AMERICAN ELECTRIC POWER CO INC
Form 10-Q
July 23, 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 June 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 July 23, 2015
American Electric Power Company, Inc.	490,559,618 ($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
June 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.
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.
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.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.

Term	Meaning
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RPM	Reliability Pricing Model.
RSR	Retail Stability Rider.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SEC	U.S. Securities and Exchange Commission.
SEET	Significantly Excessive Earnings Test.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant, a 534 MW natural gas unit owned by SWEPCo.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated variable interest entity formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Transource Missouri	A 100% wholly-owned subsidiary of Transource Energy.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in “Item 7 – Management’s Discussion and Analysis of Financial Condition and Results of Operations” of the 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 of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of competition, including competition for retail customers.
- Weather conditions, including storms and drought conditions, and our ability to recover significant storm restoration costs.
- The costs of and transportation for fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generation capacity and the performance of our generation plants.
- Our ability to recover 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 transition to market for generation in Ohio, including the implementation of ESPs and our ability to recover investments in our Ohio generation assets.

Our ability to successfully and profitably manage our separate competitive generation assets.
Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
Actions of rating agencies, including changes in the ratings of our debt.
The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements.
Accounting pronouncements periodically issued by accounting standard-setting bodies.
Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

The forward looking statements of AEP and its Registrant Subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see “Risk Factors” in Part I of the 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 second quarter of 2015 increased by 0.9% from the second quarter of 2014. Our second quarter 2015 industrial sales increased 0.6% compared to the second quarter of 2014 primarily due to increased sales to customers in oil and gas related sectors. Weather-normalized commercial and residential sales increased 1.9% and 0.3% in the second quarter of 2015, respectively, from the second quarter of 2014.

Our weather-normalized retail sales volumes for the six months ended June 30, 2015 decreased 0.3% compared to the six months ended June 30, 2014. Industrial sales volumes increased 0.9% compared to 2014, while weather-normalized commercial sales increased by 0.7%. Weather-normalized residential sales decreased 2.2% in comparison to the first six 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.

AEP River Operations Alternatives

AEP is evaluating strategic alternatives for its non-regulated AEP River Operations segment, which primarily includes commercial barging operations that transport liquids, coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi rivers. Potential alternatives may include, but are not limited to, continued ownership or a sale of the non-regulated river operations. We have not made a decision regarding the potential alternatives, nor have we set a specific time frame for a decision. We do not expect to incur a loss related to a potential sale transaction.

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 segment. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the facility.

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.

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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. If the Supreme Court of Ohio upholds its June 2015 order, it would remand the matter back to the PUCO for reinstatement of the weighted average cost of capital 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.

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 July 2014, OPCo submitted a separate application to continue the RSR to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh, until the balance of the capacity deferrals has been collected. In April 2015, the PUCO issued an order approving the application to continue the RSR, with modifications. In May 2015, the PUCO granted intervenors requests for rehearing. As of June 30, 2015, OPCo’s incurred deferred capacity costs balance was $432 million, including debt carrying costs.

In November 2013, the PUCO issued an order approving OPCo’s competitive bid process with modifications. As ordered, in 2014, OPCo conducted multiple energy-only auctions for a total of 100% of the SSO load with delivery beginning April 2014 through May 2015. As provided for in the June 2015 - May 2018 ESP, for delivery starting in June 2015, OPCo now conducts energy and capacity auctions for its entire SSO load. 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.

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June 2015 - May 2018 ESP

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 included a return on common equity of 10.65% on capital costs for certain riders. 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 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 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, on rehearing, the PUCO issued an order that increased the DIR rate caps and deferred ruling on all requests for rehearing related to the establishment of the PPA rider. In June 2015, OPCo and various intervenors filed applications for rehearing with the PUCO related to the May 2015 order on rehearing. In July 2015, the PUCO granted the requests for rehearing.

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) continued to include the 2,671 MW to be available for capacity, energy and ancillary services, produced by AGR over the lives of the respective generating units.

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 is approximately $52 million. In May 2014, intervenors filed appeals of the order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals and filed initial responses. If certain parts of the PUCT order are overturned it could reduce future net income and cash flows and impact financial condition. See the “2012 Texas Base Rate Case” section of Note 4.

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share of the Turk Plant. In February 2013, a settlement was approved by the LPSC that increased 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 for 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 equity of 10.5% and is proposed to be effective in January 2016, except for the $44 million for environmental investments, which is proposed to be effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls go in service. In addition, the filing also notified the OCC that future incremental purchased capacity and energy costs of an estimated $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. 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.

2014 West Virginia Base Rate Case

In June 2014, APCo and WPCo filed a request with the WVPSC to increase annual base rates by $181 million to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates primarily due to the increase in plant investment and changes in the expected service lives of various generating units. The filing also requested recovery of $89 million in regulatory assets over five years related to 2012 West Virginia storm costs, IGCC and other deferred costs. The filing also included a request to implement a rider of approximately $45 million annually to recover vegetation management costs, including a return on capital investment.

In May 2015, the WVPSC issued an order on the 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. 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 weighted average cost of capital rate for the $25 million annual 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. See the “2014 West Virginia Base Rate Case” section of Note 4.

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 impairments related to new carbon emission guidelines issued by the Federal EPA.

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Kentucky Fuel Adjustment Clause Review

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. 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 April 2015, the Franklin County Circuit Court issued an order approving intervenors' requests to hold this case in abeyance until the KPSC issues a final order in KPCo’s two-year FAC review case for the period November 2012 through October 2014. See the “Kentucky Fuel Adjustment Clause Review” section of Note 4.

2014 Kentucky Base Rate Case

In December 2014, KPCo filed a request with the KPSC for a net increase in rates of $70 million, which consists of a $75 million increase in rider rates, offset by a $5 million decrease in annual base rates, to be effective July 2015. 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. 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 for November 2012 through October 2014.

In June 2015, the KPSC issued an order that approved a modified stipulation agreement. The order approved a net revenue increase of $45 million 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. Once this order becomes final and non-appealable, KPCo will withdraw its appeal of the KPSC order in the KPCo fuel adjustment clause review. See "Kentucky Fuel Adjustment Clause Review" section above. See the “2014 Kentucky Base Rate Case” section of 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. AGR’s excess capacity was subject to the PJM RPM auction. After May 2015, AGR's generation assets are subject to PJM capacity prices. Shown below are the base RPM results through the June 2017 through May 2018 period:

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

Management expects a significant decline in AGR capacity revenues after May 2015 because the Power Supply Agreement between AGR and OPCo ended. Management also expects a further decline in AGR capacity revenues from June 2016 through May 2017 based upon the RPM results.

FERC has previously accepted incremental improvements relating to the PJM RPM auction including: (a) assuring that capacity imports have firm transmission, (b) placing limits on the number of MWs of summer-only demand response, (c) modification and enforcement of the dispatch of demand response to better reflect real-time capacity requirements, and (d) redesigning the RPM demand curve. Collectively, these improvements should reduce capacity price volatility and improve reliability.

In December 2014, PJM filed with FERC for approval of a new type of capacity product, the Capacity Performance Product (CP), intended to improve generator performance and reliability during emergency events by: (a) assessing higher penalties for non-performance during emergency events, (b) allowing higher offers into the auction and (c) requiring generators to provide assurances that they can perform reliably during emergency events.

In June 2015, FERC issued an order accepting most of PJM's recommendations, including: (a) non-performance assessments based on the calculated cost of new entry, (b) capacity offers up to approximately $250/MW day for the June 2018 through May 2019 period without mitigation, (c) significant authority to review capacity offers for compliance with CP criteria, and (d) supplemental CP auctions for the June 2016 through May 2017, and June 2017 through May 2018 periods. These supplemental auctions address capacity performance and reliability issues in these interim years, and allow generators to re-offer at a higher price for capacity already cleared if they can perform as a CP resource. In July 2015, FERC issued a revision to its order, allowing demand response providers to participate in the supplemental auctions. The supplemental auctions for the June 2016 through May 2017 and June 2017 through May 2018 periods will take place during the third quarter of 2015.

