AMERICAN ELECTRIC POWER CO INC
Form 10-Q
April 28, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended March 31, 2016
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 April 28, 2016 |
|---|---|
| American Electric Power Company, Inc. | 491,313,380 ($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
March 31, 2016

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 | American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and 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. |
| AEPRO | AEP River Operations, LLC, a commercial barge operation sold in November 2015. |
| AFUDC | Allowance for Funds Used During Construction. |
| AGR | AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation & Marketing segment. |
| 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 LLC 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. |

| | |
|---|---|
| ETT | Electric Transmission Texas, LLC, an equity interest joint venture between Parent and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT. |

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| Term | Meaning |
|---|---|
| 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. |
| 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. |
| Parent | American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation. |
| PIRR | Phase-In Recovery Rider. |
| PJM | Pennsylvania – New Jersey – Maryland regional transmission organization. |
| PM | Particulate Matter. |
| PPA | Power Purchase and Sale Agreement. |
| 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. |
| Registrants | SEC registrants: AEP, APCo, I&M, OPCo, PSO and SWEPCo. |

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|---|---|
| Risk Management Contracts | Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges. |
| Rockport Plant | A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2. |
| RPM | Reliability Pricing Model. |

| Term | Meaning |
|---|---|
| RSR | Retail Stability Rider. |
| RTO | Regional Transmission Organization, responsible for moving electricity over large interstate areas. |
| Sabine | Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo. |
| SEC | U.S. Securities and Exchange Commission. |
| SEET | Significantly Excessive Earnings Test. |
| SNF | Spent Nuclear Fuel. |
| $SO_2$ | Sulfur dioxide. |
| SPP | Southwest Power Pool regional transmission organization. |
| SSO | Standard service offer. |
| Stall Unit | J. Lamar Stall Unit at Arsenal Hill Plant, a 534 MW natural gas unit owned by SWEPCo. |
| SWEPCo | Southwestern Electric Power Company, an AEP electric utility subsidiary. |
| TCC | AEP Texas Central Company, an AEP electric utility subsidiary. |
| Texas Restructuring Legislation | Legislation enacted in 1999 to restructure the electric utility industry in Texas. |
| TNC | AEP Texas North Company, an AEP electric utility subsidiary. |
| TRA | Tennessee Regulatory Authority. |
| Transition Funding | AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. |
| Transource Energy | Transource Energy, LLC, a consolidated variable interest entity formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates. |
| Transource Missouri | A 100% wholly-owned subsidiary of Transource Energy. |
| Turk Plant | John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo. |
| Utility Money Pool | Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries. |
| VIE | Variable Interest Entity. |
| Virginia SCC | Virginia State Corporation Commission. |
| WPCo | Wheeling Power Company, an AEP electric utility subsidiary. |
| WVPSC | Public Service Commission of West Virginia. |

FORWARD-LOOKING INFORMATION

This report made by the Registrants 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 2015 Annual Report, but there are others throughout this document which may be identified by words such as “expect,” “anticipate,” “intend,” “plan,” “believe,” “will,” “should,” “ “would,” “project,” “continue” and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, management undertakes 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 AEP service territories.

Inflationary or deflationary interest rate trends.

Volatility in the financial markets, particularly developments affecting the availability or cost of capital to finance new capital projects and refinance existing debt.

The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.

Electric load, customer growth and the impact of competition, including competition for retail customers.

Weather conditions, including storms and drought conditions, and the ability to recover significant storm restoration costs.

The cost of fuel and its transportation and the creditworthiness and performance of fuel suppliers and transporters.

Availability of necessary generation capacity and the performance of generation plants.

The ability to recover fuel and other energy costs through regulated or competitive electric rates.

The ability to build transmission lines and facilities (including the 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 that could impact the continued operation, cost recovery and/or profitability of 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.

The ability to constrain operation and maintenance costs.

The ability to develop and execute a strategy based on a view regarding prices of electricity and gas.

Prices and demand for power generated and sold at wholesale.

Changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation.

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

Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas and capacity auction returns.

Changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP.

The market for generation in Ohio and PJM and the ability to recover investments in Ohio generation assets.
The ability to successfully and profitably manage competitive generation assets, including the evaluation of strategic alternatives for these assets as some of the alternatives could result in a loss.
Changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market.
Actions of rating agencies, including changes in the ratings of debt.

The impact of volatility in the capital markets on the value of the investments held by the 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 the Registrants speak only as of the date of this report or as of the date they are made. The Registrants 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 2015 Annual Report and in Part II of this report.

Investors should note that the Registrants announce material financial information in SEC filings, press releases and public conference calls. Based on guidance from the SEC, the Registrants may use the Investors section of AEP's website (www.aep.com) to communicate with investors about the Registrants. It is possible that the financial and other information posted there could be deemed to be material information. The information on AEP's website is not part 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

AEP's weather-normalized retail sales volumes for the first quarter of 2016 decreased by 0.1% from the first quarter of 2015. AEP's first quarter 2016 industrial sales increased 0.9% compared to the first quarter of 2015 primarily due to increased sales to customers in oil and gas related sectors. Weather-normalized residential and commercial sales decreased 1.6% and increased 0.7% in the first quarter of 2016, respectively, from the first quarter of 2015.

Ohio PPA Application

In December 2015, a contested stipulation agreement related to the PPA rider application was filed with the PUCO. The stipulation agreement provided for a 10.38% return on common equity, for AGR, with the PPA rider term extending through May 2024. The stipulation agreement included (a) an affiliate PPA between OPCo and AGR to be included in the PPA rider, (b) OPCo's OVEC contractual entitlement to be included in the PPA rider, (c) potential additional contingent customer credits of up to $100 million to be included in the PPA rider over the final four years of the PPA rider, (d) annual compliance reviews before the PUCO, (e) an agreement to retire, refuel or repower to 100% natural gas, Conesville Plant, Units 5 and 6 and Cardinal Plant, Unit 1 by 2029 and 2030, respectively, and (f) a commitment by OPCo to submit an amended ESP filing by April 30, 2016 which would extend all ESP riders through May 2024. Additionally, subject to cost recovery and PUCO approval, OPCo agreed to develop and implement, by 2021, a solar energy project(s) of at least 400 MW and a wind energy project(s) of at least 500 MW, with 100% of all output to be received by OPCo. AEP affiliates could own up to 50% of these solar and wind projects. OPCo agreed to file a carbon reduction plan with the PUCO by December 2016 that will focus on fuel diversification and carbon emission reductions.

In March 2016, the PUCO modified and approved the stipulation agreement. The PPA is effective April 2016 through May 2024, with quarterly PPA rider reconciliations to actual PPA costs compared to PJM market revenues, subject to audit and review by the PUCO. PUCO modifications to the stipulation agreement included (a) a temporary customer-specific rate impact cap of 5% through May 2018, (b) a directive that OPCo will not seek recovery from customers for any costs associated with the retirement, refueling, co-firing or repowering of PPA units, (c) the limitation that OPCo will not flow through any capacity performance penalties or bonuses through the PPA rider, (d) the right for the PUCO to exclude costs associated with a forced outage lasting longer than 90 days, (e) the limitation that OPCo will not flow through any net costs or revenues associated with AGR's obligations or entitlements related to Cardinal Plant, Units 2 and 3 and (f) the right for the PUCO to re-evaluate or modify the PPA rider if there is a change to PJM's tariffs or rules that prohibits the PPA units from being bid into PJM auctions.

The PUCO order did not modify OPCo's agreement to provide potential additional customer credits of up to $100 million during the final four years of the PPA rider, which are shown in the following table:

| PJM Planning Year | Potential Credit |
|---|---|
| June 2020 through May 2021 | $10 million |
| June 2021 through May 2022 | $20 million |
| June 2022 through May 2023 | $30 million |
| June 2023 through May 2024 | $40 million |

In accordance with accounting guidance for “Contingencies,” management will perform ongoing reviews of projected PPA plant costs compared to related market prices for energy and capacity to determine if additional credits to customers are probable.  Management is unable to determine a range of potential losses that are reasonably possible of occurring. Potential PPA credits could reduce future net income and cash flows and impact financial condition.

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In January 2016, a complaint was filed at the FERC against AGR and OPCo requesting that FERC review the PPA under its standards for affiliate transactions. In March 2016, a group of merchant generation owners filed a complaint at the FERC against PJM seeking revisions to the Minimum Offer Price Rule (MOPR) in PJM's tariff. The complaint against PJM requested the FERC act in advance of the May 2016 Base Residual Auction for the 2019/2020 delivery year. If approved as proposed, the revised MOPR would apply to the PPA units and could affect bidding into PJM.

In April 2016, the FERC issued an order granting the January 2016 complaint filed against AGR and OPCo. The FERC order rescinded the waivers of the FERC's affiliate rules as to the affiliate PPA between AGR and OPCo. As a result, AGR and OPCo are required to submit the affiliate PPA to the FERC for review in accordance with FERC's rules governing affiliate transactions. The affiliate PPA is not effective until the FERC review is completed and the affiliate PPA is approved. Management is evaluating its alternatives in response to this order.

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.

Ohio Electric Security Plan Filings

2009 - 2011 ESP

In 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. In October 2015 this matter was remanded back to the PUCO for reinstatement of the weighted average cost of capital (WACC) rate. A decision from the PUCO is pending.

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. In 2013, this ruling was generally upheld in PUCO rehearing orders.

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 included 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 April 2015, the PUCO issued an order that approved, with modifications, OPCo's July 2014 application to collect the unrecovered portion of the deferred capacity costs. In May 2015, the PUCO granted intervenors requests for rehearing. As of March 31, 2016, OPCo's net deferred capacity costs balance was $320 million, including debt carrying costs. Through March 31, 2016, OPCo has collected $266 million in deferred capacity costs, and related carrying charges.

In 2013, the PUCO issued its Orders on Rehearing for the ESP which generally upheld its August 2012 order. The PUCO clarified that a final reconciliation of revenues and expenses would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket related to the competitive bid process (CBP). In 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO’s ESP order.

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In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings.

In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC. In March 2014, the PUCO approved OPCo's request to implement riders related to the unbundling of the FAC. In October 2014, the independent auditor, selected by the PUCO, filed its report with the PUCO for the period August 2012 through May 2015. 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.

In April 2016, the Supreme Court of Ohio issued two opinions related to the deferral of OPCo's capacity charges. The Supreme Court of Ohio ruled that the PUCO must reconsider an energy credit that was used to determine OPCo's authorized capacity deferral threshold of $188.88/MW day during the August 2012 through May 2015 period. The PUCO reduced OPCo's authorized capacity deferral threshold to $188.88/MW day largely due to an offset for an energy credit of $147.41/MW day. The Supreme Court of Ohio directed the PUCO to substantively address OPCo's arguments that the $147.41/MW day credit was overstated by approximately $100.00/MW day due to various inaccuracies affecting input data and assumptions.

The Supreme Court of Ohio also rejected a portion of OPCo's RSR revenues collected during the period September 2012 through May 2015 and directed the PUCO to apply these RSR revenues against OPCo's deferred capacity costs. The Supreme Court of Ohio was not able to determine the amount of the reduction to OPCo's deferred capacity costs and remanded the issue to the PUCO to determine the appropriate reduction.

Due to the interrelated nature of these two Supreme Court of Ohio opinions that directly relate to OPCo's deferred capacity costs, management believes that the PUCO will rule upon both issues together. Further, management believes that the net impact of these issues will largely offset and will not result in a material future reduction of OPCo's net income.

Additionally, the Supreme Court of Ohio agreed with OPCo's cross-appeal assertion that the 12% threshold was not based on a comparison of OPCo's return on equity to the returns during the same period of comparable publicly traded companies, including utilities, that face comparable business and financial risk. The Supreme Court of Ohio reversed the 12% threshold and remanded this issue to the PUCO.

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.

Merchant Fleet Alternatives

AEP is evaluating strategic alternatives for AGR's merchant generation fleet, included in the Generation & Marketing segment, as well as AEGCo's Lawrenceburg Plant, all of which operate in PJM. Potential alternatives may include, but are not limited to, continued ownership of the merchant generation fleet or a sale of the merchant generation fleet. Management has not made a decision regarding the potential alternatives, nor have they set a specific time frame for a decision. These alternatives could result in a loss which could reduce future net income and cash flows and impact financial condition.

Merchant Portion of Turk Plant

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

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.

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 would review base rates in 2014 and 2015 and that SWEPCo would 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. A hearing at the LPSC related to the Turk Plant prudence review is scheduled for November 2016. 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.

Welsh Plant - Environmental Impact

Management currently estimates that the investment necessary to meet proposed environmental regulations through 2025 for Welsh Plant, Units 1 and 3 could cost approximately $900 million, excluding AFUDC. As part of this investment, 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 $400 million, excluding AFUDC. As of March 31, 2016, SWEPCo had incurred costs of $372 million, including AFUDC, and had remaining contractual construction obligations of $28 million related to these projects. In March 2016, SWEPCo filed a request with the APSC to recover $69 million in environmental costs related to the Arkansas retail jurisdictional share of Welsh Plant, Units 1 and 3. SWEPCo began recovering the Arkansas jurisdictional share of these costs in March 2016, subject to review in the next filed base rate proceeding. SWEPCo will seek recovery of the remaining project costs from customers 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. Management continues to evaluate the impact of environmental rules and related project cost estimates.

