other Comprehensive Income	(94)	676	(999)	(417)
Balance in AOCI as of September 30, 2014	$—	$3,766	$(1,232)	$2,534

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2012	$(644)	$2,077	$(31,331)	$(29,898)
Change in Fair Value Recognized in AOCI	684	—	—	684
Amounts Reclassified from AOCI	(74)	759	1,075	1,760
Net Current Period Other Comprehensive Income	610	759	1,075	2,444
Balance in AOCI as of September 30, 2013	$(34)	$2,836	$(30,256)	$(27,454)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of June 30, 2014	$—	$(15,155)	$507	$(14,648)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	410	42	452
Net Current Period Other Comprehensive Income	—	410	42	452
Balance in AOCI as of September 30, 2014	$—	$(14,745)	$549	$(14,196)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of June 30, 2013	$147	$(16,796)	$(8,439)	$(25,088)
Change in Fair Value Recognized in AOCI	(49)	—	—	(49)
Amounts Reclassified from AOCI	(117)	410	174	467
Net Current Period Other Comprehensive Income	(166)	410	174	418
Balance in AOCI as of September 30, 2013	$(19)	$(16,386)	$(8,265)	$(24,670)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2013	$46	$(15,976)	$421	$(15,509)
Change in Fair Value Recognized in AOCI	1,130	—	—	1,130
Amounts Reclassified from AOCI	(1,176)	1,231	128	183
Net Current Period Other Comprehensive Income	(46)	1,231	128	1,313
Balance in AOCI as of September 30, 2014	$—	$(14,745)	$549	$(14,196)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2012	$(446)	$(19,647)	$(8,790)	$(28,883)
Change in Fair Value Recognized in AOCI	443	2,248	—	2,691
Amounts Reclassified from AOCI	(16)	1,013	525	1,522
Net Current Period Other Comprehensive Income	427	3,261	525	4,213
Balance in AOCI as of September 30, 2013	$(19)	$(16,386)	$(8,265)	$(24,670)

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of June 30, 2014	$—	$6,288	$—	$6,288
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	(343)	—	(343)
Net Current Period Other Comprehensive Income	—	(343)	—	(343)
Balance in AOCI as of September 30, 2014	$—	$5,945	$—	$5,945

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of June 30, 2013	$289	$7,415	$(166,369)	$(158,665)
Change in Fair Value Recognized in AOCI	(86)	—	—	(86)
Amounts Reclassified from AOCI	(250)	(339)	2,985	2,396
Net Current Period Other Comprehensive Income	(336)	(339)	2,985	2,310
Distribution of Cook Coal Terminal to Parent	—	—	19,652	19,652
Balance in AOCI as of September 30, 2013	$(47)	$7,076	$(143,732)	$(136,703)

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OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2013	$105	$6,974	$—	$7,079
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	(105)	(1,029)	—	(1,134)
Net Current Period Other Comprehensive Income	(105)	(1,029)	—	(1,134)
Balance in AOCI as of September 30, 2014	$—	$5,945	$—	$5,945

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2012	$(912)	$8,095	$(172,908)	$(165,725)
Change in Fair Value Recognized in AOCI	907	—	—	907
Amounts Reclassified from AOCI	(42)	(1,019)	9,524	8,463
Net Current Period Other Comprehensive Income	865	(1,019)	9,524	9,370
Distribution of Cook Coal Terminal to Parent	—	—	19,652	19,652
Balance in AOCI as of September 30, 2013	$(47)	$7,076	$(143,732)	$(136,703)

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2014

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
	(in thousands)		
Balance in AOCI as of June 30, 2014	$—	$5,322	$5,322
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	—	(190)	(190)
Net Current Period Other Comprehensive Income	—	(190)	(190)
Balance in AOCI as of September 30, 2014	$—	$5,132	$5,132

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2013

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
	(in thousands)		
Balance in AOCI as of June 30, 2013	$(21)	$6,081	$6,060
Change in Fair Value Recognized in AOCI	32	—	32
Amounts Reclassified from AOCI	(14)	(190)	(204)
Net Current Period Other Comprehensive Income	18	(190)	(172)
Balance in AOCI as of September 30, 2013	$(3)	$5,891	$5,888

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2014

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
	(in thousands)		
Balance in AOCI as of December 31, 2013	$57	$5,701	$5,758
Change in Fair Value Recognized in AOCI	—	—	—
Amounts Reclassified from AOCI	(57)	(569)	(626)
Net Current Period Other Comprehensive Income	(57)	(569)	(626)
Balance in AOCI as of September 30, 2014	$—	$5,132	$5,132

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2013

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
	(in thousands)		
Balance in AOCI as of December 31, 2012	$21	$6,460	$6,481
Change in Fair Value Recognized in AOCI	7	1	8
Amounts Reclassified from AOCI	(31)	(570)	(601)
Net Current Period Other Comprehensive Income	(24)	(569)	(593)
Balance in AOCI as of September 30, 2013	$(3)	$5,891	$5,888

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of June 30, 2014	$—	$(12,169)	$4,325	$(7,844)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	567	(235)	332
Net Current Period Other Comprehensive Income	—	567	(235)	332
Balance in AOCI as of September 30, 2014	$—	$(11,602)	$4,090	$(7,512)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of June 30, 2013	$(26)	$(14,437)	$(2,438)	$(16,901)
Change in Fair Value Recognized in AOCI	40	—	—	40
Amounts Reclassified from AOCI	(17)	566	(64)	485
Net Current Period Other Comprehensive Income	23	566	(64)	525
Balance in AOCI as of September 30, 2013	$(3)	$(13,871)	$(2,502)	$(16,376)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2013	$66	$(13,304)	$4,794	$(8,444)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	(66)	1,702	(704)	932
Net Current Period Other Comprehensive Income	(66)	1,702	(704)	932
Balance in AOCI as of September 30, 2014	$—	$(11,602)	$4,090	$(7,512)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2012	$22	$(15,571)	$(2,311)	$(17,860)
Change in Fair Value Recognized in AOCI	13	—	—	13
Amounts Reclassified from AOCI	(38)	1,700	(191)	1,471
Net Current Period Other Comprehensive Income	(25)	1,700	(191)	1,484
Balance in AOCI as of September 30, 2013	$(3)	$(13,871)	$(2,502)	$(16,376)

Reclassifications from Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and nine months ended September 30, 2014 and 2013. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 for additional details.

APCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended September 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Electric Generation, Transmission and Distribution Revenues	$—	$(75)
Purchased Electricity for Resale	—	21
Other Operation Expense	—	(14)
Maintenance Expense	—	(11)
Property, Plant and Equipment	—	(15)
Regulatory Assets/(Liabilities), Net (a)	—	(190)
Subtotal – Commodity	—	(284)
Interest Rate and Foreign Currency:		
Interest Expense	262	390
Subtotal – Interest Rate and Foreign Currency	262	390
Reclassifications from AOCI, before Income Tax (Expense) Credit	262	106
Income Tax (Expense) Credit	92	37
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	170	69
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(1,281)	(1,282)
Amortization of Actuarial (Gains)/Losses	769	1,834
Reclassifications from AOCI, before Income Tax (Expense) Credit	(512)	552
Income Tax (Expense) Credit	(179)	193
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(333)	359
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(163)	$428

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APCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI Nine Months Ended September 30, 2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Electric Generation, Transmission and Distribution Revenues	$—	$(53)
Purchased Electricity for Resale	(526)	47
Other Operation Expense	(10)	(38)
Maintenance Expense	(20)	(29)
Property, Plant and Equipment	(17)	(34)
Regulatory Assets/(Liabilities), Net (a)	(2,165)	(9)
Subtotal – Commodity	(2,738)	(116)
Interest Rate and Foreign Currency:		
Interest Expense	1,042	1,169
Subtotal – Interest Rate and Foreign Currency	1,042	1,169
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1,696)	1,053
Income Tax (Expense) Credit	(592)	368
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(1,104)	685
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(3,846)	(3,847)
Amortization of Actuarial (Gains)/Losses	2,309	5,501
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1,537)	1,654
Income Tax (Expense) Credit	(538)	579
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(999)	1,075
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(2,103)	$1,760

I&M

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended September 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Electric Generation, Transmission and Distribution Revenues	$—	$(173)
Purchased Electricity for Resale	—	47
Other Operation Expense	—	(8)
Maintenance Expense	—	(5)
Property, Plant and Equipment	—	(10)
Regulatory Assets/(Liabilities), Net (a)	—	(31)
Subtotal – Commodity	—	(180)
Interest Rate and Foreign Currency:		
Interest Expense	631	631
Subtotal – Interest Rate and Foreign Currency	631	631
Reclassifications from AOCI, before Income Tax (Expense) Credit	631	451
Income Tax (Expense) Credit	221	158
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	410	293
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(200)	(199)
Amortization of Actuarial (Gains)/Losses	264	467
Reclassifications from AOCI, before Income Tax (Expense) Credit	64	268
Income Tax (Expense) Credit	22	94
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	42	174
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$452	$467

I&M

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI Nine Months Ended September 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Electric Generation, Transmission and Distribution Revenues	$—	$(89)
Purchased Electricity for Resale	(812)	115
Other Operation Expense	(7)	(23)
Maintenance Expense	(7)	(14)
Property, Plant and Equipment	(10)	(20)
Regulatory Assets/(Liabilities), Net (a)	(973)	7
Subtotal – Commodity	(1,809)	(24)
Interest Rate and Foreign Currency:		
Interest Expense	1,893	1,558
Subtotal – Interest Rate and Foreign Currency	1,893	1,558
Reclassifications from AOCI, before Income Tax (Expense) Credit	84	1,534
Income Tax (Expense) Credit	29	537
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	55	997
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(597)	(596)
Amortization of Actuarial (Gains)/Losses	791	1,404
Reclassifications from AOCI, before Income Tax (Expense) Credit	194	808
Income Tax (Expense) Credit	66	283
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	128	525
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$183	$1,522

OPCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended September 30, 2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Electric Generation, Transmission and Distribution Revenues	$—	$(461)
Purchased Electricity for Resale	—	129
Other Operation Expense	—	(20)
Maintenance Expense	—	(11)
Property, Plant and Equipment	—	(21)
Subtotal – Commodity	—	(384)
Interest Rate and Foreign Currency:		
Depreciation and Amortization Expense	(3)	2
Interest Expense	(524)	(524)
Subtotal – Interest Rate and Foreign Currency	(527)	(522)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(527)	(906)
Income Tax (Expense) Credit	(184)	(317)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(343)	(589)
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	—	(1,451)
Amortization of Actuarial (Gains)/Losses	—	6,044
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	4,593
Income Tax (Expense) Credit	—	1,608
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	2,985
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(343)	$2,396

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OPCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI Nine Months Ended September 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Electric Generation, Transmission and Distribution Revenues	$—	$(246)
Purchased Electricity for Resale	—	309
Other Operation Expense	(11)	(57)
Maintenance Expense	(11)	(26)
Property, Plant and Equipment	(18)	(44)
Regulatory Assets/(Liabilities), Net (a)	(122)	—
Subtotal – Commodity	(162)	(64)
Interest Rate and Foreign Currency:		
Depreciation and Amortization Expense	(9)	5
Interest Expense	(1,572)	(1,573)
Subtotal – Interest Rate and Foreign Currency	(1,581)	(1,568)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1,743)	(1,632)
Income Tax (Expense) Credit	(609)	(571)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(1,134)	(1,061)
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	—	(4,388)
Amortization of Actuarial (Gains)/Losses	—	19,040
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	14,652
Income Tax (Expense) Credit	—	5,128
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	9,524
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(1,134)	$8,463

PSO

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended September 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Other Operation Expense	$—	$(10)
Maintenance Expense	—	(5)
Property, Plant and Equipment	—	(7)
Subtotal – Commodity	—	(22)
Interest Rate and Foreign Currency:		
Interest Expense	(292)	(292)
Subtotal – Interest Rate and Foreign Currency	(292)	(292)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(292)	(314)
Income Tax (Expense) Credit	(102)	(110)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(190)	$(204)

PSO

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI Nine Months Ended September 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Other Operation Expense	$(8)	$(25)
Maintenance Expense	(9)	(9)
Property, Plant and Equipment	(13)	(14)
Regulatory Assets/(Liabilities), Net (a)	(58)	—
Subtotal – Commodity	(88)	(48)
Interest Rate and Foreign Currency:		
Interest Expense	(876)	(876)
Subtotal – Interest Rate and Foreign Currency	(876)	(876)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(964)	(924)
Income Tax (Expense) Credit	(338)	(323)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(626)	$(601)

SWEPCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended September 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Other Operation Expense	$—	$(12)
Maintenance Expense	—	(7)
Property, Plant and Equipment	—	(8)
Subtotal – Commodity	—	(27)
Interest Rate and Foreign Currency:		
Interest Expense	872	872
Subtotal – Interest Rate and Foreign Currency	872	872
Reclassifications from AOCI, before Income Tax (Expense) Credit	872	845
Income Tax (Expense) Credit	305	296
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	567	549
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(478)	(446)
Amortization of Actuarial (Gains)/Losses	118	348
Reclassifications from AOCI, before Income Tax (Expense) Credit	(360)	(98)
Income Tax (Expense) Credit	(125)	(34)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(235)	(64)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$332	$485