FERC rejected AEP's request for a full exemption from the CP rules for Fixed Resource Requirement entities, but did allow an exemption for the June 2018 through May 2019 period. FERC also rejected PJM's recommendation for a monthly stop-loss provision. AEP filed a rehearing request in July 2015, 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 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of June 30, 2015, SWEPCo has incurred costs of $256 million, including AFUDC, and has remaining contractual construction obligations of $89 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 June 30, 2015, the net book value of Welsh Plant, Units 1 and 3 was $484 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. In July 2015, the plaintiffs responded to the motion for partial judgment and simultaneously moved for partial summary judgment on their claims for breach of the lease and participation agreement. 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 June 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. If natural gas conversion is not completed, the units could be retired sooner than planned.

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

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 June 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 was $752 million. Of this amount, $608 million has been approved for recovery while $144 million 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 June 30, 2015, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of the regulated plants in the table above was $178 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.

In addition, we are in the process of obtaining permits following the KPSC's approval for the conversion of KPCo's 278 MW Big Sandy Plant, Unit 1 to natural gas. As of June 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 $104 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.

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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. 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 will submit 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 has 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.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for PM, SO_2 and is currently reviewing the NAAQS for ozone. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for our facilities as a result of those evaluations. We cannot currently predict the nature, stringency or timing of those requirements.

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

Cross-State Air Pollution Rule (CSAPR)

In 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in 2012. CSAPR relies on newly-created SO_2 and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units in 28 states. Interstate trading of allowances is allowed on a restricted sub-regional basis. Arkansas and Louisiana are subject only to the seasonal NO_x program in the rule. Texas is subject to the annual programs for SO_2 and NO_x in addition to the seasonal NO_x program. The annual SO_2 allowance budgets in Indiana, Ohio and West Virginia were reduced significantly in the rule. A supplemental rule includes Oklahoma in the seasonal NO_x program. The supplemental rule was finalized in December 2011 with an increased NO_x emission budget for the 2012 compliance year. The Federal EPA issued a final Error Corrections Rule and further CSAPR revisions in 2012 to make corrections to state budgets and unit allocations and to remove the restrictions on interstate trading in the first phase of CSAPR.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. 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 have filed briefs, presented oral arguments and the case remains pending. Separate appeals of the Error Corrections Rule and the further revisions were filed but no briefing schedules have been established. We cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for 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 will be 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

National public policy makers and regulators in the 11 states we serve have diverse views on climate change, carbon regulation and energy policy. We are currently focused on responding to these emerging views with prudent actions across a range of plausible scenarios and outcomes. We are active participants in both state and federal policy development to assure that any proposed new requirements are feasible and the economies of the states we serve are not placed at a competitive disadvantage.

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. This proposal was published in the Federal Register in January 2014 and the comment period has closed.

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. The Federal EPA issued guidelines for the development of standards for existing sources in June 2014. The guidelines use a "portfolio" approach to reducing emissions from existing sources that includes efficiency improvements at coal plants, displacing coal-fired generation with increased utilization of natural gas combined cycle units, expanding renewable generation resources and increasing customer energy efficiency. Comments were due in December 2014. The Federal EPA also issued proposed regulations governing emissions of CO_2 from modified and reconstructed EGUs in June 2014 and comments were due in October 2014. The standards for modified and reconstructed units include several options, including use of historic baselines or energy efficiency audits to establish source-specific CO_2 emission rates or to limit CO_2 emission rates which could be no less than 1,900 pounds per MWh at larger coal units and 2,100 pounds per MWh at smaller coal units. The Federal EPA announced in January 2015 that the schedule for finalizing its action on all of these rules will extend into the summer of 2015 and that it will develop and propose for public comment a model FIP that will be finalized for individual states that fail to submit a timely state plan to implement the existing source guidelines. We cannot currently predict the impact these programs may have on future resource plans or our existing generating fleet, but the costs may be substantial.

In 2012, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA's endangerment finding, its regulatory program for CO_2 emissions from new motor vehicles and its plan to phase in regulation of CO_2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. In 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 are pending.

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. 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 future effective date of the rule and 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 issued an information collection request and is developing revised effluent limitation guidelines for electricity generating facilities. A proposed rule was signed in April 2013 with a final rule expected in September 2015. The Federal EPA proposed eight options of increasing stringency and cost for fly ash and bottom ash transport water, scrubber wastewater, leachate from coal combustion byproduct landfills and impoundments and other wastewaters associated with coal-fired generating units, with four labeled preferred options. Certain of the Federal EPA's preferred options have already been implemented or are part of our long-term plans. We continue to review the proposal in detail to evaluate whether our plants are currently meeting the proposed limitations, what technologies have been incorporated into our long-range plans and what additional costs might be incurred if the Federal EPA's most stringent options were adopted. We submitted detailed comments to the Federal EPA in September 2013 and participated in comments filed by various organizations of which we are members.

In April 2014, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a proposed rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases and published the proposed rule in the Federal Register. The CWA provides for federal jurisdiction over "navigable waters" defined as "the waters of the United States." This proposed jurisdictional definition applied to all CWA programs, potentially impacting generation, transmission and distribution permitting and compliance requirements. Among those programs are: permits for wastewater and storm water discharges, permits for impacts to wetlands and water bodies and oil spill prevention planning. We submitted detailed comments to the Federal EPA in November 2014 and also participated in comments filed by various organizations of which we are members. In June 2015, the Federal EPA published the final rule that included a few changes from the proposal. The effective date of the rule is 60 days following publication. 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 agree that clarity and efficiency in the permitting process is needed. We are 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. We anticipate that the final rule will be challenged in the courts.

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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Vertically Integrated Utilities	$207	$154	$506	$432
Transmission and Distribution Utilities	78	90	175	187
AEP Transmission Holdco	65	47	101	71
Generation & Marketing	82	98	269	261
AEP River Operations	1	3	12	6
Corporate and Other (a)	(3)	(2)	(4)	(7)
Earnings Attributable to AEP Common Shareholders	$430	$390	$1,059	$950

(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

Second Quarter of 2015 Compared to Second Quarter of 2014

Earnings Attributable to AEP Common Shareholders increased from $390 million in 2014 to $430 million in 2015 primarily due to:

- Successful rate proceedings in various jurisdictions.
- An increase in annual formula rate adjustments.
- An increase in transmission investment which resulted in higher revenues and income.
- A decrease in employee-related expenses.
- Favorable retail, trading and marketing activity.

These increases were partially offset by:

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

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Earnings Attributable to AEP Common Shareholders increased from $1.0 billion in 2014 to $1.1 billion in 2015 primarily due to:

- Successful rate proceedings in various jurisdictions.
- An increase in annual formula rate adjustments.
- An increase in transmission investment which resulted in higher revenues and income.
- A decrease in employee-related expenses.
- Favorable retail, trading and marketing activity.