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As of March 31, 2016, the net book value of Welsh Plant, Units 1 and 3 was $606 million, before cost of removal, including materials and supplies inventory and CWIP. As of March 31, 2016, the net book value of Welsh Plant, Unit 2 was $84 million, before cost of removal, including materials and supplies inventory and CWIP. Welsh Plant, Unit 2 was considered probable of abandonment and was retired in April 2016.

If any of these costs are not recoverable, including retirement-related costs for Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition.

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, (b) a rider or base rate increase of $44 million to recover costs for environmental controls and (c) a request to include environmental consumable costs in the FAC, estimated to be $4 million annually. The rate increase includes a proposed return on common equity of 10.5% effective in January 2016. The proposed $44 million increase related to environmental investments was effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls were placed in service.

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

In October 2015, testimony was filed by OCC staff and intervenors with recommendations that included increases to base rates and/or the proposed environmental rider ranging from $10 million to $31 million, based upon returns on common equity ranging from 8.75% to 9.3%, and increases to depreciation expense ranging from $23 million to $46 million. Additionally, recommendations by certain intervenors included (a) no recovery of PSO’s investment in Northeastern Plant, Unit 3 environmental controls, (b) no recovery of the plant balances at the time the units are retired in 2016 and 2026, (c) denial of returns on the book values after the retirement dates, or to be set at only the cost of debt, and (d) the disallowance of the capacity costs associated with the PPAs. Additionally, some intervenors recommended no change in depreciation rates for Northeastern Plant, Units 3 and 4. These units are currently being depreciated through 2040. Hearings at the OCC were held in December 2015. In January 2016, PSO implemented an interim annual base rate increase of $75 million, subject to refund pending a final order from the OCC. An order from the OCC is anticipated by the end of the third quarter of 2016. 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.

2016 West Virginia Expanded Net Energy Charge Filing

In March 2016, APCo and WPCo filed their combined annual ENEC filing with the WVPSC which requested an increase in ENEC rates of $108 million to be effective July 2016. The increase primarily relates to recovery of the December 2015 under-recovered ENEC deferral balance and the recovery of costs associated with the continuation and expansion of certain transmission and generation construction projects. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

TCC and TNC Distribution Cost Recovery Factor (DCRF) Filings

In April 2016, TCC and TNC filed separate requests with the PUCT for approval of DCRF riders to allow recovery of eligible net distribution investments. TCC’s and TNC’s requests included revenue requirements of $54 million and $16 million, respectively, both to be effective September 2016.  Amounts approved would be subject to refund based upon a prudence review of the investments in TCC's and TNC's next base rate cases.

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

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Kingsport Base Rate Case

In January 2016, KGPCo filed a request with the TRA to increase base rates by $12 million annually based upon a proposed return on common equity of 10.66%. New rates are expected to be implemented in the third quarter of 2016. A hearing at the TRA is scheduled for August 2016. If KGPCo does not recover its costs, it could reduce future net income and cash flows and impact financial condition.

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 amendments provide that APCo will absorb its Virginia jurisdictional share of incremental generation and distribution costs incurred during 2014 through 2017 that are associated with severe weather events and/or natural disasters and costs associated with potential asset impairments related to new carbon emission guidelines issued by the Federal EPA.

In February 2016, certain APCo industrial customers filed a petition with the Virginia SCC requesting the issuance of a declaratory order that finds the amendments to Virginia law suspending biennial reviews unconstitutional and, accordingly, directs APCo to make biennial review filings beginning in 2016. In February 2016, APCo filed a motion to stay the Virginia SCC's consideration of the petition due to a pending appeal at the Supreme Court of Virginia by industrial customers of a non-related utility regarding the constitutionality of the amendments. APCo and other parties have filed their responses to the petition. Oral arguments at the Virginia SCC were held in March 2016. Management is unable to predict the outcome of these challenges. If the biennial review process is reinstated in advance of March 2020, it could reduce future net income and cash flows and impact financial condition.

PJM Capacity Market

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

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

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

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

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

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

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

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

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

The FERC order exempted Fixed Resource Requirement entities, including APCo, I&M, KPCo and WPCo, from the CP rules through the delivery period ending May 2019. In July 2015, AEP filed a request seeking rehearing of the FERC order approving CP. AEP is awaiting an order on its request for rehearing and will continue to advocate for further improvements to the CP rules and the capacity market as a whole through the PJM stakeholder process.

LITIGATION

In the ordinary course of business, AEP is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on the 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 2015 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 a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiff's claims. Several claims remained, 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. The plaintiff subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. In November 2015, AEGCo and I&M filed a motion to strike the plaintiff's motion for partial judgment and filed a motion to dismiss the case for failure to state a claim. In March 2016, the court entered an opinion and order in favor of AEGCo and I&M, dismissing certain of the plaintiffs' claims for breach of contract and dismissing claims for breach of implied covenant of good faith and fair dealing, and further dismissing plaintiffs' claim for indemnification of costs. By the same order, the court permitted plaintiffs to move forward with their claim that AEGCo and I&M failed to exercise prudent utility practices in the maintenance and operation of Rockport Plant, Unit 2. In April 2016, the plaintiffs filed a notice of voluntary dismissal of the other remaining claims with prejudice and the court subsequently entered a final judgment. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL ISSUES

AEP is implementing a substantial capital investment program and incurring additional operational costs to comply with environmental control requirements. Additional investments and operational changes will need to be made in response to existing and anticipated requirements such as CAA requirements to reduce emissions of $SO_2$, $NO_x$, PM, $CO_2$ and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, rules governing the beneficial use and disposal of coal combustion products, clean water rules and renewal permits for certain water discharges.

AEP is engaged in litigation about environmental issues, was notified of potential responsibility for the clean-up of contaminated sites and incurred costs for disposal of SNF and future decommissioning of the nuclear units. AEP, along with various industry groups, affected states and other parties challenged some of the Federal EPA requirements in court. Management is also engaged in the development of possible future requirements including the items discussed below and state plans to reduce $CO_2$ emissions to address concerns about global climate change. Management believes that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

See a complete discussion of these matters in the "Environmental Issues" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2015 Annual Report. AEP 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 AEP is 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. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of March 31, 2016, the AEP System had a total generating capacity of approximately 32,000 MWs, of which approximately 18,000 MWs are coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on the fossil generating facilities. Based upon management estimates, AEP's investment to meet these proposed requirements ranges from approximately $3.2 billion to $3.8 billion through 2025. These amounts include investments to convert some of the coal generation to natural gas.

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

In May 2015, AEP 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 March 31, 2016, the net book value of the AGR units listed above was zero. 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 approved for recovery, except for $148 million which management plans to seek regulatory approval.

In April 2016, AEP retired the following units of plants:

| 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 March 31, 2016, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of the PSO and SWEPCo units listed above was $178 million. For Northeastern Station, Unit 4, PSO is seeking regulatory recovery of remaining net book values. For Welsh Plant, Unit 2, management will seek regulatory recovery of remaining net book values.

In October 2015, KPCo obtained permits following the KPSC's approval to convert its 278 MW Big Sandy Plant, Unit 1 to natural gas. Management expects to begin operations as a natural gas unit in the second quarter of 2016. As of March 31, 2016, the net book value, before cost of removal, including related materials and supplies inventory and CWIP balances of Big Sandy Plant, Unit 1 was $110 million.

APCo obtained permits following the Virginia SCC's and WVPSC's approval to convert its 470 MW Clinch River Plant, Units 1 and 2 to natural gas. In the third and fourth quarters of 2015, APCo retired the coal-related assets of Clinch River Plant, Units 1 and 2. Of the retired coal related assets for Clinch River Plant, Units 1 and 2, management plans to seek regulatory approval for $24 million. Clinch River Plant, Unit 1 and Unit 2 began operations as natural gas units in February 2016 and April 2016, respectively. As of March 31, 2016, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of Clinch River Plant, Units 1 and 2 was $155 million.

To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially reduce future net income and cash flows and impact financial condition.

Clean Air Act Requirements

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

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The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in $SO_2$ and $NO_x$ emissions from power plants. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. In 2012, a panel of the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. That decision was appealed to the U.S. Supreme Court, which reversed the decision and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit ordered CSAPR to take effect on January 1, 2015 while the remand proceeding was still pending. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the Federal EPA. All of the states in which AEP's 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, but the rule was remanded to the Federal EPA upon further review and remains in effect. 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, management submitted comments to the proposed Arkansas FIP and participated in comments filed by industry associations of which AEP is a member. Management supports compliance with CSAPR programs as satisfaction of the BART requirements.

The Federal EPA issued rules for $CO_2$ emissions that apply to new and existing electric utility units. See "Climate Change, $CO_2$ Regulation and Energy Policy" section below.

The Federal EPA also issued new, more stringent national ambient air quality standards (NAAQS) for PM, $SO_2$ and ozone. In October 2015, the Federal EPA announced a lower final NAAQS for ozone of 70 parts per billion. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for facilities as a result of those evaluations. Management cannot currently predict the nature, stringency or timing of those requirements.

Notable developments in significant CAA regulatory requirements affecting AEP's 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. A petition for review filed by the Federal EPA and other parties in the U.S. Supreme Court was granted in June 2013. In April 2014, the U.S. Supreme Court issued a decision reversing in part the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanding the case for further proceedings consistent with the opinion. The Federal EPA filed a motion to lift the stay and allow Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. The court granted the Federal EPA's motion. The parties filed briefs and presented oral arguments. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit found that the Federal EPA over-controlled the $SO_2$ and/or $NO_x$ budgets of 14 states. The U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the Federal EPA to timely revise the rule consistent with the court's opinion while CSAPR remains in place.

In December 2015, the Federal EPA issued a proposal to revise the ozone season $NO_x$ budgets in 23 states beginning in 2017 to address transport issues associated with the 2008 ozone standard and the budget errors identified in the U.S. Court of Appeals for the District of Columbia Circuit's July 2015 decision. The proposal was open for public comment through February 1, 2016. Management believes that the Federal EPA mistakenly relied on future projected retirements and failed to take into account actual operating experience when establishing the 2017 budgets. Management also believes there is insufficient time to implement the required reductions.

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. Management 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.

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. The U.S. Court of Appeals for the District of Columbia Circuit remanded the MATS rule for further proceedings consistent with the U.S. Supreme Court's 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 Federal EPA issued notice of a supplemental finding concluding that it is appropriate and necessary to regulate HAP emissions from coal-fired and oil-fired units. Management submitted comments on the proposal and will continue to monitor future regulatory developments. In April 2016, the Federal EPA affirmed its determination that regulation of HAPs from electric generating units is necessary and appropriate. The rule remains in effect.

Climate Change, $CO_2$ Regulation and Energy Policy

The majority of the states where AEP has generating facilities passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements that can assist in reducing carbon emissions.  Management is taking steps to comply with these requirements, including increasing wind power purchases and broadening the AEP System's portfolio of energy efficiency programs.

In October 2015, the Federal EPA published the final standards for new, modified and reconstructed fossil fired steam generating units and combustion turbines, and final guidelines for the development of state plans to regulate $CO_2$ emissions from existing sources. The final standard for new combustion turbines is 1,000 pounds of $CO_2$ per MWh and the final standard for new fossil steam units is 1,400 pounds of $CO_2$ per MWh. Reconstructed turbines are subject to the same standard as new units and no standard for modified combustion turbines was issued. Reconstructed fossil steam units are subject to a standard of 1,800 pounds of $CO_2$ per MWh for larger units and 2,000 pounds of $CO_2$ per MWh for smaller units. Modified fossil steam units will be subject to a site specific standard no lower than the standards that would be applied if the units were reconstructed.

The final emissions guidelines for existing sources, known as the Clean Power Plan, are based on a series of declining emission rates that are implemented beginning in 2022 through 2029. The final emission rate is 771 pounds of $CO_2$ per MWh for existing natural gas combined cycle units and 1,305 pounds of $CO_2$ per MWh for existing fossil steam units in 2030 and thereafter. The Federal EPA also developed a set of rate-based and mass-based state goals.

The Federal EPA also published proposed “model” rules that can be adopted by the states that would allow sources within “trading ready” state programs to trade, bank or sell allowances or credits issued by the states. These rules would also be the basis for any federal plan issued by the Federal EPA in a state that fails to submit or receive approval for a state plan. The Federal EPA intends to finalize either a rate-based or mass-based trading program that can be enforced in states that fail to submit approved plans by the deadlines established in the final guidelines. States are required to submit final plans or an extension request by September 2016 to the Federal EPA. States receiving an extension request must submit final plans by September 2018. Management is evaluating the rules impact as well as the anticipated actions by states where assets are located. The final rules are being challenged in the courts. In February 2016, the U.S. Supreme Court issued a stay on the final Clean Power Plan, including all of the deadlines for submission of initial or final state plans. The stay will remain in effect until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review. The Federal EPA established a 90-day public comment period on the proposed rules and management submitted comments.

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 AEP to close some coal-fired facilities and could lead to possible impairment of assets.

Coal Combustion Residual Rule

In April 2015, the Federal EPA published a final 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 final rule became effective in October 2015. The Federal EPA will regulate CCR as a non-hazardous solid waste and issued new minimum federal solid waste management standards. 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. The CCR rule requirements contain a compliance schedule spanning an approximate four year implementation period. If CCR units do not meet these standards within the timeframes provided, they will be required to close. Extensions of time for closure are available provided there is no alternative disposal capacity or the owner can certify cessation of a boiler by a certain date. Challenges to the rule by industry associations of which AEP is a member are proceeding. In April 2016, the parties entered into a settlement agreement that would require the Federal EPA to reconsider certain aspects of the rule. If approved, under the settlement agreement, the provisions creating specific closure requirements will be vacated for inactive impoundments that complete closure by April 17, 2018. The Federal EPA will propose a

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rule to extend the deadlines for these facilities to comply with the CCR standards promptly and attempt to finalize that rule within four months. The Federal EPA will also use its best efforts to complete reconsideration of all of the affected provisions within three years.

