AMERICAN ELECTRIC POWER CO INC
Form 10-Q
October 22, 2015

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, 2015
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 22, 2015
American Electric Power Company, Inc.	490,817,402 ($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
INDEX OF QUARTERLY REPORTS ON FORM 10-Q
September 30, 2015

Part II. OTHER INFORMATION

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 Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
AEPRO	AEP River Operations, LLC.
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.
APSC	Arkansas Public Service Commission.
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.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel IV LLC, DCC Fuel VI LLC, DCC Fuel VII and DCC Fuel VIII 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.
IMT	International Marine Terminals, an equity method investment of AEPRO.
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.
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.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, I&M, OPCo, PSO and SWEPCo.

Term	Meaning
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.
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.
TRA	Tennessee Regulatory Authority.
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 2014 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 or cost of capital to finance new capital projects and refinance existing debt.
- 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 competition, including competition for retail customers.
- Weather conditions, including storms and drought conditions, and our ability to recover significant storm restoration costs.
- The cost of fuel and its transportation 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 fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build 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 and capacity auction returns.
Changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP.
The market for generation in Ohio and PJM and our ability to recover investments in our Ohio generation assets.
Our ability to successfully and profitably manage our competitive generation assets, including our evaluation of strategic alternatives for these assets as some of the alternatives could result in a loss.

- 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 2014 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

Our weather-normalized retail sales volumes for the third quarter of 2015 increased by 0.9% from the third quarter of 2014. Our third quarter 2015 industrial sales increased 0.7% compared to the third quarter of 2014 primarily due to increased sales to customers in oil and gas related sectors. Weather-normalized commercial and residential sales increased 1.3% and 0.8% in the third quarter of 2015, respectively, from the third quarter of 2014.
Our weather-normalized retail sales volumes for the nine months ended September 30, 2015 increased 0.1% compared to the nine months ended September 30, 2014. Industrial sales volumes increased 0.8% compared to 2014, while weather-normalized commercial sales increased by 1.0%. Weather-normalized residential sales decreased 1.1% in comparison to the first nine months of 2014.

Merchant Fleet Alternatives

AEP is evaluating strategic alternatives for its merchant generation fleet, included in the Generation & Marketing segment, which primarily includes AGR’s generation fleet and AEGCo's Lawrenceburg Plant, both of which operate in PJM as well as a purchased power agreement related to a 54.7% interest in the Oklaunion Plant which operates in ERCOT. Potential alternatives may include, but are not limited to, continued ownership of the merchant generation fleet, executing a purchased power agreement with a regulated affiliate for certain merchant generation units in Ohio, a spin-off of the merchant generation fleet or a sale of the merchant generation fleet. We have not made a decision regarding the potential alternatives, nor have we set a specific time frame for a decision. Certain of these alternatives could result in a loss which could reduce future net income and cash flow and impact financial condition.

Disposition of AEP River Operations

In October 2015, we signed an agreement to sell our commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. The sale of AEPRO is subject to regulatory approval including federal clearance pursuant to the Hart-Scott-Rodino Antitrust Improvements Act of 1976. Upon close of the sale, the nonaffiliated party will acquire AEPRO by purchasing all of the common stock of AEP Resources, Inc., the parent company of AEPRO. The nonaffiliated party will assume certain assets and liabilities of AEPRO, excluding the equity method investment in International Marine Terminals (IMT) which is a bulk commodity transfer facility jointly owned with Kinder Morgan L.P. "C", pension and benefit assets and liabilities and debt obligations. We expect to net approximately $400 million in cash after taxes, debt retirement and transaction fees. The sale is expected to close in the fourth quarter of 2015. An after tax gain ranging from approximately $100 million to $150 million is expected from the sale subject to working capital and other adjustments.

AEPRO's assets and liabilities have been recorded as Assets Held for Sale and Liabilities Held for Sale, respectively, on our condensed balance sheets as of September 30, 2015 and December 31, 2014. The results of operations of AEPRO have been classified as Discontinued Operations on our condensed statements of income. See "AEPRO (AEP River Operations Segment)" section of Note 6 for additional information.

Merchant Portion of Turk Plant

SWEPCo constructed the Turk Plant, a base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012 and is included in the Vertically Integrated Utilities segment. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the facility.

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The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant (approximately 20%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to an Arkansas Supreme Court decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This share of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the wholesale market. Approximately 80% of the Turk Plant investment is recovered under cost-based rate recovery in Texas, Louisiana, and through SWEPCo's wholesale customers under FERC-based rates.

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

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. In June 2015, the Supreme Court of Ohio issued a decision that reversed, as requested by OPCo, the PUCO order on the carrying cost rate issue and dismissed the appeal filed by the IEU. In June 2015, the IEU filed a motion for reconsideration with the Supreme Court of Ohio related to the accumulated deferred income tax credit. In September 2015, the Supreme Court of Ohio denied the IEU's request for reconsideration and in October 2015 this matter was remanded back to the PUCO for reinstatement of the WACC rate.

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 established 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 $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, which has scheduled oral arguments for the fourth quarter of 2015.

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 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. In April 2015, the PUCO issued an order that approved, with modifications, OPCo's July 2014 application to collect the unrecovered portion of the deferred capacity costs. In May 2015, the PUCO granted intervenors requests for rehearing. As of September 30, 2015, OPCo's net deferred capacity costs balance was $392 million, including debt carrying costs. Through September 30, 2015, OPCo has collected $183 million in deferred capacity costs, and related carrying charges.

In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. 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.

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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 October 2014, the independent auditor, selected by the PUCO, 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/MW day capacity charge, the independent auditor has recommended 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 disagrees with the findings in the audit report.

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

June 2015 - May 2018 ESP Including PPA Application

In December 2013, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments and the continuation and modification of certain existing riders effective June 2015 through May 2018. The proposal also included 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 PPA.

In February 2015, the PUCO issued an order approving OPCo's ESP application, subject to certain modifications, with a return on common equity of 10.2% on capital costs for certain riders. The order included (a) approval of the Distribution Investment Rider (DIR) with modified rate caps established by the PUCO, (b) authorization to establish a zero rate rider for OPCo's proposed PPA, (c) the option for OPCo to reapply in a future proceeding with a more detailed PPA proposal and (d) a directive to continue to pursue the transfer of the OVEC contractual entitlement to AGR or to otherwise divest of its interest in OVEC. In May 2015, the PUCO issued an order on rehearing that increased the DIR rate caps and deferred ruling on all requests for rehearing related to the establishment of the PPA rider. In July 2015, the PUCO granted OPCo's and various intervenors' requests for rehearing related to the May 2015 order. In July 2015, intervenors filed appeals with the Supreme Court of Ohio that included opposition to the authorization of a PPA rider and the modifications to a transmission rider.

In October 2014, OPCo filed a separate application with the PUCO to propose a new extended PPA with AGR for 2,671 MW for inclusion in the PPA rider. In May 2015, OPCo filed an amended PPA application between OPCo and AGR that (a) included OPCo's OVEC contractual entitlement, (b) addressed the PPA requirements set forth in the PUCO's February 2015 order, (c) updated supporting testimony to reflect a current analysis of the PPA proposal and (d) included the 2,671 MW to be available for capacity, energy and ancillary services, produced by AGR over the lives of the respective generating units. A hearing at the PUCO related to the PPA commenced in September 2015. In October 2015, the PUCO staff submitted testimony that opposed the PPA application as currently proposed but concluded that, with changes, a PPA could be in the public interest.

If OPCo is ultimately not permitted to fully collect all components of its ESP rates, 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 was 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 SWEPCo's 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. In December 2014, the LPSC approved a settlement agreement related to the staff review of the cost of service. The settlement agreement reduced the requested revenue increase by $3 million, primarily due to the timing of both the allowed recovery of certain existing regulatory assets and the establishment of a regulatory asset for certain previously expensed costs. If the LPSC orders refunds based upon the pending prudence review of the Turk Plant investment, it could reduce future net income and cash flows and impact financial condition. See the “2012 Louisiana Formula Rate Filing” section of Note 4.

2015 Oklahoma Base Rate Case

In July 2015, PSO filed a request with the OCC to increase annual revenues by $137 million to recover costs associated with its environmental compliance plan and to recover investments and other costs that have increased since the last base rate case. The annual increase consists of (a) a base rate increase of $89 million, which includes $48 million in increased depreciation expense that reflects, among other things, recovery through June 2026 of Northeastern Plant, Units 3 and 4, (b) a rider or base rate increase of $44 million to recover costs for the environmental controls being installed on Northeastern Plant, Unit 3 and the Comanche Plant and (c) a request to include environmental consumable costs in the FAC, estimated to be $4 million annually. The rate increase includes a proposed return on common equity of 10.5% to be effective in January 2016, except for the $44 million for environmental investments, which is effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls go in service.

In addition, the filing also notified the OCC that the incremental replacement capacity and energy costs, including the first year effects of new PPAs, estimated to be $35 million, will be incurred related to the environmental compliance plan due to the closure of Northeastern Plant, Unit 4 in April 2016, which would be recovered through the FAC.

In October 2015, testimony was filed by OCC staff and intervenors with recommendations that included increases to base rates and/or the proposed environmental rider ranging from $10 million to $31 million, based upon returns on common equity ranging from 8.75% to 9.3%, and increases to depreciation expense ranging from $23 million to $46 million. Additionally, recommendations by certain intervenors included (a) no recovery of PSO’s investment in Northeastern Plant, Unit 3 environmental controls, (b) no recovery of the plant balances at the time the units are retired in 2016 and 2026, (c) denial of returns on the book values after the retirement dates, or to be set at only the cost of debt, and (d) the disallowance of the capacity costs associated with the PPAs. Additionally, certain intervenors did not support an increase in depreciation expense for the Northeastern Plant, Units 3 and 4 to permit cost recovery by Unit 3’s 2026 retirement date as the proposals called for no change in existing cost recovery by 2040. Hearings at the OCC are scheduled for December 2015. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “2015 Oklahoma Base Rate Case" section of Note 4.

2015 Kingsport Base Rate Case

In September 2015, KGPCo filed a request with the TRA to increase base rates by $12 million annually based upon a proposed return on common equity of 10.66% with the new rates expected to be implemented by July 2016. See the

“2015 Kingsport Base Rate Case" section of Note 4.

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New Virginia Legislation Affecting Biennial Reviews

In February 2015, amendments to Virginia law governing the regulation of investor-owned electric utilities were enacted. Under the amended Virginia law, APCo’s existing generation and distribution base rates are frozen until after the Virginia SCC rules on APCo’s next biennial review, which APCo will file in March 2020 for the 2018 and 2019 test years. These amendments also preclude the Virginia SCC from performing biennial reviews of APCo’s earnings for the years 2014 through 2017. APCo's financial statements adequately address the impact of these amendments. The new law provides that APCo will absorb its Virginia jurisdictional share of incremental generation and distribution costs incurred during 2014 through 2017 that are associated with severe weather events and/or natural disasters and costs associated with potential asset impairments related to new carbon emission guidelines issued by the Federal EPA.

Kentucky Fuel Adjustment Clause Review

In January 2015, the KPSC issued an order disallowing certain FAC costs during the period of January 2014 through May 2015 while KPCo owned and operated both Big Sandy Plant, Unit 2 and its one-half interest in the Mitchell Plant. As a result of this order, KPCo recorded a regulatory disallowance of $36 million in December 2014. In February 2015, KPCo filed an appeal of this order with the Franklin County Circuit Court. In September 2015, the Franklin County Circuit Court issued an order that dismissed all appeals filed related to this FAC review, as agreed to by the parties to the stipulation agreement in the "2014 Kentucky Base Rate Case" discussed in Note 4.

PJM Capacity Market

AGR is required to offer all of its available generation capacity in the PJM Reliability Pricing Model (RPM) auction, which is conducted three years in advance of the delivery year.

Through May 2015, AGR provided generation capacity to OPCo for both switched and non-switched OPCo generation customers. For switched customers, OPCo paid AGR $188.88/MW day for capacity. For non-switched OPCo generation customers, OPCo paid 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. As of June 2015, AGR's generation resources are compensated through the PJM capacity auction. Shown below are the RPM results through the June 2017 through May 2018 period:

PJM Auction Period	PJM 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

In June 2015, FERC approved PJM’s proposal to create a new Capacity Performance (CP) product, intended to improve generator performance and reliability during emergency events by allowing higher offers into the RPM auction and imposing greater charges for non-performance during emergency events. PJM will procure approximately 80% CP and 20% Base Capacity for the June 2018 through May 2019 and June 2019 through May 2020 periods, while transitioning to 100% CP with the June 2020 through May 2021 period. FERC also approved transition incremental auctions to procure CP for the June 2016 through May 2017 and June 2017 through May 2018 periods.

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In the third quarter of 2015, PJM conducted the two transition auctions. The transition auctions allowed generators, including AGR, to re-offer cleared capacity that qualifies as CP. Shown below are the results of the two transition auctions:

PJM Auction Period	Capacity Performance Transition Incremental Auction Price (per MW day)
June 2016 through May 2017	$134.00
June 2017 through May 2018	151.50

AGR cleared 7,169MW at $134/MW-day for the June 2016 through May 2017 period, replacing the original auction clearing price of $59.37/MW-day. AGR cleared 6,495MW for the June 2017 through May 2018 period at $151.50/MW-day, replacing the original auction clearing price of $120/MW-day.

In August 2015, PJM held its first Base Residual Auction implementing CP rules for the June 2018 through May 2019 period. PJM cleared approximately 81% of the capacity for the June 2018 through May 2019 period as CP and 19% as Base Capacity. AGR cleared 7,209 MW at $164.77/MW-day. Shown below are the results for the June 2018 through May 2019 period:

PJM Auction Period	Capacity Performance Auction Price (per MW day)	Base Capacity Auction Price (per MW day)
June 2018 through May 2019	$164.77	$150.00

The FERC order exempted Fixed Resource Requirement entities, including APCo, I&M, KPCo and WPCo, from the CP rules through the June 2018 through May 2019 period. In July 2015, AEP filed a request seeking rehearing of the FERC order approving CP, and will continue to advocate for further improvements through the PJM stakeholder process.

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 2024 for Welsh Plant, Units 1 and 3 will cost approximately $700 million, excluding AFUDC. As of September 30, 2015, SWEPCo has incurred costs of $303 million, including AFUDC, and has remaining contractual construction obligations of $62 million related to these projects. SWEPCo will seek recovery of these project costs from customers through filings at the state commissions and the FERC. See "Mercury and Other Hazardous Air Pollutants (HAPs) Regulation" and "Climate Change, CO_2 Regulation and Energy Policy" sections of "Environmental Issues" below. As of September 30, 2015, the net book value of Welsh Plant, Units 1 and 3 was $529 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

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 2014 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. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs' claims. Several claims remain, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. In June 2015, AEGCo and I&M filed a motion for partial judgment on the claims seeking dismissal of the breach of participation agreement claim as well as any claim for indemnification of costs associated with this case. Plaintiffs subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. We will continue to defend against the remaining 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, rules governing the beneficial use and disposal of coal combustion products, proposed and final 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 2014 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.

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, 2015, the AEP System had a total generating capacity of approximately 32,100 MWs, of which approximately 18,200 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 $2.8 billion to $3.3 billion through 2020. These amounts include investments to convert some of our coal generation to natural gas.

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.

In May 2015, we retired the following plants or units of plants:

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
Total		5,535

As of September 30, 2015, the net book value of the AGR units listed above was zero. The book value of the regulated plants in the table above has been approved for recovery, except for $147 million which is pending regulatory approval.

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

Company	Plant Name and Unit	Generating Capacity (in MWs)
PSO	Northeastern Station, Unit 4	470
SWEPCo	Welsh Plant, Unit 2	528
Total		998

As of September 30, 2015, the net book value of the PSO and SWEPCo units listed above before cost of removal, including related materials and supplies inventory and CWIP balances, was $177 million. 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 Northeastern Station, Unit 4 and Welsh Plant, Unit 2, we are seeking regulatory recovery of remaining net book values.

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. We expect to begin conversion of Big Sandy Plant, Unit 1 in the fourth quarter of 2015. We expect to begin operations as a natural gas unit in the second quarter of 2016. As of September 30, 2015, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of Big Sandy Plant, Unit 1 was $110 million.

We are also in the process of obtaining permits following the Virginia SCC and WVPSC's approval for the conversion of APCo's 470 MW Clinch River Plant, Units 1 and 2 to natural gas. In September 2015, we retired the coal-related assets of Clinch River Plant, Units 1 and 2. Of the coal-related assets retired in September 2015, $14 million is pending regulatory approval. We expect to begin operations as a natural gas unit in the first quarter of 2016 for Clinch River

Plant, Unit 1 and the second quarter of 2016 for Clinch River Plant, Unit 2. As of September 30, 2015, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of Clinch River Plant, Units 1 and 2 was $148 million.

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. 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 and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit ordered CSAPR to take effect on January 1, 2015 while the remand proceeding was still pending. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the Federal EPA. All of the states in which our power plants are located are covered by CSAPR. 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) will 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 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. In March 2012, the Federal EPA disapproved certain portions of the Arkansas regional haze SIP. In April 2015, the Federal EPA published a proposed FIP to replace the disapproved portions, including revised BART determinations for the Flint Creek Plant that are consistent with the environmental controls currently under construction. 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 July 2015, we submitted comments to the proposed Arkansas FIP and participate in comments filed by industry associations of which we are members. We support compliance with CSAPR programs as satisfaction of the BART requirements.

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. This rule was overturned by the U.S. Supreme Court. The Federal EPA proposed to include CO_2 emissions in standards that apply to new and existing electric utility units. See "Climate Change, CO_2 Regulation and Energy Policy" section below.

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The Federal EPA also issued new, more stringent national ambient air quality standards (NAAQS) for PM, SO_2 and ozone. In October 2015, the Federal EPA announced a lower final NAAQS for ozone of 70 parts per billion. 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. In 2012, the court issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing 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 petition for 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 Federal EPA 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. The court granted the Federal EPA's motion. The parties filed briefs and presented oral arguments. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit found that the Federal EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the Federal EPA to timely revise the rule consistent with the court’s opinion while CSAPR remains in place. The Federal EPA is reviewing the decision and will take further action once their review is complete. Separate appeals of the Error Corrections Rule and the further revisions were filed but no briefing schedules have been established.

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 units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of nonmercury metals) and hydrogen chloride (as a surrogate for acid gases). 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 was required within three years. The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and the revised rule provides alternative work practice standards for operators during start-up and shut down periods. 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 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 (MATS) schedule and other environmental requirements.

Petitions for administrative reconsideration and judicial review of the final rule 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. A final rule on reconsideration was issued in 2014 and a proposed rule containing technical corrections was issued in early 2015. 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 trade groups and several states filed petitions for further review in the U.S. Supreme Court and the court granted those petitions in November 2014.

In June 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanded the MATS rule for further proceedings consistent with its decision that the Federal EPA was unreasonable in refusing to consider costs in its determination whether to regulate emissions of HAPs from power plants. The case has been remanded to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings consistent with the U.S. Supreme Court’s decision. We will continue to evaluate the impact of this decision and until further action by the U.S. Court of Appeals for the District of Columbia Circuit, the rule remains in place.

Climate Change, CO_2 Regulation and Energy Policy

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 that can assist in reducing carbon emissions. We are taking steps to comply with these requirements, including increasing our wind power purchases and broadening our portfolio of energy efficiency programs.

In the absence of comprehensive federal climate change or energy policy legislation, 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 under the CAA. The new proposal was issued in September 2013 and requires new large natural gas units to meet a limit of 1,000 pounds of CO_2 per MWh of electricity generated and small natural gas units to meet a limit of 1,100 pounds of CO_2 per MWh. New coal-fired units are required to meet a limit of 1,100 pounds of CO_2 per MWh, with the option to meet a 1,000 pound per MWh limit if they choose to average emissions over multiple years.

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 plans implementing the guidelines no later than June 2016.

In August 2015, the Federal EPA announced the final standards for new, modified and reconstructed fossil fired steam generating units and combustion turbines, guidelines for the development of state plans to regulate CO_2 emissions from existing sources and proposed two options for a federal plan. The rules will become effective 60 days following publication. The final standard for new combustion turbines is 1,000 pounds of CO_2 per MWh and the final standard for new fossil steam units is 1,400 pounds of CO_2 per MWh. Reconstructed turbines are subject to the same standard as new units and no standard for modified combustion turbines was issued. Reconstructed fossil steam units are subject to a standard of 1,800 pounds of CO_2 per MWh for larger units and 2,000 pounds of CO_2 per MWh for smaller units. Modified fossil steam units will be subject to a site specific standard no lower than the standards that would be applied if the units were reconstructed.

The final emissions guidelines for existing sources are based on a series of declining performance standards that are implemented beginning in 2022 through 2029. Affected units must achieve a standard of 771 pounds of CO_2 per MWh for existing natural gas combined cycle units and 1,305 pounds of CO_2 per MWh for existing fossil steam units by 2030. The Federal EPA also developed a set of rate-based and mass-based state goals and has proposed “model” rules that can be adopted by the states that would allow sources within “trading ready” state programs to trade, bank or sell

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allowances or credits issued by the states or Federal EPA. The Federal EPA intends to finalize either a rate-based or mass-based trading program that can be enforced in states that fail to submit approved plans by the deadlines established in the final guidelines. States are required to submit final plans or an extension request by September 2016 to the Federal EPA. States receiving an extension request must submit final plans by September 2018. We are reviewing the pre-publication version of the final rule and evaluating the rule's impacts as well as the anticipated actions by states where our assets are located. The final rule was already challenged in the courts and we expect additional lawsuits once the rule is published in the Federal Register.

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 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 (BACT) analysis for CO_2 emissions if they exceed a reasonable level. The Federal EPA removed those provisions of the final rule from the Code of Federal Regulations that were inconsistent with the U.S. Supreme Court's decision but continues to apply a 75,000 ton per year threshold to trigger the need for a BACT analysis. Petitions were filed with the U.S. Court of Appeals for the District of Columbia Circuit seeking to amend the judgment in the case to require Federal EPA to establish a reasonable minimum level. Those petitions were denied.

Federal and state legislation or regulations that mandate limits on the emission of CO_2 could 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.

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 (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The proposed rule contained two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and existing unlined surface impoundments.