SWEPCo

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI Nine Months Ended September 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Other Operation Expense	$(13)	$(28)
Maintenance Expense	(10)	(14)
Property, Plant and Equipment	(11)	(16)
Regulatory Assets/(Liabilities), Net (a)	(67)	—
Subtotal – Commodity	(101)	(58)
Interest Rate and Foreign Currency:		
Interest Expense	2,616	2,616
Subtotal – Interest Rate and Foreign Currency	2,616	2,616
Reclassifications from AOCI, before Income Tax (Expense) Credit	2,515	2,558
Income Tax (Expense) Credit	879	896
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1,636	1,662
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(1,433)	(1,338)
Amortization of Actuarial (Gains)/Losses	351	1,044
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1,082)	(294)
Income Tax (Expense) Credit	(378)	(103)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(704)	(191)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$932	$1,471

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

4. RATE MATTERS

As discussed in the 2013 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 2013 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 2014 and updates the 2013 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

	APCo	
	September 30, 2014	December 31, 2013
Noncurrent Regulatory Assets	(in thousands)	
Regulatory Assets Currently Earning a Return		
West Virginia Vegetation Management Program	$16,115	$—
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	65,206	65,206
IGCC Pre-Construction Costs	20,528	—
Mountaineer Carbon Capture and Storage Product Validation Facility	13,264	13,264
Expanded Net Energy Charge – Coal Inventory	8,554	20,528
Virginia Demand Response Program Costs	7,779	5,012
Virginia Environmental Rate Adjustment Clause	1,941	2,440
Mountaineer Carbon Capture and Storage Commercial Scale Facility	1,287	1,287
Transmission Agreement Phase-In	—	3,313
Other Regulatory Assets Pending Final Regulatory Approval	1,201	168
Total Regulatory Assets Pending Final Regulatory Approval	$135,875	$111,218

	I&M	
	September 30, 2014	December 31, 2013
Noncurrent Regulatory Assets	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Cook Plant Turbine	$5,810	$3,452
Stranded Costs on Abandoned Plants	3,897	3,896
Storm Related Costs	1,855	1,836
Michigan Deferred Cook Plant Life Cycle Management Project Costs	1,093	164
Indiana Deferred Cook Plant Life Cycle Management Project Costs	—	4,093
Indiana Under-Recovered Capacity Costs	—	21,945
Other Regulatory Assets Pending Final Regulatory Approval	1,065	—
Total Regulatory Assets Pending Final Regulatory Approval	$13,720	$35,386

	OPCo	
	September 30, 2014	December 31, 2013
Noncurrent Regulatory Assets	(in thousands)	
Regulatory Assets Currently Earning a Return		
Ohio Economic Development Rider	$—	$13,854
Regulatory Assets Currently Not Earning a Return		

Ormet Special Rate Recovery Mechanism	10,483	35,631
Storm Related Costs	—	57,589
Total Regulatory Assets Pending Final Regulatory Approval	$10,483	$107,074

Noncurrent Regulatory Assets	PSO September 30, 2014	December 31, 2013
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$17,936	$18,743
Other Regulatory Assets Pending Final Regulatory Approval	1,079	845
Total Regulatory Assets Pending Final Regulatory Approval	$19,015	$19,588

Noncurrent Regulatory Assets	SWEPCo September 30, 2014	December 31, 2013
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Rate Case Expenses	$8,051	$7,934
Mountaineer Carbon Capture and Storage Commercial Scale Facility	1,143	1,143
Other Regulatory Assets Pending Final Regulatory Approval	2,175	1,951
Total Regulatory Assets Pending Final Regulatory Approval	$11,369	$11,028

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

OPCo Rate Matters

Ohio Electric Security Plan Filings

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 (OCC) 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. In February 2014, the Supreme Court of Ohio affirmed the PUCO's decision and rejected all appeals filed by the OCC and the IEU.

In August 2012, the PUCO issued an order in a separate proceeding which implemented a 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 related to the PUCO decision in the PIRR proceeding claiming a long-term debt rate modified the previously adjudicated 2009 - 2011 ESP order, which granted a weighted average cost of capital rate. In November 2012, the IEU and the OCC filed appeals regarding the PUCO decision in the PIRR proceeding. These appeals principally argued that the PUCO should have reduced the deferred fuel balance to reflect the prior “improper” collection of POLR revenues which could reduce OPCo’s net deferred fuel balance up to the full amount. These intervenors’ appeals also argued that carrying costs should be reduced due to an accumulated deferred income tax credit which, as of September 30, 2014, could reduce carrying costs by $28 million including $14 million of unrecognized equity carrying costs. As of September 30, 2014, OPCo’s net deferred fuel balance was $395 million, excluding unrecognized equity carrying costs. 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. This ruling was generally upheld in rehearing orders in January and March 2013.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the 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 OPCo RPM price collected from CRES providers, which includes reserve margins, was approximately $34/MW day through May 2014 and is $150/MW day from June 2014 through May 2015. 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 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and is currently collected at $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 September 30, 2014, OPCo's incurred deferred capacity costs balance of $409 million, including debt carrying costs, was recorded in regulatory assets on the condensed balance sheet.

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 expenses 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 bid process (CBP). In April and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO’s ESP order, including the RSR.

In November 2013, the PUCO issued an order approving OPCo’s CBP with modifications which included the delay of the energy auctions that were originally ordered in the ESP order. As ordered, in February 2014, OPCo conducted an energy-only auction for 10% of the SSO load with delivery beginning April 2014 through May 2015. Also as ordered, in May 2014 and September 2014, OPCo conducted energy-only auctions for an additional 50% of the SSO load with delivery beginning November 2014 through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions 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. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit. In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC. In March 2014, the PUCO approved OPCo’s request to implement riders related to the unbundling of the FAC. In May 2014, an independent auditor was selected by the PUCO and an audit of the recovery of the fixed fuel costs began in June 2014. In October 2014, the independent auditor filed its report for the period August 2012 through May 2015 with the PUCO. If the PUCO ultimately concludes that a portion of the fixed fuel costs are also recovered through OPCo's $188.88 capacity charge, the independent auditor recommends a methodology for calculating a refund of a portion of certain fixed fuel costs. The retail share of these fixed fuel costs is approximately $90 million annually. A hearing related to this matter has not been scheduled. Management believes that no over-recovery of costs has occurred and intends to oppose the findings in the audit report.

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

Proposed June 2015 - May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that includes proposed rate adjustments and the continuation and modification of certain existing riders, including the Distribution Investment Rider (DIR), effective June 2015 through May 2018. The proposal includes a recommended auction schedule, a return on common equity of 10.65% on capital costs for certain riders and estimates an average decrease in rates of 9% over the three-year term of the plan for customers who receive their RPM capacity and energy auction-based generation through OPCo. The proposal also includes a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based purchase power agreement. The PPA would initially be based upon the OVEC contractual entitlement and could, upon further approval, be expanded to include other contracts involving other Ohio legacy generation assets. In May 2014, intervenors and the PUCO staff filed testimony that provided various recommendations including the rejection and/or modification of various riders, including the DIR and the proposed PPA. Hearings at the PUCO in the ESP case were held in June 2014. Additionally, in July 2014, OPCo submitted a separate application to continue the RSR established in the June 2012 - May 2015 ESP to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh until the balance of the capacity deferrals has been collected. In October 2014, OPCo filed a separate application with the PUCO to propose a new PPA for inclusion in the PPA rider, discussed above. The new PPA would include an additional 2,671 MW to be purchased from AGR over the life of the respective generating units.

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

Significantly Excessive Earnings Test Filings

In January 2011, the PUCO issued an order on the 2009 SEET filing. The 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. In September 2013, a proposed second phase of OPCo’s gridSMART® program was filed with the PUCO which included a proposed project to satisfy this PUCO directive. A decision from the PUCO is pending.

In March 2014, the PUCO approved a stipulation agreement between OPCo and the PUCO staff that there were no significantly excessive earnings in 2011 for CSPCo or OPCo. In May 2014, the PUCO approved a stipulation agreement between OPCo and the PUCO staff that there were no significantly excessive earnings in 2012 for OPCo. In May 2014, OPCo filed its 2013 SEET filing with the PUCO. In October 2014, OPCo entered into a stipulation agreement with the PUCO staff in which both parties agree that there were no significantly excessive earnings in 2013 for OPCo. A hearing at the PUCO related to the 2013 SEET filing is scheduled for November 2014.

Management believes its financial statements adequately address the impact of SEET requirements.

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 and associated generation liabilities at net book value to AGR. In June 2013, the IEU filed an appeal with the Supreme Court of Ohio claiming the PUCO order approving the corporate separation was unlawful. A decision from the Supreme Court of Ohio is pending. In December 2013, corporate separation of OPCo's generation assets was completed. If any part of the PUCO order is overturned, it could reduce future net income and cash flows and impact financial condition.

Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates to recover 2012 incremental storm distribution expenses. In April 2014, the PUCO approved a stipulation agreement between OPCo, the PUCO staff and all intervenors, except the Ohio Consumers' Counsel, to recover $55 million over a 12-month period. The agreement also provided that carrying charges using a long-term debt rate will be assessed from April 2013 until recovery begins, but no additional carrying charges will accrue during the actual recovery period. Compliance tariffs were filed with the PUCO and new rates were implemented in April 2014. In May 2014, the PUCO upheld the settlement agreement on rehearing.

2009 Fuel Adjustment Clause Audit

In January 2012, the PUCO issued an order in OPCo's 2009 FAC 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. As a result, OPCo recorded a $30 million net favorable adjustment on the statement of income in 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.

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. In September 2014, the Supreme Court of Ohio upheld the PUCO order. A review of the coal reserve valuation by an outside consultant is still pending. 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.

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 with the use of a weighted average cost of capital (WACC). The PUCO subsequently ruled in the PIRR proceeding that the fuel clause for these years was approved with a WACC carrying cost and that the carrying costs on the balance should not be net of accumulated income taxes. See the 2009 - 2011 ESP section of "Ohio Electric Security Plan Filings" above for a discussion of the PUCO order in the PIRR proceeding. In May 2014, the PUCO issued an order that generally approved OPCo's 2010-2011 fuel costs and rejected the auditor recommendation to adjust the WACC carrying charges related to accumulated deferred income taxes. Additionally, the PUCO requested further review related to an affiliate barging agreement and the modification of certain fuel procurement processes and practices. Further, the order provided for the auditor to address any remaining concerns in their next audit report, as they deem necessary. In July 2014, the PUCO issued an order that denied all requests for rehearing.

2012 and 2013 Fuel Adjustment Clause Audits

In May 2014, the PUCO-selected outside consultant provided its final report related to its 2012 and 2013 FAC audit which included certain unfavorable recommendations related to the FAC recovery for 2012 and 2013. These recommendations are opposed by OPCo. In addition, the PUCO will consider the results of the final audit of the recovery of fixed fuel costs that was issued in October 2014. See the "June 2012 – May 2015 ESP Including Capacity Charge" section above. If the PUCO orders a reduction to the FAC deferral or a refund to customers, it could reduce future net income and cash flows and impact financial condition.

Ormet

Ormet, a large aluminum company, had a contract to purchase power from OPCo through 2018. In February 2013, Ormet filed Chapter 11 bankruptcy proceedings in the state of Delaware and subsequently shut down operations in October 2013. Based upon previous PUCO rulings providing rate assistance to Ormet, the PUCO is expected to permit OPCo to recover unpaid Ormet amounts through the Economic Development Rider (EDR), except where recovery from ratepayers is limited to $20 million related to previously deferred payments from Ormet's October and November 2012 power bills. In February 2014, a stipulation agreement between OPCo and Ormet was filed with the PUCO. The stipulation recommended approval of OPCo's right to fully recover approximately $49 million of foregone revenues through the EDR. Also in February 2014, intervenor comments were filed objecting to full recovery of these foregone revenues. In March 2014, the PUCO issued an order in OPCo's EDR filing allowing OPCo to include $39 million of Ormet-related foregone revenues in the EDR effective April 2014. The order stated that if the stipulation agreement between OPCo and Ormet is subsequently adopted by the PUCO, OPCo could file an application to modify the EDR rate for the remainder of the period requesting recovery of the remaining $10 million of Ormet deferrals which, as of September 30, 2014, is recorded in regulatory assets on the condensed balance sheet. In April 2014, an intervenor filed testimony objecting to $5 million of the remaining foregone revenues. A hearing at the PUCO related to the stipulation agreement was held in May 2014.

In addition, in the 2009 - 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related revenues under a previous interim arrangement (effective from January 2009 through September 2009) and requested that the PUCO prevent OPCo from collecting Ormet-related revenues in the future. 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. The PUCO did not take any action on this request. The intervenors raised this issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement.

To the extent amounts discussed above are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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 September 30, 2014, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions and comments with the PUCO requesting that OPCo refund all collected pre-construction costs to Ohio ratepayers with interest. A hearing at the PUCO is scheduled for December 2014.

Management cannot predict the outcome of this proceeding or what effect, if any, this proceeding could 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

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In October 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo's recovery of AFUDC in addition to limits on its recovery of cash construction costs. Additionally, the PUCT deferred consideration of the requested increase in depreciation expense related to the change in the 2016 retirement date of the Welsh Plant, Unit 2. As of September 30, 2014, the net book value of Welsh Plant, Unit 2 was $85 million, before cost of removal, including materials and supplies inventory and CWIP.