Because AEP currently uses surface impoundments and landfills to manage CCR materials at generating facilities, significant costs will be incurred to upgrade or close and replace these existing facilities at some point in the future as the new rule is implemented. Management recorded a $95 million increase in asset retirement obligations in the second quarter of 2015 primarily due to the publication of the final rule. Management will continue to evaluate the rule’s impact on operations.

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 AEP’s generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. 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.

Clean Water Act (CWA) Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant’s cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The final rule affects all plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with the impingement standard and requires site-specific studies to determine appropriate entrainment compliance measures at facilities withdrawing more than 125 million gallons per day. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats. Facilities with existing closed cycle recirculating cooling systems, as defined in the rule, are not expected to require any technology changes. Facilities subject to both the impingement standard and site-specific entrainment studies will typically be given at least three years to conduct and submit the results of those studies to the permit agency. Compliance timeframes will then be established by the permit agency through each facility’s National Pollutant Discharge Elimination System (NPDES) permit for installation of any required technology changes, as those permits are renewed over the next five to eight years. Petitions for review of the final rule were filed by industry and environmental groups and are currently pending in the U.S. Court of Appeals for the Second Circuit.

In addition, the Federal EPA developed revised effluent limitation guidelines for electricity generating facilities. A final rule was issued in November 2015. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. In addition to other requirements, the final rule establishes limits on flue gas desulfurization wastewater, zero discharge for fly ash and bottom ash transport water and flue gas mercury control wastewater. The applicability of these requirements is as soon as possible after November 2018 and no later than December 2023. These new requirements will be implemented through each facility’s wastewater discharge permit. Management will continue to review the final rule in detail to evaluate whether the plants are currently meeting the proposed limitations, what technologies are incorporated into AEP’s long-range plans and what additional costs might be incurred. Management is assessing technology additions and retrofits.

In June 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of “waters of the United States” in light of recent U.S. Supreme Court cases. The CWA provides for federal jurisdiction over “navigable waters” defined as “the waters of the United States.” This jurisdictional definition applies to all CWA programs, potentially impacting generation, transmission and distribution permitting and compliance requirements. Among those programs are: permits for wastewater and storm water discharges, permits for impacts to wetlands and water bodies and oil spill prevention planning. The final definition continues to recognize traditional navigable waters of the U.S. as jurisdictional as well as certain exclusions. The rule also contains a number of new specific definitions and criteria for determining whether certain other waters are jurisdictional because of a “significant nexus.” Management believes that clarity and efficiency in the permitting process is needed. Management remains concerned that the rule introduces new concepts and could subject more of AEP's operations to CWA jurisdiction, thereby increasing the time and complexity of permitting. The final rule is being challenged in both courts of appeal and district courts. Challengers include industry associations of which AEP is a member. The U.S. Court of Appeals for the Sixth Circuit granted a nationwide stay of the rule pending jurisdictional determinations. In February 2016, the U.S. Court of Appeals for the Sixth Circuit issued a decision holding that it has exclusive jurisdiction to decide the challenges to the "waters of the United States" rule. Industry, state and related associations, including an association in which AEP is a member, have filed petitions for a rehearing of the jurisdictional decision.

RESULTS OF OPERATIONS

SEGMENTS

AEP's primary business is the generation, transmission and distribution of electricity. Within its Vertically Integrated Utilities segment, AEP centrally dispatches generation assets and manages its 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.

AEP's 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 AEP's wholly-owned transmission-only subsidiaries and transmission-only joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

Generation & Marketing

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

The remainder of AEP's activities is presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries, Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs. With the sale of AEPRO in November 2015, the activities related to the AEP River Operations segment have been moved to Corporate and Other for the periods presented. See "AEPRO (Corporate and Other)" section of Note 6 for additional information.

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The table below presents Earnings Attributable to AEP Common Shareholders by segment for the three months ended March 31, 2016 and 2015.

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in millions) | |
| Vertically Integrated Utilities | $277.6 | $299.3 |
| Transmission and Distribution Utilities | 108.0 | 97.2 |
| AEP Transmission Holdco | 43.9 | 35.8 |
| Generation & Marketing | 70.7 | 187.4 |
| Corporate and Other | 1.0 | 9.5 |
| Earnings Attributable to AEP Common Shareholders | $501.2 | $629.2 |

AEP CONSOLIDATED

First Quarter of 2016 Compared to First Quarter of 2015

Earnings Attributable to AEP Common Shareholders decreased from $629 million in 2015 to $501 million in 2016 primarily due to:

- A decrease in generation revenues due to lower capacity revenue and a decrease in wholesale energy prices.
- A decrease in weather-related usage.
- Reduced trading and marketing activity as compared to 2015.
- A decrease in off-system sales margins due to lower market prices, reduced sales volumes and losses from a power contract with OVEC.

These decreases were partially offset by:

- A decrease in system income taxes due to lower pretax book income.
- An increase in transmission investment primarily at AEP Transmission Holdco which resulted in higher revenues and income.
- An increase in weather-normalized sales.

AEP’s results of operations by operating segment are discussed below.

VERTICALLY INTEGRATED UTILITIES

| Vertically Integrated Utilities | Three Months Ended March 31, 2016 | 2015 |
|---|---|---|
| | (in millions) | |
| Revenues | $2,245.6 | $2,505.1 |
| Fuel and Purchased Electricity | 742.0 | 983.2 |
| Gross Margin | 1,503.6 | 1,521.9 |
| Other Operation and Maintenance | 629.6 | 575.4 |
| Depreciation and Amortization | 266.8 | 272.2 |
| Taxes Other Than Income Taxes | 97.9 | 96.9 |
| Operating Income | 509.3 | 577.4 |
| Interest and Investment Income | 0.6 | 0.5 |
| Carrying Costs Income | 2.2 | 1.9 |
| Allowance for Equity Funds Used During Construction | 14.8 | 14.1 |
| Interest Expense | (127.3) | (130.6) |
| Income Before Income Tax Expense and Equity Earnings | 399.6 | 463.3 |
| Income Tax Expense | 121.9 | 163.6 |
| Equity Earnings of Unconsolidated Subsidiaries | 1.0 | 0.6 |
| Net Income | 278.7 | 300.3 |
| Net Income Attributable to Noncontrolling Interests | 1.1 | 1.0 |
| Earnings Attributable to AEP Common Shareholders | $277.6 | $299.3 |

Summary of KWh Energy Sales for Vertically Integrated Utilities

| | Three Months Ended March 31, 2016 | 2015 |
|---|---|---|
| | (in millions of KWhs) | |
| Retail: | | |
| Residential | 9,124 | 10,379 |
| Commercial | 5,880 | 6,011 |
| Industrial | 8,267 | 8,360 |
| Miscellaneous | 541 | 548 |
| Total Retail | 23,812 | 25,298 |
| | | |
| Wholesale (a) | 4,792 | 8,268 |
| | | |
| Total KWhs | 28,604 | 33,566 |

(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 the eastern region have a larger effect on revenues than changes in the 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 March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in degree days) | |
| Eastern Region | | |
| Actual – Heating (a) | 1,520 | 2,045 |
| Normal – Heating (b) | 1,633 | 1,604 |
| | | |
| Actual – Cooling (c) | 5 | — |
| Normal – Cooling (b) | 5 | 5 |
| | | |
| Western Region | | |
| Actual – Heating (a) | 678 | 1,040 |
| Normal – Heating (b) | 892 | 877 |
| | | |
| Actual – Cooling (c) | 30 | 14 |
| Normal – Cooling (b) | 23 | 23 |

(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) Cooling degree days are calculated on a 65 degree temperature base.

First Quarter of 2016 Compared to First Quarter of 2015
Reconciliation of First Quarter of 2015 to First Quarter of 2016
Earnings Attributable to AEP Common Shareholders from
Vertically Integrated Utilities
(in millions)

| | |
|---|---|
| First Quarter of 2015 | $299.3 |
| | |
| Changes in Gross Margin: | |
| Retail Margins | 8.9 |
| Off-system Sales | (17.5) |
| Transmission Revenues | (11.6) |
| Other Revenues | 1.9 |
| Total Change in Gross Margin | (18.3) |
| | |
| Changes in Expenses and Other: | |
| Other Operation and Maintenance | (54.2) |
| Depreciation and Amortization | 5.4 |
| Taxes Other Than Income Taxes | (1.0) |
| Interest and Investment Income | 0.1 |
| Carrying Costs Income | 0.3 |
| Allowance for Equity Funds Used During Construction | 0.7 |
| Interest Expense | 3.3 |
| Total Change in Expenses and Other | (45.4) |
| | |
| Income Tax Expense | 41.7 |
| Equity Earnings | 0.4 |
| Net Income Attributable to Noncontrolling Interests | (0.1) |
| | |
| First Quarter of 2016 | $277.6 |

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

- Retail Margins increased $9 million primarily due to the following:
- The effect of successful rate proceedings in AEP's service territories which included:
- A $27 million increase primarily due to increases in rates in West Virginia and Virginia, offset by a prior year adjustment due to the amended Virginia Law impacting biennial reviews.
- A $17 million increase for KPCo primarily due to increases in base rates and riders.
- A $6 million increase for I&M primarily due to rate increases from annual FERC formula rate adjustments and Indiana rate riders.
- A $4 million increase for PSO primarily due to interim base rate increases.

For the rate increases described above, $39 million relate to riders/trackers which have corresponding increases in expense items below.

- A $28 million increase in weather-normalized margins primarily in the residential and commercial classes.
- A $9 million decrease in Fuel and Purchased Electricity due to the transfer of a one-half interest in the Mitchell Plant from AGR to WPCo in January 2015. This decrease was partially offset by increases in other expense items below.

These increases were partially offset by:

- An $83 million decrease in weather-related usage.
- Margins from Off-system Sales decreased $18 million primarily due to lower market prices and decreased sales volumes.
- Transmission Revenues decreased $12 million primarily due to lower Network Integration Transmission Service revenues.

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

- Other Operation and Maintenance expenses increased $54 million primarily due to the following:
  - A $22 million increase in employee-related expenses.
  - A $14 million increase associated with amortization of deferred transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause effective January 2016. This increase in expense is offset within Retail Margins above.
  - A $12 million increase in recoverable expenses, primarily including vegetation management and storm expenses currently fully recovered in rate recovery riders/trackers.
  - A $6 million increase due to the reduction of an environmental liability in 2015 at I&M.
- Depreciation and Amortization expenses decreased $5 million primarily due to the impact of plant retirements in 2015 for APCo, I&M and KPCo.
- Income Tax Expense decreased $42 million primarily due to a decrease in pretax book income and by the recording of federal and state income tax adjustments.

TRANSMISSION AND DISTRIBUTION UTILITIES

| Transmission and Distribution Utilities | Three Months Ended March 31, 2016 | 2015 |
|---|---|---|
| | (in millions) | |
| Revenues | $1,096.8 | $1,270.1 |
| Purchased Electricity | 217.6 | 420.8 |
| Amortization of Generation Deferrals | 55.1 | 31.4 |
| Gross Margin | 824.1 | 817.9 |
| Other Operation and Maintenance | 324.4 | 319.3 |
| Depreciation and Amortization | 156.3 | 167.7 |
| Taxes Other Than Income Taxes | 123.3 | 122.2 |
| Operating Income | 220.1 | 208.7 |
| Interest and Investment Income | 2.2 | 1.9 |
| Carrying Costs Income | 1.9 | 6.5 |
| Allowance for Equity Funds Used During Construction | 4.3 | 3.7 |
| Interest Expense | (67.2 ) | (69.6 ) |
| Income Before Income Tax Expense | 161.3 | 151.2 |
| Income Tax Expense | 53.3 | 54.0 |
| Net Income | 108.0 | 97.2 |
| Net Income Attributable to Noncontrolling Interests | — | — |
| Earnings Attributable to AEP Common Shareholders | $108.0 | $97.2 |

Summary of KWh Energy Sales for Transmission and Distribution Utilities

| | Three Months Ended March 31, 2016 | 2015 |
|---|---|---|
| | (in millions of KWhs) | |
| Retail: | | |
| Residential | 6,241 | 7,266 |
| Commercial | 5,787 | 5,915 |
| Industrial | 5,498 | 5,280 |
| Miscellaneous | 166 | 161 |
| Total Retail (a) | 17,692 | 18,622 |
| Wholesale (b) | 323 | 534 |
| Total KWhs | 18,015 | 19,156 |

(a) Represents energy delivered to distribution customers.
(b) Primarily 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 the eastern region have a larger effect on revenues than changes in the 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 March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in degree days) | |
| Eastern Region | | |
| Actual – Heating (a) | 1,691 | 2,438 |
| Normal – Heating (b) | 1,919 | 1,881 |
| | | |
| Actual – Cooling (c) | 1 | — |
| Normal – Cooling (b) | 3 | 3 |
| | | |
| Western Region | | |
| Actual – Heating (a) | 121 | 320 |
| Normal – Heating (b) | 194 | 188 |
| | | |
| Actual – Cooling (d) | 159 | 41 |
| Normal – Cooling (b) | 109 | 109 |

(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.