These increases were partially offset by:

- A decrease in off-system sales margins due to lower market prices and reduced sales volumes.
- A decrease in generation sales due to lower capacity revenue.
- 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 June 30, 2015	2014	Six Months Ended June 30, 2015	2014
	(in millions)			
Revenues	$2,183	$2,252	$4,688	$4,838
Fuel and Purchased Electricity	781	934	1,764	2,028
Gross Margin	1,402	1,318	2,924	2,810
Other Operation and Maintenance	615	618	1,191	1,194
Depreciation and Amortization	266	252	538	515
Taxes Other Than Income Taxes	94	87	191	183
Operating Income	427	361	1,004	918
Interest and Investment Income	2	—	3	1
Carrying Costs Income	3	2	5	1
Allowance for Equity Funds Used During Construction	16	11	30	21
Interest Expense	(131)	(132)	(262)	(263)
Income Before Income Tax Expense and Equity Earnings	317	242	780	678
Income Tax Expense	110	88	274	245
Equity Earnings of Unconsolidated Subsidiaries	1	1	2	1
Net Income	208	155	508	434
Net Income Attributable to Noncontrolling Interests	1	1	2	2
Earnings Attributable to AEP Common Shareholders	$207	$154	$506	$432

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
	(in millions of KWhs)			
Retail:				
Residential	6,672	6,716	17,051	17,621
Commercial	6,296	6,122	12,307	12,237
Industrial	8,937	9,025	17,297	17,357
Miscellaneous	574	577	1,122	1,132
Total Retail	22,479	22,440	47,777	48,347
Wholesale (a)	5,903	8,602	14,171	18,786

(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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in degree days)			
Eastern Region				
Actual – Heating (a)	93	118	2,138	2,246
Normal – Heating (b)	139	138	1,743	1,731
Actual – Cooling (c)	402	362	402	362
Normal – Cooling (b)	324	324	329	329
Western Region				
Actual – Heating (a)	9	47	1,049	1,233
Normal – Heating (b)	34	33	911	920
Actual – Cooling (c)	704	674	718	680
Normal – Cooling (b)	693	686	716	710

(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.

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

Second Quarter of 2014	$154	
Changes in Gross Margin:		
Retail Margins	111	
Off-system Sales	(23	)
Transmission Revenues	1	
Other Revenues	(5	)
Total Change in Gross Margin	84	
Changes in Expenses and Other:		
Other Operation and Maintenance	3	
Depreciation and Amortization	(14	)
Taxes Other Than Income Taxes	(7	)
Interest and Investment Income	2	
Carrying Costs Income	1	
Allowance for Equity Funds Used During Construction	5	
Interest Expense	1	
Total Change in Expenses and Other	(9	)
Income Tax Expense	(22	)
Second Quarter of 2015	$207	

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 $111 million primarily due to the following:
  - The effect of successful rate proceedings in our service territories which include:
    - A $37 million increase for I&M primarily due to rate increases from Indiana rate riders and annual formula rate adjustments.
    - A $33 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.
    - An $18 million increase primarily due to rate increases in Virginia and West Virginia, offset by a decrease in annual formula rates.
    - A $7 million increase for PSO primarily due to revenue increases from rate riders.

For the increases described above, $14 million relate to riders/trackers which have corresponding increases in expense items below.

- Margins from Off-system Sales decreased $23 million primarily due to lower market prices and decreased sales volumes.
- Other Revenues decreased $5 million primarily due to a decrease in River Transportation Division (RTD) barging resulting from reduced deliveries to the Rockport Plant. This decrease in RTD revenue has a corresponding decrease in Other Operation and Maintenance expenses for barging as discussed below.

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

- Other Operation and Maintenance expenses decreased $3 million primarily due to the following:
- A $16 million decrease in employee-related expenses.
- A $15 million decrease in storm expenses and vegetation management expenses primarily in the APCo region.
- A $4 million decrease in uncollectible accounts expense due to the establishment of a regulatory asset for recovery in the May 2015 West Virginia base case order.

These decreases were partially offset by:

- A $13 million increase in nuclear expenses.
- A $14 million increase in recoverable expenses, primarily including PJM expenses currently fully recovered in rate recovery riders/trackers partially offset by lower RTD barging costs.
- A $5 million increase in SPP and PJM transmission services expenses.
- Depreciation and Amortization expenses increased $14 million primarily due to overall higher depreciable base and amortization related to an advanced metering rider implemented in November 2014 in Oklahoma.
- Taxes Other Than Income Taxes increased $7 million primarily due to an increase in property taxes.
- Allowance for Equity Funds Used During Construction increased $5 million primarily due to increases in environmental construction and transmission projects.
- Income Tax Expense increased $22 million primarily due an increase in pretax book income partially offset by the regulatory accounting treatment of state income taxes.

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

Six Months Ended June 30, 2014	$432	
Changes in Gross Margin:		
Retail Margins	212	
Off-system Sales	(95	)
Transmission Revenues	1	
Other Revenues	(4	)
Total Change in Gross Margin	114	
Changes in Expenses and Other:		
Other Operation and Maintenance	3	
Depreciation and Amortization	(23	)
Taxes Other Than Income Taxes	(8	)
Interest and Investment Income	2	
Carrying Costs Income	4	
Allowance for Equity Funds Used During Construction	9	
Interest Expense	1	
Total Change in Expenses and Other	(12	)
Income Tax Expense	(29	)
Equity Earnings	1	
Six Months Ended June 30, 2015	$506	

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 $212 million primarily due to the following:
- The effect of successful rate proceedings in our service territories which include:
- A $68 million increase primarily due to rate increases in Virginia and West Virginia, including an adjustment due to the amended Virginia law affecting biennial reviews.
- A $54 million increase for I&M primarily due to rate increases from Indiana rate riders and annual formula rate adjustments.
- A $43 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 $16 million increase for PSO primarily due to revenue increases from rate riders.

For the increases described above, $47 million relate to riders/trackers which have corresponding increases in expense items below.

- A $31 million decrease in PJM expenses net of recovery or offsets.

These increases were partially offset by:

- A $34 million decrease in weather-normalized load primarily due to lower residential sales in the eastern region.
- Margins from Off-system Sales decreased $95 million primarily due to lower market prices and decreased sales volumes.
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Other Revenues decreased $4 million primarily due to a decrease in River Transportation Division (RTD) barging resulting from reduced deliveries to the Rockport Plant. This decrease in RTD revenue has a corresponding decrease in Other Operation and Maintenance expenses for barging as discussed below.

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

- Other Operation and Maintenance expenses decreased $3 million primarily due to the following:
  - A $38 million decrease in employee-related expenses.
  - A $12 million decrease in storm expenses and vegetation management expenses primarily in the APCo region.

  These decreases were partially offset by:
  - A $38 million increase in recoverable expenses, primarily including PJM expenses currently fully recovered in rate recovery riders/trackers partially offset by lower RTD barging costs.
  - A $7 million increase in PJM transmission services expenses.
- Depreciation and Amortization expenses increased $23 million primarily due to overall higher depreciable base and amortization related to an advanced metering rider implemented in November 2014 in Oklahoma.
- Taxes Other Than Income Taxes increased $8 million primarily due to an increase in property taxes.
- Allowance for Equity Funds Used During Construction increased $9 million primarily due to increases in environmental construction and transmission projects.
- Income Tax Expense increased $29 million primarily due an increase in pretax book income partially offset by the regulatory accounting treatment of state income taxes.

TRANSMISSION AND DISTRIBUTION UTILITIES

	Three Months Ended June 30,		Six Months Ended June 30,	
Transmission and Distribution Utilities	2015	2014	2015	2014
	(in millions)			
Revenues	$1,061	$1,134	$2,331	$2,349
Fuel and Purchased Electricity	270	343	691	746
Amortization of Generation Deferrals	36	25	67	56
Gross Margin	755	766	1,573	1,547
Other Operation and Maintenance	289	298	608	591
Depreciation and Amortization	170	156	338	317
Taxes Other Than Income Taxes	118	108	240	227
Operating Income	178	204	387	412
Interest and Investment Income	1	3	3	6
Carrying Costs Income	6	7	12	14
Allowance for Equity Funds Used During Construction	4	2	8	5
Interest Expense	(68)	(72)	(138)	(142)
Income Before Income Tax Expense	121	144	272	295
Income Tax Expense	43	54	97	108
Net Income	78	90	175	187
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$78	$90	$175	$187

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions of KWhs)			
Retail:				
Residential	5,630	5,559	12,896	13,086
Commercial	6,372	6,314	12,287	12,216
Industrial	5,809	5,630	11,089	10,773
Miscellaneous	177	182	338	353
Total Retail (a)	17,988	17,685	36,610	36,428
Wholesale (b)	429	453	963	1,152

(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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in degree days)			
Eastern Region				
Actual – Heating (a)	137	130	2,575	2,539
Normal – Heating (b)	186	187	2,067	2,067
Actual – Cooling (c)	350	362	350	362
Normal – Cooling (b)	287	280	290	283
Western Region				
Actual – Heating (a)	—	2	320	302
Normal – Heating (b)	4	4	192	200
Actual – Cooling (d)	863	872	904	942
Normal – Cooling (b)	917	904	1,026	1,012

(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.