Upon rehearing in January 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. The resulting annual base rate increase is approximately $52 million. In March 2014, the PUCT issued an order related to the January 2014 PUCT ruling and in April 2014, this order became final. In May 2014, intervenors filed appeals of that order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals and filed initial responses.

If certain parts of the PUCT order are overturned or if SWEPCo cannot ultimately recover its Texas jurisdictional share of the Turk Plant investment, including AFUDC, or its retirement-related costs of Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition.

Texas Transmission Cost Recovery Factor Filing

In May 2014, SWEPCo filed an application with the PUCT to implement its transmission cost recovery factor (TCRF) requesting additional annual revenue of $15 million. The TCRF is designed to recover increases from the amounts included in SWEPCo's Texas retail base rates for transmission infrastructure improvement costs and wholesale transmission charges under a tariff approved by the FERC. SWEPCo's application included Turk Plant transmission-related costs. In July 2014, intervenors filed testimony with recommendations that included revenue increases ranging from $1 million to $10 million. Hearings at the PUCT were held in August 2014. In October 2014, the Administrative Law Judge issued a proposal for decision that recommended approval of SWEPCo's application with an increase in annual revenue of $14 million. An order is anticipated in the fourth quarter of 2014. If the PUCT were to disallow any portion of the TCRF, 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. The rates are subject to refund based on the staff review of the cost of service and the prudency review of the Turk Plant. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. If the LPSC orders refunds based upon the pending staff review of the cost of service or the prudence review of the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

2014 Louisiana Formula Rate Filing

In April 2014, SWEPCo filed its annual formula rate plan for test year 2013 with the LPSC. The filing included a $5 million annual increase, which was effective August 2014, subject to refund. SWEPCo also proposed to increase rates by an additional $15 million annually, effective January 2015, for a total annual increase of $20 million. This additional increase reflects the cost of incremental generation to be used to serve Louisiana customers in 2015 due to the expiration of a purchase power agreement attributable to Louisiana customers. These increases are subject to LPSC staff review. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Welsh Plant, Units 1 and 3 - Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet mercury and air toxics standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of September 30, 2014, SWEPCo has incurred costs of $112 million and has contractual construction obligations of $84 million related to these projects. SWEPCo will seek to recover these project costs from customers through filings at the state commissions and FERC. These environmental projects could be adversely impacted by pending carbon emission regulations. As of September 30, 2014, the net book value of Welsh Plant, Units 1 and 3 was $335 million, before cost of removal, including materials and supplies inventory and CWIP. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

APCo Rate Matters

Plant Transfer

APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a cost-of-service basis. West Virginia generally allows for timely recovery of fuel costs through an expanded net energy cost which trues-up to actual expenses. In March 2014, APCo and WPCo filed a request with the WVPSC for approval to transfer at net book value to WPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity presently owned by AGR. In April 2014, APCo and WPCo filed testimony that supported their request and proposed a base rate surcharge of $113 million, to be offset by an equal reduction in the ENEC revenues, to be effective upon the transfer of the Mitchell Plant to WPCo until APCo's West Virginia base rates are updated. See the "2014 West Virginia Base Rate Case" below. In April 2014, AGR and WPCo filed a request with the FERC for approval to transfer AGR’s one-half interest in the Mitchell Plant to WPCo. In June 2014, the FERC issued an order approving this request.

In August 2014, intervenors filed testimony with the WVPSC with recommendations that ranged from transferring only a portion of the one-half interest in the Mitchell Plant to denial of the transfer in its entirety. Additionally, recommendations included reducing the net book value of the one-half interest in the Mitchell Plant and reducing the base rate surcharge to $87 million. Intervenors also expressed concerns related to the amount of liability assumed by WPCo should the transfer be approved. In October 2014, a stipulation agreement between APCo, WPCo, the WVPSC staff and intervenors in the case was filed with the WVPSC. The stipulation agreement recommended approval for WPCo to acquire, at net book value, the one-half interest in the Mitchell Plant, excluding $20 million of certain assets, which will be paid by WPCo and recovered as a regulatory asset over the life of the plant. Additionally, the agreement stated that 82.5% of the costs associated with the acquired interest will be reflected in rates effective from the date of the transfer via a surcharge with an offset in ENEC revenues. The remaining 17.5% of the costs associated with the acquired interest is to be included in rates by January 2020. The agreement also proposed that WPCo share the energy margins for 82.5% of the plant’s output with ratepayers and that WPCo retain all of the energy margins from sales into the wholesale market on the remaining 17.5%, to offset fixed costs associated with this portion, until the remaining portion is approved for inclusion in rates. Management anticipates an order related to the proposed transfer will be issued in the fourth quarter of 2014. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

APCo IGCC Plant

As of September 30, 2014, 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. In March 2014, APCo submitted a request to the Virginia SCC as part of the 2014 Virginia Biennial Base Rate Case to amortize the Virginia jurisdictional share of these costs over two years. In June 2014, APCo submitted a request to the WVPSC as part of the 2014 West Virginia Base Rate Case to amortize the West Virginia jurisdictional share of these costs over five years. In August 2014, intervenors filed testimony with the Virginia SCC that recommended APCo write-off the entire $10 million applicable to the Virginia jurisdiction. Hearings at the Virginia SCC were held in September 2014. A decision is expected in

November 2014. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2013 Virginia Transmission Rate Adjustment Clause (transmission RAC)

In December 2013, APCo filed with the Virginia SCC to increase its transmission RAC revenues by $50 million annually to be effective May 2014. In March 2014, the Virginia SCC issued an order approving a stipulation agreement between APCo and the Virginia SCC staff increasing the transmission RAC revenues by $49 million annually, subject to true-up, effective May 2014. Pursuant to the order, the Virginia SCC staff will audit APCo’s transmission RAC under-recoveries and report its findings and recommendations in testimony in APCo’s next transmission RAC proceeding in 2015.

2014 Virginia Biennial Base Rate Case

In March 2014, APCo filed a biennial generation and distribution base rate case with the Virginia SCC. In accordance with a Virginia statute, APCo did not request a change in base rates as its Virginia retail combined rate of return on common equity for 2012 and 2013 is within the statutory range of the approved return on common equity of 10.9%. The filing included a request to decrease generation depreciation rates, effective February 2015, primarily due to changes in the expected service lives of various generating units and the extended recovery through 2040 of the net book value of certain planned 2015 plant retirements. Additionally, the filing included a request to amortize $7 million annually for two years, beginning February 2015, related to IGCC and other deferred costs.

In August 2014, the Virginia SCC staff and intervenors filed testimony concluding that APCo's adjusted earned rate of return on common equity for 2012 and 2013, reflecting their recommended adjustments, was above the allowed threshold. Recommendations included (a) refunds to customers ranging from $15 million to $22 million, (b) the write-off of certain APCo assets, including IGCC pre-construction costs and previously approved 2009 storm costs, totaling $27 million and (c) $38 million in increased depreciation expense annually, retroactive to January 1, 2014, primarily related to accelerating depreciation on APCo generation assets to be retired in the second quarter of 2015. Hearings at the Virginia SCC were held in September 2014. A decision is expected in November 2014. If any of these costs are not recoverable, or if refunds are ordered, it could reduce future net income and cash flows and impact financial condition.

2014 West Virginia Base Rate Case

In June 2014, APCo filed a request with the WVPSC to increase annual base rates by $156 million, based upon a 10.62% return on common equity, to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates primarily due to the increase in plant investment and changes in the expected service lives of various generating units. The filing also requested recovery of $77 million over five years related to 2012 West Virginia storm costs, IGCC and other deferred costs. In addition to the base rate request, the filing also included a request to implement a rider of approximately $38 million annually to recover vegetation management costs, including a return on capital investment. In October 2014, the WVPSC approved APCo's motion to revise the procedural schedule which included the extension of the intervention period to November 2014 and a delay in the implementation of new rates from April 2015 to May 2015. Hearings at the WVPSC are scheduled for January 2015. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

WPCo Merger with APCo

In December 2011, APCo and WPCo filed an application with the WVPSC requesting authority to merge WPCo into APCo. In December 2012, APCo and WPCo filed merger applications with the Virginia SCC and the FERC. In April 2013, the FERC approved the merger. Also 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. In June 2013, the WVPSC issued an order consolidating the merger case with APCo's plant asset transfer case. In July 2013, the Virginia SCC approved the merger of WPCo into APCo and the transfer of the two-thirds interest in the Amos Plant, Unit 3 to APCo but denied the proposed transfer of the one-half interest in the Mitchell Plant to APCo. In December 2013, the WVPSC issued an order that deferred ruling on the

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merger of WPCo into APCo. The order also directed APCo and WPCo to submit a plan with the WVPSC identifying a course of action to serve the load of WPCo. See the "Plant Transfer" section of APCo Rate Matters. The feasibility of the merger remains under review.

PSO Rate Matters

2014 Oklahoma Base Rate Case

In January 2014, PSO filed a request with the OCC to increase annual base rates by $38 million, based upon a 10.5% return on common equity. This revenue increase includes a proposed increase in depreciation rates of $29 million. In addition, the filing proposed recovery of advanced metering costs through a separate rider over a three-year deployment period requesting $7 million of revenues in year one, increasing to $28 million in year three. The filing also proposed expansion of an existing transmission rider currently recovered in base rates to include additional transmission-related costs that are expected to increase over the next several years.

In April and May 2014, testimony was filed by the OCC staff and intervenors with recommendations that included adjustments to annual base rates ranging from an increase of $16 million to a reduction of $22 million, primarily based upon the determination of depreciation rates and a return on common equity between 9.18% and 9.5%. Additionally, the recommendations did not support the advanced metering rider or the expansion of the transmission rider. In May 2014, PSO filed rebuttal testimony that included an updated annual base rate increase request of $42 million to reflect certain updated costs.

In June 2014, a non-unanimous stipulation agreement between PSO, the OCC staff and certain intervenors was filed with the OCC. The parties to the stipulation recommended no overall change to the transmission rider or to annual revenues, other than additional revenues through a separate rider related to advanced metering costs, and that the terms of the stipulation be effective November 2014. The advanced metering rider would provide $7 million of revenues in 2014 and increase to $27 million in 2016. New depreciation rates are recommended for advanced metering investments and existing meters, also to be effective November 2014. Further, the stipulation recommends a return on common equity of 9.85% to be used only in the formula to calculate AFUDC, factoring of customer receivables and for riders with an equity component. Additionally, the stipulation recommends recovery of regulatory assets for 2013 storms and regulatory case expenses. In July 2014, the Attorney General joined in the stipulation agreement. A hearing at the OCC was held in July 2014. An order is anticipated in the fourth quarter of 2014. If the OCC were to disallow any portion of this settlement agreement, 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% and adjusted the authorized annual increase in base rates to $92 million in March 2013. In April 2014, the Indiana Office of Utility Consumer Counselor (OUCC) filed an appeal to the Indiana Supreme Court related to the inclusion of a prepaid pension asset in rate base, which is approximately $7 million in annual revenues. In August 2014, the Indiana Supreme Court denied the appeal filed by the OUCC.

Cook Plant Life Cycle Management Project (LCM Project)

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the LCM Project, which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life (2034 for Unit 1 and 2037 for Unit 2). The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. As of September 30, 2014, I&M has incurred costs of $492 million related to the LCM Project, including AFUDC.

In July 2013, the IURC approved I&M's proposed project with the exception of an estimated $23 million related to certain items that might accommodate a future potential power uprate which the IURC stated I&M could seek recovery of in a subsequent base rate case. I&M will recover approved costs through an LCM rider which will be determined in semi-annual proceedings. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in rates. In May 2014, the IURC issued a final order approving the LCM rider rates that were implemented in January 2014.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project and authorized deferral accounting for costs incurred related to the approved projects effective January 2013 until these costs are included in rates. In February 2013, intervenors filed appeals 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. In October 2014, the Michigan Court of Appeals issued an order that affirmed the MPSC decision in part, but reversed the portion of the MPSC decision related to certain costs. The order indicated that I&M could recover those costs in a future Michigan base case if they can show that the costs were reasonable and prudent.

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.

Tanners Creek Plant

In 2011, I&M announced that it would retire Tanners Creek Plant, Units 1-3 by June 2015 to comply with proposed environmental regulations. In September 2013, I&M announced that Tanners Creek Plant, Unit 4 would also be retired in mid-2015 rather than being converted from coal to natural gas. I&M is currently recovering depreciation and a return on the net book value of the Tanners Creek Plant in base rates and plans to seek recovery of all of the plant's retirement related costs in its next Indiana and Michigan base rate cases.

In December 2013, I&M filed an application with the MPSC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and the Tanners Creek Plant due to the retirement of the Tanners Creek Plant in 2015. Upon the retirement of the Tanners Creek Plant, I&M proposed that, for purposes of determining its depreciation rates, the net book value of the Tanners Creek Plant be recovered over the remaining life of the Rockport Plant.

In September 2014, a settlement agreement was approved by the MPSC that included the authorization for I&M to implement revised depreciation rates for Rockport Plant, Unit 1, effective upon the retirement date of the Tanners Creek Plant. Upon implementation of the revised depreciation rates, I&M is authorized to reduce customer rates through a credit rider until the revised rates for Rockport Plant, Unit 1 are included in base rates.