First Quarter of 2016 Compared to First Quarter of 2015
Reconciliation of First Quarter of 2015 to First Quarter of 2016
Earnings Attributable to AEP Common Shareholders from
Transmission and Distribution Utilities
(in millions)

| | |
|---|---|
| First Quarter of 2015 | $97.2 |
| | |
| Changes in Gross Margin: | |
| Retail Margins | 54.8 |
| Off-System Sales | (10.9) |
| Transmission Revenues | (20.6) |
| Other Revenues | (17.1) |
| Total Change in Gross Margin | 6.2 |
| | |
| Changes in Expenses and Other: | |
| Other Operation and Maintenance | (5.1) |
| Depreciation and Amortization | 11.4 |
| Taxes Other Than Income Taxes | (1.1) |
| Interest and Investment Income | 0.3 |
| Carrying Costs Income | (4.6) |
| Allowance for Equity Funds Used During Construction | 0.6 |
| Interest Expense | 2.4 |
| Total Change in Expenses and Other | 3.9 |
| | |
| Income Tax Expense | 0.7 |
| | |
| First Quarter of 2016 | $108.0 |

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 $55 million primarily due to the following:
- A $54 million increase in Ohio transmission and PJM revenues primarily due to the energy supplied as a result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
- An $8 million increase in Texas weather-normalized margins primarily in the residential class.
- A $6 million increase in revenues associated with the Ohio Distribution Investment Rider.
- A $5 million increase in carrying charges primarily due to the collection of carrying costs on deferred capacity charges in Ohio beginning June 2015.

These increases were partially offset by:

- A $14 million decrease in revenues associated with the recovery of 2012 storm costs under the Ohio Storm Damage Recovery Rider which ended in April 2015. This decrease in Retail Margins is primarily offset by a decrease in Other Operation and Maintenance expenses below.
- An $11 million decrease in weather-related usage in Texas.
- Margins from Off-system Sales decreased $11 million primarily due to losses from a power contract with OVEC.
- Transmission Revenues decreased $21 million primarily due to the following:
- A $30 million decrease in Network Integrated Transmission Service revenue primarily due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the

CRES providers prior to June 2015, partially offset by a corresponding increase in Retail Margins above.

This decrease was partially offset by:

- A $9 million increase primarily due to increased transmission investment in ERCOT.
- Other Revenues decreased $17 million primarily due to a decrease in Texas securitization revenue offset in Depreciation and Amortization and other expense items below.

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Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $5 million primarily due to the following:
- A $25 million increase in recoverable expenses, primarily including PJM expenses and gridSMART® expenses, currently fully recovered in rate recovery riders/trackers.

These increases were partially offset by:

- A $13 million decrease due to the amortization of 2012 Ohio deferred storm expenses in 2015. This decrease was offset by a corresponding decrease in Retail Margins above.
- A $6 million decrease due to a PUCO ordered contribution to the Ohio Growth Fund recorded in 2015.
- Depreciation and Amortization expenses decreased $11 million primarily due to a decrease in TCC's securitization transition asset, which is partially offset in Other Revenues.
- Carrying Costs Income decreased $5 million primarily due to the collection of carrying costs on Ohio deferred capacity charges beginning June 2015.

AEP TRANSMISSION HOLDCO

| AEP Transmission Holdco | Three Months Ended March 31, 2016 | 2015 |
|---|---|---|
| | (in millions) | |
| Transmission Revenues | $88.6 | $57.9 |
| Other Operation and Maintenance | 11.7 | 7.8 |
| Depreciation and Amortization | 15.5 | 9.1 |
| Taxes Other Than Income Taxes | 21.2 | 16.2 |
| Operating Income | 40.2 | 24.8 |
| Interest and Investment Income | — | 0.1 |
| Allowance for Equity Funds Used During Construction | 12.4 | 11.9 |
| Interest Expense | (11.8 ) | (8.6 ) |
| Income Before Income Tax Expense and Equity Earnings | 40.8 | 28.2 |
| Income Tax Expense | 20.4 | 13.7 |
| Equity Earnings of Unconsolidated Subsidiaries | 24.3 | 21.8 |
| Net Income | 44.7 | 36.3 |
| Net Income Attributable to Noncontrolling Interests | 0.8 | 0.5 |
| Earnings Attributable to AEP Common Shareholders | $43.9 | $35.8 |

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

| | March 31, 2016 | 2015 |
|---|---|---|
| | (in millions) | |
| Net Plant in Service | $2,879.3 | $1,832.2 |
| CWIP | 1,287.2 | 1,119.9 |

First Quarter of 2016 Compared to First Quarter of 2015

Reconciliation of First Quarter of 2015 to First Quarter of 2016
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

| | |
|---|---|
| First Quarter of 2015 | $35.8 |
| | |
| Changes in Transmission Revenues: | |
| Transmission Revenues | 30.7 |
| Total Change in Transmission Revenues | 30.7 |
| | |
| Changes in Expenses and Other: | |
| Other Operation and Maintenance | (3.9 ) |
| Depreciation and Amortization | (6.4 ) |
| Taxes Other Than Income Taxes | (5.0 ) |
| Interest and Investment Income | (0.1 ) |
| Allowance for Equity Funds Used During Construction | 0.5 |
| Interest Expense | (3.2 ) |
| Total Change in Expenses and Other | (18.1 ) |
| | |
| Income Tax Expense | (6.7 ) |
| Equity Earnings | 2.5 |
| Net Income Attributable to Noncontrolling Interests | (0.3 ) |
| | |
| First Quarter of 2016 | $43.9 |

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 $31 million primarily due to an increase in projects placed in-service by AEP's wholly-owned transmission subsidiaries.

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

- Other Operation and Maintenance expenses increased $4 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $6 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $5 million primarily due to increased property taxes due to additional transmission investment.
- Interest Expense increased $3 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.

GENERATION & MARKETING

| Generation & Marketing | Three Months Ended March 31, 2016 | 2015 |
|---|---|---|
| | (in millions) | |
| Revenues | $748.0 | $1,170.5 |
| Fuel, Purchased Electricity and Other | 479.5 | 716.0 |
| Gross Margin | 268.5 | 454.5 |
| Other Operation and Maintenance | 93.6 | 100.0 |
| Depreciation and Amortization | 48.7 | 50.1 |
| Taxes Other Than Income Taxes | 9.9 | 9.1 |
| Operating Income | 116.3 | 295.3 |
| Interest and Investment Income | 0.5 | 1.0 |
| Allowance for Equity Funds Used During Construction | 0.2 | — |
| Interest Expense | (9.0) | (10.5) |
| Income Before Income Tax Expense | 108.0 | 285.8 |
| Income Tax Expense | 37.3 | 98.4 |
| Net Income | 70.7 | 187.4 |
| Net Income Attributable to Noncontrolling Interests | — | — |
| Earnings Attributable to AEP Common Shareholders | $70.7 | $187.4 |

Summary of MWhs Generated for Generation & Marketing

| | Three Months Ended March 31, 2016 | 2015 |
|---|---|---|
| | (in millions of MWhs) | |
| Fuel Type: | | |
| Coal | 5 | 10 |
| Natural Gas | 4 | 4 |
| Total MWhs | 9 | 14 |

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First Quarter of 2016 Compared to First Quarter of 2015
Reconciliation of First Quarter of 2015 to First Quarter of 2016
Earnings Attributable to AEP Common Shareholders from
Generation & Marketing
(in millions)

| | |
|---|---|
| First Quarter of 2015 | $187.4 |
| | |
| Changes in Gross Margin: | |
| Generation | (148.3) |
| Retail, Trading and Marketing | (37.2) |
| Other | (0.5) |
| Total Change in Gross Margin | (186.0) |
| | |
| Changes in Expenses and Other: | |
| Other Operation and Maintenance | 6.4 |
| Depreciation and Amortization | 1.4 |
| Taxes Other Than Income Taxes | (0.8) |
| Interest and Investment Income | (0.5) |
| Allowance for Equity Funds Used During Construction | 0.2 |
| Interest Expense | 1.5 |
| Total Change in Expenses and Other | 8.2 |
| | |
| Income Tax Expense | 61.1 |
| | |
| First Quarter of 2016 | $70.7 |

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 $148 million primarily due to lower capacity revenue and a decrease in wholesale energy prices.
- Retail, Trading and Marketing decreased $37 million due to the impact of favorable wholesale trading and marketing performance in 2015.

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

- Other Operation and Maintenance expenses decreased $6 million primarily due to plant retirements in June 2015.
- Income Tax Expense decreased $61 million primarily due to a decrease in pretax book income.

CORPORATE AND OTHER

First Quarter of 2016 Compared to First Quarter of 2015

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from income of $10 million in 2015 to income of $1 million in 2016 primarily due to decreased income from the discontinued operations of AEP River Operations which was sold in November 2015.

AEP SYSTEM INCOME TAXES

First Quarter of 2016 Compared to First Quarter of 2015

Income Tax Expense decreased $92 million primarily due to a decrease in pretax book income.

FINANCIAL CONDITION

AEP measures financial condition by the strength of its balance sheet and the liquidity provided by its cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

| | March 31, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| | (dollars in millions) | | | |
| Long-term Debt, including amounts due within one year | $19,782.6 | 50.6 % | $19,572.7 | 51.1 % |
| Short-term Debt | 1,221.0 | 3.1 | 800.0 | 2.1 |
| Total Debt | 21,003.6 | 53.7 | 20,372.7 | 53.2 |
| AEP Common Equity | 18,126.5 | 46.3 | 17,891.7 | 46.8 |
| Noncontrolling Interests | 15.2 | — | 13.2 | — |
| Total Debt and Equity Capitalization | $39,145.3 | 100.0% | $38,277.6 | 100.0% |

AEP's ratio of debt-to-total capital increased from 53.2% as of December 31, 2015 to 53.7% as of March 31, 2016 primarily due to an increase in short-term debt.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity under its existing credit facilities. As of March 31, 2016, AEP had $3.5 billion in aggregate credit facility commitments to support its operations. Additional liquidity is available from cash from operations and a receivables securitization agreement. Management is committed to maintaining adequate liquidity. AEP generally uses short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Commercial Paper Credit Facilities

AEP manages liquidity by maintaining adequate external financing commitments. As of March 31, 2016, available liquidity was approximately $3.2 billion as illustrated in the table below:

| | Amount (in millions) | Maturity |
|---|---|---|
| Commercial Paper Backup: | | |
| Revolving Credit Facility | $1,750.0 | June 2017 |
| Revolving Credit Facility | 1,750.0 | July 2018 |
| Total | 3,500.0 | |
| Cash and Cash Equivalents | 190.4 | |
| Total Liquidity Sources | 3,690.4 | |
| Less: AEP Commercial Paper Outstanding | 502.0 | |
| Letters of Credit Issued | 1.8 | |
| Net Available Liquidity | $3,186.6 | |

AEP has credit facilities totaling $3.5 billion to support its commercial paper program. The credit facilities allow management to issue letters of credit in an amount up to $1.2 billion.

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds certain nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during the first three months of 2016 was $585 million. The weighted-average interest rate for AEP's commercial paper during 2016 was 0.71%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit under three uncommitted facilities totaling $225 million. As of March 31, 2016, the maximum future payments for letters of credit issued under the uncommitted facilities was $190 million with maturities ranging from June 2016 to March 2017.

Securitized Accounts Receivables

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

Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a 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 AEP's credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of March 31, 2016, this contractually-defined percentage was 51%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of March 31, 2016, AEP complied with all of the covenants contained in these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's 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 AEP's non-exchange traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange traded commodity contracts would not cause an event of default under its 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 AEP manages its borrowings to stay within those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.56 per share in April 2016. Future dividends may vary depending upon AEP's profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

Management does not believe these restrictions related to AEP's various financing arrangements and regulatory requirements will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock.

Credit Ratings

AEP does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade, but its access to the commercial paper market may depend on their credit ratings.  In addition, downgrades in AEP's credit ratings by one of the rating agencies could increase its borrowing costs.  Counterparty concerns about the credit quality of AEP or its utility subsidiaries could subject AEP to additional collateral demands under adequate assurance clauses under its derivative and non-derivative energy contracts.

CASH FLOW

AEP relies primarily on cash flows from operations, debt issuances and its existing cash and cash equivalents to fund its liquidity and investing activities. AEP's investing and capital requirements are primarily capital expenditures, repaying of long-term debt and paying dividends to shareholders.

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in millions) | |
| Cash and Cash Equivalents at Beginning of Period | $176.4 | $162.5 |
| Net Cash Flows from Continuing Operating Activities | 799.9 | 1,257.7 |
| Net Cash Flows Used for Continuing Investing Activities | (1,138.3) | (1,020.9) |
| Net Cash Flows from (Used for) Continuing Financing Activities | 352.4 | (209.3) |
| Net Cash Flows from Discontinued Operations | — | 0.4 |
| Net Increase in Cash and Cash Equivalents | 14.0 | 27.9 |
| Cash and Cash Equivalents at End of Period | $190.4 | $190.4 |

AEP uses short-term debt, including commercial paper, as a bridge to long-term debt financing. The levels of borrowing may vary significantly due to the timing of long-term debt financings and the impact of fluctuations in cash flows.

Operating Activities

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in millions) | |
| Income from Continuing Operations | $503.1 | $620.2 |
| Depreciation and Amortization | 497.1 | 495.4 |
| Other | (200.3) | 142.1 |
| Net Cash Flows from Continuing Operating Activities | $799.9 | $1,257.7 |

Net Cash Flows from Continuing Operating Activities were $800 million in 2016 consisting primarily of Income from Continuing Operations of $503 million and $497 million of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Deferred Income Taxes increased primarily due to provisions in the Protecting Americans from Tax Hikes Act of 2015 and an increase in tax versus book temporary differences from operations.