In the final rule, the Federal EPA elected to regulate CCR as a non-hazardous solid waste and issued new minimum federal solid waste management standards. On the effective date, the rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes new and additional construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria and additional groundwater monitoring requirements. The rule does not apply to inactive CCR landfills and inactive surface impoundments at retired generating stations or the beneficial use of CCR. The rule is self-implementing so state action is not required. Because of this self-implementing feature, the rule contains extensive record keeping, notice and internet posting requirements. Because we currently use surface impoundments and landfills to manage CCR materials at our generating facilities, we will incur significant costs to upgrade or close and replace these existing facilities at some point in the future as the new rule is implemented.

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. Encapsulated beneficial uses are not materially impacted by the new rule but additional demonstrations may be required to continue land applications in significant amounts except in road construction projects.

The final rule was published in the Federal Register in April 2015 and becomes effective six months after publication. The final rule provides for a staggered compliance schedule for the implementation of the rule's many requirements. We recorded a $95 million increase in asset retirement obligations in the second quarter of 2015 primarily due to the publication of the final rule. Given the schedule for implementation, we will continue to evaluate the rule's impact on operations.

Clean Water Act (CWA) Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The final rule 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 were filed by industry and environmental groups and are currently pending in the U.S. Court of Appeals for the Second Circuit.

In addition, the Federal EPA developed revised effluent limitation guidelines for electricity generating facilities. A pre-publication copy of the final rule was announced and made available in September 2015. In addition to other requirements, in the final rule the Federal EPA establishes limits on flue gas desulfurization wastewater, zero discharge for fly ash and bottom ash transport water and flue gas mercury control wastewater. Compliance with the final rule is as soon as possible after November 2018 and no later than December 2023. These new requirements will be implemented through each facility's wastewater discharge permit. We continue to review the final rule 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.

In June 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases. The CWA provides for federal jurisdiction over "navigable waters" defined as "the waters of the United States." This jurisdictional definition applies 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. The final definition continues to recognize traditional navigable waters of the U.S. as jurisdictional as well as certain exclusions. The rule also contains a number of new specific definitions and criteria for determining whether certain other waters are jurisdictional because of a "significant nexus." We believe that clarity and efficiency in the permitting process is needed. We remain concerned that the rule introduces new concepts and could subject more of our operations to CWA jurisdiction, thereby increasing the time and complexity of permitting. The final rule is being challenged in both courts of appeal and district courts. Challengers include industry associations of which we are members. The U.S. Court of Appeal for the Sixth Circuit has granted a nationwide stay of the rule pending jurisdictional determinations.

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.

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 and capacity to serve SSO customers and provides transmission and distribution services 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.
- In October 2015, we signed an agreement to sell AEPRO to a nonaffiliated party. The AEP River Operations segment is comprised entirely of AEPRO. However, we will retain AEPRO's investment in IMT. See "AEPRO (AEP River Operations Segment)" section of Note 6 for additional information.

The table below presents Earnings Attributable to AEP Common Shareholders by segment for the three and nine months ended September 30, 2015 and 2014.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Vertically Integrated Utilities	$274	$219	$780	$651
Transmission and Distribution Utilities	113	92	288	279
AEP Transmission Holdco	46	43	147	114
Generation & Marketing	91	117	360	378
AEP River Operations	4	11	16	17
Corporate and Other (a)	(9)	11	(13)	4
Earnings Attributable to AEP Common Shareholders	$519	$493	$1,578	$1,443

(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 2015 Compared to Third Quarter of 2014

Earnings Attributable to AEP Common Shareholders increased from $493 million in 2014 to $519 million in 2015 primarily due to:

- Successful rate proceedings in various jurisdictions.
- An increase in revenues due to annual formula rate adjustments.
- An increase in weather-related usage.
- A decrease in expenses due to a settlement and revision of certain asset retirement obligations.
- An increase in transmission investment which resulted in higher revenues and income.

These increases were partially offset by:

- A decrease in generation revenues due to lower capacity revenue.
- A decrease in off-system sales margins due to lower market prices and reduced sales volumes.
- An increase in employee-related expenses.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Earnings Attributable to AEP Common Shareholders increased from $1.4 billion in 2014 to $1.6 billion in 2015 primarily due to:

- Successful rate proceedings in various jurisdictions.
- An increase in revenues due to annual formula rate adjustments.
- An increase in weather-related usage.
- A decrease in expenses due to a settlement and revision of certain asset retirement obligations.
- An increase in transmission investment which resulted in higher revenues and income.
- Favorable retail, trading and marketing activity.

These increases were partially offset by:

- A decrease in generation revenues due to lower capacity revenue.
- A decrease in off-system sales margins due to lower market prices and reduced sales volumes.
- A decrease in weather normalized sales.

Our results of operations by operating segment are discussed below.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
	(in millions)			
Revenues	$2,471	$2,450	$7,159	$7,288
Fuel and Purchased Electricity	931	1,010	2,695	3,038
Gross Margin	1,540	1,440	4,464	4,250
Other Operation and Maintenance	653	615	1,844	1,809
Depreciation and Amortization	264	257	802	772
Taxes Other Than Income Taxes	97	95	288	278
Operating Income	526	473	1,530	1,391
Interest and Investment Income	1	2	4	3
Carrying Costs Income	4	1	9	2
Allowance for Equity Funds Used During Construction	16	12	46	33
Interest Expense	(130)	(133)	(392)	(396)
Income Before Income Tax Expense and Equity Earnings	417	355	1,197	1,033
Income Tax Expense	142	135	416	380
Equity Earnings of Unconsolidated Subsidiaries	—	—	2	1
Net Income	275	220	783	654
Net Income Attributable to Noncontrolling Interests	1	1	3	3
Earnings Attributable to AEP Common Shareholders	$274	$219	$780	$651

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
	(in millions of KWhs)			
Retail:				
Residential	9,019	8,505	26,070	26,126
Commercial	7,008	6,743	19,315	18,980
Industrial	8,882	8,962	26,178	26,319
Miscellaneous	616	608	1,739	1,740
Total Retail	25,525	24,818	73,302	73,165
Wholesale (a)	6,577	8,632	20,748	27,418

(a) Includes off-system sales, municipalities and cooperatives, unit power and other wholesale customers.

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 revenues 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,	
	2015	2014	2015	2014
	(in degree days)			
Eastern Region				
Actual – Heating (a)	—	2	2,138	2,248
Normal – Heating (b)	5	5	1,748	1,736
Actual – Cooling (c)	702	559	1,104	921
Normal – Cooling (b)	728	733	1,057	1,062
Western Region				
Actual – Heating (a)	—	—	1,049	1,233
Normal – Heating (b)	1	1	912	921
Actual – Cooling (c)	1,472	1,246	2,190	1,926
Normal – Cooling (b)	1,398	1,399	2,114	2,109

(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 2015 Compared to Third Quarter of 2014
Reconciliation of Third Quarter of 2014 to Third Quarter of 2015
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Third Quarter of 2014	$219
Changes in Gross Margin:	
Retail Margins	128
Off-system Sales	(24)
Transmission Revenues	(10)
Other Revenues	6
Total Change in Gross Margin	100
Changes in Expenses and Other:	
Other Operation and Maintenance	(38)
Depreciation and Amortization	(7)
Taxes Other Than Income Taxes	(2)
Interest and Investment Income	(1)
Carrying Costs Income	3
Allowance for Equity Funds Used During Construction	4
Interest Expense	3
Total Change in Expenses and Other	(38)
Income Tax Expense	(7)
Third Quarter of 2015	$274

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 $128 million primarily due to the following:
- The effect of successful rate proceedings in our service territories which include:
- A $40 million increase primarily due to increases in rates in West Virginia, offset by decreases in rates in Virginia and formula rates in both jurisdictions.
- A $25 million increase for SWEPCo primarily due to revenue increases from rate riders in Louisiana and Texas.
- A $20 million increase for I&M primarily due to rate increases from Indiana rate riders and annual formula rate adjustments.
- An $11 million increase for PSO primarily due to revenue increases from rate riders.

For the increases described above, $30 million relate to riders/trackers which have corresponding increases in expense items below.

- A $51 million increase in weather-related usage.

These increases were partially offset by:

- A $19 million decrease primarily due to lower weather-normalized retail sales in our western region.
- Margins from Off-system Sales decreased $24 million primarily due to lower market prices and decreased sales volumes.
- Transmission Revenues decreased $10 million primarily due to decreased PJM revenues, partially offset by an increase in SPP margins.
-

Other Revenues increased $6 million primarily due to a 2014 MPSC order disallowing $4 million of 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 $38 million primarily due to the following:
  - A $20 million increase in employee-related expenses.
  - A $17 million increase in recoverable expenses, primarily PJM expenses currently fully recovered in rate recovery riders/trackers, partially offset by lower River Transportation Division (RTD) barging costs.
  - A $5 million increase in SPP transmission services.
  - A $4 million increase in storm expenses.

  These increases were partially offset by:
  - An $8 million decrease due to a 2014 accrual for expected environmental remediation costs at I&M.
- Depreciation and Amortization expenses increased $7 million primarily due to amortization related to an advanced metering rider implemented in November 2014 in Oklahoma as well as an overall higher depreciable base.
- Allowance for Equity Funds Used During Construction increased $4 million primarily due to increases in environmental construction and transmission projects.
- Income Tax Expense increased $7 million primarily due to an increase in pretax book income, partially offset by the regulatory accounting treatment of state income taxes and other book/tax differences which are accounted for on a flow-through basis.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014
Reconciliation of Nine Months Ended September 30, 2014 to Nine Months Ended September 30, 2015
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Nine Months Ended September 30, 2014	$651	
Changes in Gross Margin:		
Retail Margins	340	
Off-system Sales	(118	)
Transmission Revenues	(9	)
Other Revenues	1	
Total Change in Gross Margin	214	
Changes in Expenses and Other:		
Other Operation and Maintenance	(35	)
Depreciation and Amortization	(30	)
Taxes Other Than Income Taxes	(10	)
Interest and Investment Income	1	
Carrying Costs Income	7	
Allowance for Equity Funds Used During Construction	13	
Interest Expense	4	
Total Change in Expenses and Other	(50	)
Income Tax Expense	(36	)
Equity Earnings	1	
Nine Months Ended September 30, 2015	$780	

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 $340 million primarily due to the following:
  - The effect of successful rate proceedings in our service territories which include:
    - A $108 million increase primarily due to increases in rates in West Virginia and Virginia, as well as an adjustment due to the amended Virginia law impacting biennial reviews.
    - A $74 million increase for I&M primarily due to rate increases from Indiana rate riders and annual formula rate adjustments.
    - A $68 million increase for SWEPCo primarily due to increases in municipal and cooperative revenues due to annual formula rate adjustments and revenue increases from SWEPCo rate riders in Louisiana and Texas.
    - A $27 million increase for PSO primarily due to revenue increases from rate riders.

  For the increases described above, $77 million relate to riders/trackers which have corresponding increases in expense items below.
  - A $52 million increase in weather-related usage.

  These increases were partially offset by:
  - A $25 million decrease in weather-normalized load primarily due to lower residential sales in the eastern region.
- Margins from Off-system Sales decreased $118 million primarily due to lower market prices and decreased sales volumes.
-

Transmission Revenues decreased $9 million primarily due to decreased PJM revenues, partially offset by an increase in SPP margins.

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

- Other Operation and Maintenance expenses increased $35 million primarily due to the following:
- A $54 million increase in recoverable expenses, primarily PJM expenses and vegetation management expenses currently fully recovered in rate recovery riders/trackers, partially offset by lower RTD barging costs.
- A $13 million increase in SPP and PJM transmission services.

These increases were partially offset by:

- An $18 million decrease in vegetation management expenses and storm expenses.
- A $14 million decrease due to a 2014 accrual for expected environmental remediation costs and a 2015 reduction of an environmental liability at I&M.
- Depreciation and Amortization expenses increased $30 million primarily due to amortization related to an advanced metering rider implemented in November 2014 in Oklahoma as well as an overall higher depreciable base.
- Taxes Other Than Income Taxes increased $10 million primarily due to an increase in property taxes.
- Carrying Costs Income increased $7 million primarily due to increased riders and trackers in our jurisdictions, including the Indiana and Michigan Life Cycle Management Riders, the Kentucky Environmental Surcharge Rider, the Indiana Dry Sorbent Injection Rider, as well as an increase in carrying charges related to West Virginia ENEC deferrals.
- Allowance for Equity Funds Used During Construction increased $13 million primarily due to increases in environmental construction and transmission projects.
- Income Tax Expense increased $36 million primarily due to an increase in pretax book income, partially offset by the regulatory accounting treatment of state income taxes.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
	(in millions)			
Revenues	$1,189	$1,231	$3,520	$3,580
Fuel and Purchased Electricity	229	377	920	1,123
Amortization of Generation Deferrals	55	27	122	83
Gross Margin	905	827	2,478	2,374
Other Operation and Maintenance	348	329	956	920
Depreciation and Amortization	198	182	536	499
Taxes Other Than Income Taxes	122	117	362	344
Operating Income	237	199	624	611
Interest and Investment Income	2	3	5	9
Carrying Costs Income (Expense)	(2)	6	10	20
Allowance for Equity Funds Used During Construction	3	3	11	8
Interest Expense	(68)	(68)	(206)	(210)
Income Before Income Tax Expense	172	143	444	438
Income Tax Expense	59	51	156	159
Net Income	113	92	288	279
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$113	$92	$288	$279

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
	(in millions of KWhs)			
Retail:				
Residential	7,590	7,194	20,486	20,280
Commercial	7,033	6,796	19,320	19,012
Industrial	5,665	5,489	16,754	16,262
Miscellaneous	194	187	532	540
Total Retail (a)	20,482	19,666	57,092	56,094
Wholesale (b)	497	575	1,460	1,727

(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. In general, degree day changes in our eastern region have a larger effect on revenues 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,	
	2015	2014	2015	2014
	(in degree days)			
Eastern Region				
Actual – Heating (a)	—	1	2,575	2,540
Normal – Heating (b)	6	7	2,073	2,074
Actual – Cooling (c)	620	581	970	943
Normal – Cooling (b)	666	663	956	946
Western Region				
Actual – Heating (a)	—	—	320	302
Normal – Heating (b)	—	—	192	200
Actual – Cooling (d)	1,476	1,367	2,380	2,309
Normal – Cooling (b)	1,355	1,346	2,381	2,358

(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 2015 Compared to Third Quarter of 2014
Reconciliation of Third Quarter of 2014 to Third Quarter of 2015
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Third Quarter of 2014	$92
Changes in Gross Margin:	
Retail Margins	117
Off-system Sales	(9)
Transmission Revenues	(33)
Other Revenues	3
Total Change in Gross Margin	78
Changes in Expenses and Other:	
Other Operation and Maintenance	(19)
Depreciation and Amortization	(16)
Taxes Other Than Income Taxes	(5)
Interest and Investment Income	(1)
Carrying Costs Income	(8)
Total Change in Expenses and Other	(49)
Income Tax Expense	(8)
Third Quarter of 2015	$113

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 $117 million primarily due to the following:
  - A $65 million increase in Ohio transmission and PJM revenues primarily due to the energy supplied as result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
  - A $33 million Ohio regulatory provision recorded in 2014.
  - A $7 million increase in revenues associated with the Ohio Distribution Investment Rider (DIR).
  - A $7 million increase in revenues associated with the gridSMART®, Enhanced Service Reliability and Retail Stability Riders. These riders have corresponding increases in other expense items below.
  - A $6 million increase in TCC and TNC revenues primarily due to the recovery of ERCOT transmission expenses, offset in Other Operation and Maintenance expenses below.
  - A $4 million increase in commercial sales in Ohio.
  - A $4 million increase in weather-related usage in Texas.

  These increases were partially offset by:
  - A $14 million decrease in base rates due to the discontinuance of seasonal rates in Ohio.
  - A $14 million decrease in revenues associated with the recovery of 2012 storm costs under the Ohio Storm Damage Recovery Rider which ended in April 2015. This decrease in Retail Margins is primarily offset by a decrease in Other Operation and Maintenance expenses below.
- Margins from Off-system Sales decreased $9 million primarily due to losses from a legacy OPCo power contract.
- Transmission Revenues decreased $33 million primarily due to:
-

A $37 million decrease in Network Integrated Transmission Service (NITS) revenue due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, partially offset by a corresponding increase in Retail Margins above.

This decrease was partially offset by:

- A $5 million increase primarily due to increased transmission investment in ERCOT.

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

- Other Operation and Maintenance expenses increased $19 million primarily due to the following:
  - A $24 million increase primarily due to PJM and ERCOT expenses fully recovered in rate recovery riders/trackers.
  - A $7 million increase in employee-related expenses.

  These increases were partially offset by:
  - A $14 million decrease due to the completion of the amortization of 2012 deferred Ohio storm expenses in April 2015. This decrease was offset by a corresponding decrease in Retail Margins above.
- Depreciation and Amortization expenses increased $16 million primarily due to the following:
  - A $7 million increase due to an increase in the depreciable base of transmission and distribution assets.
  - A $4 million increase in amortization of TCC's securitization transition asset, partially offset in Other Revenues above.
  - A $3 million increase in Ohio gridSMART® capital carrying charges primarily due to a rider rate increase effective June 2015. This increase was offset by a corresponding increase in Retail Margins above.
- Taxes Other Than Income Taxes increased $5 million primarily due to an increase in property taxes.
- Carrying Costs Income decreased $8 million primarily due to the collection of carrying costs on deferred capacity charges beginning June 2015.
- Income Tax Expense increased $8 million primarily due to an increase in pretax book income.

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Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014
Reconciliation of Nine Months Ended September 30, 2014 to Nine Months Ended September 30, 2015
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Nine Months Ended September 30, 2014	$279	
Changes in Gross Margin:		
Retail Margins	161	
Off-system Sales	(13	)
Transmission Revenues	(54	)
Other Revenues	10	
Total Change in Gross Margin	104	
Changes in Expenses and Other:		
Other Operation and Maintenance	(36	)
Depreciation and Amortization	(37	)
Taxes Other Than Income Taxes	(18	)
Interest and Investment Income	(4	)
Carrying Costs Income	(10	)
Allowance for Equity Funds Used During Construction	3	
Interest Expense	4	
Total Change in Expenses and Other	(98	)
Income Tax Expense	3	
Nine Months Ended September 30, 2015	$288	

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 $161 million primarily due to the following:
- A $91 million increase in Ohio transmission and PJM revenues primarily due to the energy supplied as result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
- A $33 million Ohio regulatory provision recorded in 2014.
- A $24 million increase in TCC and TNC revenues primarily due to the recovery of ERCOT transmission expenses, offset in Other Operation and Maintenance expenses below.
- A $22 million increase in revenues associated with the Ohio DIR.
- A $5 million increase in weather-related usage in Texas.

These increases were partially offset by:

- A $19 million decrease in the Energy Efficiency (EE), Peak Demand Reduction Cost Recovery Rider (PDR) revenues in Ohio and associated deferrals. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
- An $11 million decrease in revenues associated with the recovery of 2012 storm costs under the Ohio Storm Damage Recovery Rider which ended in April 2015. This decrease in Retail Margins is primarily offset by a decrease in Other Operation and Maintenance expenses below.
- Margins from Off-system Sales decreased $13 million primarily due to losses from a legacy OPCo power contract.
- Transmission Revenues decreased $54 million primarily due to the following:

- A $44 million decrease in NITS revenue primarily due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, partially offset by a corresponding increase in Retail Margins above.

- A $12 million decrease in Ohio revenues related to a lower annual transmission formula rate true-up.
- A $9 million OPCo transmission regulatory settlement in 2015.

These decreases were partially offset by:

- An $18 million increase primarily due to increased transmission investment in ERCOT.
- Other Revenues increased $10 million primarily due to $5 million of increased pole attachment revenue for OPCo and a $3 million increase in Texas securitization revenues, offset in Depreciation and Amortization below.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $36 million primarily due to the following:
- A $36 million increase primarily due to PJM and ERCOT expenses fully recovered in rate recovery riders/trackers.
- A $13 million increase in distribution expenses including system improvements and vegetation management expenses.
- An $8 million increase in PJM and SPP transmission services.
- A $6 million increase due to PUCO ordered contributions to the Ohio Growth Fund.

These increases were partially offset by:

- A $19 million decrease in EE and PDR costs and associated deferrals. This decrease was offset by a corresponding decrease in Retail Margins above.
- A $6 million decrease in remitted Universal Service Fund surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset by a corresponding decrease in Retail Margins above.
- Depreciation and Amortization expenses increased $37 million primarily due to the following:
- A $19 million increase due to an increase in the depreciable base of transmission and distribution assets.
- An $11 million increase in amortization of TCC's securitization transition asset, partially offset in Other Revenues.
- Taxes Other Than Income Taxes increased $18 million primarily due to increased property taxes.
- Carrying Costs Income decreased $10 million primarily due to the collection of carrying costs on deferred capacity charges beginning June 2015.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
	(in millions)			
Transmission Revenues	$88	$55	$245	$140
Other Operation and Maintenance	11	7	27	18
Depreciation and Amortization	12	6	30	17
Taxes Other Than Income Taxes	17	10	50	23
Operating Income	48	32	138	82
Allowance for Equity Funds Used During Construction	14	12	40	33
Interest Expense	(10)	(6)	(27)	(16)
Income Before Income Tax Expense and Equity Earnings	52	38	151	99
Income Tax Expense	23	17	66	47
Equity Earnings of Unconsolidated Subsidiaries	17	22	63	62
Net Income	46	43	148	114
Net Income Attributable to Noncontrolling Interests	—	—	1	—
Earnings Attributable to AEP Common Shareholders	$46	$43	$147	$114

Summary of Net Plant in Service and CWIP for AEP Transmission Holdco

	As of September 30, 2015	2014
	(in millions)	
Net Plant in Service	$2,253	$1,308
CWIP	1,298	1,050

Third Quarter of 2015 Compared to Third Quarter of 2014

Reconciliation of Third Quarter of 2014 to Third Quarter of 2015
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Third Quarter of 2014	$43	
Changes in Transmission Revenues:		
Transmission Revenues	33	
Total Change in Transmission Revenues	33	
Changes in Expenses and Other:		
Other Operation and Maintenance	(4	)
Depreciation and Amortization	(6	)
Taxes Other Than Income Taxes	(7	)
Allowance for Equity Funds Used During Construction	2	
Interest Expense	(4	)
Total Change in Expenses and Other	(19	)
Income Tax Expense	(6	)
Equity Earnings	(5	)
Third Quarter of 2015	$46	

The major components of the increase in transmission revenues, which consists of wholesale sales to affiliates and non-affiliates, were as follows:

- Transmission Revenues increased $33 million primarily due to an increase in projects placed in-service by our wholly-owned transmission subsidiaries.