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

Second Quarter of 2014	$90	
Changes in Gross Margin:		
Retail Margins	13	
Off-system Sales	(5	)
Transmission Revenues	(25	)
Other Revenues	6	
Total Change in Gross Margin	(11	)
Changes in Expenses and Other:		
Other Operation and Maintenance	9	
Depreciation and Amortization	(14	)
Taxes Other Than Income Taxes	(10	)
Interest and Investment Income	(2	)
Carrying Costs Income	(1	)
Allowance for Equity Funds Used During Construction	2	
Interest Expense	4	
Total Change in Expenses and Other	(12	)
Income Tax Expense	11	
Second Quarter of 2015	$78	

The major components of the decrease 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 $13 million primarily due to the following:
  - A $14 million increase in transmission rider and PJM retail revenues primarily due to CRES transmission revenue collected through a non-bypassable retail transmission rider beginning in June 2015, which is partially offset by a corresponding decrease in Transmission Revenues below.
  - A $7 million increase in revenues associated with the Ohio Distribution Investment Rider (DIR).
  - A $6 million increase in TCC and TNC revenues primarily due to the recovery of ERCOT transmission expenses, which is offset in Other Operation and Maintenance expenses below.
  - A $4 million increase in industrial sales in Ohio.

  These increases were partially offset by:
  - A $12 million decrease in revenues associated with the Ohio Storm Damage Recovery Rider which started in April 2014 and ended in April 2015. This decrease in Retail Margins is primarily offset by a decrease in Other Operation and Maintenance expenses below.
  - An $8 million decrease in the Energy Efficiency (EE), Peak Demand Reduction Cost Recovery Rider (PDR) revenues in Ohio. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
- Margins from Off-system Sales decreased $5 million primarily due to lower margins on PJM liquidations on a legacy OPCo power contract and lower Oklaunion purchased power agreement (PPA) revenues.
- Transmission Revenues decreased $25 million primarily due to:
  - A $12 million decrease in Ohio revenues related to a lower transmission formula rate true-up than in the prior year.

- A $10 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

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responsibility of the CRES providers prior to June 2015, which is partially offset by a corresponding increase in Retail Margins above.

- A $7 million OPCo transmission regulatory loss provision in 2015.

These decreases were partially offset by:

- A $7 million increase primarily due to increased transmission investment in ERCOT.
- Other Revenues increased $6 million primarily due to $3 million of increased pole attachment revenue for OPCo and $2 million in Texas securitization revenues which is offset in Depreciation and Amortization below.

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:
- A $12 million decrease due to the completion of the amortization of Ohio 2012 deferred storm expenses. This decrease was offset by a corresponding decrease in Retail Margins above.
- An $8 million decrease in EE and PDR expenses. This decrease was offset by a corresponding decrease in Retail Margins above.
- A $5 million decrease in employee-related expenses.

These decreases were partially offset by:

- A $9 million increase in PJM and ERCOT transmission services expenses.
- A $6 million increase in storm expenses primarily in the Texas region.
- Depreciation and Amortization expenses increased $14 million primarily due to the following:
- An $8 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, which is partially offset in Other Revenues.
- Taxes Other Than Income Taxes increased $10 million primarily due to an increase in property taxes.
- Interest Expense decreased $4 million primarily due to reduced TCC long-term debt outstanding, which is partially offset in Other Revenues.
- Income Tax Expense decreased $11 million primarily due to a decrease in pretax book income and the regulatory accounting treatment of state income taxes.

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

Six Months Ended June 30, 2014	$187
Changes in Gross Margin:	
Retail Margins	44
Off-system Sales	(4)
Transmission Revenues	(21)
Other Revenues	7
Total Change in Gross Margin	26
Changes in Expenses and Other:	
Other Operation and Maintenance	(17)
Depreciation and Amortization	(21)
Taxes Other Than Income Taxes	(13)
Interest and Investment Income	(3)
Carrying Costs Income	(2)
Allowance for Equity Funds Used During Construction	3
Interest Expense	4
Total Change in Expenses and Other	(49)
Income Tax Expense	11
Six Months Ended June 30, 2015	$175

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 $44 million primarily due to the following:
  - A $23 million increase in TCC and TNC revenues primarily due to the recovery of ERCOT transmission expenses, which is offset in Other Operation and Maintenance expenses below.
  - A $15 million increase in revenues associated with the Ohio Distribution Investment Rider (DIR).
  - A $14 million increase in transmission rider and PJM retail revenues primarily due to CRES transmission revenue collected through a non-bypassable retail transmission rider beginning in June 2015, which is partially offset by a corresponding decrease in Transmission Revenues below.
  - A $10 million increase in Ohio base rates due to the discontinuance of seasonal rates.

  These increases were partially offset by:
  - A $17 million decrease in the Energy Efficiency (EE), Peak Demand Reduction Cost Recovery Rider (PDR) revenues in Ohio. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
- Margins from Off-system Sales decreased $4 million primarily due to lower margins on PJM liquidations on a legacy OPCo power contract and lower Oklaunion PPA revenues.
- Transmission Revenues decreased $21 million primarily due to:
  - A $12 million decrease in Ohio revenues related to a lower transmission formula rate true-up than in the prior year.
  - A $10 million decrease in 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, which is partially offset by a corresponding increase in Retail Margins above.

• A $7 million OPCo transmission regulatory loss provision in 2015.

These decreases were partially offset by:

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- An $11 million increase primarily due to increased transmission investment in ERCOT.
- Other Revenues increased $7 million primarily due to $4 million of increased pole attachment revenue for OPCo and a $2 million increase in Texas securitization revenues which is offset in Depreciation and Amortization below.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $17 million primarily due to the following:
- A $17 million increase in recoverable ERCOT transmission expenses currently recovered dollar-for-dollar in rate recovery riders/trackers.
- A $14 million increase in PJM transmission services expenses.
- A $13 million increase in distribution expenses including system improvements and storm expenses.
- A $6 million increase due to PUCO ordered contributions to the Ohio Growth Fund.

These increases were partially offset by:

- A $17 million decrease in EE and PDR costs and associated deferrals. This decrease was offset by a corresponding decrease in Retail Margins above.
- An $11 million decrease in employee-related expenses.
- Depreciation and Amortization expenses increased $21 million primarily due to the following:
- A $12 million increase due to an increase in the depreciable base of transmission and distribution assets.
- A $7 million increase in amortization of TCC's securitization transition asset, which is partially offset in Other Revenues.
- Taxes Other Than Income Taxes increased $13 million primarily due to increased property taxes.
- Interest Expense decreased $4 million primarily due to reduced TCC long-term debt outstanding, which is partially offset in Other Revenues.
- Income Tax Expense decreased $11 million primarily due to a decrease in pretax book income and by the regulatory accounting treatment of state income taxes.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
	(in millions)			
Transmission Revenues	$99	$57	$157	$85
Other Operation and Maintenance	8	6	16	11
Depreciation and Amortization	9	6	18	11
Taxes Other Than Income Taxes	17	6	33	13
Operating Income	65	39	90	50
Allowance for Equity Funds Used During Construction	14	12	26	21
Interest Expense	(9)	(5)	(17)	(10)
Income Before Income Tax Expense and Equity Earnings	70	46	99	61
Income Tax Expense	29	22	43	30
Equity Earnings of Unconsolidated Subsidiaries	24	23	46	40
Net Income	65	47	102	71
Net Income Attributable to Noncontrolling Interests	—	—	1	—
Earnings Attributable to AEP Common Shareholders	$65	$47	$101	$71

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

	As of June 30, 2015	2014
	(in millions)	
Net Plant in Service	$2,111	$1,167
CWIP	1,130	895