Net Cash Flows from Continuing Operating Activities were $1.3 billion in 2015 consisting primarily of Income from Continuing Operations of $620 million and $495 million of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. 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, Material and Supplies balances reflects a decrease in fuel inventory due to the cold winter weather and increased generation.

Investing Activities

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in millions) | |
| Construction Expenditures | $(1,203.5) | $(1,077.0) |
| Acquisitions of Nuclear Fuel | (45.5 ) | (51.8 ) |
| Other | 110.7 | 107.9 |
| Net Cash Flows Used for Continuing Investing Activities | $(1,138.3) | $(1,020.9) |

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Net Cash Flows Used for Continuing Investing Activities were $1.1 billion in 2016 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Net Cash Flows Used for Continuing Investing Activities were $1 billion in 2015 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Financing Activities

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in millions) | |
| Issuance of Common Stock, Net | $12.1 | $30.4 |
| Issuance/Retirement of Debt, Net | 623.7 | 44.0 |
| Dividends Paid on Common Stock | (276.5) | (261.0) |
| Other | (6.9) | (22.7) |
| Net Cash Flows from (Used for) Continuing Financing Activities | $352.4 | $(209.3) |

Net Cash Flows from Continuing Financing Activities in 2016 were $352 million. AEP's net debt issuances were $624 million. The net issuances included an increase in short-term borrowing of $421 million, issuances of $400 million of senior unsecured notes and $125 million of pollution control bonds offset by retirements of $162 million of securitization bonds, $125 million of pollution control bonds and $35 million of senior unsecured and other debt notes. AEP paid common stock dividends of $277 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows Used for Continuing Financing Activities in 2015 were $209 million. AEP's net debt issuances were $44 million. The net issuances included issuances of $700 million of senior unsecured notes, $54 million of pollution control bonds and $20 million of other debt notes offset by retirements of $153 million of securitization bonds, $54 million of pollution control bonds, $32 million of senior unsecured and other debt notes and a decrease in short-term borrowing of $491 million. AEP paid common stock dividends of $261 million. See Note 12 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

In April 2016, I&M retired $13 million of Notes Payable related to DCC Fuel.

In April 2016, Transource Missouri drew $6 million on an existing variable rate credit facility due in 2018.

OFF-BALANCE SHEET ARRANGEMENTS

AEP's current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements that AEP enters in the normal course of business. The following identifies significant off-balance sheet arrangements:

| | March 31, | December 31, |
|---|---|---|
| | 2016 | 2015 |
| | (in millions) | |
| Rockport Plant, Unit 2 Future Minimum Lease Payments | $1,034.0 | $ 1,034.0 |
| Railcars Maximum Potential Loss from Lease Agreement | 18.1 | 18.1 |

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 2015

Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2015 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 2015 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 2016

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 statements of income. 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. Management adopted ASU 2015-01 effective January 1, 2016.

The FASB issued ASU 2015-05 “Customer’s Accounting for Fees paid in a Cloud Computing Arrangement” providing guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management adopted ASU 2015-05 prospectively, effective January 1, 2016, with no impact on results of operations, financial position or cash flows.

#### Pronouncements Effective in the Future

The FASB issued ASU 2014-09 “Revenue from Contracts with Customers” clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts. The FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, “Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date.” The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted for annual periods beginning after December 15, 2016. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2018.

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. Management does not expect the new standard to impact the Registrants’ results of operations, financial position or cash flows. Management plans to adopt ASU 2015-11 prospectively, effective January 1, 2017.

The FASB issued ASU 2016-01 “Recognition and Measurement of Financial Assets and Financial Liabilities” enhancing the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance sheet or the accompanying notes to the financial statements. The amendments also clarify that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for sale securities in combination with the entity's other deferred tax assets.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted. The amendments will be applied by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-01 effective January 1, 2018.

The FASB issued ASU 2016-02 "Accounting for Leases" increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheets and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, a capital lease will be known as a finance lease going forward. Leases with lease terms of 12 months or longer will be subject to the new requirements. Fundamentally, the criteria used to determine lease classification will remain the same, but will be more subjective under the new standard. The new accounting guidance is effective for annual periods beginning after December 15, 2018 with early adoption permitted. The guidance will be applied by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented as well as a number of optional practical expedients that entities may elect to apply. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption. Management expects the new standard to impact the Registrants' financial position, but not the Registrants' results of operations or cash flows. Management plans to adopt ASU 2016-02 effective January 1, 2019.

The FASB issued ASU 2016-09 "Compensation – Stock Compensation" simplifying the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities and classification on the statements of cash flows. Under the new standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit on the statements of income. Under current GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income. The new accounting guidance is effective for annual periods beginning after December 15, 2016. Early adoption is permitted in any interim or annual period. Certain provisions require retrospective/modified retrospective transition while others are to be applied prospectively. Management plans to adopt ASU 2016-09 effective January 1, 2017.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including financial instruments, pension and postretirement benefits, 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

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

The Transmission and Distribution Utilities segment is exposed to energy procurement risk and interest rate risk.

The Generation & Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risks which may be subject to capacity risk, credit risk as well as interest rate risk.

These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates. In addition, the Generation & Marketing segment is also exposed to certain market risks as a major power producer and through transactions in wholesale electricity, natural gas and marketing contracts.

Management employs risk management contracts including physical forward purchase-and-sale contracts and financial forward purchase-and-sale contracts. Management engages in risk management of power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. As a result, AEP is subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) 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, positions are modified 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, 2015:
MTM Risk Management Contract Net Assets (Liabilities)
Three Months Ended March 31, 2016

| | Vertically Integrated Utilities | Transmission and Distribution Utilities | Generation & Marketing | Total |
|---|---|---|---|---|
| | (in millions) | | | |
| Total MTM Risk Management Contract Net Assets as of December 31, 2015 | $8.6 | $ 14.4 | $ 143.2 | $166.2 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | (16.2) | 1.3 | 1.4 | (13.5) |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | — | — | 17.9 | 17.9 |
| Changes in Fair Value Due to Market Fluctuations During the Period (b) | — | (0.1) | 0.5 | 0.4 |
| Changes in Fair Value Allocated to Regulated Jurisdictions (c) | 8.1 | (27.6) | — | (19.5) |
| Total MTM Risk Management Contract Net Assets as of March 31, 2016 | $0.5 | $ (12.0) | $ 163.0 | 151.5 |
| Commodity Cash Flow Hedge Contracts | | | | (20.3) |
| Interest Rate and Foreign Currency Cash Flow Hedge Contracts | | | | (0.4) |
| Fair Value Hedge Contracts | | | | 0.5 |
| Collateral Deposits | | | | 31.2 |
| Elimination of Affiliated MTM Risk Management Contracts | | | | (1.7) |
| Total MTM Derivative Contract Net Assets as of March 31, 2016 | | | | $160.8 |

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c)

Relates to the net gains (losses) of those contracts that are not reflected on the condensed statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 9 – Derivatives and Hedging and Note 10 – Fair Value Measurements for additional information related to risk management contracts. The following tables and discussion provide information on credit risk and market volatility risk.

Credit Risk

Credit risk is limited in 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. Management uses 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.

AEP has risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of March 31, 2016, credit exposure net of collateral to sub investment grade counterparties was approximately 7.4%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of March 31, 2016, the following table approximates AEP's 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 | $783.1 | $ 6.3 | $ 776.8 | 2 | $ 300.9 |
| Split Rating | 28.5 | — | 28.5 | 1 | 26.7 |
| Noninvestment Grade | 1.2 | 1.2 | — | — | — |
| No External Ratings: | | | | | |
| Internal Investment Grade | 108.2 | — | 108.2 | 2 | 52.0 |
| Internal Noninvestment Grade | 89.3 | 16.8 | 72.5 | 3 | 44.9 |
| Total as of March 31, 2016 | $1,010.3 | $ 24.3 | $ 986.0 | 8 | $ 424.5 |
| Total as of December 31, 2015 | $973.6 | $ 21.9 | $ 951.7 | 11 | $ 437.1 |

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

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of March 31, 2016, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

Management calculates the VaR for both a trading and non-trading portfolio. The trading portfolio consists primarily of contracts related to energy trading and marketing activities. The non-trading portfolio consists primarily of economic hedges of generation and retail supply activities. The following tables show the end, high, average and low market risk as measured by VaR for the periods indicated:

VaR Model
Trading Portfolio

| Three Months Ended March 31, 2016 | | | | Twelve Months Ended December 31, 2015 | | | |
|---|---|---|---|---|---|---|---|
| End | High | Average | Low | End | High | Average | Low |
| (in millions) | | | | (in millions) | | | |
| $0.2 | $0.4 | $ 0.2 | $0.1 | $0.2 | $0.9 | $ 0.2 | $0.1 |

VaR Model
Non-Trading Portfolio

| Three Months Ended March 31, 2016 | | | | Twelve Months Ended December 31, 2015 | | | |
|---|---|---|---|---|---|---|---|
| End | High | Average | Low | End | High | Average | Low |
| (in millions) | | | | (in millions) | | | |
| $0.7 | $1.2 | $ 0.7 | $0.4 | $1.1 | $2.4 | $ 0.9 | $0.4 |

Management back-tests VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

As the VaR calculation captures recent price movements, management also performs regular stress testing of the trading portfolio to understand AEP’s exposure to extreme price movements. A historical-based method is employed 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. Management then researches the underlying positions, price movements and market events that created the most significant exposure and reports the findings to the Risk Executive Committee, Regulated Risk Committee, or Competitive Risk Committee as appropriate.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of March 31, 2016 and December 31, 2015, the estimated EaR on AEP’s debt portfolio for the following twelve months was $29 million and $25 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2016 and 2015
(in millions, except per-share and share amounts)
(Unaudited)

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| REVENUES | | |
| Vertically Integrated Utilities | $2,218.1 | $ 2,487.4 |
| Transmission and Distribution Utilities | 1,077.3 | 1,206.3 |
| Generation & Marketing | 713.9 | 859.2 |
| Other Revenues | 35.6 | 27.5 |
| TOTAL REVENUES | 4,044.9 | 4,580.4 |
| | | |
| EXPENSES | | |
| Fuel and Other Consumables Used for Electric Generation | 675.6 | 1,071.2 |
| Purchased Electricity for Resale | 731.4 | 718.4 |
| Other Operation | 715.1 | 661.3 |
| Maintenance | 278.7 | 285.6 |
| Depreciation and Amortization | 497.1 | 495.4 |
| Taxes Other Than Income Taxes | 254.1 | 245.7 |
| TOTAL EXPENSES | 3,152.0 | 3,477.6 |
| | | |
| OPERATING INCOME | 892.9 | 1,102.8 |
| | | |
| Other Income (Expense): | | |
| Interest and Investment Income | 2.1 | 1.4 |
| Carrying Costs Income | 3.9 | 8.4 |
| Allowance for Equity Funds Used During Construction | 31.7 | 29.7 |
| Interest Expense | (217.0 ) | (218.7 ) |
| | | |
| INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS | 713.6 | 923.6 |
| | | |
| Income Tax Expense | 235.5 | 327.2 |
| Equity Earnings of Unconsolidated Subsidiaries | 25.0 | 23.8 |
| | | |
| INCOME FROM CONTINUING OPERATIONS | 503.1 | 620.2 |
| | | |
| INCOME FROM DISCONTINUED OPERATIONS, NET OF TAX | — | 10.5 |
| | | |
| NET INCOME | 503.1 | 630.7 |
| | | |
| Net Income Attributable to Noncontrolling Interests | 1.9 | 1.5 |
| | | |
| EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS | $501.2 | $ 629.2 |

| | | |
|---|---|---|
| WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING | 491,108,392 | 489,597,986 |
| | | |
| BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS | $1.02 | $ 1.27 |
| BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS | — | 0.02 |
| TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS | $1.02 | $ 1.29 |
| | | |
| WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING | 491,332,305 | 489,936,726 |
| | | |
| DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS | $1.02 | $ 1.27 |
| DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS | — | 0.02 |
| TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS | $1.02 | $ 1.29 |
| | | |
| CASH DIVIDENDS DECLARED PER SHARE | $0.56 | $ 0.53 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| Net Income | $503.1 | $630.7 |
| | | |
| OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES | | |
| Cash Flow Hedges, Net of Tax of $(4.0) and $(3.4) in 2016 and 2015, Respectively | (7.4) | (6.4) |
| Securities Available for Sale, Net of Tax of $0.3 and $0.3 in 2016 and 2015, Respectively | 0.6 | 0.5 |
| Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0.1 and $0.2 in 2016 and 2015, Respectively | 0.1 | 0.4 |
| | | |
| TOTAL OTHER COMPREHENSIVE LOSS | (6.7) | (5.5) |
| | | |
| TOTAL COMPREHENSIVE INCOME | 496.4 | 625.2 |
| | | |
| Total Comprehensive Income Attributable to Noncontrolling Interests | 1.9 | 1.5 |
| | | |
| TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS | $494.5 | $623.7 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Three Months Ended March 31, 2016 and 2015
(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, 2014 | 509.7 | $3,313.3 | $6,203.4 | $7,406.6 | $ (103.1) | $ 4.3 | $16,824.5 |
| Issuance of Common Stock | 0.6 | 3.4 | 27.0 | | | | 30.4 |
| Common Stock Dividends | | | | (259.9) | | (1.1) | (261.0) |
| Other Changes in Equity | | | 3.6 | | | 2.0 | 5.6 |
| Deferred State Income Tax Rate Adjustment | | | 16.8 | | | | 16.8 |
| Net Income | | | | 629.2 | | 1.5 | 630.7 |
| Other Comprehensive Loss | | | | | (5.5) | | (5.5) |
| Pension and OPEB Adjustment Related to Mitchell Plant | | | | | 5.1 | | 5.1 |
| TOTAL EQUITY – MARCH 31, 2015 | 510.3 | $3,316.7 | $6,250.8 | $7,775.9 | $ (103.5) | $ 6.7 | $17,246.6 |
| TOTAL EQUITY – DECEMBER 31, 2015 | 511.4 | $3,324.0 | $6,296.5 | $8,398.3 | $ (127.1) | $ 13.2 | $17,904.9 |
| Issuance of Common Stock | 0.2 | 1.3 | 10.8 | | | | 12.1 |
| Common Stock Dividends | | | | (275.3) | | (1.2) | (276.5) |
| Other Changes in Equity | | | 2.9 | 0.6 | | 1.3 | 4.8 |
| Net Income | | | | 501.2 | | 1.9 | 503.1 |
| Other Comprehensive Loss | | | | | (6.7) | | (6.7) |
| TOTAL EQUITY – MARCH 31, 2016 | 511.6 | $3,325.3 | $6,310.2 | $8,624.8 | $ (133.8) | $ 15.2 | $18,141.7 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2016 and December 31, 2015
(in millions)
(Unaudited)