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

- Other Operation and Maintenance expenses increased $4 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $6 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $7 million primarily due to increased property taxes.
- Interest Expense increased $4 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $6 million primarily due to an increase in pretax book income and by the recording of federal and state income tax adjustments in the third quarter of 2015 compared to the third quarter of 2014.
- Equity Earnings decreased $5 million primarily due to increased expense related to cross-arms on ETT transmission lines.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Reconciliation of Nine Months Ended September 30, 2014 to Nine Months Ended September 30, 2015
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Nine Months Ended September 30, 2014	$114
Changes in Transmission Revenues:	
Transmission Revenues	105
Total Change in Transmission Revenues	105
Changes in Expenses and Other:	
Other Operation and Maintenance	(9)
Depreciation and Amortization	(13)
Taxes Other Than Income Taxes	(27)
Allowance for Equity Funds Used During Construction	7
Interest Expense	(11)
Total Change in Expenses and Other	(53)
Income Tax Expense	(19)
Equity Earnings	1
Net Income Attributable to Noncontrolling Interests	(1)
Nine Months Ended September 30, 2015	$147

The major components of the increase in transmission revenues, which consists of wholesale sales to affiliates and non-affiliates, were as follows:

- Transmission Revenues increased $105 million primarily due to an increase in projects placed in-service by our wholly-owned transmission subsidiaries.

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

- Other Operation and Maintenance expenses increased $9 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $13 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $27 million primarily due to increased property taxes.
- Allowance for Equity Funds Used During Construction increased $7 million primarily due to increased transmission investment.
- Interest Expense increased $11 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $19 million primarily due to an increase in pretax book income.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
	(in millions)			
Revenues	$835	$901	$2,806	$3,065
Fuel, Purchased Electricity and Other	564	529	1,771	1,894
Gross Margin	271	372	1,035	1,171
Other Operation and Maintenance	61	122	277	363
Depreciation and Amortization	51	56	152	169
Taxes Other Than Income Taxes	10	12	30	37
Operating Income	149	182	576	602
Interest and Investment Income	—	2	2	4
Interest Expense	(10)	(12)	(31)	(35)
Income Before Income Tax Expense	139	172	547	571
Income Tax Expense	48	55	187	193
Net Income	91	117	360	378
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$91	$117	$360	$378

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
	(in millions of MWhs)			
Fuel Type:				
Coal	7	16	23	37
Natural Gas	3	2	10	6
Wind	1	—	1	—
Total MWhs	11	18	34	43

Third Quarter of 2015 Compared to Third Quarter of 2014
Reconciliation of Third Quarter of 2014 to Third Quarter of 2015
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Third Quarter of 2014	$117
Changes in Gross Margin:	
Generation	(96)
Retail, Trading and Marketing	(6)
Other	1
Total Change in Gross Margin	(101)
Changes in Expenses and Other:	
Other Operation and Maintenance	61
Depreciation and Amortization	5
Taxes Other Than Income Taxes	2
Interest and Investment Income	(2)
Interest Expense	2
Total Change in Expenses and Other	68
Income Tax Expense	7
Third Quarter of 2015	$91

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 certain cost of service for retail operations were as follows:

- Generation decreased $96 million primarily due to lower capacity revenue due to the termination of the Power Supply Agreement between AGR and OPCo on May 31, 2015.
- Retail, Trading and Marketing decreased $6 million primarily due to decreased wholesale trading and marketing performance.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $61 million primarily due to a settlement and revision of certain asset retirement obligations and decreased plant outage and maintenance costs.
- Depreciation and Amortization expenses decreased $5 million primarily due to reduced plant in-service.
- Income Tax Expense decreased $7 million primarily due to a decrease in pretax book income, partially offset by the recording of federal and state income tax adjustments.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014
Reconciliation of Nine Months Ended September 30, 2014 to Nine Months Ended September 30, 2015
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Nine Months Ended September 30, 2014	$378
Changes in Gross Margin:	
Generation	(172)
Retail, Trading and Marketing	40
Other	(4)
Total Change in Gross Margin	(136)
Changes in Expenses and Other:	
Other Operation and Maintenance	86
Depreciation and Amortization	17
Taxes Other Than Income Taxes	7
Interest and Investment Income	(2)
Interest Expense	4
Total Change in Expenses and Other	112
Income Tax Expense	6
Nine Months Ended September 30, 2015	$360

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 certain cost of service for retail operations were as follows:

- Generation decreased $172 million primarily due to lower capacity revenue due to the termination of the Power Supply Agreement between AGR and OPCo on May 31, 2015.
- Retail, Trading and Marketing increased $40 million primarily due to favorable wholesale trading and marketing performance as well as an increase in retail volumes.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $86 million primarily due to a settlement and revision of certain asset retirement obligations and decreased plant outage and maintenance costs.
- Depreciation and Amortization expenses decreased $17 million primarily due to reduced plant in-service.
- Taxes Other Than Income Taxes decreased $7 million primarily due to a decrease in property taxes.
- Income Tax Expense decreased $6 million primarily due to a decrease in pretax book income, partially offset by the recording of federal and state income tax adjustments.

AEP RIVER OPERATIONS

Third Quarter of 2015 Compared to Third Quarter of 2014

Earnings Attributable to AEP Common Shareholders from our AEP River Operations segment decreased from $11 million in 2014 to $4 million in 2015 primarily due to a loss on AEPRO's equity investment in IMT due to bankruptcy of an IMT customer.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Earnings Attributable to AEP Common Shareholders from our AEP River Operations segment decreased from $17 million in 2014 to $16 million in 2015 primarily due to a loss on AEPRO's equity investment in IMT due to bankruptcy of an IMT customer, partially offset by lower fuel prices and reduced consumption.

CORPORATE AND OTHER

Third Quarter of 2015 Compared to Third Quarter of 2014

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from income of $11 million in 2014 to a loss of $9 million in 2015 primarily due to an increase in reserves for our captive insurance program as well as the impact of a 2014 tax adjustment.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from income of $4 million in 2014 to a loss of $13 million in 2015 primarily due to an increase in reserves for our captive insurance program as well as the impact of a 2014 tax adjustment.

AEP SYSTEM INCOME TAXES

Third Quarter of 2015 Compared to Third Quarter of 2014

Income Tax Expense increased $11 million primarily due to an increase in pretax book income and by the recording of federal and state income tax adjustments in the third quarter of 2015 compared to the third quarter of 2014, partially offset by the regulatory accounting treatment of state income taxes.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Income Tax Expense increased $44 million primarily due to an increase in pretax book income and by the recording of federal and state income tax adjustments in 2015 compared to 2014, partially offset by the regulatory accounting treatment of state income taxes.

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, 2015			December 31, 2014		
	(dollars in millions)					
Long-term Debt, including amounts due within one year (a)	$19,507	51.3	%	$18,684	50.7	%
Short-term Debt	782	2.1		1,346	3.6	
Total Debt (a)	20,289	53.4		20,030	54.3	
AEP Common Equity	17,699	46.6		16,820	45.7	
Noncontrolling Interests	10	—		4	—	
Total Debt and Equity Capitalization	$37,998	100.0	%	$36,854	100.0	%

(a) Amounts include debt related to AEPRO that have been classified as Liabilities Held for Sale on the condensed balance sheets. See "AEPRO (AEP River Operations Segment)" section of Note 6 for additional information.

Our ratio of debt-to-total capital improved from 54.3% as of December 31, 2014 to 53.4% as of September 30, 2015 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, 2015, 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, 2015, our available liquidity was approximately $3.6 billion as illustrated in the table below:

		Amount	Maturity
		(in millions)	
Commercial Paper Backup:			
	Revolving Credit Facility	$1,750	June 2017
	Revolving Credit Facility	1,750	July 2018
Total		3,500	
Cash and Cash Equivalents		178	
Total Liquidity Sources		3,678	
Less:	AEP Commercial Paper Outstanding	32	
	Letters of Credit Issued	33	
Net Available Liquidity		$3,613	

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

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during the first nine months of 2015 was $788 million. The weighted-average interest rate for our commercial paper during 2015 was 0.45%.

Other Credit Facilities

We issue letters of credit under two uncommitted facilities totaling $150 million. As of September 30, 2015, the maximum future payment for letters of credit issued under the uncommitted facilities was $122 million with maturities ranging from October 2015 to September 2016. 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 expires in June 2017.

Debt Covenants and Borrowing Limitations

Our 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, 2015, this contractually-defined percentage was 50.6%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of September 30, 2015, 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 and we manage our borrowings to stay within those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.56 per share in October 2015. 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,	
	2015	2014
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$163	$118
Net Cash Flows from Operating Activities	3,910	3,715
Net Cash Flows Used for Investing Activities	(3,248)	(3,079)
Net Cash Flows Used for Financing Activities	(647)	(560)
Net Increase in Cash and Cash Equivalents	15	76
Cash and Cash Equivalents at End of Period	$178	$194

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,	
	2015	2014
	(in millions)	
Net Income	$1,564	$1,430
Depreciation and Amortization	1,528	1,418
Other	818	867
Net Cash Flows from Operating Activities	$3,910	$3,715

Net Cash Flows from Operating Activities were $3.9 billion in 2015 consisting primarily of Net Income of $1.6 billion and $1.5 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Deferred Income Taxes increased primarily due to provisions in the Taxpayer Relief Act of 2014 and an increase in tax/book temporary differences from operations. The reduction in Fuel, Materials and Supplies balances reflects a decrease in fuel inventory due to the cold winter weather and plants retired during the second quarter of 2015.

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.

Investing Activities

	Nine Months Ended September 30,	
	2015	2014
	(in millions)	
Construction Expenditures	$(3,283)	$(2,897)
Acquisitions of Nuclear Fuel	(53)	(109)
Acquisitions of Assets/Businesses	(1)	(45)
Other	89	(28)
Net Cash Flows Used for Investing Activities	$(3,248)	$(3,079)

Net Cash Flows Used for Investing Activities were $3.2 billion in 2015 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Net Cash Flows Used for Investing Activities were $2.9 billion in 2014 primarily due to Construction Expenditures for environmental, distribution and transmission investments. We also purchased transmission assets for $38 million.

Financing Activities

	Nine Months Ended September 30,	
	2015	2014
	(in millions)	
Issuance of Common Stock, Net	$68	$63
Issuance of Debt, Net	236	195
Dividends Paid on Common Stock	(783)	(736)
Other	(168)	(82)
Net Cash Flows Used for Financing Activities	$(647)	$(560)

Net Cash Flows Used for Financing Activities in 2015 were $647 million. Our net debt issuances were $236 million. The net issuances included issuances of $2.1 billion of senior unsecured notes, $140 million of pollution control bonds and $757 million of other debt notes offset by retirements of $907 million of senior unsecured notes, $308 million of securitization bonds, $229 million of pollution control bonds and $687 of other debt notes and a decrease in short term borrowing of $564 million. We paid common stock dividends of $783 million. Other includes a make whole premium payment on the extinguishment of long-term debt of $93 million in addition to capital lease principal payments of $74 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 2014 were $560 million. Our net debt issuances were $195 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 $951 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.

In October 2015, KPCo drew the remaining $25 million on an existing $75 million variable rate credit facility due in 2018.

In October 2015, Transource Missouri drew $6 million on an existing $300 million variable rate credit facility due in 2018.

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BUDGETED CONSTRUCTION EXPENDITURES

In July 2015, we increased our forecast for construction expenditures by $200 million to approximately $4.6 billion for 2015. The increase is primarily for transmission investment in the Vertically Integrated Utilities, Transmission and Distribution Utilities, and AEP Transmission Holdco 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, 2015	December 31, 2014
	(in millions)	
Rockport Plant, Unit 2 Future Minimum Lease Payments	$1,110	$1,184
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 2014 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of our contractual obligations is included in our 2014 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 2014 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

New Accounting Pronouncements Adopted During the First Quarter of 2015

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. We adopted ASU 2014-08 effective January 1, 2015.

Pronouncements Effective in the Future

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, determine 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 FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, “Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date.” The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted for 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, 2018.

The FASB issued ASU 2015-01 “Income Statement – Extraordinary and Unusual Items” eliminating the concept of extraordinary items for presentation on the face of the income statement. Under the new standard, a material event or transaction that is unusual in nature, infrequent or both shall be reported as a separate component of income from continuing operations. Alternatively, it may be disclosed in the notes to financial statements. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015. Early adoption is permitted if applied from the beginning of a fiscal year. As applicable, this standard may change the presentation of amounts in the income statements. We plan to adopt ASU 2015-01 effective January 1, 2016.

The FASB issued ASU 2015-03 “Simplifying the Presentation of Debt Issuance Costs” to simplify the presentation of debt issuance costs on the balance sheets. Under the new standard, debt issuance costs related to a recognized debt liability will be presented on the balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with discounts. We include debt issuance costs in Deferred Charges and Other Noncurrent Assets on the condensed balance sheets. Debt issuance costs represent less than 1% of total long-term debt. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. We intend to early adopt ASU 2015-03 for the 2015 Form 10-K.

The FASB issued ASU 2015-05 “Customer's Accounting for Fees Paid in a Cloud Computing Arrangement” providing guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. We plan to adopt ASU 2015-05 effective January 1, 2016.

The FASB issued ASU 2015-11 “Simplifying the Measurement of Inventory” to simplify the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first-out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. We plan to adopt ASU 2015-11 effective January 1, 2017.

The FASB issued ASU 2015-13 “Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets” clarifying whether a contract for the purchase or sale of electricity on a forward basis should be eligible to meet the physical delivery criterion of the normal purchases and normal sales scope exception when either the delivery location is within a nodal energy market or the contract necessitates transmission through a nodal energy market and one of the contracting parties incurs charges (or credits) for the transmission of electricity based in part on locational marginal pricing differences payable to (or receivable from) an independent system operator. Under the new standard, the use of locational marginal pricing by an independent system operator does not cause a contract to fail to meet the physical delivery criterion of the normal purchases and normal sales scope exception. As a result, an entity may elect to designate that contract as a normal purchase or normal sale. The new accounting guidance is effective upon issuance and applied prospectively. We have analyzed the impact of this new standard and determined that it will have no impact on the accounting of our contracts. Additionally, adoption has no impact on net income. We adopted ASU 2015-13 upon its issuance date.

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, consolidation policy and balance sheet classification of deferred taxes. 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 was exposed to FTR price risk as it related to RTO congestion during the June 2012 - May 2015 Ohio ESP period. Additional risks include energy procurement risk and 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, diesel 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 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, 2014:
MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2015

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
	(in millions)			
Total MTM Risk Management Contract Net Assets as of December 31, 2014	$36	$46	$140	$222
Gain from Contracts Realized/Settled During the Period and Entered in a Prior Period	(30)	(5)	(22)	(57)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	54	54
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	(17)	(17)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	23	(27)	—	(4)
Total MTM Risk Management Contract Net Assets as of September 30, 2015	$29	$14	$155	198
Commodity Cash Flow Hedge Contracts				(17)
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(1)
Fair Value Hedge Contracts				1
Collateral Deposits				43
Elimination of Affiliated MTM Risk Management Contracts				(4)
Total MTM Derivative Contract Net Assets as of September 30, 2015				$220

(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, 2015, our credit exposure net of collateral to sub investment grade counterparties was approximately 7%, 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, 2015, 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	$727	$1	$726	2	$269
Split Rating	25	—	25	1	25
Noninvestment Grade	1	1	—	—	—
No External Ratings:					
Internal Investment Grade	123	—	123	3	66
Internal Noninvestment Grade	83	18	65	2	36
Total as of September 30, 2015	$959	$20	$939	8	$396
Total as of December 31, 2014	$817	$21	$796	8	$347

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, 2015, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

The following tables show the end, high, average and low market risk as measured by VaR for the periods indicated:

VaR Model
Trading Portfolio

Nine Months Ended September 30, 2015				Twelve Months Ended December 31, 2014			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$—	$1	$—	$—	$—	$3	$1	$—

VaR Model
Non-Trading Portfolio

Nine Months Ended September 30, 2015				Twelve Months Ended December 31, 2014			
End	High	Average	Low	End	High	Average	Low

(in millions)				(in millions)			
$1	$2	$1	$—	$2	$3	$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.

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As our VaR calculation captures recent price movements, we also perform regular stress testing of the trading portfolio to understand our exposure to extreme price movements. We employ a historical-based method whereby the current trading 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, 2015 and December 31, 2014, the estimated EaR on our debt portfolio for the following twelve months was $34 million and $33 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2015 and 2014
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
REVENUES				
Vertically Integrated Utilities	$2,436	$2,432	$7,082	$7,217
Transmission and Distribution Utilities	1,164	1,163	3,378	3,388
Generation & Marketing	802	538	2,289	1,932
Other Revenues	30	28	90	22
TOTAL REVENUES	4,432	4,161	12,839	12,559
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	955	1,080	2,782	3,291
Purchased Electricity for Resale	731	449	2,050	1,560
Other Operation	691	685	1,955	1,985
Maintenance	312	313	923	929
Depreciation and Amortization	535	499	1,528	1,418
Taxes Other Than Income Taxes	248	230	733	679
TOTAL EXPENSES	3,472	3,256	9,971	9,862
OPERATING INCOME	960	905	2,868	2,697
Other Income (Expense):				
Interest and Investment Income	2	1	6	5
Carrying Costs Income	1	7	18	22
Allowance for Equity Funds Used During Construction	33	27	97	74
Interest Expense	(221)	(217)	(659)	(650)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	775	723	2,330	2,148
Income Tax Expense	275	264	827	783
Equity Earnings of Unconsolidated Subsidiaries	12	24	61	65
INCOME FROM CONTINUING OPERATIONS	512	483	1,564	1,430
INCOME FROM DISCONTINUED OPERATIONS, NET OF TAX	8	11	18	16
NET INCOME	520	494	1,582	1,446
Net Income Attributable to Noncontrolling Interests	1	1	4	3
	$519	$493	$1,578	$1,443

EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS				
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	490,648,929	488,912,892	490,155,315	488,361,017
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$1.04	$0.99	$3.18	$2.92
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	$0.02	$0.02	$0.04	$0.03
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$1.06	$1.01	$3.22	$2.95
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	490,800,335	488,970,647	490,411,020	488,597,178
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$1.04	$0.99	$3.18	$2.92
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	$0.02	$0.02	$0.04	$0.03
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$1.06	$1.01	$3.22	$2.95
CASH DIVIDENDS DECLARED PER SHARE	$0.53	$0.50	$1.59	$1.50

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 51.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2015 and 2014
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net Income	$520	$494	$1,582	$1,446
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $3 and $1 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $6 and $3 for the Nine Months Ended September 30, 2015 and 2014, Respectively	(6)	(2)	(11)	6
Securities Available for Sale, Net of Tax of $1 and $0 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $1 and $0 for the Nine Months Ended September 30, 2015 and 2014, Respectively	(1)	—	(1)	1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $1 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $0 and $2 for the Nine Months Ended September 30, 2015 and 2014, Respectively	—	1	1	3
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(7)	(1)	(11)	10
TOTAL COMPREHENSIVE INCOME	513	493	1,571	1,456
Total Comprehensive Income Attributable to Noncontrolling Interests	1	1	4	3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$512	$492	$1,567	$1,453

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 51.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2015 and 2014
(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, 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
TOTAL EQUITY - DECEMBER 31, 2014	510	$3,313	$6,204	$7,406	$(103)	$4	$16,824
Issuance of Common Stock	1	9	59				68
Common Stock Dividends				(780)		(3)	(783)
Other Changes in Equity			19			5	24
Net Income				1,578		4	1,582
Other Comprehensive Loss					(11)		(11)
Pension and OPEB Adjustment Related to Mitchell Plant					5		5
TOTAL EQUITY - SEPTEMBER 30, 2015	511	$3,322	$6,282	$8,204	$(109)	$10	$17,709

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 51.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2015 and December 31, 2014
(in millions)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$178	$163
Other Temporary Investments (September 30, 2015 and December 31, 2014 Amounts Include $307 and $371, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and EIS)	315	386
Accounts Receivable:		
Customers	662	637
Accrued Unbilled Revenues	147	146
Pledged Accounts Receivable – AEP Credit	987	987
Miscellaneous	84	85
Allowance for Uncollectible Accounts	(27)	(20)
Total Accounts Receivable	1,853	1,835
Fuel	376	581
Materials and Supplies	729	736
Risk Management Assets	143	178
Regulatory Asset for Under-Recovered Fuel Costs	105	127
Margin Deposits	85	95
Assets Held for Sale	608	103
Prepayments and Other Current Assets	156	274
TOTAL CURRENT ASSETS	4,548	4,478
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	25,665	25,727
Transmission	13,305	12,433
Distribution	17,812	17,157
Other Property, Plant and Equipment (September 30, 2015 and December 31, 2014 Amounts Include Plant to be Retired, Coal Mining and Nuclear Fuel, December 31, 2014 Amount Includes 2015 Plant Retirement)	4,036	5,074
Construction Work in Progress	4,008	3,215
Total Property, Plant and Equipment	64,826	63,606
Accumulated Depreciation and Amortization	19,588	19,971
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	45,238	43,635
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,950	4,264
Securitized Assets	1,841	2,072
Spent Nuclear Fuel and Decommissioning Trusts	2,047	2,096
Goodwill	53	53
Long-term Risk Management Assets	353	294

Assets Held for Sale	—	522
Deferred Charges and Other Noncurrent Assets	2,069	2,219
TOTAL OTHER NONCURRENT ASSETS	11,313	11,520
TOTAL ASSETS	$61,099	$59,633