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Second Quarter of 2015 Compared to Second Quarter of 2014

Reconciliation of Second Quarter of 2014 to Second Quarter of 2015	
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco	
(in millions)	
Second Quarter of 2014	$47
Changes in Transmission Revenues:	
Transmission Revenues	42
Total Change in Transmission Revenues	42
Changes in Expenses and Other:	
Other Operation and Maintenance	(2)
Depreciation and Amortization	(3)
Taxes Other Than Income Taxes	(11)
Allowance for Equity Funds Used During Construction	2
Interest Expense	(4)
Total Change in Expenses and Other	(18)
Income Tax Expense	(7)
Equity Earnings	1
Second Quarter of 2015	$65

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 $42 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 $2 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $3 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $11 million primarily due to increased property taxes.
- Allowance for Equity Funds Used During Construction increased $2 million primarily due to increased transmission investment.
- Interest Expense increased $4 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $7 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

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

Six Months Ended June 30, 2014	$71	
Changes in Transmission Revenues:		
Transmission Revenues	72	
Total Change in Transmission Revenues	72	
Changes in Expenses and Other:		
Other Operation and Maintenance	(5	)
Depreciation and Amortization	(7	)
Taxes Other Than Income Taxes	(20	)
Allowance for Equity Funds Used During Construction	5	
Interest Expense	(7	)
Total Change in Expenses and Other	(34	)
Income Tax Expense	(13	)
Equity Earnings	6	
Net Income Attributable to Noncontrolling Interests	(1	)
Six Months Ended June 30, 2015	$101	

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 $72 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 $5 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $7 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $20 million primarily due to increased property taxes.
- Allowance for Equity Funds Used During Construction increased $5 million primarily due to increased transmission investment.
- Interest Expense increased $7 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $13 million primarily due to an increase in pretax book income.
- Equity Earnings increased $6 million primarily due to increased transmission investment by ETT.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
	(in millions)			
Revenues	$801	$913	$1,971	$2,164
Fuel, Purchased Electricity and Other	491	560	1,207	1,365
Gross Margin	310	353	764	799
Other Operation and Maintenance	116	125	216	241
Depreciation and Amortization	51	56	101	113
Taxes Other Than Income Taxes	11	13	20	25
Operating Income	132	159	427	420
Interest and Investment Income	1	1	2	2
Interest Expense	(10)	(11)	(21)	(23)
Income Before Income Tax Expense	123	149	408	399
Income Tax Expense	41	51	139	138
Net Income	82	98	269	261
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$82	$98	$269	$261

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
	(in millions of MWhs)			
Fuel Type:				
Coal	6	9	16	21
Natural Gas	3	2	7	4
Total MWhs	9	11	23	25

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

Second Quarter of 2014	$98	
Changes in Gross Margin:		
Generation	(53	)
Retail, Trading and Marketing	12	
Other	(2	)
Total Change in Gross Margin	(43	)
Changes in Expenses and Other:		
Other Operation and Maintenance	9	
Depreciation and Amortization	5	
Taxes Other Than Income Taxes	2	
Interest Expense	1	
Total Change in Expenses and Other	17	
Income Tax Expense	10	
Second Quarter of 2015	$82	

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 $53 million primarily due to lower capacity revenue due to the termination of the Power Supply Agreement between AGR and OPCo.
- Retail, Trading and Marketing increased $12 million primarily due to an increase in retail volumes.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $9 million primarily due to a decrease in plant outage and maintenance costs.
- Depreciation and Amortization expenses decreased $5 million primarily due to reduced plant in service.
- Income Tax Expense decreased $10 million primarily due to a decrease in pretax book income.

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

Six Months Ended June 30, 2014	$261
Changes in Gross Margin:	
Generation	(77)
Retail, Trading and Marketing	46
Other	(4)
Total Change in Gross Margin	(35)
Changes in Expenses and Other:	
Other Operation and Maintenance	25
Depreciation and Amortization	12
Taxes Other Than Income Taxes	5
Interest Expense	2
Total Change in Expenses and Other	44
Income Tax Expense	(1)
Six Months Ended June 30, 2015	$269

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 $77 million primarily due to lower capacity revenue due to the termination of the Power Supply Agreement between AGR and OPCo.
- Retail, Trading and Marketing increased $46 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 $25 million primarily due to a decrease in plant outage and maintenance costs.
- Depreciation and Amortization expenses decreased $12 million primarily due to reduced plant in service.
- Taxes Other Than Income Taxes decreased $5 million primarily due to a decrease in property taxes.

AEP RIVER OPERATIONS

Second Quarter of 2015 Compared to Second Quarter of 2014

Earnings Attributable to AEP Common Shareholders from our AEP River Operations segment decreased from $3 million in 2014 to $1 million in 2015 primarily due to lower freight revenue compared to second quarter 2014 resulting from various high water operating restrictions during the quarter.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Earnings Attributable to AEP Common Shareholders from our AEP River Operations segment increased from $6 million in 2014 to $12 million in 2015 primarily due to lower fuel prices and reduced consumption, partially offset by lower freight revenue.

CORPORATE AND OTHER

Second Quarter of 2015 Compared to Second Quarter of 2014

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $2 million in 2014 to a loss of $3 million in 2015 primarily due to increased income tax expense of $1 million primarily due to book/tax differences which are accounted for on a flow-through basis.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $7 million in 2014 to a loss of $4 million in 2015 primarily due to book/tax differences which are accounted for on a flow-through basis.

AEP SYSTEM INCOME TAXES

Second Quarter of 2015 Compared to Second Quarter of 2014

Income Tax Expense increased $10 million primarily due to an increase in pretax book income partially offset by the regulatory accounting treatment of state income taxes.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

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.

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

	June 30, 2015	December 31, 2014
	(dollars in millions)	

Long-term Debt, including amounts due within one year	$19,578	51.4	%	$18,684	50.7	%
Short-term Debt	1,105	2.9		1,346	3.6	
Total Debt	20,683	54.3		20,030	54.3	
AEP Common Equity	17,434	45.7		16,820	45.7	
Noncontrolling Interests	8	—		4	—	
Total Debt and Equity Capitalization	$38,125	100.0	%	$36,854	100.0	%

Our ratio of debt-to-total capital remained unchanged at 54.3% as of December 31, 2014 and June 30, 2015.

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 June 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 June 30, 2015, our available liquidity was approximately $3.2 billion as illustrated in the table below:

		Amount (in millions)	Maturity
Commercial Paper Backup:			
	Revolving Credit Facility	$ 1,750	June 2017
	Revolving Credit Facility	1,750	July 2018
Total		3,500	
Cash and Cash Equivalents		195	
Total Liquidity Sources		3,695	
Less:	AEP Commercial Paper Outstanding	397	
	Letters of Credit Issued	61	
Net Available Liquidity		$ 3,237	

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 six months of 2015 was $788 million. The weighted-average interest rate for our commercial paper during 2015 was 0.46%.

Other Credit Facilities

We issue letters of credit under a $100 million uncommitted facility. As of June 30, 2015, the maximum future payment for letters of credit issued under the uncommitted facility was $100 million with a maturity date of December 2015. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

Securitized Accounts Receivable

Our receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement expires in June 2017.

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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 June 30, 2015, this contractually-defined percentage was 51.4%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of June 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 $0.53 per share in July 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.

	Six Months Ended June 30,	
	2015	2014
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$163	$118
Net Cash Flows from Operating Activities	2,203	2,197

Net Cash Flows Used for Investing Activities	(2,190)	(2,068)
Net Cash Flows from (Used for) Financing Activities	19	(57)
Net Increase in Cash and Cash Equivalents	32	72
Cash and Cash Equivalents at End of Period	$195	$190

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

Operating Activities

	Six Months Ended June 30,	
	2015	2014
	(in millions)	
Net Income	$1,062	$952
Depreciation and Amortization	1,011	934
Other	130	311
Net Cash Flows from Operating Activities	$2,203	$2,197

Net Cash Flows from Operating Activities were $2.2 billion in 2015 consisting primarily of Net Income of $1.1 billion and $1 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, increased generation and plants retired during the second quarter of 2015.