Transmission, Distribution and Storage System Improvement Charge (TDSIC)

In October 2014, I&M filed petitions with the IURC for approval of a TDSIC Rider and approval of I&M's seven-year TDSIC Plan, from 2015 through 2021, for eligible transmission, distribution and storage system improvements. The initial estimated cost of the capital improvements and associated operation and maintenance expenses included in the TDSIC Plan of $787 million will be updated annually. The TDSIC Plan included distribution investments specific to the Indiana jurisdiction. The TDSIC Rider will allow the periodic adjustment of I&M's rates to provide for timely recovery of 80% of approved TDSIC Plan costs. I&M will defer the remaining 20% of approved TDSIC Plan costs to be recovered in I&M's next general rate case. I&M is not seeking a rate adjustment in this proceeding but is seeking approval of a TDSIC Rider rate adjustment mechanism for subsequent proceedings. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

5. 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 2013 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 and OPCo

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 revolving credit facilities totaling $3.5 billion, under which up to $1.2 billion may be issued as letters of credit. As of September 30, 2014, the maximum future payments for letters of credit issued under the revolving credit facilities were as follows:

Company	Amount (in thousands)	Maturity
I&M	$150	March 2015
OPCo	4,200	June 2015

The Registrant Subsidiaries have $307 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $310 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 2016 to March 2017
I&M	77,000	77,886	March 2015

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 completed in 2010, 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 September 30, 2014, SWEPCo has collected approximately $63 million through a rider for final mine closure and reclamation costs, of which $16 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $47 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 September 30, 2014, 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 September 30, 2014, 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	$3,852
I&M	2,792
OPCo	4,549
PSO	1,812
SWEPCo	2,668

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 $12 million and $14 million for I&M and SWEPCo, respectively, for the remaining railcars as of September 30, 2014.

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 83% 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 $9 million and $10 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

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 generation 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 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. In September 2014, I&M recorded an accrual for remediation at certain additional sites in Michigan. As of September 30, 2014, I&M's accrual for all of these sites is approximately $17 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 sites or changes in the scope of remediation. 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 generation 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.

OPERATIONAL CONTINGENCIES

Rockport Plant Litigation – Affecting I&M

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. AEGCo's and I&M's motion to dismiss the case, filed in October 2013, is pending. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Wage and Hours Lawsuit – Affecting PSO

In August 2013, PSO received an amended complaint filed in the U.S. District Court for the Northern District of Oklahoma by 36 current and former line and warehouse employees alleging that they have been denied overtime pay in violation of the Fair Labor Standards Act. Plaintiffs claim that they are entitled to overtime pay for "on call" time.

They allege that restrictions placed on them during on call hours are burdensome enough that they are entitled to compensation for these hours as hours worked. Plaintiffs also filed a motion to conditionally certify this action as a class action, claiming there are an additional 70 individuals similarly situated to plaintiffs. Plaintiffs seek damages in the amount of unpaid overtime over a three-year period and liquidated damages in the same amount.

In March 2014, the federal court granted plaintiffs' motion to conditionally certify the action as a class action. Notice was given to all potential class members and an additional 43 individuals opted in to the class, bringing the plaintiff class to 79 current and former employees. Management will continue to defend the case. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Gavin Landfill Litigation – Affecting OPCo

In August 2014, a complaint was filed in the Mason County, West Virginia Circuit Court against AEP, AEPSC, OPCo and an individual supervisor alleging wrongful death and personal injury/illness claims arising out of purported exposure to coal combustion by-product waste at the Gavin Plant landfill. The lawsuit was filed on behalf of 77 plaintiffs, consisting of 39 current and former contractors of the landfill and 38 family members of those contractors. Eleven of the family members are pursuing personal injury/illness claims and the remainder are pursuing loss of consortium claims. The plaintiffs seek compensatory and punitive damages, as well as medical monitoring. In September 2014, management filed a motion to dismiss the complaint, contending the case should be filed in Ohio. That motion is pending. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

6. DISPOSITION AND IMPAIRMENTS

DISPOSITION

2013

Conesville Coal Preparation Facility – Affecting OPCo

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

IMPAIRMENTS

2013

Turk Plant – Affecting SWEPCo

In the third quarter of 2013, SWEPCo recorded a pretax write-off of $111 million in Asset Impairments and Other Related Charges on the statement of income related to AFUDC on the Turk Plant that was included in the Texas capital cost cap. See the "2012 Texas Base Rate Case" section of Note 4.

Muskingum River Plant, Unit 5 – Affecting OPCo

In May 2013, the U.S. District Court for the Southern District of Ohio approved a modification to the consent decree, which was initially entered into in 2007, requiring certain types of pollution control equipment to be installed at certain AEP plants, including OPCo’s 600 MW Muskingum River Plant, Unit 5 (MR5) coal-fired generation plant. Under the modification to the consent decree, OPCo has the option to cease burning coal and retire MR5 in 2015 or to cease burning coal in 2015 and complete a natural gas refueling project no later than June 2017. In the second quarter of 2013, based on the approval of the modified consent decree and changes in other market factors, management re-evaluated potential courses of action with respect to the planned operation of MR5 and concluded that completion of a refueling project, which would have extended the useful life of MR5, is remote. As a result, management completed an impairment analysis and concluded that MR5 was impaired. Under a market-based value approach, using level 3 unobservable inputs, management determined that the fair value of this generating unit was zero based on the lack of installed environmental control equipment and the nature and condition of this generating unit. In the second quarter of 2013, OPCo recorded a pretax impairment of $154 million in Asset Impairments and Other Related Charges on the statement of income which includes a $6 million pretax impairment of related material and supplies inventory. Management will retire the plant in 2015.

7. 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 and nine months ended September 30, 2014 and 2013:

APCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$1,759	$1,543	$362	$641
Interest Cost	7,406	6,916	3,197	3,363
Expected Return on Plan Assets	(8,482)	(9,260)	(4,634)	(4,537)
Amortization of Prior Service Cost (Credit)	49	49	(2,512)	(2,512)
Amortization of Net Actuarial Loss	4,149	6,256	1,145	3,063
Net Periodic Benefit Cost (Credit)	$4,881	$5,504	$(2,442)	$18

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$5,277	$4,628	$1,086	$1,924
Interest Cost	22,218	20,747	9,591	10,090
Expected Return on Plan Assets	(25,445)	(27,780)	(13,900)	(13,610)
Amortization of Prior Service Cost (Credit)	148	148	(7,537)	(7,537)
Amortization of Net Actuarial Loss	12,445	18,769	3,436	9,187
Net Periodic Benefit Cost (Credit)	$14,643	$16,512	$(7,324)	$54

I&M

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$2,517	$2,183	$486	$804
Interest Cost	6,573	6,025	1,909	2,056
Expected Return on Plan Assets	(7,749)	(8,206)	(3,363)	(3,295)
Amortization of Prior Service Cost (Credit)	49	49	(2,355)	(2,356)
Amortization of Net Actuarial Loss	3,647	5,422	592	1,882
Net Periodic Benefit Cost (Credit)	$5,037	$5,473	$(2,731)	$(909)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$7,551	$6,551	$1,460	$2,414
Interest Cost	19,720	18,075	5,728	6,166
Expected Return on Plan Assets	(23,245)	(24,619)	(10,090)	(9,887)
Amortization of Prior Service Cost (Credit)	146	146	(7,066)	(7,066)
Amortization of Net Actuarial Loss	10,939	16,266	1,776	5,645
Net Periodic Benefit Cost (Credit)	$15,111	$16,419	$(8,192)	$(2,728)

OPCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$1,285	$2,362	$256	$1,028
Interest Cost	5,527	10,268	1,900	4,100
Expected Return on Plan Assets	(6,607)	(15,103)	(3,379)	(6,221)
Amortization of Prior Service Cost (Credit)	40	71	(1,731)	(3,219)
Amortization of Net Actuarial Loss	3,105	9,287	595	3,761
Net Periodic Benefit Cost (Credit)	$3,350	$6,885	$(2,359)	$(551)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$3,855	$7,107	$769	$3,627
Interest Cost	16,579	30,852	5,701	12,994
Expected Return on Plan Assets	(19,820)	(45,386)	(10,139)	(18,698)
Amortization of Prior Service Cost (Credit)	118	212	(5,192)	(9,680)

Amortization of Net Actuarial Loss	9,316	27,905	1,785	11,843
Net Periodic Benefit Cost (Credit)	$10,048	$20,690	$(7,076)	$86

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PSO

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$1,301	$1,391	$209	$343
Interest Cost	3,015	2,748	893	948
Expected Return on Plan Assets	(3,651)	(3,919)	(1,575)	(1,522)
Amortization of Prior Service Cost (Credit)	74	75	(1,072)	(1,072)
Amortization of Net Actuarial Loss	1,689	2,461	278	869
Net Periodic Benefit Cost (Credit)	$2,428	$2,756	$(1,267)	$(434)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$3,905	$4,172	$629	$1,029
Interest Cost	9,043	8,245	2,680	2,844
Expected Return on Plan Assets	(10,953)	(11,756)	(4,725)	(4,566)
Amortization of Prior Service Cost (Credit)	222	223	(3,217)	(3,217)
Amortization of Net Actuarial Loss	5,065	7,383	832	2,607
Net Periodic Benefit Cost (Credit)	$7,282	$8,267	$(3,801)	$(1,303)

SWEPCo

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$1,655	$1,752	$253	$424
Interest Cost	3,163	2,864	998	1,075
Expected Return on Plan Assets	(3,857)	(4,126)	(1,754)	(1,720)
Amortization of Prior Service Cost (Credit)	87	87	(1,289)	(1,289)
Amortization of Net Actuarial Loss	1,762	2,553	309	982
Net Periodic Benefit Cost (Credit)	$2,810	$3,130	$(1,483)	$(528)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$4,964	$5,258	$759	$1,270
Interest Cost	9,488	8,591	2,994	3,226
Expected Return on Plan Assets	(11,571)	(12,381)	(5,262)	(5,160)
Amortization of Prior Service Cost (Credit)	262	262	(3,867)	(3,867)

Amortization of Net Actuarial Loss	5,285	7,660	926	2,946
Net Periodic Benefit Cost (Credit)	$8,428	$9,390	$(4,450)	$(1,585)

8. BUSINESS SEGMENTS

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business, except OPCo, an electricity transmission and distribution business starting in 2014. 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.

9. 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, natural gas, 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 extent, heating oil, gasoline 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.

The following tables represent the gross notional volume of the Registrant Subsidiaries' outstanding derivative contracts as of September 30, 2014 and December 31, 2013:

Notional Volume of Derivative Instruments
September 30, 2014

Primary Risk Exposure	Unit of Measure	APCo	I&M	OPCo	PSO	SWEPCo
		(in thousands)				
Commodity:						
Power	MWhs	50,109	36,076	23,709	6,486	7,918
Coal	Tons	465	889	—	250	542
Natural Gas	MMBtus	811	550	—	—	—
Heating Oil and Gasoline	Gallons	990	474	1,007	558	636
Interest Rate	USD	$6,894	$4,676	$—	$—	$—

Notional Volume of Derivative Instruments
December 31, 2013

Primary Risk Exposure	Unit of Measure	APCo	I&M	OPCo	PSO	SWEPCo
		(in thousands)				
Commodity:						
Power	MWhs	48,995	33,231	34,843	13,469	17,057
Coal	Tons	31	3,389	—	1,013	1,692
Natural Gas	MMBtus	2,477	1,680	—	—	—
Heating Oil and Gasoline	Gallons	1,089	521	1,108	614	699
Interest Rate	USD	$12,720	$8,627	$—	$—	$—

Fair Value Hedging Strategies

AEPSC, 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

AEPSC, on behalf of the Registrant Subsidiaries, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power and natural gas ("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. Cash flow hedge accounting for these derivative contracts was discontinued effective March 31, 2014. During the three and nine months ended September 30, 2013, the Registrant Subsidiaries designated financial heating oil and gasoline derivatives as cash flow hedges. For disclosure purposes, these contracts were included with other hedging activities as “Commodity” as of December 31, 2013. In March 2014, these contracts were grouped as "Commodity" with other risk management activities. 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 September 30, 2014 and December 31, 2013 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:

	September 30, 2014		December 31, 2013	
Company	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
	(in thousands)			
APCo	$441	$261	$—	$2,993

I&M	154	151	—	2,030
OPCo	—	248	—	—
PSO	—	141	—	1
SWEPCo	—	160	—	3

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The following tables represent the gross fair value of the Registrant Subsidiaries' derivative activity on the condensed balance sheets as of September 30, 2014 and December 31, 2013:

APCo

Fair Value of Derivative Instruments
September 30, 2014

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$31,542	$—	$—	$31,542	$(9,723)	$21,819
Long-term Risk Management Assets	7,937	—	—	7,937	(1,436)	6,501
Total Assets	39,479	—	—	39,479	(11,159)	28,320
Current Risk Management Liabilities	16,086	—	—	16,086	(9,715)	6,371
Long-term Risk Management Liabilities	4,557	—	—	4,557	(1,264)	3,293
Total Liabilities	20,643	—	—	20,643	(10,979)	9,664
Total MTM Derivative Contract Net Assets (Liabilities)	$18,836	$—	$—	$18,836	$(180)	$18,656

APCo

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$46,431	$389	$—	$46,820	$(25,649)	$21,171

Long-term Risk Management Assets	20,948	—	—	20,948	(4,000)	16,948
Total Assets	67,379	389	—	67,768	(29,649)	38,119
Current Risk Management Liabilities	37,010	313	—	37,323	(28,431)	8,892
Long-term Risk Management Liabilities	14,452	—	—	14,452	(4,211)	10,241
Total Liabilities	51,462	313	—	51,775	(32,642)	19,133
Total MTM Derivative Contract Net Assets (Liabilities)	$15,917	$76	$—	$15,993	$2,993	$18,986

(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.