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 51.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2015 and December 31, 2014
(dollars in millions)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT LIABILITIES		
Accounts Payable	$1,274	$1,258
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	750	744
Other Short-term Debt	32	602
Total Short-term Debt	782	1,346
Long-term Debt Due Within One Year (September 30, 2015 and December 31, 2014 Amounts Include $424 and $431, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	1,826	2,500
Risk Management Liabilities	75	92
Customer Deposits	335	324
Accrued Taxes	748	863
Accrued Interest	236	238
Regulatory Liability for Over-Recovered Fuel Costs	74	55
Liabilities Held for Sale	474	85
Other Current Liabilities	1,234	1,206
TOTAL CURRENT LIABILITIES	7,058	7,967
NONCURRENT LIABILITIES		
Long-term Debt (September 30, 2015 and December 31, 2014 Amounts Include $2,004 and $2,260, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy and Sabine)	17,600	16,101
Long-term Risk Management Liabilities	201	131
Deferred Income Taxes	11,425	10,892
Regulatory Liabilities and Deferred Investment Tax Credits	3,762	3,892
Asset Retirement Obligations	1,944	1,951
Employee Benefits and Pension Obligations	535	630
Liabilities Held for Sale	—	350
Deferred Credits and Other Noncurrent Liabilities	865	895
TOTAL NONCURRENT LIABILITIES	36,332	34,842
TOTAL LIABILITIES	43,390	42,809
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2015	2014		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	511,141,256	509,739,159		
(20,336,592 Shares were Held in Treasury as of September 30, 2015 and December 31, 2014)			3,322	3,313
Paid-in Capital			6,282	6,204
Retained Earnings			8,204	7,406
Accumulated Other Comprehensive Income (Loss)			(109)	(103)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			17,699	16,820
Noncontrolling Interests			10	4
TOTAL EQUITY			17,709	16,824
TOTAL LIABILITIES AND EQUITY			$61,099	$59,633

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 51.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2015 and 2014
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2015	2014
OPERATING ACTIVITIES		
Net Income	$1,582	$1,446
Income from Discontinued Operations	18	16
Income from Continuing Operations	1,564	1,430
Adjustments to Reconcile Income from Continuing Operations to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,528	1,418
Deferred Income Taxes	529	385
Carrying Costs Income	(18)	(22)
Allowance for Equity Funds Used During Construction	(97)	(74)
Mark-to-Market of Risk Management Contracts	18	15
Amortization of Nuclear Fuel	102	114
Pension Contributions to Qualified Plan Trust	(92)	(70)
Property Taxes	247	220
Fuel Over/Under-Recovery, Net	93	(77)
Deferral of Ohio Capacity Costs, Net	35	(106)
Change in Other Noncurrent Assets	(106)	(41)
Change in Other Noncurrent Liabilities	(1)	271
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(18)	(19)
Fuel, Materials and Supplies	194	222
Accounts Payable	(13)	(40)
Accrued Taxes, Net	(68)	20
Other Current Assets	11	—
Other Current Liabilities	2	69
Net Cash Flows from Operating Activities	3,910	3,715
INVESTING ACTIVITIES		
Construction Expenditures	(3,283)	(2,897)
Change in Other Temporary Investments, Net	81	37
Purchases of Investment Securities	(1,489)	(791)
Sales of Investment Securities	1,437	746
Acquisitions of Nuclear Fuel	(53)	(109)
Acquisitions of Assets/Businesses	(1)	(45)
Other Investing Activities	60	(20)
Net Cash Flows Used for Investing Activities	(3,248)	(3,079)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	68	63
Issuance of Long-term Debt	2,931	1,206
Change in Short-term Debt, Net	(564)	525

Retirement of Long-term Debt	(2,131)	(1,536)
Make Whole Premium on Extinguishment of Long-term Debt	(93)	—
Principal Payments for Capital Lease Obligations	(74)	(85)
Dividends Paid on Common Stock	(783)	(736)
Other Financing Activities	(1)	3
Net Cash Flows Used for Financing Activities	(647)	(560)
Net Increase in Cash and Cash Equivalents	15	76
Cash and Cash Equivalents at Beginning of Period	163	118
Cash and Cash Equivalents at End of Period	$178	$194
CASH FLOWS FROM DISCONTINUED OPERATIONS		
Operating Activities	$10	$10
Investing Activities	2	(2)
Financing Activities	(12)	(8)
Net Change in Cash and Cash Equivalents from Discontinued Operations	—	—
Cash and Cash Equivalents from Discontinued Operations - Beginning of Period	—	—
Cash and Cash Equivalents from Discontinued Operations - End of Period	$—	$—

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 51.

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

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

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

In the opinion of management, the unaudited condensed consolidated interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of our net income, financial position and cash flows for the interim periods. Net income for the three and nine months ended September 30, 2015 is not necessarily indicative of results that may be expected for the year ending December 31, 2015. The condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2014 consolidated financial statements and notes thereto, which are included in our Form 10-K as filed with the SEC on February 20, 2015.

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, KPCo and WPCo 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 on January 1, 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.

Earnings Per Share (EPS)

Basic EPS is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS 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,			
	2015		2014	
	(in millions, except per share data)			
		$/share		$/share
Income from Continuing Operations	$512		$483	
Less: Net Income Attributable to Noncontrolling Interests	1		1	
Earnings Attributable to AEP Common Shareholders from Continuing Operations	$511		$482	
Weighted Average Number of Basic Shares Outstanding	490.6	$1.04	488.9	$0.99
Weighted Average Dilutive Effect of Restricted Stock Units	0.2	—	0.1	—
Weighted Average Number of Diluted Shares Outstanding	490.8	$1.04	489.0	$0.99

	Nine Months Ended September 30,			
	2015		2014	
	(in millions, except per share data)			
		$/share		$/share
Income from Continuing Operations	$1,564		$1,430	
Less: Net Income Attributable to Noncontrolling Interests	4		3	
Earnings Attributable to AEP Common Shareholders from Continuing Operations	$1,560		$1,427	
Weighted Average Number of Basic Shares Outstanding	490.2	$3.18	488.4	$2.92
Weighted Average Dilutive Effect of Restricted Stock Units	0.2	—	0.2	—
Weighted Average Number of Diluted Shares Outstanding	490.4	$3.18	488.6	$2.92

There were no antidilutive shares outstanding as of September 30, 2015 and 2014.

Supplementary Cash Flow Information

	Nine Months Ended September 30,	
Cash Flow Information	2015	2014
	(in millions)	
Cash Paid (Received) for:		
Cash Paid for Interest, Net of Capitalized Amounts	$639	$649
Net Cash Paid for Income Taxes	116	109
Noncash Investing and Financing Activities:		
Noncash Acquisitions Under Capital Leases	97	80
Construction Expenditures Included in Current Liabilities as of September 30,	579	515
Construction Expenditures Included in Noncurrent Liabilities as of September 30,	66	—
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	31	—

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.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. 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. We adopted ASU 2014-08 effective January 1, 2015.

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, determine 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 FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, “Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date.” The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted for annual periods beginning after December 15, 2016. 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, 2018.

ASU 2015-01 “Income Statement – Extraordinary and Unusual Items” (ASU 2015-01)

In January 2015, the FASB issued ASU 2015-01 eliminating the concept of extraordinary items for presentation on the face of the income statement. Under the new standard, a material event or transaction that is unusual in nature, infrequent or both shall be reported as a separate component of income from continuing operations. Alternatively, it may be disclosed in the notes to financial statements.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015. Early adoption is permitted if applied from the beginning of a fiscal year. As applicable, this standard may change the presentation of amounts in the income statements. We plan to adopt ASU 2015-01 effective January 1, 2016.

ASU 2015-03 “Simplifying the Presentation of Debt Issuance Costs” (ASU 2015-03)

In April 2015, the FASB issued ASU 2015-03 simplifying the presentation of debt issuance costs on the balance sheets. Under the new standard, debt issuance costs related to a recognized debt liability will be presented on the balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with discounts. We include debt issuance costs in Deferred Charges and Other Noncurrent Assets on the condensed balance sheets. Debt issuance costs represent less than 1% of total long-term debt.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. We intend to early adopt ASU 2015-03 for the 2015 Form 10-K.

ASU 2015-05 “Customer's Accounting for Fees Paid in a Cloud Computing Arrangement” (ASU 2015-05)

In April 2015, the FASB issued ASU 2015-05 providing guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. We plan to adopt ASU 2015-05 effective January 1, 2016.

ASU 2015-11 “Simplifying the Measurement of Inventory” (ASU 2015-11)

In July 2015, the FASB issued ASU 2015-11 simplifying the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first-out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. We plan to adopt ASU 2015-11 effective January 1, 2017.

ASU 2015-13 “Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets” (ASU 2015-13)

In August 2015, the FASB issued ASU 2015-13 clarifying whether a contract for the purchase or sale of electricity on a forward basis should be eligible to meet the physical delivery criterion of the normal purchases and normal sales scope exception when either the delivery location is within a nodal energy market or the contract necessitates transmission through a nodal energy market and one of the contracting parties incurs charges (or credits) for the transmission of electricity based in part on locational marginal pricing differences payable to (or receivable from) an independent system operator. Under the new standard, the use of locational marginal pricing by an independent system operator does not cause a contract to fail to meet the physical delivery criterion of the normal purchases and normal sales scope exception. As a result, an entity may elect to designate that contract as a normal purchase or normal sale.

The new accounting guidance is effective upon issuance and applied prospectively. We have analyzed the impact of this new standard and determined that it will have no impact on the accounting of our contracts. Additionally, adoption has no impact on net income. We adopted ASU 2015-13 upon its issuance date.

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, 2015 and 2014. 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, 2015

	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, 2015	$(5)	$(18)	$8	$(87)	$(102)
Change in Fair Value Recognized in AOCI	(3)	—	(1)	—	(4)
Amounts Reclassified from AOCI	(3)	—	—	—	(3)
Net Current Period Other Comprehensive Loss	(6)	—	(1)	—	(7)
Balance in AOCI as of September 30, 2015	$(11)	$(18)	$7	$(87)	$(109)

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 (Loss)	(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 Nine Months Ended September 30, 2015

	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, 2014	$1	$(19)	$8	$(93)	$(103)
Change in Fair Value Recognized in AOCI	(2)	—	(1)	—	(3)
Amounts Reclassified from AOCI	(10)	1	—	1	(8)
	(12)	1	(1)	1	(11)

Net Current Period Other Comprehensive Income (Loss)					
Pension and OPEB Adjustment Related to Mitchell Plant	—	—	—	5	5
Balance in AOCI as of September 30, 2015	$(11)	$(18)	$7	$(87)	$(109)

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)
Change in Fair Value Recognized in AOCI	(8)	—	1	—	(7)
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)

Reclassifications from Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and nine months ended September 30, 2015 and 2014. 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, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended September 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in millions)	
Commodity:		
Generation & Marketing Revenues	$(19)	$—
Purchased Electricity for Resale	14	(9)
Subtotal – Commodity	(5)	(9)
Interest Rate and Foreign Currency:		
Interest Expense	—	2
Subtotal – Interest Rate and Foreign Currency	—	2
Reclassifications from AOCI, before Income Tax (Expense) Credit	(5)	(7)
Income Tax (Expense) Credit	(2)	(2)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(3)	(5)
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(5)	(5)
Amortization of Actuarial (Gains)/Losses	5	7
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	2
Income Tax (Expense) Credit	—	1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	1

Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(3)	$(4)

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Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Nine Months Ended September 30, 2015	2014
Gains and Losses on Cash Flow Hedges	(in millions)	
Commodity:		
Generation & Marketing Revenues	$(36)	$—
Purchased Electricity for Resale	20	20
Regulatory Assets/(Liabilities), Net (a)	—	(3)
Subtotal – Commodity	(16)	17
Interest Rate and Foreign Currency:		
Interest Expense	1	6
Subtotal – Interest Rate and Foreign Currency	1	6
Reclassifications from AOCI, before Income Tax (Expense) Credit	(15)	23
Income Tax (Expense) Credit	(6)	9
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(9)	14
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(15)	(15)
Amortization of Actuarial (Gains)/Losses	16	21
Reclassifications from AOCI, before Income Tax (Expense) Credit	1	6
Income Tax (Expense) Credit	—	3
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1	3
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(8)	$17

(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 2014 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2014 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 2015 and updates the 2014 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	September 30, 2015 (in millions)	December 31, 2014
Regulatory Assets Currently Earning a Return		
Storm Related Costs	$24	$20
Material and Supplies Related to Retired Plants	20	—
West Virginia Vegetation Management Program	—	20
Regulatory Assets Currently Not Earning a Return		
Asset Retirement Obligation Costs Related to Retired Plants	59	—
Virginia Peak Demand Reduction/Energy Efficiency	12	9
Ormet Special Rate Recovery Mechanism	10	10
Storm Related Costs	7	100
Carbon Capture and Storage Product Validation Facility	—	13
IGCC Pre-Construction Costs	—	11
Other Regulatory Assets Pending Final Regulatory Approval	27	43
Total Regulatory Assets Pending Final Regulatory Approval	$159	$226

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. 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.

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 appealed that PUCO order to the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated 2009 - 2011 ESP order, which granted a weighted average cost of capital (WACC) rate. In November 2012, the IEU filed an appeal of the PUCO decision that included the argument that carrying costs should be reduced due to an accumulated deferred income tax credit. In June 2015, the Supreme Court of Ohio issued a decision that reversed the PUCO order on the carrying cost rate issue and dismissed the appeal filed by the IEU. In June 2015, the IEU filed a motion for reconsideration with the Supreme Court of Ohio related to the accumulated deferred income tax credit. In September 2015, the Supreme Court of Ohio denied the IEU's request for reconsideration and in October 2015 this matter was remanded back to the PUCO for reinstatement of the WACC rate.

June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that established 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 $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, which has scheduled oral arguments for the fourth quarter of 2015.

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 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 2015, the PUCO issued an order that approved, with modifications, OPCo's July 2014 application to collect the unrecovered portion of the deferred capacity costs. The order included approval to continue the collection of deferred capacity costs at a rate of $4.00/MWh beginning June 1, 2015 for approximately 32 months, with carrying costs at a long-term cost of debt rate. Additionally, the order stated that an audit will be conducted of the May 31, 2015 capacity deferral balance, which was $444 million. In May 2015, the PUCO granted intervenors requests for rehearing. As of September 30, 2015, OPCo's net deferred capacity costs balance of $392 million, including debt carrying costs, was recorded in Regulatory Assets on the condensed balance sheet. Through September 30, 2015, OPCo has collected $183 million in deferred capacity costs, and related carrying charges.

In 2013, the PUCO issued its Orders on Rehearing for the ESP which generally upheld its August 2012 order. 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 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO’s ESP order. Oral arguments at the Supreme Court of Ohio were held in May 2015.

In November 2013, the PUCO issued an order approving OPCo’s CBP with modifications. 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.

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 October 2014, the independent auditor, selected by the PUCO, 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/MW day capacity charge, the independent auditor has recommended 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 disagrees with the findings in the audit report.

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

June 2015 - May 2018 ESP Including PPA Application

In December 2013, OPCo filed an application with the PUCO to approve an ESP that included 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 also included 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 PPA. 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 February 2015, the PUCO issued an order approving OPCo's ESP application, subject to certain modifications, with a return on common equity of 10.2% on capital costs for certain riders. The order included (a) approval of the DIR, with modified rate caps established by the PUCO, (b) authorization to establish a zero rate rider for OPCo's proposed PPA, (c) the option for OPCo to reapply in a future proceeding with a more detailed PPA proposal and (d) a directive to continue to pursue the transfer of the OVEC contractual entitlement to AGR or to otherwise divest of its interest in OVEC. In May 2015, the PUCO issued an order on rehearing that increased the DIR rate caps and deferred ruling on all requests for rehearing related to the establishment of the PPA rider. In July 2015, the PUCO granted OPCo's and various intervenors' requests for rehearing related to the May 2015 order. In July 2015, intervenors filed appeals with the Supreme Court of Ohio that included opposition to the authorization of a PPA rider and the modifications to a transmission rider.

In October 2014, OPCo filed a separate application with the PUCO to propose a new extended PPA with AGR for 2,671 MW for inclusion in the PPA rider. In May 2015, OPCo filed an amended PPA application between OPCo and AGR that (a) included OPCo's OVEC contractual entitlement, (b) addressed the PPA requirements set forth in the PUCO's February 2015 order, (c) updated supporting testimony to reflect a current analysis of the PPA proposal and (d) included the 2,671 MW to be available for capacity, energy and ancillary services, produced by AGR over the lives of the respective generating units. A hearing at the PUCO related to the PPA commenced in September 2015. In October 2015, the PUCO staff submitted testimony that opposed the PPA application as currently proposed but concluded that, with changes, a PPA could be in the public interest.

If OPCo is ultimately not permitted to fully collect all components of its ESP rates, 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 June 2015, OPCo submitted its 2014 SEET filing with the PUCO. Management believes its financial statements adequately address the impact of 2014 SEET requirements.

Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation and 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.

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 September 2014, the Supreme Court of Ohio upheld the PUCO order on appeal. A review of the coal reserve valuation by an outside consultant has not been initiated by the PUCO. 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.

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 2013, Ormet filed for bankruptcy and subsequently shut down operations. In March 2014, the PUCO issued an order in OPCo’s Economic Development Rider (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, 2015, 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.

SWEPCo Rate Matters

2012 Texas Base Rate Case

In 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 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, 2015, the net book value of Welsh Plant, Unit 2 was $83 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 was 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 and potential fuel or replacement power disallowances related to Welsh Plant, Unit 2, 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 SWEPCo's 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 review base rates in 2014 and 2015 and that SWEPCo 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. In December 2014, the LPSC approved a settlement agreement related to the staff review of the cost of service. The settlement agreement reduced the requested revenue increase by $3 million, primarily due to the timing of both the allowed recovery of certain existing regulatory assets and the establishment of a regulatory asset for certain previously expensed costs. If the LPSC orders refunds based upon the pending prudence review of the Turk Plant investment, 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. 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 purchased power agreement attributable to Louisiana customers. In December 2014, the LPSC approved a partial settlement agreement that included the implementation of the $15 million annual increase in rates effective January 2015. These increases are subject to LPSC staff review and are subject to refund. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2015 Louisiana Formula Rate Filing

In April 2015, SWEPCo filed its formula rate plan for test year 2014 with the LPSC. The filing included a $14 million annual increase, which was effective August 2015. This increase is subject to LPSC staff review and is subject to refund. 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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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 2024 for Welsh Plant, Units 1 and 3 will cost approximately $700 million, excluding AFUDC. As of September 30, 2015, SWEPCo has incurred costs of $303 million, including AFUDC, and has remaining contractual construction obligations of $62 million related to these projects. SWEPCo will seek recovery of these project costs from customers through filings at the state commissions and the FERC. As of September 30, 2015, the net book value of Welsh Plant, Units 1 and 3 was $529 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

2014 West Virginia Base Rate Case

In May 2015, the WVPSC issued an order on APCo and WPCo's base rate case. Upon implementation of the order in May 2015, and consistent with the WVPSC authorized total revenue, annual base rates were authorized to be increased by $99 million based upon a 9.75% return on common equity. The order included a delayed billing of $25 million of the annual base rate increase to residential customers until July 2016. The order provided for carrying charges based upon a WACC rate for the $25 million delayed billing through June 2016, and stated recovery would be addressed in the next ENEC case scheduled for 2016. Additionally, the order included approval of (a) an initial vegetation management rider of $45 million annually, (b) revised deprecation rates, including recovery of plants to be retired and (c) the recovery of $89 million in previously recorded regulatory assets, which will predominantly be recovered over five years.

2015 Virginia Regulatory Asset Proceeding

In January 2015, the Virginia SCC initiated a proceeding to address the proper treatment of APCo’s authorized regulatory assets. In February and March 2015, briefs related to this proceeding were filed by various parties. As of September 30, 2015, APCo’s authorized regulatory assets under review in this proceeding were $11 million. If any of these costs, or any additional costs that may be subject to review, are not recoverable, it could reduce future net income and cash flows and impact financial condition.

New Virginia Legislation Affecting Biennial Reviews

In February 2015, amendments to Virginia law governing the regulation of investor-owned electric utilities were enacted. Under the amended Virginia law, APCo’s existing generation and distribution base rates are frozen until after the Virginia SCC rules on APCo’s next biennial review, which APCo will file in March 2020 for the 2018 and 2019 test years. These amendments also preclude the Virginia SCC from performing biennial reviews of APCo’s earnings for the years 2014 through 2017. APCo's financial statements adequately address the impact of these amendments. The new law provides that APCo will absorb its Virginia jurisdictional share of incremental generation and distribution costs incurred during 2014 through 2017 that are associated with severe weather events and/or natural disasters and costs associated with potential asset impairments related to new carbon emission guidelines issued by the Federal EPA.

PSO Rate Matters

2015 Oklahoma Base Rate Case

In July 2015, PSO filed a request with the OCC to increase annual revenues by $137 million to recover costs associated with its environmental compliance plan for the Federal EPA's Regional Haze Rule and Mercury and Air Toxics Standards, and to recover investments and other costs that have increased since the last base rate case. The annual increase consists of (a) a base rate increase of $89 million, which includes $48 million in increased depreciation expense that reflects, among other things, recovery through June 2026 of Northeastern Plant, Units 3 and 4, (b) a rider or base rate increase of $44 million to recover costs for the environmental controls being installed on Northeastern Plant, Unit 3 and the Comanche Plant and (c) a request to include environmental consumable costs in the FAC, estimated to be $4 million annually. The rate increase includes a proposed return on common equity of 10.5% to be effective in January 2016, except for the $44 million for environmental investments, which is effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls go in service. The total estimated cost of the environmental controls to be installed at Northeastern Plant, Unit 3 and the Comanche Plant is $219 million, excluding AFUDC. As of September 30, 2015, PSO has incurred costs of $162 million related to these projects, including AFUDC.

In addition, the filing also notified the OCC that the incremental replacement capacity and energy costs, including the first year effects of new PPAs, estimated to be $35 million, will be incurred related to the environmental compliance plan due to the closure of Northeastern Plant, Unit 4 in April 2016, which would be recovered through the FAC. As of September 30, 2015, the net book value of Northeastern Plant, Unit 4 was $94 million, before cost of removal, including materials and supplies inventory and CWIP.

In October 2015, testimony was filed by OCC staff and intervenors with recommendations that included increases to base rates and/or the proposed environmental rider ranging from $10 million to $31 million, based upon returns on common equity ranging from 8.75% to 9.3%, and increases to depreciation expense ranging from $23 million to $46 million. Additionally, recommendations by certain intervenors included (a) no recovery of PSO's investment in Northeastern Plant, Unit 3 environmental controls, (b) no recovery of the plant balances at the time the units are retired in 2016 and 2026, (c) denial of returns on the book values after the retirement dates, or to be set at only the cost of debt, and (d) the disallowance of the capacity costs associated with the PPAs. Additionally, certain intervenors did not support an increase in depreciation expense for the Northeastern Plant, Units 3 and 4 to permit cost recovery by Unit 3's 2026 retirement date as the proposals called for no change in existing cost recovery by 2040. Hearings at the OCC are scheduled for December 2015.