Net Cash Flows from Operating Activities were $2.2 billion in 2014 consisting primarily of Net Income of $952 million and $934 million of noncash Depreciation and Amortization partially offset by $105 million of net fuel cost deferrals and $99 million of net 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, Materials and Supplies balances reflects a decrease in fuel inventory due to the cold winter weather and increased generation.

Investing Activities

	Six Months Ended June 30,	
	2015	2014
	(in millions)	
Construction Expenditures	$(2,182)	$(1,883)
Acquisitions of Nuclear Fuel	(52)	(58)
Acquisitions of Assets/Businesses	(2)	(45)
Other	46	(82)
Net Cash Flows Used for Investing Activities	$(2,190)	$(2,068)

Net Cash Flows Used for Investing Activities were $2.2 billion in 2015 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Net Cash Flows Used for Investing Activities were $2.1 billion in 2014 primarily due to Construction Expenditures for environmental, distribution and transmission investments. We also purchased transmission assets for $38 million.

Financing Activities

	Six Months Ended June 30,	
	2015	2014
	(in millions)	
Issuance of Common Stock, Net	$56	$29
Issuance of Debt, Net	635	459
Dividends Paid on Common Stock	(522)	(490)
Other	(150)	(55)
Net Cash Flows from (Used for) Financing Activities	$19	$(57)

Net Cash Flows from Financing Activities in 2015 were $19 million. Our net debt issuances were $635 million. The net issuances included issuances of $1.7 billion of senior unsecured notes, $140 million of pollution control bonds and $729 million of other debt notes offset by retirements of $754 million of senior unsecured and other debt notes, $180 million of securitization bonds, $140 million of pollution control bonds and $654 of other debt notes and a decrease in short term borrowing of $241 million. We paid common stock dividends of $522 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 $57 million. See Note 11 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows Used for Financing Activities in 2014 were $57 million. Our net debt issuances were $459 million. The net issuances included issuances of $530 million of senior unsecured notes, $304 million of pollution control bonds and $114 million of other debt notes and an increase in short-term borrowing of $725 million offset by retirements of $794 million of senior unsecured and other debt notes, $273 million of pollution control bonds and $138 million of securitization bonds. We paid common stock dividends of $490 million. See Note 11 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

In July 2015, OPCo retired $23 million of Securitization Bonds.

In July 2015, SWEPCo retired $150 million of 4.9% Senior Unsecured Notes due in 2015.

In July 2015, TCC retired $94 million of Securitization Bonds.

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:

	June 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. There were no events requiring application of the new accounting guidance.

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, the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016. We are analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. We plan to adopt ASU 2014-09 effective January 1, 2017.

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” to provide 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.

Future Accounting Changes

The FASB’s standard-setting process is ongoing and until new standards have been finalized and issued, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including financial instruments, leases, insurance, hedge accounting and consolidation policy. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

Our Vertically Integrated Utilities segment is exposed to certain market risks as a major power producer and through its transactions in power, coal, natural gas and marketing contracts. These risks include commodity price risk, interest rate risk and credit risk. In addition, we are exposed to foreign currency exchange risk as we occasionally procure various services and materials used in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Transmission and Distribution Utilities segment 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)
Six Months Ended June 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	(28)	(6)	(9)	(43)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	52	52
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	8	8
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	43	(3)	—	40
Total MTM Risk Management Contract Net Assets as of June 30, 2015	$51	$37	$191	279
Commodity Cash Flow Hedge Contracts				(9)
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(1)
Fair Value Hedge Contracts				(3)
Collateral Deposits				24
Elimination of Affiliated MTM Risk Management Contracts				(7)
Total MTM Derivative Contract Net Assets as of June 30, 2015				$283

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

See Note 8 – Derivatives and Hedging and Note 9 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

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

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of June 30, 2015, our credit exposure net of collateral to sub investment grade counterparties was approximately 7.8%, 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 June 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	$678	$—	$678	2	$254
Split Rating	23	—	23	1	23
Noninvestment Grade	2	—	2	2	2
No External Ratings:					
Internal Investment Grade	110	—	110	3	62
Internal Noninvestment Grade	84	17	67	2	35
Total as of June 30, 2015	$897	$17	$880	10	$376
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 June 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

Six Months Ended June 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

Six Months Ended June 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 June 30, 2015 and December 31, 2014, the estimated EaR on our debt portfolio for the following twelve months was $37 million and $33 million, respectively.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
REVENUES				
Vertically Integrated Utilities	$2,159	$2,236	$4,646	$4,785
Transmission and Distribution Utilities	1,008	1,064	2,214	2,225
Generation & Marketing	628	573	1,487	1,394
Other Revenues	147	171	303	288
TOTAL REVENUES	3,942	4,044	8,650	8,692
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	756	1,043	1,827	2,211
Purchased Electricity for Resale	601	473	1,319	1,111
Other Operation	695	760	1,441	1,540
Maintenance	333	340	627	632
Depreciation and Amortization	506	443	1,011	934
Taxes Other Than Income Taxes	242	218	492	456
TOTAL EXPENSES	3,133	3,277	6,717	6,884
OPERATING INCOME	809	767	1,933	1,808
Other Income (Expense):				
Interest and Investment Income	3	3	4	4
Carrying Costs Income	9	9	17	15
Allowance for Equity Funds Used During Construction	34	25	64	47
Interest Expense	(224)	(221)	(447)	(441)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	631	583	1,571	1,433
Income Tax Expense	225	215	558	522
Equity Earnings of Unconsolidated Subsidiaries	25	23	49	41
NET INCOME	431	391	1,062	952
Net Income Attributable to Noncontrolling Interests	1	1	3	2
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$430	$390	$1,059	$950
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	490,207,482	488,291,576	489,904,417	488,080,505

TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.88	$0.80	$2.16	$1.95
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	490,484,450	488,538,227	490,212,271	488,405,869
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.88	$0.80	$2.16	$1.95
CASH DIVIDENDS DECLARED PER SHARE	$0.53	$0.50	$1.06	$1.00

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 49.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net Income	$431	$391	$1,062	$952
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $1 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $3 and $4 for the Six Months Ended June 30, 2015 and 2014, Respectively	1	3	(5)	8
Securities Available for Sale, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $0 and $0 for the Six Months Ended June 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 June 30, 2015 and 2014, Respectively, and $0 and $1 for the Six Months Ended June 30, 2015 and 2014, Respectively	1	1	1	2
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	1	5	(4)	11
TOTAL COMPREHENSIVE INCOME	432	396	1,058	963
Total Comprehensive Income Attributable to Noncontrolling Interests	1	1	3	2
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$431	$395	$1,055	$961

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 49.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Six Months Ended June 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	1	5	24				29
Common Stock Dividends				(488)		(2)	(490)
Other Changes in Equity				(6)		3	(3)
Net Income				950		2	952
Other Comprehensive Income					11		11
TOTAL EQUITY - JUNE 30, 2014	509	$3,308	$6,155	$7,222	$(104)	$4	$16,585
TOTAL EQUITY - DECEMBER 31, 2014	510	$3,313	$6,204	$7,406	$(103)	$4	$16,824
Issuance of Common Stock	1	8	48				56
Common Stock Dividends				(520)		(2)	(522)
Other Changes in Equity			1			3	4
Deferred State Income Tax Rate Adjustment			17				17
Net Income				1,059		3	1,062
Other Comprehensive Loss					(4)		(4)
Pension and OPEB Adjustment Related to Mitchell Plant					5		5
TOTAL EQUITY - JUNE 30, 2015	511	$3,321	$6,270	$7,945	$(102)	$8	$17,442

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 49.