| | March 31, 2016 | December 31, 2015 |
|---|---|---|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | $ 190.4 | $ 176.4 |
| Other Temporary Investments (March 31, 2016 and December 31, 2015 Amounts Include $250 and $376.6, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and EIS) | 264.5 | 386.8 |
| Accounts Receivable: | | |
| Customers | 651.2 | 615.9 |
| Accrued Unbilled Revenues | 91.1 | 31.2 |
| Pledged Accounts Receivable – AEP Credit | 870.7 | 940.3 |
| Miscellaneous | 72.3 | 82.1 |
| Allowance for Uncollectible Accounts | (35.3) | (29.0) |
| Total Accounts Receivable | 1,650.0 | 1,640.5 |
| Fuel | 701.6 | 600.8 |
| Materials and Supplies | 650.3 | 738.6 |
| Risk Management Assets | 143.8 | 134.4 |
| Accrued Tax Benefits | 226.1 | 58.9 |
| Regulatory Asset for Under-Recovered Fuel Costs | 102.3 | 115.2 |
| Margin Deposits | 81.3 | 107.3 |
| Prepayments and Other Current Assets | 136.0 | 113.5 |
| TOTAL CURRENT ASSETS | 4,146.3 | 4,072.4 |
| | | |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Generation | 26,145.0 | 25,559.8 |
| Transmission | 14,435.3 | 14,247.9 |
| Distribution | 18,231.3 | 18,046.9 |
| Other Property, Plant and Equipment (Including Plant to be Retired, Coal Mining and Nuclear Fuel) | 3,812.3 | 3,722.9 |
| Construction Work in Progress | 3,806.3 | 3,903.9 |
| Total Property, Plant and Equipment | 66,430.2 | 65,481.4 |
| Accumulated Depreciation and Amortization | 19,597.3 | 19,348.2 |
| TOTAL PROPERTY, PLANT AND EQUIPMENT – NET | 46,832.9 | 46,133.2 |
| | | |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 5,109.5 | 5,140.3 |
| Securitized Assets | 1,689.2 | 1,749.9 |
| Spent Nuclear Fuel and Decommissioning Trusts | 2,152.4 | 2,106.4 |
| Goodwill | 52.5 | 52.5 |
| Long-term Risk Management Assets | 328.9 | 321.8 |
| Deferred Charges and Other Noncurrent Assets | 2,174.8 | 2,106.6 |

| | | |
|---|---|---|
| TOTAL OTHER NONCURRENT ASSETS | 11,507.3 | 11,477.5 |
| TOTAL ASSETS | $62,486.5 | $ 61,683.1 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
March 31, 2016 and December 31, 2015
(dollars in millions)
(Unaudited)

| | March 31, 2016 | December 31, 2015 |
|---|---|---|
| CURRENT LIABILITIES | | |
| Accounts Payable | $1,219.5 | $ 1,418.0 |
| Short-term Debt: | | |
| Securitized Debt for Receivables – AEP Credit | 719.0 | 675.0 |
| Other Short-term Debt | 502.0 | 125.0 |
| Total Short-term Debt | 1,221.0 | 800.0 |
| Long-term Debt Due Within One Year (March 31, 2016 and December 31, 2015 Amounts Include $361 and $410.4, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine) | 2,033.3 | 1,831.8 |
| Risk Management Liabilities | 104.3 | 87.1 |
| Customer Deposits | 358.1 | 346.6 |
| Accrued Taxes | 899.5 | 979.1 |
| Accrued Interest | 237.6 | 226.9 |
| Regulatory Liability for Over-Recovered Fuel Costs | 93.0 | 113.9 |
| Other Current Liabilities | 1,055.6 | 1,305.1 |
| TOTAL CURRENT LIABILITIES | 7,221.9 | 7,108.5 |
| | | |
| NONCURRENT LIABILITIES | | |
| Long-term Debt (March 31, 2016 and December 31, 2015 Amounts Include $1,835.3 and $1,971.4, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy and Sabine) | 17,749.3 | 17,740.9 |
| Long-term Risk Management Liabilities | 207.6 | 179.1 |
| Deferred Income Taxes | 12,133.8 | 11,733.2 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 3,765.2 | 3,736.1 |
| Asset Retirement Obligations | 1,824.4 | 1,806.5 |
| Employee Benefits and Pension Obligations | 569.9 | 583.3 |
| Deferred Credits and Other Noncurrent Liabilities | 872.7 | 890.6 |
| TOTAL NONCURRENT LIABILITIES | 37,122.9 | 36,669.7 |
| | | |
| TOTAL LIABILITIES | 44,344.8 | 43,778.2 |

Rate Matters (Note 4)
Commitments and Contingencies (Note 5)

EQUITY
Common Stock – Par Value – $6.50 Per Share:

| | 2016 | 2015 |
|---|---|---|

| | | | | |
|---|---|---|---|---|
| Shares Authorized | 600,000,000 | 600,000,000 | | |
| Shares Issued | 511,579,970 | 511,389,173 | | |
| (20,336,592 Shares were Held in Treasury as of March 31, 2016 and December 31, 2015) | | | 3,325.3 | 3,324.0 |
| Paid-in Capital | | | 6,310.2 | 6,296.5 |
| Retained Earnings | | | 8,624.8 | 8,398.3 |
| Accumulated Other Comprehensive Income (Loss) | | | (133.8 ) | (127.1 ) |
| TOTAL AEP COMMON SHAREHOLDERS' EQUITY | | | 18,126.5 | 17,891.7 |
| Noncontrolling Interests | | | 15.2 | 13.2 |
| TOTAL EQUITY | | | 18,141.7 | 17,904.9 |
| TOTAL LIABILITIES AND EQUITY | | | $62,486.5 | $ 61,683.1 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, 2016 | 2015 |
|---|---|---|
| OPERATING ACTIVITIES | | |
| Net Income | $503.1 | $630.7 |
| Income from Discontinued Operations | — | 10.5 |
| Income from Continuing Operations | 503.1 | 620.2 |
| Adjustments to Reconcile Income from Continuing Operations to Net Cash Flows from Continuing Operating Activities: | | |
| Depreciation and Amortization | 497.1 | 495.4 |
| Deferred Income Taxes | 330.2 | 238.3 |
| Carrying Costs Income | (3.9) | (8.4) |
| Allowance for Equity Funds Used During Construction | (31.7) | (29.7) |
| Mark-to-Market of Risk Management Contracts | 20.9 | (21.0) |
| Amortization of Nuclear Fuel | 40.5 | 38.3 |
| Property Taxes | (34.4) | (34.8) |
| Fuel Over/Under-Recovery, Net | 10.6 | 3.4 |
| Recovery (Deferral) of Ohio Capacity Costs, Net | 35.1 | (6.6) |
| Change in Other Noncurrent Assets | (68.3) | 7.2 |
| Change in Other Noncurrent Liabilities | 1.8 | (26.2) |
| Changes in Certain Components of Continuing Working Capital: | | |
| Accounts Receivable, Net | (10.8) | (2.3) |
| Fuel, Materials and Supplies | (95.4) | 132.1 |
| Accounts Payable | (34.4) | 45.8 |
| Accrued Taxes, Net | (169.2) | 33.5 |
| Other Current Assets | 21.6 | (24.4) |
| Other Current Liabilities | (212.9) | (203.1) |
| Net Cash Flows from Continuing Operating Activities | 799.9 | 1,257.7 |
| | | |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (1,203.5) | (1,077.0) |
| Change in Other Temporary Investments, Net | 122.8 | 93.5 |
| Purchases of Investment Securities | (1,152.0) | (246.2) |
| Sales of Investment Securities | 1,137.7 | 228.2 |
| Acquisitions of Nuclear Fuel | (45.5) | (51.8) |
| Other Investing Activities | 2.2 | 32.4 |
| Net Cash Flows Used for Continuing Investing Activities | (1,138.3) | (1,020.9) |
| | | |
| FINANCING ACTIVITIES | | |
| Issuance of Common Stock, Net | 12.1 | 30.4 |
| Issuance of Long-term Debt | 525.1 | 773.8 |
| Change in Short-term Debt, Net | 421.0 | (491.0) |
| Retirement of Long-term Debt | (322.4) | (238.8) |
| Principal Payments for Capital Lease Obligations | (24.9) | (27.6) |

| | | |
|---|---|---|
| Dividends Paid on Common Stock | (276.5 ) | (261.0 ) |
| Other Financing Activities | 18.0 | 4.9 |
| Net Cash Flows from (Used for) Continuing Financing Activities | 352.4 | (209.3 ) |
| | | |
| Net Cash Flows from Discontinued Operating Activities | — | 0.2 |
| Net Cash Flows from Discontinued Investing Activities | — | 4.3 |
| Net Cash Flows Used for Discontinued Financing Activities | — | (4.1 ) |
| | | |
| Net Increase in Cash and Cash Equivalents | 14.0 | 27.9 |
| Cash and Cash Equivalents at Beginning of Period | 176.4 | 162.5 |
| Cash and Cash Equivalents at End of Period | $190.4 | $190.4 |
| | | |
| SUPPLEMENTARY INFORMATION | | |
| Cash Paid for Interest, Net of Capitalized Amounts | $199.0 | $222.6 |
| Net Cash Paid for Income Taxes | 7.3 | 2.1 |
| Noncash Acquisitions Under Capital Leases | 45.4 | 29.4 |
| Construction Expenditures Included in Current Liabilities as of March 31, | 544.3 | 528.9 |
| Construction Expenditures Included in Noncurrent Liabilities as of March 31, | — | 43.2 |
| Acquisition of Nuclear Fuel Included in Current Liabilities as of March 31, | 29.1 | — |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in millions of KWhs) | |
| Retail: | | |
| Residential | 3,764 | 4,202 |
| Commercial | 1,696 | 1,727 |
| Industrial | 2,268 | 2,460 |
| Miscellaneous | 217 | 216 |
| Total Retail | 7,945 | 8,605 |
| | | |
| Wholesale | 456 | 866 |
| | | |
| Total KWhs | 8,401 | 9,471 |

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

Summary of Heating and Cooling Degree Days

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in degree days) | |
| Actual – Heating (a) | 1,325 | 1,680 |
| Normal – Heating (b) | 1,344 | 1,321 |
| | | |
| Actual – Cooling (c) | 8 | — |
| Normal – Cooling (b) | 6 | 6 |

(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) Cooling degree days are calculated on a 65 degree temperature base.

First Quarter of 2016 Compared to First Quarter of 2015
Reconciliation of First Quarter of 2015 to First Quarter of 2016
Net Income
(in millions)

| | |
|---|---|
| First Quarter of 2015 | $ 141.8 |
| | |
| Changes in Gross Margin: | |
| Retail Margins | 5.4 |
| Off-system Sales | (1.3 ) |
| Transmission Revenue | (8.1 ) |
| Other Revenues | 2.1 |
| Total Change in Gross Margin | (1.9 ) |
| | |
| Changes in Expenses and Other: | |
| Other Operation and Maintenance | (31.5 ) |
| Depreciation and Amortization | 4.6 |
| Taxes Other Than Income Taxes | (0.3 ) |
| Other Income | (1.9 ) |
| Interest Expense | 3.3 |
| Total Change in Expenses and Other | (25.8 ) |
| | |
| Income Tax Expense | 12.2 |
| | |
| First Quarter of 2016 | $ 126.3 |

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 $5 million primarily due to the following:
  - A $23 million increase primarily due to increases in rates in West Virginia and Virginia, offset by a prior year adjustment due to the amended Virginia Law impacting biennial review. Of these increases, $27 million relate to riders/trackers which have corresponding increases in other expense items below.
  - A $7 million increase in weather-normalized margin primarily in the residential and commercial classes, partially offset by the industrial class.
  - A $3 million decrease in PJM fees primarily due to lower PJM ancillaries and higher FTR revenues, net of recovery.
  - A $2 million decrease in consumables and allowances expenses.
  - A $1 million increase due to previously deferred costs that were not collected from a West Virginia industrial customer in 2015.
  - A $1 million increase due to a change in allowed includable wind costs from certain wind farms in Virginia.