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I&M

Fair Value of Derivative Instruments
September 30, 2014

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$23,289	$—	$—	$23,289	$(6,959)	$16,330
Long-term Risk Management Assets	5,383	—	—	5,383	(974)	4,409
Total Assets	28,672	—	—	28,672	(7,933)	20,739
Current Risk Management Liabilities	10,705	—	—	10,705	(7,080)	3,625
Long-term Risk Management Liabilities	2,882	—	—	2,882	(850)	2,032
Total Liabilities	13,587	—	—	13,587	(7,930)	5,657
Total MTM Derivative Contract Net Assets (Liabilities)	$15,085	$—	$—	$15,085	$(3)	$15,082

I&M

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$33,229	$234	$—	$33,463	$(18,075)	$15,388
Long-term Risk Management Assets	14,208	—	—	14,208	(2,713)	11,495
Total Assets	47,437	234	—	47,671	(20,788)	26,883

Current Risk Management Liabilities	26,779	212	—	26,991	(19,962)	7,029
Long-term Risk Management Liabilities	9,802	—	—	9,802	(2,856)	6,946
Total Liabilities	36,581	212	—	36,793	(22,818)	13,975
Total MTM Derivative Contract Net Assets (Liabilities)	$10,856	$22	$—	$10,878	$2,030	$12,908

(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.

OPCo

Fair Value of Derivative Instruments
September 30, 2014

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$7,889	$—	$—	$7,889	$28	$7,917
Long-term Risk Management Assets	—	—	—	—	5	5
Total Assets	7,889	—	—	7,889	33	7,922
Current Risk Management Liabilities	180	—	—	180	(180)	—
Long-term Risk Management Liabilities	35	—	—	35	(35)	—
Total Liabilities	215	—	—	215	(215)	—
Total MTM Derivative Contract Net Assets (Liabilities)	$7,674	$—	$—	$7,674	$248	$7,922

OPCo

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$3,269	$162	$—	$3,431	$(349)	$3,082
Long-term Risk Management Assets	—	—	—	—	—	—
Total Assets	3,269	162	—	3,431	(349)	3,082

Current Risk Management Liabilities	349	—	—	349	(349)	—
Long-term Risk Management Liabilities	—	—	—	—	—	—
Total Liabilities	349	—	—	349	(349)	—
Total MTM Derivative Contract Net Assets (Liabilities)	$2,920	$162	$—	$3,082	$—	$3,082

(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.

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PSO

Fair Value of Derivative Instruments
September 30, 2014

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$595	$—	$—	$595	$(32)	$563
Long-term Risk Management Assets	—	—	—	—	3	3
Total Assets	595	—	—	595	(29)	566
Current Risk Management Liabilities	152	—	—	152	(152)	—
Long-term Risk Management Liabilities	18	—	—	18	(18)	—
Total Liabilities	170	—	—	170	(170)	—
Total MTM Derivative Contract Net Assets (Liabilities)	$425	$—	$—	$425	$141	$566

PSO

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$1,078	$84	$—	$1,162	$5	$1,167
Long-term Risk Management Assets	—	—	—	—	—	—
Total Assets	1,078	84	—	1,162	5	1,167

Current Risk Management Liabilities	81	—	—	81	4	85
Long-term Risk Management Liabilities	—	—	—	—	—	—
Total Liabilities	81	—	—	81	4	85
Total MTM Derivative Contract Net Assets (Liabilities)	$997	$84	$—	$1,081	$1	$1,082

(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.

SWEPCo

Fair Value of Derivative Instruments
September 30, 2014

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$468	$—	$—	$468	$(60)	$408
Long-term Risk Management Assets	—	—	—	—	3	3
Total Assets	468	—	—	468	(57)	411
Current Risk Management Liabilities	327	—	—	327	(196)	131
Long-term Risk Management Liabilities	21	—	—	21	(21)	—
Total Liabilities	348	—	—	348	(217)	131
Total MTM Derivative Contract Net Assets (Liabilities)	$120	$—	$—	$120	$160	$280

SWEPCo

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
	(in thousands)					
Current Risk Management Assets	$1,233	$97	$—	$1,330	$(151)	$1,179
Long-term Risk Management Assets	—	—	—	—	—	—
Total Assets	1,233	97	—	1,330	(151)	1,179

Current Risk Management Liabilities	154	—	—	154	(154)	—
Long-term Risk Management Liabilities	—	—	—	—	—	—
Total Liabilities	154	—	—	154	(154)	—
Total MTM Derivative Contract Net Assets (Liabilities)	$1,079	$97	$—	$1,176	$3	$1,179

(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 and nine months ended September 30, 2014 and 2013:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended September 30, 2014

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Electric Generation, Transmission and Distribution Revenues	$1,231	$2,988	$41	$45	$74
Sales to AEP Affiliates	—	(196)	—	196	—
Regulatory Assets (a)	(2,571)	(471)	(852)	(109)	(284)
Regulatory Liabilities (a)	(3,606)	(176)	(1,555)	120	(180)
Total Gain (Loss) on Risk Management Contracts	$(4,946)	$2,145	$(2,366)	$252	$(390)

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended September 30, 2013

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Electric Generation, Transmission and Distribution Revenues	$746	$1,742	$66	$25	$51
Regulatory Assets (a)	—	(1,349)	—	960	421
Regulatory Liabilities (a)	(950)	(2,347)	(1,264)	18	130
Total Gain (Loss) on Risk Management Contracts	$(204)	$(1,954)	$(1,198)	$1,003	$602

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Nine Months Ended September 30, 2014

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Electric Generation, Transmission and Distribution Revenues	$7,262	$10,467	$97	$172	$18
Sales to AEP Affiliates	—	(717)	—	717	—
Regulatory Assets (a)	(2,567)	(471)	(215)	(119)	(285)
Regulatory Liabilities (a)	42,444	26,934	39,311	(69)	119
Total Gain (Loss) on Risk Management Contracts	$47,139	$36,213	$39,193	$701	$(148)

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Nine Months Ended September 30, 2013

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Electric Generation, Transmission and Distribution Revenues	$1,619	$9,586	$3,599	$241	$381
Regulatory Assets (a)	—	(1,648)	(5,158)	3,162	427

Regulatory Liabilities (a)	(1,160)	(9,209)	1,557	18	157
Total Gain (Loss) on Risk Management Contracts	$459	$(1,271)	$(2)	$3,421	$965

(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 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 and nine months ended September 30, 2014 and 2013, 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 and nine months ended September 30, 2014, APCo and I&M designated power, coal and natural gas derivatives as cash flow hedges. During the three and nine months ended September 30, 2013, 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 and nine months ended September 30, 2013, the Registrant Subsidiaries designated heating oil and gasoline derivatives as cash flow hedges. Cash flow hedge accounting for these derivative contracts was discontinued effective March 31, 2014.

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 and nine months ended September 30, 2014 and 2013, I&M 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 and nine months ended September 30, 2014 and 2013, the Registrant Subsidiaries did not designate any foreign currency derivatives as cash flow hedges.

During the three and nine months ended September 30, 2014 and 2013, 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 and nine months ended September 30, 2014 and 2013, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets as of September 30, 2014 and December 31, 2013 were:

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Condensed Balance Sheets
September 30, 2014

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
	(in thousands)					
APCo	$—	$—	$—	$—	$—	$3,766
I&M	—	—	—	—	—	(14,745)
OPCo	—	—	—	—	—	5,945
PSO	—	—	—	—	—	5,132
SWEPCo	—	—	—	—	—	(11,602)

	Expected to be Reclassified to Net Income During the Next Twelve Months		
Company	Commodity	Interest Rate and Foreign Currency	Maximum Term for Exposure to Variability of Future Cash Flows
	(in thousands)		(in months)
APCo	$—	$(38)	0
I&M	—	(1,140)	0
OPCo	—	1,372	0
PSO	—	759	0
SWEPCo	—	(2,132)	0

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

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
	(in thousands)					
APCo	$363	$—	$287	$—	$94	$3,090
I&M	216	—	194	—	46	(15,976)
OPCo	162	—	—	—	105	6,974
PSO	84	—	—	—	57	5,701
SWEPCo	97	—	—	—	66	(13,304)

	Expected to be Reclassified to Net Income During the Next Twelve Months	
Company	Commodity	Interest Rate and Foreign Currency

	(in thousands)	
APCo	$94	$(806)
I&M	46	(1,568)
OPCo	105	1,363
PSO	57	759
SWEPCo	66	(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, these agreements 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 September 30, 2014 and December 31, 2013:

	September 30, 2014		
Company	Liabilities for Derivative Contracts with Credit Downgrade Triggers	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
	(in thousands)		
APCo	$ 157	$ 2,721	$ 2,697
I&M	107	1,842	1,829
OPCo	—	—	—
PSO	49	4,123	—
SWEPCo	60	176	—

	December 31, 2013		
Company	Liabilities for Derivative Contracts with Credit Downgrade Triggers	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
	(in thousands)		
APCo	$ 575	$ 2,747	$ 2,539

I&M	390	1,863	1,722
OPCo	349	—	—
PSO	—	2,930	410
SWEPCo	—	713	519

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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 September 30, 2014 and December 31, 2013:

Company	September 30, 2014 Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements (in thousands)	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
APCo	$7,769	$—	$7,219
I&M	5,269	—	4,897
OPCo	—	—	—
PSO	—	—	—
SWEPCo	—	—	—

Company	December 31, 2013 Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements (in thousands)	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
APCo	$19,648	$—	$18,568
I&M	13,326	—	12,594
OPCo	—	—	—
PSO	3	—	3
SWEPCo	3	—	3

10. 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 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. The AEP System's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, 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, Restricted Cash for Securitized Funding 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 September 30, 2014 and December 31, 2013 are summarized in the following table:

	September 30, 2014		December 31, 2013	
Company	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
APCo	$3,980,107	$4,642,320	$4,194,357	$4,587,079
I&M	1,948,931	2,166,248	2,039,016	2,174,891
OPCo	2,297,004	2,688,426	2,735,175	3,007,191
PSO	1,041,056	1,205,687	999,810	1,111,149
SWEPCo	2,140,348	2,401,635	2,043,332	2,214,730

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 September 30, 2014 and December 31, 2013:

	September 30, 2014			December 31, 2013		
	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	$13,188	$—	$ —	$18,804	$—	$ —
Fixed Income Securities:						
United States Government	609,441	35,262	(2,941)	608,875	26,114	(3,824)
Corporate Debt	46,409	3,630	(1,046)	36,782	2,450	(1,123)
State and Local Government	285,496	1,309	(215)	254,638	748	(370)
Subtotal Fixed Income Securities	941,346	40,201	(4,202)	900,295	29,312	(5,317)
Equity Securities - Domestic	1,065,714	544,995	(79,329)	1,012,511	505,538	(81,677)
Spent Nuclear Fuel and Decommissioning Trusts	$2,020,248	$585,196	$ (83,531)	$1,931,610	$534,850	$ (86,994)

The following table provides the securities activity within the decommissioning and SNF trusts for the three and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Proceeds from Investment Sales	$263,738	$249,314	$746,272	$635,256
Purchases of Investments	280,626	263,958	789,461	675,727
Gross Realized Gains on Investment Sales	7,617	4,113	24,835	16,011
Gross Realized Losses on Investment Sales	1,739	2,147	10,447	11,859

The adjusted cost of fixed income securities was $901 million and $872 million as of September 30, 2014 and December 31, 2013, respectively. The adjusted cost of equity securities was $521 million and $506 million as of September 30, 2014 and December 31, 2013, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2014 was as follows:

	Fair Value of Fixed Income Securities
	(in thousands)
Within 1 year	$103,652
1 year – 5 years	376,783
5 years – 10 years	198,064
After 10 years	262,847
Total	$941,346

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 September 30, 2014 and December 31, 2013. 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
September 30, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Restricted Cash for Securitized Funding (a)	$8,071	$—	$—	$45	$8,116
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	191	20,498	17,784	(10,153)	28,320
Total Assets:	$8,262	$20,498	$17,784	$(10,108)	$36,436
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$186	$17,679	$1,772	$(9,973)	$9,664

APCo

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

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Restricted Cash for Securitized Funding (a)	$2,714	$—	$—	$36	$2,750
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	827	54,448	12,097	(29,616)	37,756
Cash Flow Hedges:					
Commodity Hedges (b)	—	389	—	(26)	363
Total Risk Management Assets	827	54,837	12,097	(29,642)	38,119
Total Assets:	$3,541	$54,837	$12,097	$(29,606)	$40,869
Liabilities:					
Risk Management Liabilities					