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

	June 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$195	$163
Other Temporary Investments (June 30, 2015 and December 31, 2014 Amounts Include $344 and $371, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and EIS)	356	386
Accounts Receivable:		
Customers	815	727
Accrued Unbilled Revenues	64	146
Pledged Accounts Receivable – AEP Credit	997	987
Miscellaneous	71	87
Allowance for Uncollectible Accounts	(27)	(21)
Total Accounts Receivable	1,920	1,926
Fuel	424	587
Materials and Supplies	736	738
Risk Management Assets	172	178
Regulatory Asset for Under-Recovered Fuel Costs	125	127
Margin Deposits	87	95
Prepayments and Other Current Assets	210	278
TOTAL CURRENT ASSETS	4,225	4,478
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	25,619	25,727
Transmission	13,020	12,433
Distribution	17,594	17,157
Other Property, Plant and Equipment (June 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)	4,718	5,770
Construction Work in Progress	3,651	3,218
Total Property, Plant and Equipment	64,602	64,305
Accumulated Depreciation and Amortization	19,589	20,188
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	45,013	44,117
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,021	4,264
Securitized Assets	1,931	2,072
Spent Nuclear Fuel and Decommissioning Trusts	2,106	2,096
Goodwill	91	91
Long-term Risk Management Assets	363	294
Deferred Charges and Other Noncurrent Assets	2,188	2,221

TOTAL OTHER NONCURRENT ASSETS	11,700	11,038
TOTAL ASSETS	$60,938	$59,633

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 49.

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

	June 30, 2015	December 31, 2014
CURRENT LIABILITIES		
Accounts Payable	$1,236	$1,287
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	708	744
Other Short-term Debt	397	602
Total Short-term Debt	1,105	1,346
Long-term Debt Due Within One Year (June 30, 2015 and December 31, 2014 Amounts Include $463 and $431, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	1,817	2,503
Risk Management Liabilities	78	92
Customer Deposits	335	324
Accrued Taxes	749	871
Accrued Interest	232	239
Regulatory Liability for Over-Recovered Fuel Costs	39	55
Other Current Liabilities	1,059	1,250
TOTAL CURRENT LIABILITIES	6,650	7,967
NONCURRENT LIABILITIES		
Long-term Debt (June 30, 2015 and December 31, 2014 Amounts Include $2,114 and $2,260, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy and Sabine)	17,761	16,181
Long-term Risk Management Liabilities	174	131
Deferred Income Taxes	11,426	10,986
Regulatory Liabilities and Deferred Investment Tax Credits	3,850	3,892
Asset Retirement Obligations	2,038	1,951
Employee Benefits and Pension Obligations	509	630
Deferred Credits and Other Noncurrent Liabilities	1,088	1,071
TOTAL NONCURRENT LIABILITIES	36,846	34,842
TOTAL LIABILITIES	43,496	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	510,884,774	509,739,159		
(20,336,592 Shares were Held in Treasury as of June 30, 2015 and December 31, 2014)			3,321	3,313
Paid-in Capital			6,270	6,204
Retained Earnings			7,945	7,406
Accumulated Other Comprehensive Income (Loss)			(102)	(103)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			17,434	16,820
Noncontrolling Interests			8	4
TOTAL EQUITY			17,442	16,824
TOTAL LIABILITIES AND EQUITY			$60,938	$59,633

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 49.

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

	Six Months Ended June 30, 2015	2014
OPERATING ACTIVITIES		
Net Income	$1,062	$952
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,011	934
Deferred Income Taxes	453	410
Carrying Costs Income	(17)	(15)
Allowance for Equity Funds Used During Construction	(64)	(47)
Mark-to-Market of Risk Management Contracts	(41)	9
Amortization of Nuclear Fuel	66	79
Pension Contributions to Qualified Plan Trust	(93)	(71)
Property Taxes	102	92
Fuel Over/Under-Recovery, Net	22	(105)
Deferral of Ohio Capacity Costs, Net	(1)	(99)
Change in Other Noncurrent Assets	(91)	11
Change in Other Noncurrent Liabilities	12	132
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	12	(73)
Fuel, Materials and Supplies	149	207
Accounts Payable	(10)	(39)
Accrued Taxes, Net	(115)	(86)
Other Current Assets	22	(3)
Other Current Liabilities	(276)	(91)
Net Cash Flows from Operating Activities	2,203	2,197
INVESTING ACTIVITIES		
Construction Expenditures	(2,182)	(1,883)
Change in Other Temporary Investments, Net	30	(24)
Purchases of Investment Securities	(541)	(510)
Sales of Investment Securities	516	483
Acquisitions of Nuclear Fuel	(52)	(58)
Acquisitions of Assets/Businesses	(2)	(45)
Other Investing Activities	41	(31)
Net Cash Flows Used for Investing Activities	(2,190)	(2,068)
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	56	29
Issuance of Long-term Debt	2,603	939
Change in Short-term Debt, Net	(241)	725
Retirement of Long-term Debt	(1,727)	(1,205)
Make Whole Premium on Extinguishment of Long-term Debt	(93)	—
Principal Payments for Capital Lease Obligations	(57)	(60)
Dividends Paid on Common Stock	(522)	(490)

Other Financing Activities	—	5
Net Cash Flows from (Used for) Financing Activities	19	(57)
Net Increase in Cash and Cash Equivalents	32	72
Cash and Cash Equivalents at Beginning of Period	163	118
Cash and Cash Equivalents at End of Period	$195	$190
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$431	$422
Net Cash Paid for Income Taxes	98	63
Noncash Acquisitions Under Capital Leases	76	33
Construction Expenditures Included in Current Liabilities as of June 30,	543	432
Construction Expenditures Included in Noncurrent Liabilities as of June 30,	66	—
Acquisition of Nuclear Fuel Included in Current Liabilities as of June 30,	—	42

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 49.

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 six months ended June 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 June 30,			
	2015		2014	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$430		$390	
Weighted Average Number of Basic Shares Outstanding	490.2	$0.88	488.3	$0.80
Weighted Average Dilutive Effect of Restricted Stock Units	0.3	—	0.2	—
Weighted Average Number of Diluted Shares Outstanding	490.5	$0.88	488.5	$0.80

	Six Months Ended June 30,			
	2015		2014	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$1,059		$950	
Weighted Average Number of Basic Shares Outstanding	489.9	$2.16	488.1	$1.95
Weighted Average Dilutive Effect of Restricted Stock Units	0.3	—	0.3	—
Weighted Average Number of Diluted Shares Outstanding	490.2	$2.16	488.4	$1.95

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

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. There were no events requiring the application of this new accounting guidance.

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

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

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

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 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.

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 to provide 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 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.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three and six months ended June 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 June 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 March 31, 2015	$(6)	$(18)	$9	$(88)	$(103)
Change in Fair Value Recognized in AOCI	(1)	—	(1)	—	(2)
Amounts Reclassified from AOCI	2	—	—	1	3
Net Current Period Other Comprehensive Income (Loss)	1	—	(1)	1	1
Balance in AOCI as of June 30, 2015	$(5)	$(18)	$8	$(87)	$(102)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 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 March 31, 2014	$4	$(22)	$7	$(98)	$(109)
Change in Fair Value Recognized in AOCI	3	—	1	—	4
Amounts Reclassified from AOCI	(1)	1	—	1	1
Net Current Period Other Comprehensive Income	2	1	1	1	5
Balance in AOCI as of June 30, 2014	$6	$(21)	$8	$(97)	$(104)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 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	—	—	—	2
Amounts Reclassified from AOCI	(8)	1	—	1	(6)
Net Current Period Other Comprehensive Income (Loss)	(6)	1	—	1	(4)
	—	—	—	5	5

Pension and OPEB Adjustment Related to Mitchell Plant					
Balance in AOCI as of June 30, 2015	$(5)	$(18)	$8	$(87)	$(102)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 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	(11)	—	1	—	(10)
Amounts Reclassified from AOCI	17	2	—	2	21
Net Current Period Other Comprehensive Income	6	2	1	2	11
Balance in AOCI as of June 30, 2014	$6	$(21)	$8	$(97)	$(104)

Reclassifications from Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and six months ended June 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 6 for additional details.