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

2014 Oklahoma Base Rate Case

In April 2015, the OCC issued an order that approved a non-unanimous stipulation agreement between PSO, the OCC staff and certain intervenors. The approved stipulation provides for 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 provides $24 million of revenues over 14 months beginning in November 2014 and increases to $27 million in 2016. The stipulation also included (a) new depreciation rates for advanced metering investments and existing meters, also effective November 2014, (b) 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 and (c) recovery of regulatory assets for 2013 storms and regulatory case expenses. The advanced metering cost rider was implemented in November 2014.

I&M Rate Matters

Tanners Creek Plant

In October 2014, I&M filed an application with the IURC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and the Tanners Creek Plant. Upon 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. The new depreciation rates would result in a decrease in I&M's Indiana jurisdictional electric depreciation expense which I&M proposed to reduce customer rates through a credit rider. In

May 2015, the IURC issued an order approving I&M's request for revised depreciation rates.

In May 2015, Tanners Creek Plant was retired. Upon retirement, $265 million was reclassified as Regulatory Assets on the condensed balance sheet related to the net book value of Tanners Creek Plant and is being amortized over 29 years. An additional $38 million was reclassified as Regulatory Assets on the condensed balance sheet for related asset retirement obligations and materials and supplies, which are currently not being amortized, pending regulatory approval.

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 for eligible transmission, distribution and storage system improvements totaling $787 million. In April 2015, I&M filed a notice with the IURC to exclude $117 million related to certain projects. In September 2015, the IURC granted I&M's motion to withdraw its application for reconsideration and/or rehearing and I&M withdrew its appeal with the Indiana Court of Appeals.

KPCo Rate Matters

Plant Transfer

In October 2013, the KPSC issued an order that approved a modified settlement agreement which included the approval to transfer to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity. 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 of the order with the Franklin County Circuit Court. In April 2015, the Franklin County Circuit Court issued an order that affirmed the KPSC's October 2013 order. In May 2015, the Attorney General filed an appeal with the Franklin County Circuit Court of the April 2015 order that had affirmed the KPSC's order.

Consistent with KPCo’s December 2012 plant transfer filing that was approved by the KPSC, Big Sandy Plant, Unit 2 was retired in May 2015. Upon retirement, $194 million was reclassified as Regulatory Assets on the condensed balance sheet related to the net book value of Big Sandy Plant, Unit 2 and the related asset retirement obligations, costs of removal and materials and supplies. These regulatory assets will be amortized over 25 years, effective July 2015.

If any part of the KPSC order is overturned, it could reduce future net income and cash flows and impact financial condition.

Kentucky Fuel Adjustment Clause Review

In January 2015, the KPSC issued an order disallowing certain FAC costs during the period of January 2014 through May 2015 while KPCo owned and operated both Big Sandy Plant, Unit 2 and its one-half interest in the Mitchell Plant. As a result of this order, KPCo recorded a regulatory disallowance of $36 million in December 2014. In February 2015, KPCo filed an appeal of this order with the Franklin County Circuit Court. In September 2015, the Franklin County Circuit Court issued an order that dismissed all appeals filed related to this FAC review, as agreed to by the parties to the stipulation agreement in the "2014 Kentucky Base Rate Case" discussed below.

2014 Kentucky Base Rate Case

In December 2014, KPCo filed a request with the KPSC for a net increase in rates of $70 million. In April 2015, a non-unanimous stipulation agreement between KPCo and certain intervenors was filed with the KPSC. The parties to the stipulation recommended a net revenue increase of $45 million, which consisted of a $68 million increase in rider rates, offset by a $23 million decrease in annual base rates, to be effective July 2015. The proposed net increase reflects KPCo's ownership interest in the Mitchell Plant, riders to recover the Big Sandy Plant retirement and operational costs and the inclusion of an environmental compliance plan. Additionally, the agreement included (a) recovery of $12 million of deferred storm costs, (b) any difference between the actual off-system sales margins and the $15 million included in the proposed annual base rates to be shared with 75% to the customer and 25% to KPCo and (c) dismissal of the KPCo and the Kentucky Industrial Utility Customers appeals of the KPSC order in the KPCo fuel adjustment clause review. See "Kentucky Fuel Adjustment Clause Review" discussed above.

In June 2015, the KPSC issued an order that approved a modified stipulation agreement. The order approved a net revenue increase of $45 million, as proposed in the stipulation agreement, and contained modifications that included (a) approval to recover $2 million of IGCC and certain carbon capture study costs, both over 25 years, (b) no deferral of certain PJM costs and (c) denial of the recovery of certain potential purchased power costs through a rider.

KGPCo Rate Matters

2015 Kingsport Base Rate Case

In September 2015, KGPCo filed a request with the TRA to increase base rates by $12 million annually based upon a proposed return on common equity of 10.66% with the new rates expected to be implemented by July 2016. If KGPCo does not recover its costs, it could reduce future net income and cash flows and impact financial condition.

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. We accrue contingent liabilities only when we conclude that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When we determine that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, we disclose such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent our maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

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 2014 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, 2015, the maximum future payments for letters of credit issued under the revolving credit facilities were $33 million with maturities ranging from December 2015 to November 2016.

We issue letters of credit under two uncommitted facilities totaling $150 million. As of September 30, 2015, the maximum future payments for letters of credit issued under the uncommitted facilities were $122 million with maturities ranging from October 2015 to September 2016. 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 2016 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 $58 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of September 30, 2015, SWEPCo has collected $65 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 $49 million is recorded in Asset Retirement Obligations on our condensed balance sheets.

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

Indemnifications and Other Guarantees

Contracts

We enter into 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, 2015, 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, 2015, the maximum potential loss for these lease agreements was $35 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 $11 million and $12 million for I&M and SWEPCo, respectively, for the remaining railcars as of September 30, 2015.

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 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 $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 2014, I&M recorded an accrual for remediation at certain additional sites in Michigan. As a result of receiving approval of completed remediation work from the MDEQ in March 2015, I&M's accrual for all of these sites was reduced. As of September 30, 2015, I&M's accrual for all of these sites is approximately $8 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. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs’ claims. Several claims remain, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. In June 2015, AEGCo and I&M filed a motion for partial judgment on the claims seeking dismissal of the breach of participation agreement claim as well as any claim for indemnification of costs associated with this case. Plaintiffs subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. We will continue to defend against the remaining 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, filed a petition seeking further review with the U.S. Supreme Court on the preemption issue. AEP also subsequently filed a separate 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. Oral argument occurred in January 2015. In April 2015, the U.S. Supreme Court affirmed the judgment of the U.S. Court of Appeals for the Ninth Circuit on the preemption issue, holding that the plaintiffs' state antitrust claims were not preempted by the Natural Gas Act. The U.S. Supreme Court denied AEP's petition for review of the personal jurisdiction issue shortly thereafter. The cases have been remanded to the district court for further proceedings. 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 44 individuals opted in to the class, bringing the plaintiff class to 80 current and former employees. Two plaintiffs have since dismissed their claims without prejudice, leaving 78 plaintiffs. We will continue to defend the case. We do not believe a loss is probable. If there is an unfavorable outcome contrary to our expectations, we estimate possible losses of up to $30 million.

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. As a result of a mediation held in October 2014, the parties reached an agreement in principle, subject to final documentation and preliminary and final court approval. In April 2015, we filed a motion with the court for preliminary approval of the settlement. In June 2015, the court granted preliminary approval of the settlement. In September 2015, the court granted final approval of the settlement, reserving decision on the appropriate fee for plaintiff's counsel.

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. In August 2015, the court denied our motion. We appealed that decision to the West Virginia Supreme Court. 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. DISPOSITION, ASSETS AND LIABILITIES HELD FOR SALE AND DISCONTINUED OPERATIONS

DISPOSITION

2015

Muskingum River Plant (Generation & Marketing Segment)

In August 2015, AGR sold its retired Muskingum River Plant site including its associated asset retirement obligations to a nonaffiliated party. AGR paid $48 million and the nonaffiliated party took ownership of the Muskingum River Plant site assets and assumed responsibility for environmental liabilities and AROs, including ash pond closure, asbestos abatement and decommissioning and demolition. As a result of the sale, a net gain of $32 million was recognized and recorded in Other Operation on the condensed consolidated statements of income. The cash paid was recorded in Operating Activities on the condensed consolidated statements of cash flows.

ASSETS AND LIABILITIES HELD FOR SALE

AEPRO (AEP River Operations Segment)

During the third quarter of 2015, we evaluated bids from prospective buyers, selected a buyer and received approval from AEP's Board of Directors to proceed with the sale to the nonaffiliated party. In October 2015, we signed an agreement to sell our commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. The sale of AEPRO is subject to regulatory approval including federal clearance pursuant to the Hart-Scott-Rodino Antitrust Improvements Act of 1976. Upon close of the sale, the nonaffiliated party will acquire AEPRO by purchasing all of the common stock of AEP Resources, Inc., the parent company of AEPRO. The nonaffiliated party will assume certain assets and liabilities of AEPRO, excluding the equity method investment in IMT, pension and benefit assets and liabilities and debt obligations. We will retain ownership of our captive barge fleet that delivers coal to the company's regulated coal-fueled power plant units owned or leased by AEGCo, APCo, I&M, KPCo and WPCo. We signed a contract with the nonaffiliated party to dispatch and schedule our captive barge fleet for the company's regulated coal-fueled power plant units. We also contracted with the nonaffiliated party to barge coal for AGR. These agreements with the nonaffiliated party extend through the end of 2016. The sale is expected to close in the fourth quarter of 2015.

Upon evaluation, management concluded that the AEPRO business met the classification as held for sale in the third quarter of 2015. Accordingly, AEPRO's assets and liabilities have been recorded as Assets Held for Sale and Liabilities Held for Sale, respectively, on our condensed consolidated balance sheets as of September 30, 2015 and December 31, 2014 and as shown in the following table:

	September 30, 2015	December 31, 2014
Assets:	(in millions)	
Accounts Receivable	$55	$91
Property, Plant and Equipment – Net	506	482
Other Classes of Assets That Are Not Major	47	52
Total Assets Classified as Held for Sale on the Condensed Consolidated Balance Sheets	$608	$625
Liabilities:		
Long-term Debt	$81	$83
Obligations Under Capital Leases	228	189
Other Classes of Liabilities That Are Not Major	165	163

Total Liabilities Classified as Held for Sale on the Condensed Consolidated Balance Sheets	$474	$435

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DISCONTINUED OPERATIONS

Management periodically assesses the overall AEP business model and makes decisions regarding our continued support and funding of our various businesses and operations. When it is determined that we will seek to exit a particular business or activity and we have met the accounting requirements for reclassification, we will reclassify the operations of those businesses or operations as discontinued operations. The assets and liabilities of these discontinued operations are classified as Assets Held for Sale and Liabilities Held for Sale until the time they are sold. In the third quarter of 2015, AEPRO was determined to be discontinued operations and has been classified as such for third quarter 2015 reporting. Results of operations of AEPRO have been classified as discontinued operations in our condensed consolidated statements of income for the three and nine months ended September 30, 2015 and 2014 as shown in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Other Revenues	$129	$141	$372	$435
Other Operation Expense	96	102	273	342
Maintenance Expense	4	8	20	24
Depreciation and Amortization Expense	9	8	27	23
Other Expense	8	7	24	22
Total Expenses	117	125	344	411
Pretax Income of Discontinued Operations	12	16	28	24
Income Tax Expense	4	5	10	8
Total Income on Discontinued Operations as Presented on the Condensed Consolidated Statements of Income	$8	$11	$18	$16

7. BENEFIT PLANS

We sponsor a qualified pension plan and two unfunded nonqualified pension plans. Substantially all of our employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. We sponsor OPEB plans to provide health and life insurance benefits for retired employees.

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, 2015 and 2014:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Service Cost	$23	$18	$3	$4
Interest Cost	51	55	15	16
Expected Return on Plan Assets	(69)	(65)	(28)	(28)
Amortization of Prior Service Cost (Credit)	1	1	(18)	(18)
Amortization of Net Actuarial Loss	27	31	5	6
Net Periodic Benefit Cost (Credit)	$33	$40	$(23)	$(20)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Service Cost	$70	$54	$9	$11
Interest Cost	154	166	43	50
Expected Return on Plan Assets	(206)	(196)	(83)	(84)
Amortization of Prior Service Cost (Credit)	2	2	(52)	(52)
Amortization of Net Actuarial Loss	80	93	14	17
Net Periodic Benefit Cost (Credit)	$100	$119	$(69)	$(58)

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.

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 and capacity to serve SSO customers and provides transmission and distribution services 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.
- In October 2015, we signed an agreement to sell AEPRO to a nonaffiliated party. The AEP River Operations segment is comprised entirely of AEPRO. However, we will retain AEPRO's investment in IMT. See "AEPRO (AEP River Operations Segment)" section of Note 6 for additional information.

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, 2015 and 2014 and reportable segment balance sheet information as of September 30, 2015 and December 31, 2014. 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, 2015								
Revenues from:								
External Customers	$2,436	$ 1,164	$ 27	$ 802	$ —	$ 3	$ — (c)	$ 4,432
Other Operating Segments	35	25	61	33	—	21	(175)	—
Total Revenues	$2,471	$ 1,189	$ 88	$ 835	$ —	$ 24	$ (175)	$ 4,432
Income (Loss) from Continuing Operations	$275	$ 113	$ 46	$ 91	$ (4)	$ (9)	$ —	$ 512
Income from Discontinued Operations, Net of Tax	—	—	—	—	8	—	—	8
Net Income (Loss)	$275	$ 113	$ 46	$ 91	$ 4	$ (9)	$ —	$ 520

	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)	$ —	$ 7	$ — (c)	$ 4,161
Other Operating Segments	18 (b)	68	34	363 (b)	—	19	(502)	—

Total Revenues	$ 2,450	$ 1,231	$ 55	$ 901	$ —	$ 26	$ (502)	$ 4,161
Income from Continuing Operations	$ 220	$ 92	$ 43	$ 117	$ —	$ 11	$ —	$ 483
Income from Discontinued Operations, Net of Tax	—	—	—	—	11	—	—	11
Net Income	$ 220	$ 92	$ 43	$ 117	$ 11	$ 11	$ —	$ 494

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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)										
Nine Months Ended September 30, 2015											
Revenues from:											
External Customers	$7,082		$ 3,378	$ 74	$ 2,289		$ —	$ 16	$ —	(c)	$ 12,839
Other Operating Segments	77		142	171	517		—	58	(965)		—
Total Revenues	$7,159		$ 3,520	$ 245	$ 2,806		$ —	$ 74	$ (965)		$ 12,839
Income (Loss) from Continuing Operations	$783		$ 288	$ 148	$ 360		$ (2)	$ (13)	$ —		$ 1,564
Income from Discontinued Operations, Net of Tax	—		—	—	—		18	—	—		18
Net Income (Loss)	$783		$ 288	$ 148	$ 360		$ 16	$ (13)	$ —		$ 1,582

	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)	$ —	$ 19	$ (51)	(c)	$ 12,559
Other Operating Segments	71	(b)	192	86	1,133	(b)	—	55	(1,537)		—
Total Revenues	$7,288		$ 3,580	$ 140	$ 3,065		$ —	$ 74	$ (1,588)		$ 12,559

Income from Continuing Operations	$654	$ 279	$ 114	$378	$ 1	$4	$ —	$ 1,430
Income from Discontinued Operations, Net of Tax	—	—	—	—	16	—	—	16
Net Income	$654	$ 279	$ 114	$378	$ 17	$4	$ —	$ 1,446

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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, 2015											
Total Property, Plant and Equipment	$39,981	$ 13,707	$ 3,594	$7,474	$—		$349	$(279	) (d)	$ 64,826	
Accumulated Depreciation and Amortization	12,483	3,603	43	3,390	—		178	(109	) (d)	19,588	
Total Property, Plant and Equipment - Net	$27,498	$ 10,104	$ 3,551	$4,084	$—		$171	$(170	) (d)	$ 45,238	
Assets Held for Sale	$—	$ —	$ —	$—	$ 608		$—	$—		$ 608	
Total Assets	35,272	14,441	4,362	5,531	772	(f)	21,810	(21,089	) (d) (e)	61,099	
Long-term Debt Due Within One Year:											
Affiliated	$—	$ —	$ —	$—	$—		$—	$—		$ —	
Nonaffiliated	949	724	—	151	—		2	—		1,826	
Long-term Debt:											
Affiliated	20	—	—	32	—		—	(52	)	—	
Nonaffiliated	9,900	4,888	1,323	641	—		848	—		17,600	
Total Long-term Debt	$10,869	$ 5,612	$ 1,323	$824	$—		$850	$(52	)	$ 19,426	
Liabilities Held for Sale	$—	$ —	$ —	$—	$ 474		$—	$—		$ 474	(g)

	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, 2014											
Total Property, Plant and Equipment	$39,402	$ 13,024	$ 2,714	$8,394	$—		$343	$(271)	(d)	$ 63,606	
Accumulated Depreciation and Amortization	12,773	3,481	25	3,603	—		188	(99)	(d)	19,971	
Total Property, Plant and Equipment - Net	$26,629	$ 9,543	$ 2,689	$4,791	$—		$155	$(172)	(d)	$ 43,635	
Assets Held for Sale	$—	$ —	$ —	$—	$ 625		$—	$—		$ 625	
Total Assets	33,750	14,495	3,575	6,329	749	(f)	21,081	(20,346)	(d) (e)	59,633	
Long-term Debt Due Within One Year:											
Affiliated	$111	$ —	$ —	$86	$—		$—	$(197)		$ —	
Nonaffiliated	1,352	405	—	740	—		3	—		2,500	
Long-term Debt:											
Affiliated	20	—	—	32	—		—	(52)		—	
Nonaffiliated	8,634	5,256	1,153	217	—		841	—		16,101	
Total Long-term Debt	$10,117	$ 5,661	$ 1,153	$1,075	$—		$844	$(249)		$ 18,601	
Liabilities Held for Sale	$—	$ —	$ —	$—	$ 435		$—	$—		$ 435	(g)

(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 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.

(f) Amounts include intercompany advances to affiliates and intercompany accounts receivable that will be settled prior to or upon the close of the sale of AEPRO.

(g) Amounts include debt related to AEPRO. See "AEPRO (AEP River Operations Segment)" section of Note 6 for additional information.

9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

We are exposed to certain market risks as a major power producer and participant in the wholesale electricity, natural gas, coal and emission allowance markets. 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, 2015 and December 31, 2014:

Notional Volume of Derivative Instruments

	Volume		
	September 30, 2015	December 31, 2014	Unit of Measure
Primary Risk Exposure	(in millions)		
Commodity:			
Power	371	334	MWhs
Coal	4	3	Tons
Natural Gas	46	106	MMBtus
Heating Oil and Gasoline	9	6	Gallons
Interest Rate	$114	$152	USD
Interest Rate and Foreign Currency	$560	$815	USD

Fair Value Hedging Strategies

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

Cash Flow Hedging Strategies

We enter into and designate as cash flow hedges certain derivative transactions for the purchase and sale of power 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 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. 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, 2015 and December 31, 2014 condensed balance sheets, we netted $4 million and $4 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $47 million and $35 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, 2015 and December 31, 2014:

Fair Value of Derivative Instruments
September 30, 2015

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 millions)					
Current Risk Management Assets	$311	$9	$2	$322	$(179)	$ 143
Long-term Risk Management Assets	443	3	—	446	(93)	353
Total Assets	754	12	2	768	(272)	496
Current Risk Management Liabilities	267	7	1	275	(200)	75
Long-term Risk Management Liabilities	293	22	1	316	(115)	201
Total Liabilities	560	29	2	591	(315)	276
Total MTM Derivative Contract Net Assets (Liabilities)	$194	$(17)	$—	$177	$43	$ 220

Fair Value of Derivative Instruments
December 31, 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	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign			

			Currency (a)		Position (b)	
	(in millions)					
Current Risk Management Assets	$392	$30	$3	$425	$(247)	$ 178
Long-term Risk Management Assets	367	3	—	370	(76)	294
Total Assets	759	33	3	795	(323)	472
Current Risk Management Liabilities	329	23	1	353	(261)	92
Long-term Risk Management Liabilities	208	8	9	225	(94)	131
Total Liabilities	537	31	10	578	(355)	223
Total MTM Derivative Contract Net Assets (Liabilities)	$222	$2	$(7)	$217	$32	$ 249

(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."

(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, 2015 and 2014:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three and Nine Months Ended September 30, 2015 and 2014

	Three Months Ended September 30,		Nine Months Ended September 30,	
Location of Gain (Loss)	2015	2014	2015	2014
	(in millions)			
Vertically Integrated Utilities Revenues	$—	$7	$7	$29
Transmission and Distribution Utilities Revenues	(1)	—	(1)	—
Generation & Marketing Revenues	1	21	60	69
Other Operation Expense	—	—	(1)	—
Maintenance Expense	(1)	—	(2)	—
Purchased Electricity for Resale	1	—	4	—
Regulatory Assets (a)	—	(6)	—	(6)
Regulatory Liabilities (a)	(20)	(7)	33	111
Total Gain (Loss) on Risk Management Contracts	$(20)	$15	$100	$203

(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. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the condensed statements of income as that of the associated risk. 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. The following table shows the results of our hedging gains (losses) during the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Gain (Loss) on Fair Value Hedging Instruments	$4	$(2)	$7	$2
Gain (Loss) on Fair Value Portion of Long-term Debt	(4)	2	(7)	(2)

During the three and nine months ended September 30, 2015 and 2014, hedge ineffectiveness was immaterial.

Accounting for Cash Flow Hedging Strategies

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

Realized gains and losses on derivative contracts for the purchase and sale of power and natural gas designated as cash flow hedges are included in Revenues 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, 2015 and 2014, we designated power derivatives as cash flow hedges but did not designate 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. The impact of cash flow hedge accounting for these derivative contracts was immaterial and discontinued 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, 2015 and 2014, 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, 2015 and 2014, we did not designate any foreign currency derivatives as cash flow hedges.