Risk Management Commodity Contracts (b) (c)	$700	$49,220	$1,535	$(32,609)	$18,846
Cash Flow Hedges:					
Commodity Hedges (b)	—	313	—	(26)	287
Total Risk Management Liabilities	$700	$49,533	$1,535	$(32,635)	$19,133

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	$129	$14,516	$13,344	$(7,250)	$20,739
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (d)	4,470	—	—	8,718	13,188
Fixed Income Securities:					
United States Government	—	609,441	—	—	609,441
Corporate Debt	—	46,409	—	—	46,409
State and Local Government	—	285,496	—	—	285,496
Subtotal Fixed Income Securities	—	941,346	—	—	941,346
Equity Securities - Domestic (e)	1,065,714	—	—	—	1,065,714
Total Spent Nuclear Fuel and Decommissioning Trusts	1,070,184	941,346	—	8,718	2,020,248
Total Assets	$1,070,313	$955,862	$13,344	$1,468	$2,040,987
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$125	$11,577	$1,202	$(7,247)	$5,657

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I&M

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

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	$561	$38,667	$8,205	$(20,766)	$26,667
Cash Flow Hedges:					
Commodity Hedges (b)	—	234	—	(18)	216
Total Risk Management Assets	561	38,901	8,205	(20,784)	26,883
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (d)	8,082	—	—	10,722	18,804
Fixed Income Securities:					
United States Government	—	608,875	—	—	608,875
Corporate Debt	—	36,782	—	—	36,782
State and Local Government	—	254,638	—	—	254,638
Subtotal Fixed Income Securities	—	900,295	—	—	900,295
Equity Securities - Domestic (e)	1,012,511	—	—	—	1,012,511
Total Spent Nuclear Fuel and Decommissioning Trusts	1,020,593	900,295	—	10,722	1,931,610
Total Assets	$1,021,154	$939,196	$8,205	$(10,062)	$1,958,493
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$475	$35,061	$1,041	$(22,796)	$13,781
Cash Flow Hedges:					
Commodity Hedges (b)	—	212	—	(18)	194
Total Risk Management Liabilities	$475	$35,273	$1,041	$(22,814)	$13,975

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Restricted Cash for Securitized Funding (a)	$17,734	$—	$—	$22	$17,756
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	—	—	7,889	33	7,922
Total Assets	$17,734	$—	$7,889	$55	$25,678
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$—	$215	$—	$(215)	$—

OPCo

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

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Restricted Cash for Securitized Funding (a)	$19,387	$—	$—	$12	$19,399
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	—	—	3,269	(349)	2,920
Cash Flow Hedges:					
Commodity Hedges (b)	—	162	—	—	162
Total Risk Management Assets	—	162	3,269	(349)	3,082
Total Assets	$19,387	$162	$3,269	$(337)	$22,481
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$—	$—	$349	$(349)	$—

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	$—	$232	$383	$(49)	$566
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$—	$141	$49	$(190)	$—

PSO

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

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	$—	$1,078	$—	$5	$1,083
Cash Flow Hedges:					
Commodity Hedges (b)	—	84	—	—	84
Total Risk Management Assets	$—	$1,162	$—	$5	$1,167
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$—	$81	$—	$4	$85

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2014

Assets:	Level 1 (in thousands)	Level 2	Level 3	Other	Total
Cash and Cash Equivalents (a)	$21,611	$—	$—	$2,375	$23,986
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	—	3	468	(60)	411
Total Assets	$21,611	$3	$468	$2,315	$24,397
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$—	$291	$60	$(220)	$131

SWEPCo

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

Assets:	Level 1 (in thousands)	Level 2	Level 3	Other	Total
Cash and Cash Equivalents (a)	$15,871	$—	$—	$1,370	$17,241
Risk Management Assets					
Risk Management Commodity Contracts (b) (c)	—	1,233	—	(151)	1,082
Cash Flow Hedges:					
Commodity Hedges (b)	—	97	—	—	97
Total Risk Management Assets	—	1,330	—	(151)	1,179
Total Assets	$15,871	$1,330	$—	$1,219	$18,420
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (b) (c)	$—	$154	$—	$(154)	$—

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 amounts primarily represent investment in money market funds.
(b) 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.”
(c) Substantially comprised of power contracts for APCo, I&M and OPCo and coal contracts for PSO and SWEPCo.
(d) Amounts in “Other” column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.
(e) Amounts represent publicly traded equity securities and equity-based mutual funds.

There were no transfers between Level 1 and Level 2 during the three and nine months ended September 30, 2014 and 2013.

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 for the Registrant Subsidiaries:

Three Months Ended September 30, 2014	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Balance as of June 30, 2014	$18,394	$12,923	$9,300	$(3)	$(3)
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(5,629)	(3,832)	(3,639)	2	2
Purchases, Issuances and Settlements (c)	(1,560)	(1,244)	(637)	—	—
Transfers into Level 3 (d) (e)	(6)	(4)	—	—	—
Transfers out of Level 3 (e) (f)	(30)	(20)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	4,843	4,319	2,865	335	409
Balance as of September 30, 2014	$16,012	$12,142	$7,889	$334	$408

Three Months Ended September 30, 2013	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Balance as of June 30, 2013	$12,976	$8,967	$18,347	$—	$—
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(1,200)	(754)	(1,616)	—	—
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	—	—	(89)	—	—
Purchases, Issuances and Settlements (c)	(1,058)	(757)	(1,504)	—	—
Transfers into Level 3 (d) (e)	13	9	18	—	—
Transfers out of Level 3 (e) (f)	(15)	(11)	(21)	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	195	(275)	(164)	—	—
Balance as of September 30, 2013	$10,911	$7,179	$14,971	$—	$—

Nine Months Ended September 30, 2014	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
Balance as of December 31, 2013	$10,562	$7,164	$2,920	$—	$—
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	29,467	18,438	30,768	—	—
Purchases, Issuances and Settlements (c)	(32,213)	(20,301)	(33,688)	—	—
Transfers into Level 3 (d) (e)	(3,648)	(2,475)	—	—	—
Transfers out of Level 3 (e) (f)	(32)	(22)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	11,876	9,338	7,889	334	408
Balance as of September 30, 2014	$16,012	$12,142	$7,889	$334	$408

Nine Months Ended September 30, 2013	APCo	I&M	OPCo	PSO	SWEPCo
	(in thousands)				
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)	(3,450)	(2,386)	(4,879)	—	—
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	—	—	351	—	—
Purchases, Issuances and Settlements (c)	1,712	1,213	2,463	—	—
Transfers into Level 3 (d) (e)	961	661	1,353	—	—
Transfers out of Level 3 (e) (f)	(925)	(637)	(1,303)	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	1,634	787	1,557	—	—
Balance as of September 30, 2013	$10,911	$7,179	$14,971	$—	$—

(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 for the Registrant Subsidiaries as of September 30, 2014 and December 31, 2013:

Significant Unobservable Inputs
September 30, 2014
APCo

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$4,873	$1,615	Discounted Cash Flow	Forward Market Price	$12.55	$80.70	$41.68
FTRs	12,911	157	Discounted Cash Flow	Forward Market Price	(14.63)	15.47	1.38
Total	$17,784	$1,772					

Significant Unobservable Inputs
December 31, 2013
APCo

	Fair Value		Valuation	Significant Unobservable	Forward Price Range	
	Assets	Liabilities	Technique	Input (a)	Low	High
	(in thousands)					
Energy Contracts	$9,359	$960			$13.04	$80.50

			Discounted Cash Flow	Forward Market Price		
FTRs	2,738	575	Discounted Cash Flow	Forward Market Price	(5.10	) 10.44
Total	$12,097	$1,535				

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Significant Unobservable Inputs
September 30, 2014
I&M

	Fair Value Assets	Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$3,496	$1,095	Discounted Cash Flow	Forward Market Price	$12.55	$80.70	$41.68
FTRs	9,848	107	Discounted Cash Flow	Forward Market Price	(14.63)	15.47	1.38
Total	$13,344	$1,202					

Significant Unobservable Inputs
December 31, 2013
I&M

	Fair Value Assets	Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	High
	(in thousands)					
Energy Contracts	$6,348	$651	Discounted Cash Flow	Forward Market Price	$13.04	$80.50
FTRs	1,857	390	Discounted Cash Flow	Forward Market Price	(5.10)	10.44
Total	$8,205	$1,041				

Significant Unobservable Inputs
September 30, 2014
OPCo

	Fair Value Assets	Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	High	Weighted Average
	(in thousands)						
FTRs	$7,889	$—	Discounted Cash Flow	Forward Market Price	$(14.63)	$15.47	$1.38

Significant Unobservable Inputs
December 31, 2013
OPCo

	Fair Value Assets	Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	High
	(in thousands)					
FTRs	$3,269	$349	Discounted Cash Flow	Forward Market Price	$(5.10)	$10.44

Significant Unobservable Inputs
September 30, 2014
PSO

	Fair Value		Valuation	Significant	Forward Price Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
FTRs	$383	$49	Discounted Cash Flow	Forward Market Price	$(14.63)	$15.47	$1.38

Significant Unobservable Inputs
September 30, 2014
SWEPCo

	Fair Value		Valuation	Significant	Forward Price Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
FTRs	$468	$60	Discounted Cash Flow	Forward Market Price	$(14.63)	$15.47	$1.38

(a) Represents market prices in dollars per MWh.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs for the Registrant Subsidiaries as of September 30, 2014:

Sensitivity of Fair Value Measurements
September 30, 2014

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

11. 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 and was completed in the second quarter of 2013. The IRS examination of years 2011 and 2012 started in April 2014. 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. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. The Registrant Subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2009.

12. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2014 are shown in the tables below:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		(in thousands)	(%)	
APCo	Senior Unsecured Notes	$300,000	4.40	2044
I&M	Pollution Control Bonds	100,000	1.75	2018
PSO	Other Long-term Debt	75,000	Variable	2016
SWEPCo	Other Long-term Debt	100,000	Variable	2017

(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.

Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Retirements and Principal Payments:		(in thousands)	(%)	
APCo	Land Note	$24	13.718	2026
APCo	Securitization Bonds	12,678	2.01	2024
APCo	Senior Unsecured Notes	200,000	4.95	2015
APCo	Other Long-term Debt	300,000	Variable	2015
I&M	Notes Payable	29,275	Variable	2017
I&M	Notes Payable	22,332	Variable	2016
I&M	Notes Payable	15,472	Variable	2016
I&M	Notes Payable	10,716	2.12	2016
I&M	Notes Payable	4,402	4.00	2014
I&M	Other Long-term Debt	7,563	Variable	2015
I&M	Other Long-term Debt	790	6.00	2025
I&M	Pollution Control Bonds	100,000	6.25	2014
OPCo	Other Long-term Debt	67	1.149	2028
OPCo	Pollution Control Bonds	39,130	2.875	2014
OPCo	Pollution Control Bonds	79,450	3.25	2014
OPCo	Pollution Control Bonds	60,000	3.875	2014
OPCo	Securitization Bonds	34,936	0.958	2018
OPCo	Senior Unsecured Notes	225,000	4.85	2014
PSO	Other Long-term Debt	310	3.00	2027
PSO	Pollution Control Bonds	33,700	5.25	2014
SWEPCo	Notes Payable	3,250	4.58	2032

In October 2014, APCo remarketed $100 million of 1.625% Pollution Control Bonds due in 2018.

In October 2014, I&M retired $5 million of Notes Payable related to DCC Fuel.

As of September 30, 2014, trustees held on behalf of I&M and OPCo, $40 million and $395 million, respectively, of their reacquired Pollution Control Bonds.

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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 generation plants. Because of their respective ownership of such plants, this reserve applies to APCo and I&M.

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, PSO and SWEPCo 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 AEP's 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 the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of September 30, 2014 and December 31, 2013 are included in Advances to Affiliates and Advances from Affiliates, respectively, 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 nine months ended September 30, 2014 are described in the following table:

Company	Maximum Borrowings from the Utility Money Pool (in thousands)	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of September 30, 2014		Authorized Short-term Borrowing Limit
APCo	$44,215	$542,186	$14,038	$122,105	$70,090		$600,000
I&M	130,128	158,857	59,863	47,695	(82,400	)	500,000
OPCo	120,264	405,350	34,841	82,518	23,745		400,000
PSO	176,950	—	93,679	—	(100,867	)	300,000
SWEPCo	153,503	49,869	82,953	22,408	(6,329	)	350,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Nine Months Ended September 30,	
	2014	2013
Maximum Interest Rate	0.33 %	0.43 %
Minimum Interest Rate	0.24 %	0.28 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the nine months ended September 30, 2014 and 2013 are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Nine Months Ended September 30,		Average Interest Rate for Funds Loaned to the Utility Money Pool for Nine Months Ended September 30,	
Company	2014	2013	2014	2013
APCo	0.26 %	0.33 %	0.28 %	0.34 %
I&M	0.27 %	0.36 %	0.30 %	0.33 %
OPCo	0.27 %	0.34 %	0.29 %	0.32 %
PSO	0.27 %	0.34 %	— %	0.32 %
SWEPCo	0.28 %	0.33 %	0.27 %	0.36 %

Credit Facilities

For a discussion of credit facilities, see “Letters of Credit” section of Note 5.