  This overall increase was partially offset by:
  - A $33 million decrease in weather-related usage primarily due to a 21% decrease in heating degree days.
- Transmission Revenues decreased by $8 million primarily due to lower Network Integration Transmission Service revenues.

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

- Other Operation and Maintenance expenses increased $32 million primarily due to the following:
  - A $14 million increase associated with amortization of deferred transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause effective January 2016. This increase in expense is offset within Retail Margins above.
  - A $13 million increase in transmission and distribution expenses due to vegetation management and storm amortization. This increase in expense is offset within Retail Margins above.
  - A $3 million increase in plant maintenance expenses due to 2016 outages at certain plants.
  - A $2 million increase in customer assistance expense due to energy efficiency programs. This increase in expense is offset within Retail Margins above.

  These increases were partially offset by:
  - A $4 million decrease in PJM transmission expenses.
- Depreciation and Amortization expenses decreased $5 million primarily due to the following:
  - A $3 million decrease in asset retirement obligations and plant amortizations due to plant retirements in 2015.
  - A $2 million decrease due to prior year amortization of Virginia environmental deferrals. This decrease in expense is offset within Retail Margins above.
- Interest Expense decreased $3 million primarily due to lower interest rate on long-term debt.
- Income Tax Expense decreased $12 million primarily due to a decrease in pretax book income.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, 2016 | Three Months Ended March 31, 2015 |
|---|---|---|
| REVENUES | | |
| Electric Generation, Transmission and Distribution | $775.5 | $854.2 |
| Sales to AEP Affiliates | 40.4 | 42.5 |
| Other Revenues | 4.1 | 2.3 |
| TOTAL REVENUES | 820.0 | 899.0 |
| | | |
| EXPENSES | | |
| Fuel and Other Consumables Used for Electric Generation | 150.7 | 223.3 |
| Purchased Electricity for Resale | 108.2 | 112.7 |
| Other Operation | 120.6 | 106.1 |
| Maintenance | 69.3 | 52.3 |
| Depreciation and Amortization | 95.5 | 100.1 |
| Taxes Other Than Income Taxes | 31.3 | 31.0 |
| TOTAL EXPENSES | 575.6 | 625.5 |
| | | |
| OPERATING INCOME | 244.4 | 273.5 |
| | | |
| Other Income (Expense): | | |
| Other Income | 1.8 | 3.7 |
| Interest Expense | (47.0) | (50.3) |
| | | |
| INCOME BEFORE INCOME TAX EXPENSE | 199.2 | 226.9 |
| | | |
| Income Tax Expense | 72.9 | 85.1 |
| | | |
| NET INCOME | $126.3 | $141.8 |

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

See Condensed Notes to Condensed Financial Statements of

Registrants beginning on page 90.

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| Net Income | $126.3 | $141.8 |
| | | |
| OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES | | |
| Cash Flow Hedges, Net of Tax of $(0.1) and $0.1 in 2016 and 2015, Respectively | (0.2) | 0.1 |
| Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.2) and $(0.2) in 2016 and 2015, Respectively | (0.3) | (0.4) |
| | | |
| TOTAL OTHER COMPREHENSIVE LOSS | (0.5) | (0.3) |
| | | |
| TOTAL COMPREHENSIVE INCOME | $125.8 | $141.5 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2014 | $ 260.4 | $ 1,809.6 | $ 1,291.9 | $ 5.0 | $ 3,366.9 |
| Common Stock Dividends | | | (56.3) | | (56.3) |
| Net Income | | | 141.8 | | 141.8 |
| Other Comprehensive Loss | | | | (0.3) | (0.3) |
| TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2015 | $ 260.4 | $ 1,809.6 | $ 1,377.4 | $ 4.7 | $ 3,452.1 |
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2015 | $ 260.4 | $ 1,828.7 | $ 1,388.7 | $ (2.8) | $ 3,475.0 |
| Common Stock Dividends | | | (75.0) | | (75.0) |
| Net Income | | | 126.3 | | 126.3 |
| Other Comprehensive Loss | | | | (0.5) | (0.5) |
| TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2016 | $ 260.4 | $ 1,828.7 | $ 1,440.0 | $ (3.3) | $ 3,525.8 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2016 and December 31, 2015
(in millions)
(Unaudited)

| | March 31, 2016 | December 31, 2015 |
|---|---|---|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | $6.4 | $ 2.8 |
| Restricted Cash for Securitized Funding | 7.5 | 14.8 |
| Advances to Affiliates | 24.8 | 25.6 |
| Accounts Receivable: | | |
| Customers | 130.4 | 120.9 |
| Affiliated Companies | 49.2 | 51.2 |
| Accrued Unbilled Revenues | 37.1 | 17.9 |
| Miscellaneous | 2.0 | 2.2 |
| Allowance for Uncollectible Accounts | (4.7) | (4.3) |
| Total Accounts Receivable | 214.0 | 187.9 |
| Fuel | 147.7 | 119.3 |
| Materials and Supplies | 104.1 | 127.0 |
| Risk Management Assets – Nonaffiliated | 11.2 | 14.7 |
| Risk Management Assets – Affiliated | 0.7 | 0.9 |
| Accrued Tax Benefits | 5.4 | 30.6 |
| Regulatory Asset for Under-Recovered Fuel Costs | 82.2 | 86.9 |
| Prepayments and Other Current Assets | 21.4 | 17.4 |
| TOTAL CURRENT ASSETS | 625.4 | 627.9 |
| | | |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Generation | 6,251.2 | 6,200.8 |
| Transmission | 2,414.6 | 2,408.1 |
| Distribution | 3,432.8 | 3,402.5 |
| Other Property, Plant and Equipment | 357.2 | 345.5 |
| Construction Work in Progress | 507.0 | 475.1 |
| Total Property, Plant and Equipment | 12,962.8 | 12,832.0 |
| Accumulated Depreciation and Amortization | 3,473.5 | 3,407.6 |
| TOTAL PROPERTY, PLANT AND EQUIPMENT – NET | 9,489.3 | 9,424.4 |
| | | |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 1,125.7 | 1,154.2 |
| Securitized Assets | 322.4 | 328.0 |
| Long-term Risk Management Assets – Nonaffiliated | 0.3 | 0.1 |
| Deferred Charges and Other Noncurrent Assets | 139.0 | 113.7 |
| TOTAL OTHER NONCURRENT ASSETS | 1,587.4 | 1,596.0 |
| | | |
| TOTAL ASSETS | $11,702.1 | $ 11,648.3 |

See
Condensed

Notes to Condensed Financial Statements of Registrants beginning on page 90.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2016 and December 31, 2015
(Unaudited)

| | March 31, 2016 | December 31, 2015 |
|---|---|---|
| | (in millions) | |
| CURRENT LIABILITIES | | |
| Advances from Affiliates | $171.2 | $ 181.0 |
| Accounts Payable: | | |
| General | 182.0 | 196.5 |
| Affiliated Companies | 62.1 | 67.7 |
| Long-term Debt Due Within One Year – Nonaffiliated | 318.3 | 318.0 |
| Risk Management Liabilities – Nonaffiliated | 10.4 | 4.8 |
| Customer Deposits | 82.7 | 83.9 |
| Accrued Taxes | 108.8 | 79.5 |
| Accrued Interest | 62.9 | 40.6 |
| Other Current Liabilities | 120.5 | 153.4 |
| TOTAL CURRENT LIABILITIES | 1,118.9 | 1,125.4 |
| | | |
| NONCURRENT LIABILITIES | | |
| Long-term Debt – Nonaffiliated | 3,601.0 | 3,612.7 |
| Long-term Risk Management Liabilities – Nonaffiliated | 0.1 | 0.1 |
| Deferred Income Taxes | 2,558.5 | 2,527.0 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 628.7 | 637.1 |
| Asset Retirement Obligations | 94.9 | 98.9 |
| Employee Benefits and Pension Obligations | 112.1 | 114.4 |
| Deferred Credits and Other Noncurrent Liabilities | 62.1 | 57.7 |
| TOTAL NONCURRENT LIABILITIES | 7,057.4 | 7,047.9 |
| | | |
| TOTAL LIABILITIES | 8,176.3 | 8,173.3 |
| | | |
| Rate Matters (Note 4) | | |
| Commitments and Contingencies (Note 5) | | |
| | | |
| COMMON SHAREHOLDER'S EQUITY | | |
| Common Stock – No Par Value: | | |
| Authorized – 30,000,000 Shares | | |
| Outstanding – 13,499,500 Shares | 260.4 | 260.4 |
| Paid-in Capital | 1,828.7 | 1,828.7 |
| Retained Earnings | 1,440.0 | 1,388.7 |
| Accumulated Other Comprehensive Income (Loss) | (3.3 ) | (2.8 ) |
| TOTAL COMMON SHAREHOLDER'S EQUITY | 3,525.8 | 3,475.0 |
| | | |
| TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY | $11,702.1 | $ 11,648.3 |

See
Condensed
Notes to

Condensed Financial Statements of Registrants beginning on page 90.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, 2016 | 2015 |
|---|---|---|
| OPERATING ACTIVITIES | | |
| Net Income | $ 126.3 | $ 141.8 |
| Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities: | | |
| Depreciation and Amortization | 95.5 | 100.1 |
| Deferred Income Taxes | 30.9 | 49.8 |
| Allowance for Equity Funds Used During Construction | (2.3) | (3.0) |
| Mark-to-Market of Risk Management Contracts | 9.1 | 9.8 |
| Fuel Over/Under-Recovery, Net | 5.1 | (26.2) |
| Change in Other Noncurrent Assets | 17.7 | 3.0 |
| Change in Other Noncurrent Liabilities | (9.0) | (32.0) |
| Changes in Certain Components of Working Capital: | | |
| Accounts Receivable, Net | (26.1) | 7.3 |
| Fuel, Materials and Supplies | (28.3) | 39.6 |
| Accounts Payable | (2.9) | (2.2) |
| Accrued Taxes, Net | 54.5 | 31.8 |
| Other Current Assets | (4.1) | (3.0) |
| Other Current Liabilities | (8.4) | (15.8) |
| Net Cash Flows from Operating Activities | 258.0 | 301.0 |
| | | |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (168.9) | (140.9) |
| Change in Restricted Cash for Securitized Funding | 7.3 | 7.7 |
| Change in Advances to Affiliates, Net | 0.8 | (103.6) |
| Other Investing Activities | 4.1 | 5.3 |
| Net Cash Flows Used for Investing Activities | (156.7) | (231.5) |
| | | |
| FINANCING ACTIVITIES | | |
| | 124.8 | — |

| | | |
|---|---|---|
| Issuance of Long-term Debt – Nonaffiliated | | |
| Change in Advances from Affiliates, Net | (9.8) | — |
| Retirement of Long-term Debt – Nonaffiliated | (136.5) | (11.0) |
| Principal Payments for Capital Lease Obligations | (1.5) | (1.3) |
| Dividends Paid on Common Stock | (75.0) | (56.3) |
| Other Financing Activities | 0.3 | 0.4 |
| Net Cash Flows Used for Financing Activities | (97.7) | (68.2) |
| | | |
| Net Increase in Cash and Cash Equivalents | 3.6 | 1.3 |
| Cash and Cash Equivalents at Beginning of Period | 2.8 | 2.6 |
| Cash and Cash Equivalents at End of Period | $ 6.4 | $ 3.9 |
| | | |
| SUPPLEMENTARY INFORMATION | | |
| Cash Paid for Interest, Net of Capitalized Amounts | $ 23.1 | $ 37.3 |
| Net Cash Paid (Received) for Income Taxes | (17.9) | 0.1 |
| Noncash Acquisitions Under Capital Leases | 0.7 | 1.5 |
| Construction Expenditures Included in Current Liabilities as of March 31, | 70.4 | 70.0 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days
Summary of KWh Energy Sales

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in millions of KWhs) | |
| Retail: | | |
| Residential | 1,562 | 1,745 |
| Commercial | 1,182 | 1,209 |
| Industrial | 1,888 | 1,794 |
| Miscellaneous | 20 | 20 |
| Total Retail | 4,652 | 4,768 |
| Wholesale | 1,930 | 3,406 |
| Total KWhs | 6,582 | 8,174 |

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

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in degree days) | |
| Actual – Heating (a) | 1,917 | 2,759 |
| Normal – Heating (b) | 2,208 | 2,171 |
| Actual – Cooling (c) | — | — |
| Normal – Cooling (b) | 2 | 2 |

(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) Cooling degree days are calculated on a 65 degree temperature base.

First Quarter of 2016 Compared to First Quarter of 2015
Reconciliation of First Quarter of 2015 to
First Quarter of 2016
Net Income
(in millions)

| | |
|---|---|
| First Quarter of 2015 | $72.7 |
| | |
| Changes in Gross Margin: | |
| Retail Margins | (0.6 ) |
| Off-system Sales | (4.9 ) |
| Transmission Revenues | (2.7 ) |
| Other Revenues | 1.2 |
| Total Change in Gross Margin | (7.0 ) |
| | |
| Changes in Expenses and Other: | |
| Other Operation and Maintenance | (5.9 ) |
| Depreciation and Amortization | 4.3 |
| Other Income | (0.3 ) |
| Interest Expense | 0.3 |
| Total Change in Expenses and Other | (1.6 ) |
| | |
| Income Tax Expense | 10.6 |
| | |
| First Quarter of 2016 | $74.7 |

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

- Retail Margins decreased $1 million primarily due to the following:
- A $19 million decrease in weather-related usage due to a 30% decrease in heating degree days.