During the three and nine months ended September 30, 2015 and 2014, 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, 2015 and 2014, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets as of September 30, 2015 and December 31, 2014 were:
Impact of Cash Flow Hedges on the Condensed Balance Sheet
September 30, 2015

	Commodity	Interest Rate and Foreign Currency	Total
	(in millions)		
Hedging Assets (a)	$7	$—	$7
Hedging Liabilities (a)	24	1	25
AOCI Loss Net of Tax	(11)	(18)	(29)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	1	(1)	—

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2014

	Commodity	Interest Rate and Foreign Currency	Total
	(in millions)		
Hedging Assets (a)	$16	$—	$16
Hedging Liabilities (a)	14	1	15
AOCI Gain (Loss) Net of Tax	1	(19)	(18)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	4	(2)	2

(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, 2015, 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 87 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), we are obligated to post an additional amount of collateral for a limited number of derivative and non-derivative contracts primarily related to our competitive retail auction loads and guaranties for contractual obligations 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 our exposure if our credit ratings were to decline below a specified rating threshold as of September 30, 2015 and December 31, 2014:

	September 30, 2015	December 31, 2014
	(in millions)	
Fair Value of Contracts with Credit Downgrade Triggers	$—	$—
Amount of Collateral AEP Subsidiaries Would Have been Required to Post for Derivative Contracts as well as Derivative and Non-Derivative Contracts Subject to the Same Master Netting Arrangement	—	—
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post Attributable to RTOs and ISOs	35	36
Amount of Collateral Attributable to Other Contracts (a)	299	281

(a) Represents the amount of collateral AEP subsidiaries would have been required to post for other significant non-derivative contracts including AGR jointly owned plant contracts and various other commodity related contracts.

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, 2015 and December 31, 2014:

	September 30, 2015	December 31, 2014
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$307	$235
Amount of Cash Collateral Posted	10	9
Additional Settlement Liability if Cross Default Provision is Triggered	251	178

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 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 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, 2015 and December 31, 2014 are summarized in the following table:

	September 30, 2015		December 31, 2014	
	Book Value (a)	Fair Value	Book Value (a)	Fair Value
	(in millions)			
Long-term Debt	$19,507	$21,257	$18,684	$21,075

(a) Amounts include debt related to AEPRO that have been classified as Liabilities Held for Sale on the condensed balance sheets. See "AEPRO (AEP River Operations Segment)" section of Note 6 for additional information.

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, 2015			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (a)	$201	$—	$—	$201
Fixed Income Securities – Mutual Funds	90	—	—	90
Equity Securities – Mutual Funds	14	10	—	24
Total Other Temporary Investments	$305	$10	$—	$315

	December 31, 2014			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (a)	$280	$—	$—	$280
Fixed Income Securities – Mutual Funds	81	—	—	81
Equity Securities – Mutual Funds	13	12	—	25
Total Other Temporary Investments	$374	$12	$—	$386

(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, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Proceeds from Investment Sales	$—	$—	$—	$—
Purchases of Investments	10	—	10	1
Gross Realized Gains on Investment Sales	—	—	—	—
Gross Realized Losses on Investment Sales	—	—	—	—

As of September 30, 2015 and December 31, 2014, we had no Other Temporary Investments with an unrealized loss position. As of September 30, 2015, 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, 2015 and 2014, 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, 2015 and December 31, 2014:

	September 30, 2015			December 31, 2014		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$164	$—	$—	$20	$—	$—
Fixed Income Securities:						
United States Government	704	45	(2)	697	45	(5)
Corporate Debt	62	4	(1)	48	4	(1)
State and Local Government	50	1	—	208	1	—
Subtotal Fixed Income Securities	816	50	(3)	953	50	(6)
Equity Securities – Domestic	1,067	516	(80)	1,123	599	(79)
Spent Nuclear Fuel and Decommissioning Trusts	$2,047	$566	$(83)	$2,096	$649	$(85)

The following table provides the securities activity within the decommissioning and SNF trusts for the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Proceeds from Investment Sales	$921	$263	$1,437	$746
Purchases of Investments	938	281	1,479	790
Gross Realized Gains on Investment Sales	15	8	34	25
Gross Realized Losses on Investment Sales	13	1	23	10

The adjusted cost of fixed income securities was $766 million and $903 million as of September 30, 2015 and December 31, 2014, respectively. The adjusted cost of equity securities was $551 million and $524 million as of September 30, 2015 and December 31, 2014, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2015 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$166
1 year – 5 years	336
5 years – 10 years	140
After 10 years	174
Total	$816

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, 2015 and December 31, 2014. 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, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$12	$4	$—	$162	$178
Other Temporary Investments					
Restricted Cash (a)	189	6	—	6	201
Fixed Income Securities - Mutual Funds	90	—	—	—	90
Equity Securities – Mutual Funds (b)	24	—	—	—	24
Total Other Temporary Investments	303	6	—	6	315
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	17	478	248	(256)	487
Cash Flow Hedges:					
Commodity Hedges (c)	—	10	1	(4)	7
Fair Value Hedges	—	1	—	1	2
Total Risk Management Assets	17	489	249	(259)	496
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	157	—	—	7	164
Fixed Income Securities:					
United States Government	—	704	—	—	704
Corporate Debt	—	62	—	—	62
State and Local Government	—	50	—	—	50
Subtotal Fixed Income Securities	—	816	—	—	816
Equity Securities – Domestic (b)	1,067	—	—	—	1,067
Total Spent Nuclear Fuel and Decommissioning Trusts	1,224	816	—	7	2,047
Total Assets	$1,556	$1,315	$249	$(84)	$3,036
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$33	$440	$76	$(299)	$250
Cash Flow Hedges:					
Commodity Hedges (c)	—	22	6	(4)	24
Interest Rate/Foreign Currency Hedges	—	1	—	—	1
Fair Value Hedges	—	—	—	1	1

Total Risk Management Liabilities	$33	$463	$82	$(302)	$276

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Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Cash and Cash Equivalents (a)	$17	$1	$—	$145	$163
Other Temporary Investments					
Restricted Cash (a)	234	9	—	37	280
Fixed Income Securities - Mutual Funds	81	—	—	—	81
Equity Securities – Mutual Funds (b)	25	—	—	—	25
Total Other Temporary Investments	340	9	—	37	386
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	37	528	190	(302)	453
Cash Flow Hedges:					
Commodity Hedges (c)	—	32	—	(16)	16
Fair Value Hedges	—	1	—	2	3
Total Risk Management Assets	37	561	190	(316)	472
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	9	—	—	11	20
Fixed Income Securities:					
United States Government	—	697	—	—	697
Corporate Debt	—	48	—	—	48
State and Local Government	—	208	—	—	208
Subtotal Fixed Income Securities	—	953	—	—	953
Equity Securities – Domestic (b)	1,123	—	—	—	1,123
Total Spent Nuclear Fuel and Decommissioning Trusts	1,132	953	—	11	2,096
Total Assets	$1,526	$1,524	$190	$(123)	$3,117
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$65	$432	$36	$(334)	$199
Cash Flow Hedges:					
Commodity Hedges (c)	—	27	3	(16)	14
Interest Rate/Foreign Currency Hedges	—	1	—	—	1
Fair Value Hedges	—	7	—	2	9
Total Risk Management Liabilities	$65	$467	$39	$(348)	$223

(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, 2015 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 2015 and ($12) million in periods 2016-2018; Level 2 matures $5 million in 2015, $28 million in periods 2016-2018, $3 million in periods

2019-2020 and $2 million in periods 2021-2032; Level 3 matures $2 million in 2015, $63 million in periods 2016-2018, $25 million in periods 2019-2020 and $82 million in periods 2021-2032. Risk management commodity contracts are substantially comprised of power contracts.

(e) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.

(f) The December 31, 2014 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $(18) million in 2015 and ($10) million in periods 2016-2018; Level 2 matures $31 million in 2015, $52 million in periods 2016-2018, $12 million in periods 2019-2020 and $1 million in periods 2021-2030; Level 3 matures $50 million in 2015, $29 million in periods 2016-2018, $9 million in periods 2019-2020 and $66 million in periods 2021-2030. 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, 2015 and 2014.

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, 2015	Net Risk Management Assets (Liabilities) (in millions)
Balance as of June 30, 2015	$203
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	11
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	6
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(2)
Purchases, Issuances and Settlements (c)	(29)
Transfers into Level 3 (d) (e)	8
Transfers out of Level 3 (e) (f)	(5)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(25)
Balance as of September 30, 2015	$167

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

Nine Months Ended September 30, 2015	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2014	$151
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	14
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	54
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(4)
Purchases, Issuances and Settlements (c)	(60)
Transfers into Level 3 (d) (e)	28
Transfers out of Level 3 (e) (f)	(17)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	1
Balance as of September 30, 2015	$167

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

(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, 2015 and December 31, 2014:

Significant Unobservable Inputs
September 30, 2015

	Fair Value Assets (in millions)	Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	High	Weighted Average
Energy Contracts	$226	$79	Discounted Cash Flow	Forward Market Price (a)	$13.03	$165.93	$36.37
				Counterparty Credit Risk (b)	481		
FTRs	23	3	Discounted Cash Flow	Forward Market Price (a)	(10.67)	11.60	1.31
Total	$249	$82					

Significant Unobservable Inputs
December 31, 2014

	Fair Value Assets (in millions)	Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	High	Weighted Average
Energy Contracts	$157	$37	Discounted Cash Flow	Forward Market Price (a)	$11.37	$159.92	$57.18
				Counterparty Credit Risk (b)	303		
FTRs	33	2	Discounted Cash Flow	Forward Market Price (a)	(14.63)	20.02	0.96
Total	$190	$39					

(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, 2015:

Sensitivity of Fair Value Measurements
September 30, 2015

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.

Valuation Allowance

We assess the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to use existing deferred tax assets. On the basis of this evaluation, we recorded a valuation allowance of $165 million attributable to the unrealized capital loss associated with the excess tax basis of the stock over the book value of our investment in the operations of AEPRO. The assets and liabilities of AEPRO have been recorded as Assets Held for Sale and Liabilities Held for Sale, respectively, on our condensed balance sheets as of September 30, 2015 and December 31, 2014. See "AEPRO (AEP River Operations Segment)" section of Note 6 for additional information regarding the assets and liabilities classified as held for sale. As of September 30, 2015, valuation allowances totaling $221 million for unrealized capital losses have been recorded in order to recognize only the portion of the deferred tax assets that, more likely than not, will be realized.

Federal and State Income Tax Audit Status

We are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011, 2012 and 2013 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.

State Tax Legislation

House Bill 32 was passed by the state of Texas in June 2015 permanently reducing the Texas income/franchise tax rate from 0.95% to 0.75% effective January 1, 2016, applicable to reports originally due on or after the effective date. The Texas income/franchise tax rate had been scheduled to return to 1% in 2016. The enacted provision did not materially impact net income, cash flows or financial condition.

12. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding as of September 30, 2015 and December 31, 2014:

Type of Debt	September 30, 2015	December 31, 2014
	(in millions)	
Senior Unsecured Notes	$13,801	$12,647
Pollution Control Bonds	1,874	1,963
Notes Payable (a)	374	357
Securitization Bonds	2,072	2,380
Spent Nuclear Fuel Obligation (b)	266	266
Other Long-term Debt	1,151	1,101
Fair Value of Interest Rate Hedges	—	(6)
Unamortized Discount, Net	(31)	(24)
Total Long-term Debt Outstanding (a)	19,507	18,684
Long-term Debt Due Within One Year (a)	1,907	2,503
Long-term Debt (a)	$17,600	$16,181

(a) Amounts include debt related to AEPRO that have been classified as Liabilities Held for Sale on the condensed balance sheets. See "AEPRO (AEP River Operations Segment)" section of Note 6 for additional information.

(b) 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, 2015 and December 31, 2014, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the condensed balance sheets.

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2015 are shown in the tables below:

Company	Type of Debt	Principal Amount (in millions)	Interest Rate (%)	Due Date
Issuances:				
APCo	Pollution Control Bonds	$86	1.90	2019
APCo	Senior Unsecured Notes	350	4.45	2045
APCo	Senior Unsecured Notes	300	3.40	2025
I&M	Notes Payable	111	Variable	2019
I&M	Other Long-term Debt	100	Variable	2018
PSO	Senior Unsecured Notes	125	3.17	2025
PSO	Senior Unsecured Notes	125	4.09	2045
SWEPCo	Pollution Control Bonds	54	1.60	2019
SWEPCo	Senior Unsecured Notes	400	3.90	2045
Non-Registrant:				
AEPTCo	Senior Unsecured Notes	60	4.01	2030
AEPTCo	Senior Unsecured Notes	50	3.66	2025
AEPTCo	Senior Unsecured Notes	40	3.76	2025
AGR	Other Long-term Debt	500	Variable	2017
KPCo	Other Long-term Debt	25	Variable	2018
TCC	Senior Unsecured Notes	250	3.85	2025
TNC	Senior Unsecured Notes	50	3.75	2025
TNC	Senior Unsecured Notes	25	3.27	2022
Transource Missouri	Other Long-term Debt	20	Variable	2018
WPCo	Senior Unsecured Notes	113	3.36	2022
WPCo	Senior Unsecured Notes	122	3.70	2025
WPCo	Senior Unsecured Notes	50	4.20	2035
Total Issuances		$2,956 (a)		

(a) 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.

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Company	Type of Debt	Principal Amount Paid		Interest Rate	Due Date
Total Retirements and Principal Payments:		(in millions)		(%)	
APCo	Securitization Bonds	$23		2.008	2024
APCo	Senior Unsecured Notes	350		7.95	2020
APCo	Senior Unsecured Notes	300		3.40	2015
I&M	Other Long-term Debt	94		Variable	2015
I&M	Other Long-term Debt	1		6.00	2025
I&M	Notes Payable	18		Variable	2016
I&M	Notes Payable	21		Variable	2017
I&M	Notes Payable	26		Variable	2019
I&M	Notes Payable	16		Variable	2019
I&M	Notes Payable	1		Variable	2016
I&M	Notes Payable	1		2.12	2016
OPCo	Pollution Control Bonds	86		3.125	2015
OPCo	Securitization Bonds	45		0.958	2018
SWEPCo	Notes Payable	3		4.58	2032
SWEPCo	Pollution Control Bonds	54		3.25	2015
SWEPCo	Senior Unsecured Notes	100		5.375	2015
SWEPCo	Senior Unsecured Notes	150		4.90	2015
Non-Registrant:					
AEGCo	Senior Unsecured Notes	7		6.33	2037
AEP Subsidiaries	Notes Payable	5		Variable	2017
AEP Subsidiaries	Notes Payable	1	(a)	7.59	2026
AEP Subsidiaries	Notes Payable	1	(a)	8.03	2026
AGR	Other Long-term Debt	500		Variable	2015
AGR	Pollution Control Bonds	50		Variable	2015
AGR	Pollution Control Bonds	39		Variable	2015
TCC	Securitization Bonds	81		5.09	2015
TCC	Securitization Bonds	76		6.25	2016
TCC	Securitization Bonds	27		0.88	2017
TCC	Securitization Bonds	57		5.17	2018
Total Retirements and Principal Payments		$2,133	(a)		

(a) Amount includes principal payments of debt related to AEPRO that has been classified as Discontinued Operations on the condensed statement of cash flows.

In October 2015, KPCo drew the remaining $25 million on an existing $75 million variable rate credit facility due in 2018.

In October 2015, Transource Missouri drew $6 million on an existing $300 million variable rate credit facility due in 2018.

As of September 30, 2015, trustees held on our behalf, $475 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, 2015			December 31, 2014		
Type of Debt	Outstanding Amount (in millions)	Interest Rate (a)		Outstanding Amount (in millions)	Interest Rate (a)	
Securitized Debt for Receivables (b)	$750	0.28	%	$744	0.22	%
Commercial Paper	32	0.44	%	602	0.59	%
Total Short-term Debt	$782			$1,346		

(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 2017.

Accounts receivable information for AEP Credit is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	0.30 %	0.21 %	0.28 %	0.22 %
Net Uncollectible Accounts Receivable Written Off	$13	$16	$27	$32

	September 30, 2015	December 31, 2014
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$970	$975
Total Principal Outstanding	750	744
Delinquent Securitized Accounts Receivable	50	44
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	16	13
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	277	335

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, 2015 and 2014 were $41 million and $41 million, respectively, and for the nine months ended September 30, 2015 and 2014 were $124 million and $121 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, which 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 DCC Fuel 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, 2015 and 2014 were $29 million and $28 million, respectively, and for the nine months ended September 30, 2015 and 2014 were $86 million and $84 million, respectively. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on our control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on the condensed balance sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on our control of AEP Credit, management 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 $1.5 billion and $1.8 billion as of September 30, 2015 and December 31, 2014, respectively. Transition Funding has securitized transition assets of $1.4 billion and $1.6 billion as of September 30, 2015 and December 31, 2014, 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 $187 million and $232 million as of September 30, 2015 and December 31, 2014, respectively. Ohio Phase-in-Recovery Funding has securitized assets of $92 million and $110 million as of September 30, 2015 and December 31, 2014, 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 $345 million and $368 million as of September 30, 2015 and December 31, 2014, respectively. Appalachian Consumer Rate Relief Funding has securitized assets of $333 million and $350 million as of September 30, 2015 and December 31, 2014, 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 Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated 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 of EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate the protected cell of EIS. Our insurance premium expense to the protected cell for the three months ended September 30, 2015 and 2014 was $13 million and $16 million, respectively, and for the nine months ended September 30, 2015 and 2014 was $27 million and $33 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 (a wholly-owned subsidiary of Transource Energy) 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, construction projects, debt issuance and capital contribution. AEP provided capital contributions to Transource Energy of $32 million and $23 million during the nine months ended September 30, 2015 and the year ended December 31, 2014, respectively. AEP and the other owner of Transource Energy are required to ensure a specific equity level in Transource Missouri upon completion of projects or if a project is abandoned by the RTO. 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, 2015
(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	$61	$104	$977	$197		$20		$11		$163	$12
Net Property, Plant and Equipment	144	193	—	—		—		—		—	184
Other Noncurrent Assets	60	101	1	1,454	(a)	175	(b)	341	(c)	3	5
Total Assets	$265	$398	$978	$1,651		$195		$352		$166	$201
LIABILITIES AND EQUITY											
Current Liabilities	$40	$98	$875	$283		$47		$25		$49	$47
Noncurrent Liabilities	225	300	1	1,350		147		325		76	80

Equity	—	—	102	18	1	2	41	74
Total Liabilities and Equity	$265	$398	$978	$1,651	$195	$352	$166	$201

(a) Includes an intercompany item eliminated in consolidation of $70 million.
(b) Includes an intercompany item eliminated in consolidation of $81 million.
(c) Includes an intercompany item eliminated in consolidation of $4 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 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	$68	$97	$980	$239	$33	$18	$149	$2
Net Property, Plant and Equipment	145	158	—	—	—	—	—	98
Other Noncurrent Assets	52	80	—	1,654 (a)	210 (b)	358 (c)	2	4
Total Assets	$265	$335	$980	$1,893	$243	$376	$151	$104
LIABILITIES AND EQUITY								
Current Liabilities	$36	$86	$894	$322	$47	$27	$44	$21
Noncurrent Liabilities	228	249	—	1,553	195	347	62	55
Equity	1	—	86	18	1	2	45	28
Total Liabilities and Equity	$265	$335	$980	$1,893	$243	$376	$151	$104

(a) Includes an intercompany item eliminated in consolidation of $75 million.
(b) Includes an intercompany item eliminated in consolidation of $97 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, 2015 and 2014 were $30 million and $24 million, respectively, and for the nine months ended September 30, 2015 and 2014 were $59 million and $31 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, 2015		December 31, 2014	
	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	6	6	4	4
Advance Due to Parent	40	40	56	56
Guarantee of Debt	—	55	—	48

Total Investment in DHLC	$54	$109	$68	$116

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 and controlled by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it 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. Hearings at FERC were held in March and April 2015. In September 2015, the Administrative Law Judge who conducted the hearings issued an Initial Decision, with recommendations on various issues in the case. The Initial Decision has no binding effect. Additional briefing is scheduled during the fourth quarter of 2015, after which the case will be pending before FERC.

Our investment in PATH-WV was:

	September 30, 2015		December 31, 2014	
	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	2	2	2	2
Total Investment in PATH-WV	$21	$21	$21	$21

As of September 30, 2015, our $21 million investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the condensed balance sheet. We believe the financial statements adequately address the impact of the Initial Decision. If we cannot ultimately recover our investment related to PATH-WV, it could reduce future net income and cash flows.

14. PROPERTY, PLANT AND EQUIPMENT

Asset Retirement Obligations (ARO)

We record ARO in accordance with the accounting guidance for “Asset Retirement and Environmental Obligations” for our legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property’s use. We do not estimate the retirement for such easements because we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.

We recorded an increase in our asset retirement obligations in the second quarter of 2015, primarily related to the final Coal Combustion Residual Rule, which was published in the Federal Register in April 2015. The Federal EPA now regulates the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The Federal EPA regulates CCR as a non-hazardous solid waste and established minimum federal solid waste management standards. Noncash increases related to the CCR Rule are recorded as Property, Plant and Equipment. The following is a reconciliation of the aggregate carrying amount of ARO, including a $95 million second quarter increase and other adjustments recorded in the third quarter:

	Carrying Amount of ARO (in millions)	
ARO as of December 31, 2014	$2,019	
Accretion Expense	76	
Liabilities Incurred	48	
Liabilities Settled (a)	(126	)
Revisions in Cash Flow Estimates (b)	30	
ARO as of September 30, 2015	$2,047	

(a) Amount includes settlement of liabilities of $81 million associated with the sale of the Muskingum River Plant site. See the "Muskingum River Plant" section of Note 6.

(b) Amount includes a $20 million reduction in the ARO liability due to the execution of a joint use agreement with a third party.

As of September 30, 2015 and December 31, 2014, our ARO liability included $1.31 billion and $1.27 billion, respectively, for nuclear decommissioning of the Cook Plant. As of September 30, 2015 and December 31, 2014, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1.74 billion and $1.79 billion, respectively, and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on the condensed balance sheets.