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.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement was increased in June 2014 from $700 million and expires in June 2016.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement for each Registrant Subsidiary as of September 30, 2014 and December 31, 2013 was as follows:

Company	September 30, 2014	December 31, 2013
	(in thousands)	
APCo	$134,986	$156,599
I&M	136,897	139,257
OPCo	345,545	324,287
PSO	156,781	115,260
SWEPCo	179,687	149,337

The fees paid by the Registrant Subsidiaries to AEP Credit for customer accounts receivable sold were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2014	2013	2014	2013
	(in thousands)			
APCo	$2,166	$1,575	$6,626	$4,590
I&M	2,011	1,762	5,836	4,744
OPCo	7,213	5,076	21,358	14,440
PSO	1,745	1,549	4,417	4,314
SWEPCo	1,890	1,649	5,035	4,413

The Registrant Subsidiaries' proceeds on the sale of receivables to AEP Credit were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2014	2013	2014	2013
	(in thousands)			
APCo	$354,406	$340,438	$1,137,564	$1,081,615
I&M	372,422	384,316	1,132,603	1,097,563
OPCo	668,112	658,829	1,980,764	2,017,746
PSO	398,567	382,167	1,014,320	944,062
SWEPCo	466,828	450,294	1,278,325	1,171,306

13. 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. In addition, the Registrant Subsidiaries have not provided financial or other support to any VIE that was not previously contractually required.

SWEPCo is the primary beneficiary of Sabine. I&M is the primary beneficiary of DCC Fuel. OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding. APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding. In addition, the Registrant Subsidiaries have not provided material financial or other support to any of these entities that was not previously contractually required. SWEPCo holds a significant variable interest in DHLC. Each of the Registrant Subsidiaries hold a significant variable interest in AEPSC. I&M holds a significant variable interest in AEGCo. In 2013, I&M and OPCo each held a significant variable interest in AEGCo.

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 September 30, 2014 and 2013 were $41 million and $41 million, respectively, and for the nine months ended September 30, 2014 and 2013 were $121 million and $125 million, respectively. See the table below for the classification of Sabine's assets and liabilities on SWEPCo'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
September 30, 2014 and December 31, 2013
(in thousands)

	Sabine	
ASSETS	2014	2013
Current Assets	$61,855	$66,478
Net Property, Plant and Equipment	148,098	157,274
Other Noncurrent Assets	51,098	51,211
Total Assets	$261,051	$274,963

LIABILITIES AND EQUITY

Current Liabilities	$30,592	$32,812
Noncurrent Liabilities	230,128	241,673
Equity	331	478
Total Liabilities and Equity	$261,051	$274,963

I&M has nuclear fuel lease agreements with DCC Fuel II LLC, DCC Fuel IV LLC, DCC Fuel V LLC and DCC Fuel VI 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 September 30, 2014 and 2013 were $28 million and $32 million, respectively, and for the nine months ended September 30, 2014 and 2013 were $84 million and $96 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. In October 2013, the lease agreements ended for DCC Fuel LLC and DCC Fuel III LLC. 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
September 30, 2014 and December 31, 2013
(in thousands)

	DCC Fuel	
ASSETS	2014	2013
Current Assets	$68,819	$117,762
Net Property, Plant and Equipment	73,468	156,820
Other Noncurrent Assets	26,843	60,450
Total Assets	$169,130	$335,032
LIABILITIES AND EQUITY		
Current Liabilities	$64,754	$107,815
Noncurrent Liabilities	104,376	227,217
Total Liabilities and Equity	$169,130	$335,032

Ohio Phase-in-Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to phase-in recovery property. Management has concluded that OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding because OPCo has the power to direct the most significant activities of the VIE and OPCo's equity interest could potentially be significant. Therefore, OPCo is required to consolidate Ohio Phase-in-Recovery Funding. The securitized bonds totaled $232 million and $267 million as of September 30, 2014 and December 31, 2013, respectively, and are included in current and long-term debt on the condensed balance sheets. Ohio Phase-in-Recovery Funding has securitized assets of $116 million and $132 million as of September 30, 2014 and December 31, 2013, respectively, which are presented separately on the face of the condensed balance sheets. The phase-in recovery property represents the right to impose and collect Ohio deferred distribution charges from customers receiving electric transmission and distribution service from OPCo under a recovery mechanism approved by the PUCO. In August 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to OPCo or any other AEP entity. OPCo acts as the servicer for Ohio Phase-in-Recovery Funding's securitized assets and remits all related amounts collected from customers to Ohio Phase-in-Recovery Funding for interest and principal payments on the securitization bonds and related costs.

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The balances below represent the assets and liabilities of Ohio Phase-in-Recovery Funding that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

OHIO POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES
September 30, 2014 and December 31, 2013
(in thousands)

	Ohio Phase-In Recovery Funding	
ASSETS	2014	2013
Current Assets	$21,657	$23,198
Other Noncurrent Assets (a)	221,070	251,409
Total Assets	$242,727	$274,607
LIABILITIES AND EQUITY		
Current Liabilities	$46,263	$36,470
Noncurrent Liabilities	195,127	236,800
Equity	1,337	1,337
Total Liabilities and Equity	$242,727	$274,607

(a) Includes an intercompany item eliminated in consolidation as of September 30, 2014 and December 31, 2013 of $102 million and $116 million, respectively.

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. The securitized bonds totaled $368 million and $380 million as of September 30, 2014 and December 31, 2013, respectively, and are included in current and long term debt on the condensed balance sheets. Appalachian Consumer Rate Relief Funding has securitized assets of $356 million and $369 million as of September 30, 2014 and December 31, 2013, respectively, which are presented separately on the face of the condensed balance sheets. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs.

The balances below represent the assets and liabilities of Appalachian Consumer Rate Relief Funding that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES
September 30, 2014 and December 31, 2013
(in thousands)

	Appalachian Consumer Rate Relief Funding	
ASSETS	2014	2013
Current Assets	$10,298	$5,891
Other Noncurrent Assets (a)	363,805	378,029
Total Assets	$374,103	$383,920
LIABILITIES AND EQUITY		
Current Liabilities	$24,238	$14,000
Noncurrent Liabilities	347,963	368,018
Equity	1,902	1,902
Total Liabilities and Equity	$374,103	$383,920

(a) Includes an intercompany item eliminated in consolidation as of September 30, 2014 and December 31, 2013 of $4 million and $4 million, respectively.

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 September 30, 2014 and 2013 were $24 million and $21 million, respectively, and for the nine months ended September 30, 2014 and 2013 were $31 million and $53 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:

	September 30, 2014		December 31, 2013	
	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	3,061	3,061	1,600	1,600
SWEPCo's Guarantee of Debt	—	113,290	—	61,348
Total Investment in DHLC	$10,704	$123,994	$9,243	$70,591

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

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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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2014	2013	2014	2013
	(in thousands)			
APCo	$50,143	$39,779	$154,239	$120,315
I&M	30,613	25,988	92,686	82,192
OPCo	41,212	58,528	120,696	169,949
PSO	24,317	19,535	71,646	57,504
SWEPCo	32,787	28,431	98,528	85,506

The carrying amount and classification of variable interest in AEPSC's accounts payable are as follows:

	September 30, 2014		December 31, 2013	
Company	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in thousands)			
APCo	$15,634	$15,634	$20,191	$20,191
I&M	9,086	9,086	12,864	12,864
OPCo	12,553	12,553	31,425	31,425
PSO	7,636	7,636	10,596	10,596
SWEPCo	8,718	8,718	13,520	13,520

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 has a Unit Power Agreement associated with the Lawrenceburg Generating Station which was assigned by OPCo to AGR effective January 1, 2014. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. I&M is considered to have a significant interest in AEGCo due to these transactions. I&M is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M and KPCo, this financing would be provided by AEP. For additional information regarding AEGCo's lease, see "Rockport Lease" section of Note 12 in the 2013 Annual Report.

Total billings from AEGCo were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2014	2013	2014	2013
	(in thousands)			
I&M	$66,560	$66,114	$202,171	$177,840
OPCo	—	37,255	—	107,876

The carrying amount and classification of variable interest in AEGCo's accounts payable are as follows:

	September 30, 2014		December 31, 2013	
Company	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in thousands)			

I&M	$21,525	$21,525	$23,916	$23,916
OPCo	—	—	12,810	12,810

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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 2013 Annual Report should also be read in conjunction with this report.

EXECUTIVE OVERVIEW

Customer Demand

In comparison to 2013, heating degree days for the nine months ended September 30, 2014 were up 32% in the western region and 20% in the eastern region while cooling degree days were down 7% for the same period in both the eastern and western regions. AEP's weather-normalized retail sales volumes for the third quarter of 2014 increased by 0.1% from their levels for the third quarter of 2013 and increased by 0.4% for the first nine months of 2014 from their levels for the first nine months of 2013. In comparison to 2013, AEP's industrial sales volume increased 1.2% for the three months ended September 30, 2014 and decreased 0.7% for the nine months ended September 30, 2014. The decrease in industrial sales volume is due mainly to the closure of Ormet, a large aluminum company. Excluding Ormet, AEP's nine months ended September 30, 2014 industrial sales volumes increased 3.8% over the nine months ended September 30, 2013.

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 SO_2, NO_x, PM and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, proposals governing the beneficial use and disposal of coal combustion products, proposed clean water rules and renewal permits for certain water discharges that are currently under appeal.

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 CO_2 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 2013 Annual Report. Management will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. 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 September 30, 2014, 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 generating facilities. For the Registrant Subsidiaries, management's current ranges of estimates of environmental investments to comply with these requirements are listed below:

	Through 2020 Estimated Environmental Investment	
Company	Low	High
	(in millions)	
APCo	$310	$360
I&M	370	430
PSO	270	310
SWEPCo	910	1,010

Several proposed regulations issued during 2014, including CO_2 and Clean Water Act, are currently under review and management cannot currently predict the impact these programs may have on future resource plans or the existing generating fleet; however, the costs may be substantial. For APCo, the projected environmental investment above includes the conversion of 470 MWs of coal generation to natural gas capacity. If natural gas conversion is not completed, the units could be closed 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 for each Registrant Subsidiary will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans (SIPs) or federal implementation plans (FIPs) 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 intends 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/AGR	Sporn Plant	600
I&M	Tanners Creek Plant	995
PSO	Northeastern Station, Unit 4	470
SWEPCo	Welsh Plant, Unit 2	528

As of September 30, 2014, the net book value before cost of removal, including related material and supplies inventory and CWIP balances, of the plants in the table above was $700 million.

PSO received Federal EPA approval of the Oklahoma SIP, in February 2014, related to the environmental compliance plan for Northeastern Station, Unit 3.

Volatility in natural gas prices, pending environmental rules and other market factors could also have an adverse impact on the accounting evaluation of the recoverability of the net book values of coal-fired units. For regulated plants that may close early, management is seeking regulatory recovery of remaining net book values. 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 and impact financial condition.

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 the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. The U.S. Court of Appeals for the District of Columbia Circuit issued an order in 2011 staying the effective date of the rule pending judicial review. In 2012, a panel of the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. That decision was appealed to the U.S. Supreme Court, which reversed the decision in part and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit. Nearly all of the states in which the Registrant Subsidiaries' power plants are located are covered by CAIR. See "Cross-State Air Pollution Rule (CSAPR)" section below.

The Federal EPA issued the final maximum achievable control technology (MACT) standards for coal and oil-fired power plants in 2012. See "Mercury and Other Hazardous Air Pollutants (HAPs) Regulation" section below.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how 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 SIPs or, if SIPs are not adequate or are not developed on schedule, through FIPs. The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas. 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 CSAPR trading programs to use those programs in place of source-specific BART for SO_2 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.

In 2009, the Federal EPA issued a final mandatory reporting rule for CO_2 and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for greenhouse gas emissions from new motor vehicles in 2009. The Federal EPA determined that greenhouse gas emissions from stationary sources will be subject to regulation under the CAA beginning January 2011 and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, SIP calls and FIPs. The Federal EPA has proposed to include CO_2 emissions in standards that apply to new electric utility units and will consider whether such standards are appropriate for other source categories in the future. See "CO_2 Regulation" section below.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for PM, SO_2, 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 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in 2012. CSAPR relies on newly-created SO_2 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 is 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 SO_2 and NO_x in addition to the seasonal NO_x program. The annual SO_2 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 2011, the court granted the motions for stay. In 2012, the court issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the CAIR 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 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 petition for further review filed by the Federal EPA and other parties in the U.S. Supreme Court was granted in June 2013. In April 2014, the U.S. Supreme Court issued a decision reversing in part the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanding the case for further proceedings consistent with the opinion. The parties have filed motions to govern further proceedings. The Federal EPA has filed a motion to lift the stay and allow Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. Until the court acts on this motion, CAIR will remain in effect. Separate appeals of the Error Corrections Rule and the further revisions have been filed but no briefing schedules have been established. Management cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 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. Petitions for administrative reconsideration and judicial review were 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. The Federal EPA issued revisions to the new source standards consistent with the proposed rule, except the start-up and shut down provisions in March 2013. The Federal EPA is still considering additional changes to the start-up and shut down provisions. In April 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the April 2012 final rule. Industry and environmental groups have filed petitions for further review in the U.S. Supreme Court.