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

	Amount of (Gain) Loss Reclassified from AOCI Three Months Ended June 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in millions)	
Commodity:		
Generation & Marketing Revenues	$(4)	$—
Purchased Electricity for Resale	7	(2)
Subtotal – Commodity	3	(2)
Interest Rate and Foreign Currency:		
Interest Expense	—	2
Subtotal – Interest Rate and Foreign Currency	—	2
Reclassifications from AOCI, before Income Tax (Expense) Credit	3	—
Income Tax (Expense) Credit	1	—
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	2	—
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(5)	(5)
Amortization of Actuarial (Gains)/Losses	6	7
Reclassifications from AOCI, before Income Tax (Expense) Credit	1	2
Income Tax (Expense) Credit	—	1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1	1
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$3	$1

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

	Amount of (Gain) Loss Reclassified from AOCI Six Months Ended June 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in millions)	
Commodity:		
Generation & Marketing Revenues	$(17)	$—
Purchased Electricity for Resale	6	29
Regulatory Assets/(Liabilities), Net (a)	—	(3)
Subtotal – Commodity	(11)	26
Interest Rate and Foreign Currency:		
Interest Expense	1	4
Subtotal – Interest Rate and Foreign Currency	1	4
Reclassifications from AOCI, before Income Tax (Expense) Credit	(10)	30
Income Tax (Expense) Credit	(3)	11
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(7)	19
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(10)	(10)
Amortization of Actuarial (Gains)/Losses	11	14
Reclassifications from AOCI, before Income Tax (Expense) Credit	1	4
Income Tax (Expense) Credit	—	2
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1	2
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$(6)	$21

(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	June 30, 2015 (in millions)	December 31, 2014
Regulatory Assets Currently Earning a Return		
Storm Related Costs	$20	$20
Material and Supplies Related to Retired Plants	19	—
West Virginia Vegetation Management Program	—	20
Regulatory Assets Currently Not Earning a Return		
Asset Retirement Obligation Costs Related to Retired Plants	51	—
Virginia Demand Response Program Costs	11	9
Ormet Special Rate Recovery Mechanism	10	10
Storm Related Costs	3	100
Carbon Capture and Storage Product Validation Facility	—	13
IGCC Pre-Construction Costs	—	11
Other Regulatory Assets Pending Final Regulatory Approval	23	43
Total Regulatory Assets Pending Final Regulatory Approval	$137	$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. If the Supreme Court of Ohio upholds its June 2015 order, it would remand the matter back to the PUCO for reinstatement of the WACC rate.

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

June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that 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.

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 July 2014, OPCo submitted a separate application to continue the RSR to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh, until the balance of the capacity deferrals has been collected. In April 2015, the PUCO issued an order approving the application to continue the RSR, with modifications. 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 June 30, 2015, OPCo's incurred deferred capacity costs balance of $432 million, including debt carrying costs, was recorded in Regulatory Assets on the condensed balance sheet.

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. As ordered, in 2014, OPCo conducted multiple energy-only auctions for a total of 100% of the SSO load with delivery beginning April 2014 through May 2015. As provided for in the June 2015 - May 2018 ESP, for delivery starting in June 2015, OPCo now conducts energy and capacity auctions for its entire SSO load. 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

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 included a return on common equity of 10.65% on capital costs for certain riders. 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 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 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, on rehearing, the PUCO issued an order that increased the DIR rate caps and deferred ruling on all requests for rehearing related to the establishment of the PPA rider. In June 2015, OPCo and various intervenors filed applications for rehearing with the PUCO related to the May 2015 order on rehearing. In July 2015, the PUCO granted the requests for rehearing.

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) continued to include the 2,671 MW to be available for capacity, energy and ancillary services, produced by AGR over the lives of the respective generating units.

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

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 June 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 June 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 is approximately $52 million. In March 2014, the PUCT issued an order related to the January 2014 PUCT ruling and in April 2014, this order became final. In May 2014, intervenors filed appeals of that order with the Texas District Court. In June 2014, SWEPCo intervened in those appeals and filed initial responses.

If certain parts of the PUCT order are overturned or if SWEPCo cannot ultimately recover its Texas jurisdictional share of the Turk Plant investment, including AFUDC, or its retirement-related costs 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 purchase 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 will be 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.

Welsh Plant, Units 1 and 3 – Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet mercury and air toxics standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of June 30, 2015, SWEPCo has incurred costs of $256 million, including AFUDC, and has remaining contractual construction obligations of $89 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 June 30, 2015, the net book value of Welsh Plant, Units 1 and 3 was $484 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 June 2014, APCo filed a request with the WVPSC to increase annual base rates by $181 million, based upon a 10.62% return on common equity, to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates primarily due to the increase in plant investment and changes in the expected service lives of various generating units. The filing also requested recovery of $89 million in regulatory assets over five years related to 2012 West Virginia storm costs, IGCC and other deferred costs. In addition to the base rate request, the filing also included a request to implement a rider of approximately $45 million annually to recover vegetation management costs, including a return on capital investment.

In May 2015, the WVPSC issued an order on the 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 annual 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.

In June 2015, the WVPSC staff and intervenors filed motions for reconsideration and clarification related to various issues including recovery of lost revenues and the allowed carrying charge rate related to the delayed residential revenues. In July 2015, the WVPSC issued an order that denied all motions for reconsideration.

2015 Virginia Regulatory Asset Proceeding

In January 2015, the Virginia SCC initiated a separate proceeding to address the proper treatment of APCo’s authorized regulatory assets. As of June 30, 2015, APCo’s authorized regulatory assets under review in this proceeding are estimated to be $12 million. In February and March 2015, briefs related to this proceeding were filed by various parties. 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 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 for 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 equity of 10.5% and is proposed to be effective in January 2016, except for the $44 million for environmental investments, which is proposed to be 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 June 30, 2015, PSO has incurred costs of $140 million related to these projects, including AFUDC.

In addition, the filing also notified the OCC that future incremental purchased capacity and energy costs of an estimated $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 June 30, 2015, the net book value of Northeastern Plant, Unit 4 was $95 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.

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. These additional regulatory assets 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, from 2015 through 2021, for eligible transmission, distribution and storage system improvements. The initial estimated cost of the capital improvements and associated operation and maintenance expenses included in the TDSIC Plan of $787 million, excluding AFUDC, would be updated annually. The TDSIC Plan included distribution investments specific to the Indiana jurisdiction. The TDSIC Rider would allow the periodic adjustment of I&M's rates to provide for timely recovery of 80% of approved TDSIC Plan costs. I&M would defer the remaining 20% of approved TDSIC Plan costs to be recovered in I&M's next general rate case. I&M did not seek a rate adjustment in this proceeding but sought approval of a TDSIC Rider rate adjustment mechanism for subsequent proceedings. In April 2015, I&M filed a notice with the IURC to seek approval of the proposed TDSIC Plan excluding $117 million of certain projects that were challenged in this proceeding. In May 2015, the IURC issued an order that denied I&M's TDSIC Plan and Rider. In May 2015, I&M filed a petition for reconsideration and/or rehearing with the IURC and in June 2015, filed a notice of 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 of the April 2015 Franklin County Circuit Court order that had affirmed the KPSC's order.

Consistent with KPCo’s December 2012 plant transfer filing with 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.

Kentucky Fuel Adjustment Clause Review

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. 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 April 2015, the Franklin County Circuit Court issued an order approving intervenors' requests to hold this case in abeyance until the KPSC issues a final order in KPCo’s two-year FAC review case for the period November 2012 through October 2014.

2014 Kentucky Base Rate Case

In December 2014, KPCo filed a request with the KPSC for a net increase in rates of $70 million, which consists of a $75 million increase in rider rates, offset by a $5 million decrease in annual base rates, to be effective July 2015 based upon a 10.62% return on common equity. The net increase reflects KPCo's ownership interest in the Mitch