15. DISPOSITION PLANT SEVERANCE

AEP retired several generation plants or units of plants during 2015. These plant closures resulted in involuntary severances. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

The disposition plant severance activity for the nine months ended September 30, 2015 is described in the following table:

	Disposition Plant Severance Activity (in millions)
Balance as of December 31, 2014	$29
Incurred	3
Settled	(21)
Adjustments	—
Balance as of September 30, 2015	$11

We recorded a charge of $29 million to Other Operation expense in 2014 primarily related to employees at the disposition plants. These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the condensed statements of income. Of the cumulative expense, approximately 32% was within the Generation & Marketing segment and 68% was within the Vertically Integrated Utilities segment. The remaining liability is included in Other Current Liabilities on the condensed balance sheets. We incurred additional charges during the second quarter of 2015 as severance plans were finalized after the plants were retired. We do not expect additional severance costs to be incurred related to this initiative.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

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

EXECUTIVE OVERVIEW

Regulatory Activity

2015 Virginia Regulatory Asset Proceeding

In January 2015, the Virginia SCC initiated a proceeding to address the proper treatment of APCo’s authorized regulatory assets. In February and March 2015, briefs related to this proceeding were filed by various parties. As of September 30, 2015, APCo’s authorized regulatory assets under review in this proceeding were $11 million. If any of these costs, or any additional costs that may be subject to review, are not recoverable, it could reduce future net income and cash flows and impact financial condition.

New Virginia Legislation Affecting Biennial Reviews

In February 2015, amendments to Virginia law governing the regulation of investor-owned electric utilities were enacted. Under the amended Virginia law, APCo’s existing generation and distribution base rates are frozen until after the Virginia SCC rules on APCo’s next biennial review, which APCo will file in March 2020 for the 2018 and 2019 test years. These amendments also preclude the Virginia SCC from performing biennial reviews of APCo’s earnings for the years 2014 through 2017. APCo's financial statements adequately address the impact of these amendments. The new law provides that APCo will absorb its Virginia jurisdictional share of incremental generation and distribution costs incurred during 2014 through 2017 that are associated with severe weather events and/or natural disasters and costs associated with potential asset impairments related to new carbon emission guidelines issued by the Federal EPA.

West Virginia Inquiry into Plant Closures

Subsequent to APCo’s retirement of the Kanawha River Plant in May 2015, the WVPSC issued an order in July 2015 that requested APCo to maintain, for at least four years, any infrastructure installed at the Kanawha River Plant that would be used if the plant were to be converted to burn natural gas. The WVPSC stated that it would not be reasonable and prudent to completely demolish facilities that might be available in the future for conversion to natural gas before further consideration is given to the future of APCo’s coal fired generation. The order indicated that the WVPSC would consider prudently incurred operating fees related to Kanawha River and Sporn Plants for recovery in a future case. In October 2015, APCo filed an application with the WVPSC to request that it be relieved of any obligation to study further the future viability of the Sporn Plant and Glen Lyn Plant units and of any obligation to maintain these units. Additionally, APCo plans to consider the Kanawha River Plant units in its preparation of an integrated resource plan to be filed with the WVPSC by December 31, 2015.

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 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in the 2014 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 179. 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 256 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,	
	2015	2014	2015	2014
	(in millions of KWhs)			
Retail:				
Residential	2,599	2,503	9,039	9,131
Commercial	1,744	1,726	5,161	5,150
Industrial	2,493	2,600	7,520	7,665
Miscellaneous	205	205	633	636
Total Retail	7,041	7,034	22,353	22,582
Wholesale	681	563	2,335	2,507
Total KWhs	7,722	7,597	24,688	25,089

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,	
	2015	2014	2015	2014
	(in degree days)			
Actual - Heating (a)	—	—	1,735	1,776
Normal - Heating (b)	3	2	1,415	1,405
Actual - Cooling (c)	804	639	1,275	1,041
Normal - Cooling (b)	809	816	1,175	1,183

(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 2015 Compared to Third Quarter of 2014
Reconciliation of Third Quarter of 2014 to Third Quarter of 2015
Net Income
(in millions)

Third Quarter of 2014	$49	
Changes in Gross Margin:		
Retail Margins	35	
Off-system Sales	(1	)
Transmission Revenues	(8	)
Other Revenues	2	
Total Change in Gross Margin	28	
Changes in Expenses and Other:		
Other Operation and Maintenance	(4	)
Depreciation and Amortization	4	
Allowance for Equity Funds Used During Construction	1	
Interest Expense	6	
Total Change in Expenses and Other	7	
Income Tax Expense	(9	)
Third Quarter of 2015	$75	

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 $35 million primarily due to the following:
- A $32 million increase primarily due to increases in rates in West Virginia, offset by decreases in rates in Virginia and formula rates in both jurisdictions. Of these changes, $4 million relates to riders/trackers which have corresponding increases in other expense items below.
- A $14 million increase in weather-related usage primarily due to a 26% increase in cooling degree days.

These increases were partially offset by:

- A $12 million decrease in weather-normalized margin primarily due to lower industrial usage.
- Transmission Revenues decreased $8 million primarily due to lower Network Integrated Transmission Service (NITS) revenues. These NITS revenues are partially offset in Other Operation and Maintenance expenses below.

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

- Other Operation and Maintenance expenses increased $4 million primarily due to the following:
  - A $14 million increase in distribution expenses primarily related to implementation of a surcharge to recover West Virginia vegetation management expenses effective June 2015 and increased amortization of West Virginia storm costs.
  - A $3 million increase in generation operation expenses primarily related to amortizations of West Virginia Carbon Capture storage and IGCC and decommissioning expenses at disposition plants. This increase was partially offset in Gross Margin above.
  - A $2 million increase in customer accounts expenses related to customer assistance and uncollectible accounts.

  These increases were partially offset by:
  - A $7 million decrease in steam and electric plant maintenance expenses primarily at the Amos and Mountaineer Plants.
  - A $6 million decrease associated with the under recovery of transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause as allowed by the Virginia SCC.
  - A $2 million decrease in PJM expenses primarily related to NITS. This decrease is partially offset by a corresponding decrease in Gross Margin above.
- Depreciation and Amortization expenses decreased $4 million due to prior year amortization of Virginia environmental deferrals, which ended in the first quarter of 2015.
- Interest Expense decreased $6 million primarily due to the following:
  - A $4 million decrease due to lower interest rates on long-term debt.
- Income Tax Expense increased $9 million primarily due to an increase in pretax book income, partially offset by the recording of federal and state income tax adjustments.

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Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014
Reconciliation of Nine Months Ended September 30, 2014 to Nine Months Ended September 30, 2015
Net Income
(in millions)

Nine Months Ended September 30, 2014	$187	
Changes in Gross Margin:		
Retail Margins	116	
Off-system Sales	(3	)
Transmission Revenues	(6	)
Other Revenues	2	
Total Change in Gross Margin	109	
Changes in Expenses and Other:		
Other Operation and Maintenance	—	
Depreciation and Amortization	7	
Taxes Other Than Income Taxes	(1	)
Carrying Costs Income	2	
Allowance for Equity Funds Used During Construction	6	
Interest Expense	12	
Total Change in Expenses and Other	26	
Income Tax Expense	(47	)
Nine Months Ended September 30, 2015	$275	

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 $116 million primarily due to the following:
  - A $93 million increase primarily due to increases in rates in West Virginia and Virginia, as well as an adjustment due to the amended Virginia law impacting biennial reviews. Of these increases, $13 million relate to riders/trackers which have corresponding increases in other expense items below.
  - An $18 million increase in weather-related usage primarily due to a 23% increase in cooling degree days.
  - A $10 million decrease in generation related PJM expenses due to the polar vortex in 2014 net of recovery or offsets.
  - A $7 million decrease in fuel expense from wholesale customers due to the timing of fuel recovery in 2014.
  - A $3 million decrease in consumables and allowances expense.

  These increases were partially offset by:
  - A $32 million decrease in weather-normalized margin primarily due to lower usage.
- Transmission Revenues decreased $6 million primarily due to lower NITS revenues.

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

- Other Operation and Maintenance expenses were approximately unchanged primarily due to the following:
  - A $21 million increase in PJM expenses primarily related to NITS.

  This increase was partially offset by:
  - A $21 million decrease in plant maintenance expenses primarily at Amos Plant.
- Depreciation and Amortization expenses decreased $7 million primarily due to the following:
  - A $9 million decrease due to prior year amortization of Virginia environmental deferrals, which ended in the first quarter of 2015.
  - A $2 million decrease due to prior year amortization of West Virginia ENEC deferrals.

  These decreases were partially offset by:
  - A $4 million increase due to a higher depreciable base.
- Carrying Cost Income increased $2 million related to West Virginia ENEC deferrals.
- Allowance for Equity Funds Used During Construction increased $6 million primarily due to increased transmission projects.
- Interest Expense decreased $12 million primarily due to the following:
  - A $5 million decrease due to lower interest rates on long-term debt.
  - A $3 million decrease due to higher debt component of AFUDC from increased transmission projects.
  - A $2 million decrease due to a 2014 amortization of loss on reacquired long-term debt.
- Income Tax Expense increased $47 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 2014 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 256 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, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
REVENUES				
Electric Generation, Transmission and Distribution	$685,312	$672,459	$2,184,943	$2,202,967
Sales to AEP Affiliates	39,389	35,455	115,740	108,439
Other Revenues	2,857	1,970	7,870	6,537
TOTAL REVENUES	727,558	709,884	2,308,553	2,317,943
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	188,576	194,303	595,308	627,943
Purchased Electricity for Resale	80,452	85,656	258,836	340,680
Purchased Electricity from AEP Affiliates	—	—	—	4,662
Other Operation	101,841	103,835	311,631	297,269
Maintenance	70,459	64,333	179,793	193,907
Depreciation and Amortization	96,295	99,889	292,735	300,125
Taxes Other Than Income Taxes	32,002	31,632	93,089	92,434
TOTAL EXPENSES	569,625	579,648	1,731,392	1,857,020
OPERATING INCOME	157,933	130,236	577,161	460,923
Other Income (Expense):				
Interest Income	290	521	1,128	1,311
Carrying Costs Income (Expense)	73	482	783	(1,130)
Allowance for Equity Funds Used During Construction	3,432	1,665	10,337	4,525
Interest Expense	(46,625)	(52,738)	(145,600)	(157,540)
INCOME BEFORE INCOME TAX EXPENSE	115,103	80,166	443,809	308,089
Income Tax Expense	40,507	31,408	168,368	121,233
NET INCOME	$74,596	$48,758	$275,441	$186,856

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net Income	$74,596	$48,758	$275,441	$186,856
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $120 and $92 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $49 and $314 for the Nine Months Ended September 30, 2015 and 2014, Respectively	(222)	170	(91)	582
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $247 and $179 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $740 and $538 for the Nine Months Ended September 30, 2015 and 2014, Respectively	(458)	(333)	(1,374)	(999)
TOTAL OTHER COMPREHENSIVE LOSS	(680)	(163)	(1,465)	(417)
TOTAL COMPREHENSIVE INCOME	$73,916	$48,595	$273,976	$186,439

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$260,458	$1,809,562	$1,291,876	$5,032	$3,366,928
Common Stock Dividends			(181,250)		(181,250)
Net Income			275,441		275,441
Other Comprehensive Loss				(1,465)	(1,465)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2015	$260,458	$1,809,562	$1,386,067	$3,567	$3,459,654

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$2,411	$2,613
Restricted Cash for Securitized Funding	7,436	15,599
Advances to Affiliates	23,535	48,519
Accounts Receivable:		
Customers	118,331	114,711
Affiliated Companies	56,687	67,294
Accrued Unbilled Revenues	36,629	58,022
Miscellaneous	3,180	1,956
Allowance for Uncollectible Accounts	(3,961)	(2,364)
Total Accounts Receivable	210,866	239,619
Fuel	77,785	113,386
Materials and Supplies	126,941	131,285
Risk Management Assets – Nonaffiliated	25,970	23,792
Risk Management Assets – Affiliated	1,380	—
Deferred Income Tax Benefits	—	23,955
Regulatory Asset for Under-Recovered Fuel Costs	69,013	66,076
Prepayments and Other Current Assets	27,673	13,660
TOTAL CURRENT ASSETS	573,010	678,504
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,174,000	6,824,029
Transmission	2,271,351	2,228,029
Distribution	3,351,264	3,258,306
Other Property, Plant and Equipment	390,180	373,520
Construction Work in Progress	535,112	321,495
Total Property, Plant and Equipment	12,721,907	13,005,379
Accumulated Depreciation and Amortization	3,426,961	3,823,664
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	9,294,946	9,181,715
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,061,715	857,872
Securitized Assets	333,491	350,170
Long-term Risk Management Assets – Nonaffiliated	2,035	4,891
Deferred Charges and Other Noncurrent Assets	141,012	159,230
TOTAL OTHER NONCURRENT ASSETS	1,538,253	1,372,163
TOTAL ASSETS	$11,406,209	$11,232,382

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2015 and December 31, 2014
(Unaudited)

	September 30, 2015	December 31, 2014
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$35,224	$—
Accounts Payable:		
General	186,317	166,821
Affiliated Companies	74,006	80,602
Long-term Debt Due Within One Year – Nonaffiliated	318,020	552,212
Long-term Debt Due Within One Year – Affiliated	—	86,000
Risk Management Liabilities – Nonaffiliated	6,902	11,017
Customer Deposits	79,237	71,766
Accrued Taxes	45,938	109,482
Accrued Interest	63,837	52,141
Other Current Liabilities	182,191	145,017
TOTAL CURRENT LIABILITIES	991,672	1,275,058
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,637,275	3,342,062
Long-term Risk Management Liabilities – Nonaffiliated	973	2,057
Deferred Income Taxes	2,410,754	2,288,842
Regulatory Liabilities and Deferred Investment Tax Credits	646,262	652,867
Asset Retirement Obligations	110,474	122,300
Employee Benefits and Pension Obligations	119,986	127,980
Deferred Credits and Other Noncurrent Liabilities	29,159	54,288
TOTAL NONCURRENT LIABILITIES	6,954,883	6,590,396
TOTAL LIABILITIES	7,946,555	7,865,454
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	1,386,067	1,291,876
Accumulated Other Comprehensive Income (Loss)	3,567	5,032
TOTAL COMMON SHAREHOLDER’S EQUITY	3,459,654	3,366,928
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$11,406,209	$11,232,382

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Nine Months Ended September 30,	
	2015	2014
OPERATING ACTIVITIES		
Net Income	$275,441	$186,856
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	292,735	300,125
Deferred Income Taxes	179,143	114,778
Carrying Costs Income (Expense)	(783)	1,130
Allowance for Equity Funds Used During Construction	(10,337)	(4,525)
Mark-to-Market of Risk Management Contracts	(5,902)	255
Pension Contributions to Qualified Plan Trust	(9,981)	(8,963)
Property Taxes	27,980	25,856
Fuel Over/Under-Recovery, Net	(1,729)	(114,022)
Change in Other Noncurrent Assets	(32,481)	(19,178)
Change in Other Noncurrent Liabilities	(27,399)	29,312
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	28,753	114,387
Fuel, Materials and Supplies	31,352	78,977
Accounts Payable	2,678	(65,358)
Accrued Taxes, Net	(75,290)	(43,092)
Other Current Assets	(2,628)	(3,748)
Other Current Liabilities	15,411	9,085
Net Cash Flows from Operating Activities	686,963	601,875
INVESTING ACTIVITIES		
Construction Expenditures	(456,721)	(342,291)
Change in Advances to Affiliates, Net	24,984	22,395
Other Investing Activities	18,868	(1,114)
Net Cash Flows Used for Investing Activities	(412,869)	(321,010)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	726,330	295,039
Change in Advances from Affiliates, Net	35,224	—
Retirement of Long-term Debt – Nonaffiliated	(672,552)	(512,702)
Retirement of Long-term Debt – Affiliated	(86,000)	—
Make Whole Premium on Extinguishment of Long-term Debt – Nonaffiliated	(92,658)	—
Principal Payments for Capital Lease Obligations	(3,843)	(4,255)
Dividends Paid on Common Stock	(181,250)	(60,000)
Other Financing Activities	453	1,009
Net Cash Flows Used for Financing Activities	(274,296)	(280,909)
Net Decrease in Cash and Cash Equivalents	(202)	(44)
Cash and Cash Equivalents at Beginning of Period	2,613	2,745

Cash and Cash Equivalents at End of Period	$2,411	$2,701
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$128,435	$136,919
Net Cash Paid for Income Taxes	33,712	22,148
Noncash Acquisitions Under Capital Leases	2,257	3,451
Construction Expenditures Included in Current Liabilities as of September 30,	80,990	54,463

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

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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.

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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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 approval of I&M's seven-year TDSIC Plan for eligible transmission, distribution and storage system improvements totaling $787 million. In April 2015, I&M filed a notice with the IURC to exclude $117 million related to certain projects. In September 2015, the IURC granted I&M's motion to withdraw its application for reconsideration and/or rehearing and I&M withdrew its appeal with the Indiana Court of Appeals.

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 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in the 2014 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 179. 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 a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs' claims. Several claims remain, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. In June 2015, AEGCo and I&M filed a motion for partial judgment on the claims seeking dismissal of the breach of participation agreement claim as well as any claim for indemnification of costs associated with this case. Plaintiffs subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. Management will continue to defend against the remaining 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 256 for additional discussion of relevant factors.

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RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions of KWhs)			
Retail:				
Residential	1,441	1,347	4,311	4,413
Commercial	1,342	1,264	3,744	3,681
Industrial	1,972	1,933	5,712	5,701
Miscellaneous	15	15	50	50
Total Retail	4,770	4,559	13,817	13,845
Wholesale	2,649	3,985	8,732	13,151
Total KWhs	7,419	8,544	22,549	26,996

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,	
	2015	2014	2015	2014
	(in degree days)			
Actual - Heating (a)	—	6	2,931	3,222
Normal - Heating (b)	10	11	2,413	2,388
Actual - Cooling (c)	530	410	796	712
Normal - Cooling (b)	574	581	836	843

(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 2015 Compared to Third Quarter of 2014
Reconciliation of Third Quarter of 2014 to Third Quarter of 2015
Net Income
(in millions)

Third Quarter of 2014	$27
Changes in Gross Margin:	
Retail Margins	27
FERC Municipals and Cooperatives	7
Off-system Sales	(7)
Transmission Revenues	(3)
Other Revenues	6
Total Change in Gross Margin	30
Changes in Expenses and Other:	
Other Operation and Maintenance	9
Depreciation and Amortization	1
Taxes Other Than Income Taxes	1
Other Income	(3)
Interest Expense	(1)
Total Change in Expenses and Other	7
Income Tax Expense	(7)
Third Quarter of 2015	$57

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 $27 million primarily due to the following:
  - A $15 million increase resulting from successful rate proceedings in the Indiana service territory.
  - An $8 million increase in weather-related usage primarily due to a 29% increase in cooling degree days.
  - A $5 million increase in weather-normalized usage.

  These increases were partially offset by:
  - A $4 million decrease due to increased costs for power acquired under the Unit Power Agreement between AEGCo and I&M.
- Margins from FERC Municipal and Cooperatives increased $7 million primarily due to formula rate changes.
- Margins from Off-system Sales decreased $7 million due to lower market prices and decreased sales volumes.
- Other Revenues increased $6 million primarily due to a 2014 MPSC order disallowing $4 million of lost revenue from 2012 through 2014 related to Demand Side Management.

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

- Other Operation and Maintenance expenses decreased $9 million primarily due to the following:
- An $8 million decrease due to a 2014 accrual for expected environmental remediation costs.
- A $5 million decrease in boiler plant maintenance expenses primarily due to the retirement of the Tanners Creek Plant in May 2015.

These decreases were partially offset by:

- A $4 million increase in nuclear expenses primarily related to Cook Plant, Unit 1 diesel generator repairs.
- Other Income decreased $3 million primarily due to a decrease in AFUDC Equity accrued on nuclear fuel for the reactors at Cook Plant.
- Income Tax Expense increased $7 million primarily due to an increase in pretax book income, partially offset by the recording of federal and state income tax adjustments.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014
Reconciliation of Nine Months Ended September 30, 2014 to Nine Months Ended September 30, 2015
Net Income
(in millions)

Nine Months Ended September 30, 2014	$ 141
Changes in Gross Margin:	
Retail Margins	58
FERC Municipals and Cooperatives	32
Off-system Sales	(58)
Other Revenues	(2)
Total Change in Gross Margin	30
Changes in Expenses and Other:	
Other Operation and Maintenance	25
Taxes Other Than Income Taxes	(2)
Other Income	(2)
Interest Expense	3
Total Change in Expenses and Other	24
Income Tax Expense	(15)
Nine Months Ended September 30, 2015	$ 180

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 $58 million primarily due to the following:
  - A $42 million increase resulting from successful rate proceedings in the Indiana service territory.
  - A $12 million decrease in PJM related expenses primarily related to the polar vortex in 2014.

  These increases were partially offset by:
  - A $4 million decrease due to weather-normalized Residential sales.
- Margins from FERC Municipal and Cooperatives increased $32 million primarily due to the annual true-up adjustment of formula rates to actual costs.
- Margins from Off-system Sales decreased $58 million due to lower market prices and decreased sales volume.
- Other Revenues decreased $2 million primarily due to the following:
  - An $8 million decrease in barging deliveries to the Rockport Plant by River Transportation Division (RTD). The decrease in RTD revenue was offset by a corresponding decrease in Other Operation and Maintenance expenses for barging below.

  This decrease was partially offset by:
  - A $4 million increase relating to a 2014 MPSC order disallowing lost revenue from 2012 through 2014 related to Demand Side Management.
  - A $1 million increase relating to a net gain on coal procurement sales.

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

- Other Operation and Maintenance expenses decreased $25 million primarily due to the following:
- A $14 million decrease in environmental costs due to a 2014 accrual of $8 million for expected environmental remediation costs and a current year $6 million reduction of an environmental liability.
- An $8 million decrease in general and administrative expenses.
- An $8 million decrease in distribution expenses primarily due to lower storm restoration and forestry expense.
- A $6 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 above.

These decreases were partially offset by:
- An $11 million increase in nuclear expenses primarily related to Cook Plant, Unit 1 diesel generator repairs.
- Interest Expense decreased $3 million primarily due to a lower interest rate on a remarketed pollution control bonds.
- Income Tax Expense increased $15 million primarily due to an increase in pretax book income, partially offset by the recording of federal and state income tax adjustments.