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. The AEP System obtained a one-year administrative extension for several units to facilitate 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 remains concerned

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about the availability of compliance extensions, the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines and the lack of coordination among the Mercury and Air Toxics Standards schedule and other environmental requirements.

CO_2 Regulation

President Obama issued a memorandum to the Administrator of the Federal EPA directing the agency to develop and issue a new proposal regulating carbon emissions from new electric generating units. The new proposal was issued in September 2013 and requires new large natural gas units to meet 1,000 pounds of CO_2 per MWh of electricity generated and small natural gas units to meet 1,100 pounds of CO_2 per MWh. New coal-fired units are required to meet the 1,100 pounds of CO_2 per MWh limit, with the option to meet the tighter limits if they choose to average emissions over multiple years. The proposal was published in the Federal Register in January 2014.

The Federal EPA was also directed to develop and issue a separate proposal regulating carbon emissions from modified and reconstructed electric generating units (EGUs) and to issue guidelines for existing EGUs before June 2014, to finalize those standards by June 2015 and to require states to submit revisions to their implementation plans including such standards no later than June 2016. The President directed the Federal EPA, in developing this proposal, to directly engage states, leaders in the power sector, labor leaders and other stakeholders, to tailor the regulations to reduce costs, to develop market-based instruments and allow regulatory flexibilities and “assure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power.” The guidelines use a “portfolio” approach to reducing emissions from existing sources that includes efficiency improvements at coal plants, displacing coal-fired generation with increased utilization of natural gas combined cycle units, expanding renewable resources and increasing customer energy efficiency. The Federal EPA issued proposed guidelines establishing state goals for CO_2 emissions from existing EGUs and comments are due December 1, 2014. The Federal EPA also issued proposed regulations governing emissions of CO_2 from modified and reconstructed EGUs in June 2014 and comments are due in October 2014. The standards for modified and reconstructed units include several options, including use of historic baselines or energy efficiency audits to establish source-specific CO_2 emission rates or to limit CO_2 emissions to no more than 1,900 pounds per MWh at larger coal units and 2,100 pounds per MWh at smaller coal units. These proposed regulations are currently under review. Management cannot currently predict the impact these programs may have on future resource plans or the existing generating fleet, but the costs may be substantial.

In 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 CO_2 emissions from new motor vehicles and its plan to phase in regulation of CO_2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit denied a petition for rehearing. In June 2014, the U.S. Supreme Court determined that the Federal EPA was not compelled to regulate CO_2 emissions from stationary sources under the Title V or PSD programs as a result of its adoption of the motor vehicle standards, but that sources otherwise required to obtain a PSD permit may be required to perform a Best Available Control Technology analysis for CO_2 emissions if they exceed a reasonable level. The Federal EPA must undertake additional rulemaking to implement the court’s decision and establish an appropriate level.

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 and also FGD gypsum generated at some coal-fired plants. 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 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. In 2013, the Federal EPA also issued a notice of data availability requesting comments on a narrow set of issues.

Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. The Federal EPA opposed the petition and sought additional time to coordinate the issuance of a final rule with the issuance of new effluent limitations under the Clean Water Act (CWA) for utility facilities. In October 2013, the U.S. District Court for the District of Columbia issued a final order partially ruling in favor of the Federal EPA for dismissal of two counts, ruling in favor of the environmental organizations on one count and directing the Federal EPA to provide the court with a proposed schedule for completion of the rulemaking. The court established December 19, 2014 as the Federal EPA's deadline for publication of the rule.

In February 2014, the Federal EPA completed a risk evaluation of the beneficial uses of coal fly ash in concrete and FGD gypsum in wallboard and concluded that the Federal EPA supports these beneficial uses. 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. In 2012, the Federal EPA issued additional Notices of Data Availability and requested public comments. The final rule was released by the Federal EPA in May 2014 and affects all plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with the impingement standard and requires site-specific studies to determine appropriate entrainment compliance measures at facilities withdrawing more than 125 million gallons per day. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats. Facilities with existing closed cycle recirculating cooling systems, as defined in the rule, are not expected to require any technology changes. Facilities subject to both the impingement standard and site-specific entrainment studies will typically be given at least three years to conduct and submit the results of those studies to the permit agency. Compliance timeframes will then be established by the permit agency through each facility's National Pollutant Discharge Elimination System (NPDES) permit for installation of any required technology changes, as those permits are renewed over the next five to eight years. Petitions for review of the final rule have been filed by industry and environmental groups and have been consolidated in the U.S. Court of Appeals for the Fourth Circuit.

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 September 2015. 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 continues to 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 submitted detailed comments to the Federal EPA in September 2013 and participated in comments filed by various organizations of which the AEP System companies are members.

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In April 2014, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a proposed rule to clarify the scope of the regulatory definition of “waters of the United States” in light of recent U.S. Supreme Court cases and published the proposed rule in the Federal Register. The CWA provides for federal jurisdiction over “navigable waters” defined as “the waters of the United States.” This proposed jurisdictional definition will apply to all CWA programs, potentially impacting generation, transmission and distribution permitting and compliance requirements. Among those programs are: permits for wastewater and storm water discharges, permits for impacts to wetlands and water bodies and oil spill prevention planning. Management agrees that clarity and efficiency in the permitting process is needed. Management is concerned that the proposed rule introduces new concepts and could subject more of the Registrant Subsidiaries’ operations to CWA jurisdiction, thereby increasing the time and complexity of permitting. Management will continue to evaluate the rule and its financial impact on the AEP System. Management plans to submit comments and also participate in the preparation of comments to be filed by various organizations of which the AEP System companies are members. Comments are due in October 2014.

Climate Change

National public policy makers and regulators in the nine 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 actively participating 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 CO_2 emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing requirements of the CAA.

Several states have adopted programs that directly regulate CO_2 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.

Future federal and state legislation or regulations that mandate limits on the emission of CO_2 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 2013 Form 10-K under the headings entitled “Environmental and Other Matters” and “Combined Management’s Narrative Discussion and Analysis of Registrant Subsidiaries.”

ACCOUNTING PRONOUNCEMENTS

Pronouncements Effective in the Future

The FASB issued ASU 2014-08 “Presentation of Financial Statements and Property, Plant and Equipment” changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component meets the criteria to be classified as held-for-sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014 with early adoption permitted.

The FASB issued ASU 2014-09 "Revenue from Contracts with Customers" clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2017.

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 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.

CONTROLS AND PROCEDURES

During the third quarter of 2014, 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 September 30, 2014, 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 third quarter of 2014 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 5 incorporated herein by reference.

Item 1A. Risk Factors

The Annual Report on Form 10-K for the year ended December 31, 2013 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 2013 Annual Report on Form 10-K.

GENERAL RISKS OF OUR REGULATED OPERATIONS

Ohio may require us to refund revenue that we have collected. – Affecting AEP and OPCo

Ohio law requires that the PUCO determine on an annual basis if rate adjustments included in prior orders resulted in significantly excessive earnings. If the PUCO determines there were significantly excessive earnings, the excess amount could be returned to customers. In May 2014, OPCo filed its 2013 significantly excessive earnings filing with the PUCO. In October 2014, OPCo entered into a stipulation agreement with the PUCO staff in which both parties agree that there were no significantly excessive earnings in 2013 for OPCo. Management believes its financial statements adequately address the impact of SEET requirements. If the PUCO determines that OPCo’s earnings were significantly excessive, and requires OPCo to return a portion of its revenues to customers, it could reduce future net income and cash flows and impact financial condition.

Request for rate recovery in Louisiana may not be approved in its entirety. – Affecting AEP and SWEPCo

In April 2014, SWEPCo filed its annual formula rate plan for test year 2013 with the LPSC. The filing included a $5 million annual increase, which was effective August 2014, subject to refund. SWEPCo also proposed to increase rates by an additional $15 million annually, effective January 2015, for a total annual increase of $20 million. These increases are subject to LPSC review. If SWEPCo cannot ultimately recover its costs that are the subject of this request, it could reduce future net income and cash flows and impact financial condition.

Request for rate and other recovery in Virginia for generation and distribution service may not be approved in its entirety. – Affecting AEP and APCo

In March 2014, APCo filed a biennial generation and distribution base rate case with the Virginia SCC. APCo did not request an increase in base rates as its Virginia retail combined rate of return on common equity for 2012 and 2013 is within the statutory range of the approved return on common equity of 10.9%. The filing included a request to decrease generation depreciation rates, effective February 2015, primarily due to the changes in the expected service life of certain plants. Additionally, the filing included a request to amortize $7 million annually for two years, beginning February 2015, related to certain deferred costs. If the Virginia SCC denies all or part of the requested rate and other recovery, or if refunds are ordered, it could reduce future net income and cash flows and impact financial condition.

Ohio may require a reduction in our 2012 and 2013 fuel deferrals. – Affecting AEP and OPCo

In May 2014, the PUCO-selected outside consultant provided its final report related to their 2012 and 2013 FAC audit which included certain unfavorable recommendations related to the FAC recovery for 2012 and 2013. In addition to this report, the PUCO will also consider the results of the pending audit of the recovery of fixed fuel costs. In May 2014, an independent auditor was selected by the PUCO and an audit of the recovery of the fixed fuel costs began in June 2014. In October 2014, the independent auditor filed its report for the period August 2012 through May 2015 with the PUCO. If the PUCO ultimately concludes that a portion of the fixed fuel costs are recovered through OPCo's $188.88 capacity charge, the independent auditor recommends a methodology for calculating a refund of a portion of certain fixed fuel costs. The retail share of these fixed fuel costs is approximately $90 million annually. If the PUCO does not permit full recovery of OPCo's FAC deferral, it could reduce future net income and cash flows and impact financial condition.

Request for rate and other recovery in West Virginia may not be approved in its entirety. – Affecting AEP and APCo

In June 2014, APCo filed a request with the WVPSC to increase annual base rates by $181 million, based upon a 10.62% return on common equity, to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates primarily due to the increase in plant investment and changes in the expected service lives of various generating units. The filing also requested recovery of $89 million over five years related to 2012 West Virginia storm costs, IGCC and other deferred costs. In addition to the base rate request, the filing also included a request to implement a rider of approximately $45 million annually to recover total vegetation management costs. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Kentucky may require a reduction in our 2013 and 2014 fuel deferrals. – Affecting AEP and KPCo

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. An intervenor has requested and received a procedural schedule to determine if the allocation of fuel costs has been applied appropriately. In October 2014, intervenors filed testimony that recommended the KPSC direct KPCo to modify its fuel allocation methodology and order a refund to customers of approximately $13 million, plus carrying charges at a weighted average cost of capital, related to the period January 1, 2014 through April 30, 2014. If the KPSC directs KPCo to modify its fuel allocation methodology, it could affect the allocation of costs for all periods beginning January 2014, and if any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

RISKS RELATED TO OWNING AND OPERATING GENERATION ASSETS AND SELLING POWER

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

The U.S. Congress has not taken any significant steps toward enacting legislation to control CO_2 emissions since 2009. In December 2009, the Federal EPA issued a final endangerment finding under the CAA regarding emissions from motor vehicles. The Federal EPA also finalized CO_2 emission standards for new motor vehicles, and issued a rule that implements a permitting program for new and modified stationary sources of CO_2 emissions in a phased manner. Several groups have filed challenges to the endangerment finding and the Federal EPA's subsequent rulemakings. The Supreme Court agreed to review whether the Federal EPA reasonably determined that establishing standards for new motor vehicles automatically triggered regulation of stationary sources through the prevention of significant deterioration and Title V permitting programs, and determined that the Federal EPA was neither compelled nor authorized to automatically regulate stationary sources of CO_2 emissions under these programs, but that the Federal EPA could establish requirements for best available control technology reviews of CO_2 emissions for sources otherwise required to obtain a Prevention of Significant Deterioration permit if their emissions exceed a reasonable level. The Federal EPA must undertake additional rulemaking to establish such requirements and a reasonable level.

In 2012, the Federal EPA issued a proposed CO_2 emissions standard for new power generation sources. In response to the comments submitted on this proposed rule, and in accordance with a directive from the President, EPA withdrew the April 2012 proposed rule and has issued a new proposal. This proposed rule includes separate, but equivalent, standards for natural gas and coal-fired units, based on the use of partial carbon capture and storage at coal units. In June 2014, the Federal EPA issued standards for modified and reconstructed units, and a guideline for the development of state implementation plans that would reduce carbon emissions from existing utility units. The guidelines for existing sources include aggressive emission rate goals that are composed of a number of measures. Management believes some policy approaches being discussed would have significant and widespread negative consequences for the national economy and major U.S. industrial enterprises, including AEP and our customers.

If CO_2 and other emission standards are imposed, the standards could require significant increases in capital expenditures and operating costs and could impact the dates for retirement of our coal-fired units. We typically recover costs of complying with new requirements such as the potential CO_2 and other greenhouse gases emission standards from customers through regulated rates in regulated jurisdictions. For our sales of energy based on market rate authority, however, there is no such recovery mechanism. Failure to recover these costs, should they arise, could reduce our future net income and cash flows and possibly harm our 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 AGR and KPCo, through their 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 and Conner Run under the Mine Act for the quarter ended September 30, 2014.

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: October 23, 2014