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 2014 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 256 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, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
REVENUES				
Electric Generation, Transmission and Distribution	$536,227	$520,881	$1,617,504	$1,642,721
Sales to AEP Affiliates	9,677	401	16,634	3,753
Other Revenues – Affiliated	21,672	20,832	62,183	70,821
Other Revenues – Nonaffiliated	786	749	2,626	1,298
TOTAL REVENUES	568,362	542,863	1,698,947	1,718,593
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	90,499	117,414	264,424	387,757
Purchased Electricity for Resale	41,544	20,019	147,711	52,467
Purchased Electricity from AEP Affiliates	67,281	66,561	182,239	203,807
Other Operation	141,054	144,331	407,320	431,953
Maintenance	53,727	59,043	160,907	161,854
Depreciation and Amortization	49,215	50,585	150,162	150,062
Taxes Other Than Income Taxes	21,608	22,059	66,992	64,685
TOTAL EXPENSES	464,928	480,012	1,379,755	1,452,585
OPERATING INCOME	103,434	62,851	319,192	266,008
Other Income (Expense):				
Interest Income	1,896	1,450	7,222	4,228
Allowance for Equity Funds Used During Construction	2,157	5,596	9,107	14,364
Interest Expense	(23,144)	(22,617)	(68,889)	(71,955)
INCOME BEFORE INCOME TAX EXPENSE	84,343	47,280	266,632	212,645
Income Tax Expense	27,691	20,654	86,725	71,596
NET INCOME	$56,652	$26,626	$179,907	$141,049

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net Income	$56,652	$26,626	$179,907	$141,049
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $144 and $220 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $432 and $638 for the Nine Months Ended September 30, 2015 and 2014, Respectively	267	410	802	1,185
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $6 and $22 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $18 and $68 for the Nine Months Ended September 30, 2015 and 2014, Respectively	11	42	33	128
TOTAL OTHER COMPREHENSIVE INCOME	278	452	835	1,313
TOTAL COMPREHENSIVE INCOME	$56,930	$27,078	$180,742	$142,362

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$56,584	$980,896	$930,829	$(14,360)	$1,953,949
Common Stock Dividends			(90,000)		(90,000)
Net Income			179,907		179,907
Other Comprehensive Income				835	835
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2015	$56,584	$980,896	$1,020,736	$(13,525)	$2,044,691

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$1,264	$1,020
Advances to Affiliates	13,508	13,481
Accounts Receivable:		
Customers	58,950	56,978
Affiliated Companies	63,135	72,582
Accrued Unbilled Revenues	2,254	503
Miscellaneous	1,409	1,625
Allowance for Uncollectible Accounts	(21)	(494)
Total Accounts Receivable	125,727	131,194
Fuel	24,687	54,623
Materials and Supplies	189,764	201,089
Risk Management Assets – Nonaffiliated	8,574	22,328
Risk Management Assets – Affiliated	2,053	—
Accrued Tax Benefits	6,232	24,788
Prepayments and Other Current Assets	27,549	27,968
TOTAL CURRENT ASSETS	399,358	476,491
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,968,224	3,741,831
Transmission	1,380,689	1,358,419
Distribution	1,758,347	1,698,409
Other Property, Plant and Equipment (September 30, 2015 and December 31, 2014 Amounts Include Coal Mining and Nuclear Fuel, December 31, 2014 Amount Includes 2015 Plant Retirement)	745,858	1,490,820
Construction Work in Progress	470,794	537,237
Total Property, Plant and Equipment	8,323,912	8,826,716
Accumulated Depreciation, Depletion and Amortization	3,084,188	3,410,341
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,239,724	5,416,375
OTHER NONCURRENT ASSETS		
Regulatory Assets	818,168	536,152
Spent Nuclear Fuel and Decommissioning Trusts	2,047,260	2,095,732
Long-term Risk Management Assets – Nonaffiliated	1,338	3,317
Deferred Charges and Other Noncurrent Assets	123,676	137,209
TOTAL OTHER NONCURRENT ASSETS	2,990,442	2,772,410
TOTAL ASSETS	$8,629,524	$8,665,276

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2015 and December 31, 2014
(dollars in thousands)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT LIABILITIES		
Advances from Affiliates	$151,004	$142,501
Accounts Payable:		
General	132,292	168,294
Affiliated Companies	70,812	76,010
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2015 and December 31, 2014 Amounts Include $97,953 and $85,657, Respectively, Related to DCC Fuel)	301,148	382,187
Risk Management Liabilities – Nonaffiliated	4,615	5,223
Customer Deposits	35,641	35,206
Accrued Taxes	58,791	72,742
Accrued Interest	13,263	26,677
Obligations Under Capital Leases	40,375	42,050
Other Current Liabilities	151,489	150,566
TOTAL CURRENT LIABILITIES	959,430	1,101,456
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,759,503	1,645,210
Long-term Risk Management Liabilities – Nonaffiliated	1,248	1,395
Deferred Income Taxes	1,329,163	1,264,167
Regulatory Liabilities and Deferred Investment Tax Credits	1,041,910	1,199,694
Asset Retirement Obligations	1,379,004	1,337,179
Deferred Credits and Other Noncurrent Liabilities	114,575	162,226
TOTAL NONCURRENT LIABILITIES	5,625,403	5,609,871
TOTAL LIABILITIES	6,584,833	6,711,327
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	1,020,736	930,829
Accumulated Other Comprehensive Income (Loss)	(13,525)	(14,360)
TOTAL COMMON SHAREHOLDER’S EQUITY	2,044,691	1,953,949
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$8,629,524	$8,665,276

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Nine Months Ended September 30,	
	2015	2014
OPERATING ACTIVITIES		
Net Income	$179,907	$141,049
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	150,162	150,062
Deferred Income Taxes	38,338	15,792
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(148)	23,951
Allowance for Equity Funds Used During Construction	(9,107)	(14,364)
Mark-to-Market of Risk Management Contracts	12,926	(2,196)
Amortization of Nuclear Fuel	101,649	114,238
Fuel Over/Under-Recovery, Net	(16,055)	18,931
Change in Other Noncurrent Assets	27,286	(36,596)
Change in Other Noncurrent Liabilities	(6,330)	66,502
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	5,467	59,646
Fuel, Materials and Supplies	29,609	14,884
Accounts Payable	(14,001)	(12,052)
Accrued Taxes, Net	4,605	30,719
Other Current Assets	6,923	11,741
Other Current Liabilities	(9,276)	(8,201)
Net Cash Flows from Operating Activities	501,955	574,106
INVESTING ACTIVITIES		
Construction Expenditures	(337,021)	(345,369)
Change in Advances to Affiliates, Net	(27)	42,364
Purchases of Investment Securities	(1,479,149)	(789,461)
Sales of Investment Securities	1,437,336	746,272
Acquisitions of Nuclear Fuel	(53,262)	(109,224)
Other Investing Activities	9,000	11,773
Net Cash Flows Used for Investing Activities	(423,123)	(443,645)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	210,687	99,323
Change in Advances from Affiliates, Net	8,503	95,899
Retirement of Long-term Debt – Nonaffiliated	(178,471)	(190,550)
Principal Payments for Capital Lease Obligations	(29,875)	(35,660)
Dividends Paid on Common Stock	(90,000)	(100,000)
Other Financing Activities	568	628
Net Cash Flows Used for Financing Activities	(78,588)	(130,360)
Net Increase in Cash and Cash Equivalents	244	101

Cash and Cash Equivalents at Beginning of Period	1,020	1,317
Cash and Cash Equivalents at End of Period	$1,264	$1,418
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$77,450	$75,789
Net Cash Paid (Received) for Income Taxes	17,203	(1,475)
Noncash Acquisitions Under Capital Leases	1,990	5,015
Construction Expenditures Included in Current Liabilities as of September 30,	51,582	69,241
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	31,140	11
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	2,136	3,208

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

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.

OHIO POWER COMPANY AND SUBSIDIARIES

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

EXECUTIVE OVERVIEW

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. In June 2015, the Supreme Court of Ohio issued a decision that reversed, as requested by OPCo, the PUCO order on the carrying cost rate issue and dismissed the appeal filed by the IEU. In June 2015, the IEU filed a motion for reconsideration with the Supreme Court of Ohio related to the accumulated deferred income tax credit. In September 2015, the Supreme Court of Ohio denied the IEU's request for reconsideration and in October 2015 this matter was remanded back to the PUCO for reinstatement of the WACC rate.

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 established 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 $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, which has scheduled oral arguments for the fourth quarter of 2015.

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 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. In April 2015, the PUCO issued an order that approved, with modifications, OPCo's July 2014 application to collect the unrecovered portion of the deferred capacity costs. In May 2015, the PUCO granted intervenors requests for rehearing. As of September 30, 2015, OPCo's net deferred capacity costs balance was $392 million, including debt carrying costs. Through September 30, 2015, OPCo has collected $183 million in deferred capacity costs, and related carrying charges.

In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. 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.

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 October 2014, the independent auditor, selected by the PUCO, 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/MW day capacity charge, the independent auditor has recommended 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 disagrees with the findings in the audit report.

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

June 2015 - May 2018 ESP Including PPA Application

In December 2013, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments and the continuation and modification of certain existing riders effective June 2015 through May 2018. The proposal also included 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 PPA.

In February 2015, the PUCO issued an order approving OPCo's ESP application, subject to certain modifications, with a return on common equity of 10.2% on capital costs for certain riders. The order included (a) approval of the Distribution Investment Rider (DIR) with modified rate caps established by the PUCO, (b) authorization to establish a zero rate rider for OPCo's proposed PPA, (c) the option for OPCo to reapply in a future proceeding with a more detailed PPA proposal and (d) a directive to continue to pursue the transfer of the OVEC contractual entitlement to AGR or to otherwise divest of its interest in OVEC. In May 2015, the PUCO issued an order on rehearing that increased the DIR rate caps and deferred ruling on all requests for rehearing related to the establishment of the PPA rider. In July 2015, the PUCO granted OPCo's and various intervenors' requests for rehearing related to the May 2015 order. In July 2015, intervenors filed appeals with the Supreme Court of Ohio that included opposition to the authorization of a PPA rider and the modifications to a transmission rider.

In October 2014, OPCo filed a separate application with the PUCO to propose a new extended PPA with AGR for 2,671 MW for inclusion in the PPA rider. In May 2015, OPCo filed an amended PPA application between OPCo and AGR that (a) included OPCo's OVEC contractual entitlement, (b) addressed the PPA requirements set forth in the PUCO's February 2015 order, (c) updated supporting testimony to reflect a current analysis of the PPA proposal and (d) included the 2,671 MW to be available for capacity, energy and ancillary services, produced by AGR over the lives of the respective generating units. A hearing at the PUCO related to the PPA commenced in September 2015. In October 2015, the PUCO staff submitted testimony that opposed the PPA application as currently proposed but concluded that, with changes, a PPA could be in the public interest.

If OPCo is ultimately not permitted to fully collect all components of its ESP rates, 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 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies in the 2014 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 179. 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 256 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,	
	2015	2014	2015	2014
	(in millions of KWhs)			
Retail:				
Residential	3,788	3,513	11,249	11,189
Commercial	3,929	3,714	11,074	10,838
Industrial	3,711	3,647	11,081	10,822
Miscellaneous	28	26	88	88
Total Retail (a)	11,456	10,900	33,492	32,937
Wholesale (b)	497	575	1,460	1,727
Total KWhs	11,953	11,475	34,952	34,664

(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,	
	2015	2014	2015	2014
	(in degree days)			
Actual - Heating (a)	—	1	2,575	2,540
Normal - Heating (b)	6	7	2,073	2,074
Actual - Cooling (c)	620	581	970	943
Normal - Cooling (b)	666	663	956	946

(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 2015 Compared to Third Quarter of 2014
Reconciliation of Third Quarter of 2014 to Third Quarter of 2015
Net Income
(in millions)

Third Quarter of 2014	$54
Changes in Gross Margin:	
Retail Margins	106
Off-system Sales	(10)
Transmission Revenues	(37)
Other Revenues	1
Total Change in Gross Margin	60
Changes in Expenses and Other:	
Other Operation and Maintenance	(11)
Depreciation and Amortization	(9)
Taxes Other Than Income Taxes	(4)
Carrying Costs Income	(7)
Interest Expense	(1)
Total Change in Expenses and Other	(32)
Income Tax Expense	(10)
Third Quarter of 2015	$72

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 $106 million primarily due to the following:
- A $65 million increase in transmission and PJM revenues primarily due to the energy supplied as result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
- A $33 million regulatory provision recorded in 2014.
- A $7 million increase in revenues associated with the Distribution Investment Rider.
- A $7 million increase in revenues associated with the gridSMART®, Enhanced Service Reliability and Retail Stability Riders. These riders have corresponding increases in other expense items below.

These increases were partially offset by:

- A $14 million decrease in base rates due to the discontinuance of seasonal rates.
- A $14 million decrease in revenues associated with the recovery of 2012 storm costs under the Storm Damage Recovery Rider which ended in April 2015. This decrease in Retail Margins is primarily offset by a decrease in Other Operation and Maintenance expenses below.
- Margins from Off-system Sales decreased $10 million primarily due to losses from a legacy power contract.
- Transmission Revenues decreased $37 million primarily due to a decrease in Network Integrated Transmission Service (NITS) revenue due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, partially offset by a corresponding increase in Retail Margins above.

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

- Other Operation and Maintenance expenses increased $11 million primarily due to the following:
  - A $19 million increase in recoverable PJM expenses.
  - A $4 million increase in employee-related expenses.

  These increases were partially offset by:
  - A $14 million decrease due to the completion of the amortization of 2012 deferred storm expenses in April 2015. This decrease was offset by a corresponding decrease in Retail Margins above.
- Depreciation and Amortization expenses increased $9 million primarily due to the following:
  - A $4 million increase in amortization expenses for the collection of carrying costs on deferred capacity charges beginning June 2015. This increase was offset by a corresponding increase in Retail Margins above.
  - A $3 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.
  - A $3 million increase in gridSMART® capital carrying charges primarily due to a rider rate increase effective June 2015. This increase was offset by a corresponding increase in Retail Margins above.
- Taxes Other Than Income Taxes increased $4 million primarily due to an increase in property taxes due to additional investment in transmission and distribution assets and higher tax rates.
- Carrying Costs Income decreased $7 million primarily due to the collection of carrying costs on deferred capacity charges beginning June 2015.
- Income Tax Expense increased $10 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014
Reconciliation of Nine Months Ended September 30, 2014 to Nine Months Ended September 30, 2015
Net Income
(In Millions)

Nine Months Ended September 30, 2014	$171
Changes in Gross Margin:	
Retail Margins	133
Off-system Sales	(12)
Transmission Revenues	(72)
Other Revenues	8
Total Change in Gross Margin	57
Changes in Expenses and Other:	
Other Operation and Maintenance	(3)
Depreciation and Amortization	(13)
Taxes Other Than Income Taxes	(14)
Other Income	(2)
Carrying Costs Income	(10)
Interest Expense	1
Total Change in Expenses and Other	(41)
Income Tax Expense	(2)
Nine Months Ended September 30, 2015	$185

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 $133 million primarily due to the following:
- A $91 million increase in transmission and PJM revenues primarily due to the energy supplied as result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
- A $33 million regulatory provision recorded in 2014.
- A $22 million increase in revenues associated with the Distribution Investment Rider.
- A $14 million increase in revenues associated with the gridSMART®, Enhanced Service Reliability and Retail Stability Riders. These riders have corresponding increases in other expense items below.

These increases were partially offset by:

- A $19 million decrease in the Energy Efficiency (EE), Peak Demand Reduction Cost Recovery Rider (PDR) revenues and associated deferrals. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
- An $11 million decrease in revenues associated with the recovery of 2012 storm costs under the Storm Damage Recovery Rider which ended in April 2015. This decrease in Retail Margins is primarily offset by a decrease in Other Operation and Maintenance expenses below.
- A $6 million decrease in revenues associated with the Universal Service Fund (USF) surcharge. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
- A $4 million decrease in base rates due to the discontinuance of seasonal rates.

- Margins from Off-system Sales decreased $12 million primarily due to losses from a legacy power contract.
- Transmission Revenues decreased $72 million primarily due to the following:
  - A $44 million decrease in NITS revenue primarily due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, partially offset by a corresponding increase in Retail Margins above.
  - A $12 million decrease in revenues related to a lower annual transmission formula rate true-up.
  - A $9 million transmission regulatory settlement in 2015.
- Other Revenues increased $8 million primarily due to increased pole attachment revenue.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $3 million primarily due to the following:
  - A $33 million increase in recoverable PJM expenses.
  - A $6 million increase due to PUCO ordered contributions to the Ohio Growth Fund.

  These increases were partially offset by:
  - A $19 million decrease in EE and PDR costs and associated deferrals. This decrease was offset by a corresponding decrease in Retail Margins above.
  - A $12 million decrease due to the completion of the amortization of 2012 deferred storm expenses in April 2015. This decrease was offset by a corresponding decrease in Retail Margins above.
  - A $6 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset by a corresponding decrease in Retail Margins above.
- Depreciation and Amortization expenses increased $13 million primarily due to the following:
  - A $9 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.
  - A $5 million increase in amortization expenses for the collection of carrying costs on deferred capacity charges beginning June 2015. This increase was offset by a corresponding increase in Retail Margins above.
- Taxes Other Than Income Taxes increased $14 million primarily due to an increase in property taxes due to additional investment in transmission and distribution assets and higher tax rates.
- Carrying Costs Income decreased $10 million primarily due to the collection of carrying costs on deferred capacity charges beginning June 2015.

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 2014 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 256 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, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
REVENUES				
Electricity, Transmission and Distribution	$775,905	$793,900	$2,320,372	$2,380,768
Sales to AEP Affiliates	4,426	43,733	79,690	120,154
Other Revenues	1,953	1,564	6,416	4,628
TOTAL REVENUES	782,284	839,197	2,406,478	2,505,550
EXPENSES				
Purchased Electricity for Resale	173,094	48,541	431,608	191,730
Purchased Electricity from AEP Affiliates	45,834	315,903	462,645	897,658
Amortization of Generation Deferrals	55,466	26,655	122,221	82,818
Other Operation	170,144	145,163	446,817	428,074
Maintenance	39,437	53,724	121,224	136,965
Depreciation and Amortization	63,757	54,968	178,609	165,152
Taxes Other Than Income Taxes	93,666	89,564	283,092	268,734
TOTAL EXPENSES	641,398	734,518	2,046,216	2,171,131
OPERATING INCOME	140,886	104,679	360,262	334,419
Other Income (Expense):				
Interest Income	1,165	1,986	4,328	8,159
Carrying Costs Income (Expense)	(1,576)	5,606	10,037	19,594
Allowance for Equity Funds Used During Construction	2,228	1,825	7,015	4,893
Interest Expense	(32,593)	(31,171)	(96,313)	(96,937)
INCOME BEFORE INCOME TAX EXPENSE	110,110	82,925	285,329	270,128
Income Tax Expense	38,541	28,865	100,641	98,759
NET INCOME	$71,569	$54,060	$184,688	$171,369

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net Income	$71,569	$54,060	$184,688	$171,369
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $185 and $185 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $555 and $611 for the Nine Months Ended September 30, 2015 and 2014, Respectively	(344)	(343)	(1,030)	(1,134)
TOTAL COMPREHENSIVE INCOME	$71,225	$53,717	$183,658	$170,235

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

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OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$321,201	$838,782	$814,625	$5,602	$1,980,210
Common Stock Dividends			(156,250)		(156,250)
Net Income			184,688		184,688
Other Comprehensive Loss				(1,030)	(1,030)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2015	$321,201	$838,782	$843,063	$4,572	$2,007,618

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$3,248	$2,870
Restricted Cash for Securitized Funding	16,195	28,687
Advances to Affiliates	279,129	312,473
Accounts Receivable:		
Customers	35,711	57,906
Affiliated Companies	57,240	79,822
Accrued Unbilled Revenues	39,236	35,755
Miscellaneous	1,246	927
Allowance for Uncollectible Accounts	(421)	(171)
Total Accounts Receivable	133,012	174,239
Notes Receivable Due Within One Year – Affiliated	—	86,000
Materials and Supplies	75,878	60,909
Risk Management Assets	—	7,242
Deferred Income Tax Benefits	20,568	49,306
Accrued Tax Benefits	5,030	6,100
Prepayments and Other Current Assets	11,141	8,997
TOTAL CURRENT ASSETS	544,201	736,823
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,181,389	2,104,613
Distribution	4,231,051	4,087,601
Other Property, Plant and Equipment	446,485	390,848
Construction Work in Progress	212,093	218,667
Total Property, Plant and Equipment	7,071,018	6,801,729
Accumulated Depreciation and Amortization	2,086,931	2,038,120
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,984,087	4,763,609
OTHER NONCURRENT ASSETS		
Notes Receivable – Affiliated	32,245	32,245
Regulatory Assets	1,150,864	1,318,939
Securitized Assets	91,899	109,999
Long-term Risk Management Assets	23,265	45,102
Deferred Charges and Other Noncurrent Assets	118,942	264,150
TOTAL OTHER NONCURRENT ASSETS	1,417,215	1,770,435
TOTAL ASSETS	$6,945,503	$7,270,867

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2015 and December 31, 2014
(dollars in thousands)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT LIABILITIES		
Accounts Payable:		
General	$141,073	$145,328
Affiliated Companies	88,324	172,741
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2015 and December 31, 2014 Amounts Include $45,864 and $45,427, Respectively, Related to Ohio Phase-in-Recovery Funding)	395,938	131,497
Risk Management Liabilities	2,823	1,943
Customer Deposits	60,235	53,922
Accrued Taxes	285,003	420,772
Accrued Interest	45,452	34,279
Other Current Liabilities	147,567	179,093
TOTAL CURRENT LIABILITIES	1,166,415	1,139,575
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (September 30, 2015 and December 31, 2014 Amounts Include $141,177 and $187,041, Respectively, Related to Ohio Phase-in-Recovery Funding)	1,770,112	2,165,626
Long-term Risk Management Liabilities	4,871	3,013
Deferred Income Taxes	1,402,369	1,405,620
Regulatory Liabilities and Deferred Investment Tax Credits	535,458	514,691
Employee Benefits and Pension Obligations	29,978	36,662
Deferred Credits and Other Noncurrent Liabilities	28,682	25,470
TOTAL NONCURRENT LIABILITIES	3,771,470	4,151,082
TOTAL LIABILITIES	4,937,885	5,290,657
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	838,782	838,782
Retained Earnings	843,063	814,625
Accumulated Other Comprehensive Income (Loss)	4,572	5,602
TOTAL COMMON SHAREHOLDER’S EQUITY	2,007,618	1,980,210
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$6,945,503	$7,270,867

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 179.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Nine Months Ended September 30,	
	2015	2014
OPERATING ACTIVITIES		
Net Income	$184,688	$171,369
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		