This decrease was partially offset by:
- A $7 million increase in weather-normalized margins.
- A $4 million increase in FERC municipal and cooperative revenues primarily due to formula rate changes.
- A $3 million decrease in PJM charges not currently recovered in rate recovery riders/trackers.
- A $2 million increase from successful rate proceedings in the Indiana service territory. The increase in retail margins relating to riders/trackers has corresponding increases in other items below.
- Margins from Off-system Sales decreased $5 million due to lower market prices and decreased sales volumes.
- Transmission Revenues decreased $3 million primarily due to lower Network Integration Transmission Service revenues.

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

- Other Operation and Maintenance expenses increased $6 million primarily due to the following:
- A $6 million increase due to the reduction of an environmental liability in 2015.
- A $6 million increase in general and administrative expenses.
- A $2 million increase in accretion due to the impact of a revision in the Nuclear Asset Retirement Obligation (ARO) estimate on decommissioning expense. This increase has a corresponding offset in Depreciation and Amortization expenses below.

These increases were partially offset by:

- A $4 million decrease primarily due to Rockport environmental compliance work performed in 2015.
- A $4 million decrease due to the retirement of Tanners Creek Plant in May 2015.

- Depreciation and Amortization expenses decreased $4 million primarily due to the retirement of Tanners Creek Plant in May 2015 and a revision in the Nuclear ARO estimate. The decrease in Nuclear ARO has a corresponding offset in Other Operation and Maintenance expenses above.
- Income Tax Expense decreased $11 million primarily due to the recording of federal income tax adjustments and a decrease in pretax book income.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| REVENUES | | |
| Electric Generation, Transmission and Distribution | $500.4 | $566.2 |
| Sales to AEP Affiliates | 11.5 | 0.5 |
| Other Revenues – Affiliated | 15.3 | 18.6 |
| Other Revenues – Nonaffiliated | 5.5 | 1.0 |
| TOTAL REVENUES | 532.7 | 586.3 |
| | | |
| EXPENSES | | |
| Fuel and Other Consumables Used for Electric Generation | 69.2 | 99.9 |
| Purchased Electricity for Resale | 49.6 | 55.9 |
| Purchased Electricity from AEP Affiliates | 45.4 | 55.0 |
| Other Operation | 141.3 | 129.0 |
| Maintenance | 40.9 | 47.3 |
| Depreciation and Amortization | 47.1 | 51.4 |
| Taxes Other Than Income Taxes | 23.4 | 23.4 |
| TOTAL EXPENSES | 416.9 | 461.9 |
| | | |
| OPERATING INCOME | 115.8 | 124.4 |
| | | |
| Other Income (Expense): | | |
| Interest Income | 3.2 | 1.8 |
| Allowance for Equity Funds Used During Construction | 2.3 | 4.0 |
| Interest Expense | (22.5 ) | (22.8 ) |
| | | |
| INCOME BEFORE INCOME TAX EXPENSE | 98.8 | 107.4 |
| | | |
| Income Tax Expense | 24.1 | 34.7 |
| | | |
| NET INCOME | $74.7 | $72.7 |

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| Net Income | $74.7 | $72.7 |
| | | |
| OTHER COMPREHENSIVE INCOME, NET OF TAXES | | |
| Cash Flow Hedges, Net of Tax of $0.2 and $0.1 in 2016 and 2015, Respectively | 0.4 | 0.3 |
| | | |
| TOTAL COMPREHENSIVE INCOME | $75.1 | $73.0 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2014 | $ 56.6 | $ 980.9 | $ 930.8 | $ (14.3) | $ 1,954.0 |
| Common Stock Dividends | | | (30.0) | | (30.0) |
| Net Income | | | 72.7 | | 72.7 |
| Other Comprehensive Income | | | | 0.3 | 0.3 |
| TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2015 | $ 56.6 | $ 980.9 | $ 973.5 | $ (14.0) | $ 1,997.0 |
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2015 | $ 56.6 | $ 980.9 | $ 1,015.6 | $ (16.7) | $ 2,036.4 |
| Common Stock Dividends | | | (31.3) | | (31.3) |
| Net Income | | | 74.7 | | 74.7 |
| Other Comprehensive Income | | | | 0.4 | 0.4 |
| TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2016 | $ 56.6 | $ 980.9 | $ 1,059.0 | $ (16.3) | $ 2,080.2 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2016 and December 31, 2015
(in millions)
(Unaudited)

| | March 31, 2016 | December 31, 2015 |
|---|---|---|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | $3.3 | $ 1.1 |
| Advances to Affiliates | 12.3 | 11.7 |
| Accounts Receivable: | | |
| Customers | 54.6 | 43.9 |
| Affiliated Companies | 58.6 | 68.7 |
| Accrued Unbilled Revenues | 1.3 | 0.1 |
| Miscellaneous | 1.4 | 2.6 |
| Allowance for Uncollectible Accounts | — | (0.1 ) |
| Total Accounts Receivable | 115.9 | 115.2 |
| Fuel | 63.7 | 46.5 |
| Materials and Supplies | 155.0 | 185.9 |
| Risk Management Assets – Nonaffiliated | 8.4 | 10.6 |
| Risk Management Assets – Affiliated | 0.7 | 1.7 |
| Accrued Tax Benefits | 47.0 | 40.5 |
| Prepayments and Other Current Assets | 50.9 | 42.1 |
| TOTAL CURRENT ASSETS | 457.2 | 455.3 |
| | | |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Generation | 3,899.0 | 3,841.7 |
| Transmission | 1,410.2 | 1,406.9 |
| Distribution | 1,811.6 | 1,790.8 |
| Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel) | 672.5 | 662.3 |
| Construction Work in Progress | 547.9 | 519.8 |
| Total Property, Plant and Equipment | 8,341.2 | 8,221.5 |
| Accumulated Depreciation, Depletion and Amortization | 3,048.3 | 3,018.0 |
| TOTAL PROPERTY, PLANT AND EQUIPMENT – NET | 5,292.9 | 5,203.5 |
| | | |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 813.8 | 804.3 |
| Spent Nuclear Fuel and Decommissioning Trusts | 2,152.4 | 2,106.4 |
| Long-term Risk Management Assets – Nonaffiliated | 0.4 | — |
| Deferred Charges and Other Noncurrent Assets | 161.3 | 140.9 |
| TOTAL OTHER NONCURRENT ASSETS | 3,127.9 | 3,051.6 |
| | | |
| TOTAL ASSETS | $8,878.0 | $ 8,710.4 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2016 and December 31, 2015
(dollars in millions)
(Unaudited)

| | March 31, 2016 | December 31, 2015 |
|---|---|---|
| CURRENT LIABILITIES | | |
| Advances from Affiliates | $9.5 | $ 294.3 |
| Accounts Payable: | | |
| General | 176.3 | 201.0 |
| Affiliated Companies | 47.8 | 61.8 |
| Long-term Debt Due Within One Year – Nonaffiliated (March 31, 2016 and December 31, 2015 Amounts Include $73.2 and $84.6, Respectively, Related to DCC Fuel) | 151.5 | 162.9 |
| Risk Management Liabilities – Nonaffiliated | 6.4 | 6.3 |
| Customer Deposits | 35.6 | 35.7 |
| Accrued Taxes | 83.2 | 74.2 |
| Accrued Interest | 12.2 | 26.2 |
| Obligations Under Capital Leases | 25.2 | 32.8 |
| Other Current Liabilities | 118.2 | 142.1 |
| TOTAL CURRENT LIABILITIES | 665.9 | 1,037.3 |
| | | |
| NONCURRENT LIABILITIES | | |
| Long-term Debt – Nonaffiliated | 2,215.1 | 1,837.1 |
| Long-term Risk Management Liabilities – Nonaffiliated | 1.0 | 1.6 |
| Deferred Income Taxes | 1,421.0 | 1,361.5 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 1,104.6 | 1,076.2 |
| Asset Retirement Obligations | 1,264.8 | 1,240.9 |
| Deferred Credits and Other Noncurrent Liabilities | 125.4 | 119.4 |
| TOTAL NONCURRENT LIABILITIES | 6,131.9 | 5,636.7 |
| | | |
| TOTAL LIABILITIES | 6,797.8 | 6,674.0 |
| | | |
| Rate Matters (Note 4) | | |
| Commitments and Contingencies (Note 5) | | |
| | | |
| COMMON SHAREHOLDER'S EQUITY | | |
| Common Stock – No Par Value: | | |
| Authorized – 2,500,000 Shares | | |
| Outstanding – 1,400,000 Shares | 56.6 | 56.6 |
| Paid-in Capital | 980.9 | 980.9 |
| Retained Earnings | 1,059.0 | 1,015.6 |
| Accumulated Other Comprehensive Income (Loss) | (16.3 ) | (16.7 ) |
| TOTAL COMMON SHAREHOLDER'S EQUITY | 2,080.2 | 2,036.4 |
| | | |
| TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY | $8,878.0 | $ 8,710.4 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, 2016 | 2015 |
|---|---|---|
| OPERATING ACTIVITIES | | |
| Net Income | $ 74.7 | $ 72.7 |
| Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities: | | |
| Depreciation and Amortization | 47.1 | 51.4 |
| Deferred Income Taxes | 44.0 | 15.6 |
| Deferral of Incremental Nuclear Refueling Outage Expenses, Net | (8.4) | (9.3) |
| Allowance for Equity Funds Used During Construction | (2.3) | (4.0) |
| Mark-to-Market of Risk Management Contracts | 2.4 | 12.4 |
| Amortization of Nuclear Fuel | 40.5 | 38.3 |
| Fuel Over/Under-Recovery, Net | 3.8 | (3.0) |
| Change in Other Noncurrent Assets | (4.8) | 5.9 |
| Change in Other Noncurrent Liabilities | 9.1 | (7.5) |
| Changes in Certain Components of Working Capital: | | |
| Accounts Receivable, Net | (2.0) | 31.9 |
| Fuel, Materials and Supplies | (16.0) | 8.8 |
| Accounts Payable | (9.9) | (0.2) |
| Accrued Taxes, Net | 2.5 | 28.5 |
| Other Current Assets | 6.1 | 7.6 |
| Other Current Liabilities | (32.5) | (30.7) |
| Net Cash Flows from Operating Activities | 154.3 | 218.4 |
| | | |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (136.4) | (111.8) |
| Change in Advances to Affiliates, Net | (0.6) | — |
| Purchases of Investment Securities | (1,151.6) | (245.8) |
| Sales of Investment Securities | 1,137.7 | 228.2 |
| Acquisitions of Nuclear Fuel | (45.5) | (51.8) |

| | | |
|---|---|---|
| Other Investing Activities | 3.3 | 5.5 |
| Net Cash Flows Used for Investing Activities | (193.1) | (175.7) |
| | | |
| FINANCING ACTIVITIES | | |
| Issuance of Long-term Debt – Nonaffiliated | 394.8 | — |
| Change in Advances from Affiliates, Net | (284.8) | 25.7 |
| Retirement of Long-term Debt – Nonaffiliated | (28.8) | (25.9) |
| Principal Payments for Capital Lease Obligations | (9.6) | (12.2) |
| Dividends Paid on Common Stock | (31.3) | (30.0) |
| Other Financing Activities | 0.7 | 0.5 |
| Net Cash Flows from (Used for) Financing Activities | 41.0 | (41.9) |
| | | |
| Net Increase in Cash and Cash Equivalents | 2.2 | 0.8 |
| Cash and Cash Equivalents at Beginning of Period | 1.1 | 1.0 |
| Cash and Cash Equivalents at End of Period | $ 3.3 | $ 1.8 |
| | | |
| SUPPLEMENTARY INFORMATION | | |
| Cash Paid for Interest, Net of Capitalized Amounts | $ 35.2 | $ 35.0 |
| Net Cash Paid (Received) for Income Taxes | (4.9) | 2.0 |
| Noncash Acquisitions Under Capital Leases | 14.9 | 0.8 |
| Construction Expenditures Included in Current Liabilities as of March 31, | 68.4 | 66.3 |
| Acquisition of Nuclear Fuel Included in Current Liabilities as of March 31, | 29.1 | — |
| Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage | — | 0.1 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

OHIO POWER COMPANY AND SUBSIDIARIES

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in millions of KWhs) | |
| Retail: | | |
| Residential | 3,843 | 4,491 |
| Commercial | 3,411 | 3,595 |
| Industrial | 3,495 | 3,544 |
| Miscellaneous | 33 | 32 |
| Total Retail (a) | 10,782 | 11,662 |
| Wholesale (b) | 323 | 534 |
| Total KWhs | 11,105 | 12,196 |

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

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

Summary of Heating and Cooling Degree Days

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in degree days) | |
| Actual – Heating (a) | 1,691 | 2,438 |
| Normal – Heating (b) | 1,919 | 1,881 |
| Actual – Cooling (c) | 1 | — |
| Normal – Cooling (b) | 3 | 3 |

(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) Cooling degree days are calculated on a 65 degree temperature base.

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First Quarter of 2016 Compared to First Quarter of 2015
Reconciliation of First Quarter of 2015 to
First Quarter of 2016
Net Income
(in millions)

| | |
|---|---|
| First Quarter of 2015 | $65.4 |
| | |
| Changes in Gross Margin: | |
| Retail Margins | 56.4 |
| Off-system Sales | (8.5 ) |
| Transmission Revenues | (29.8 ) |
| Other Revenues | 2.1 |
| Total Change in Gross Margin | 20.2 |
| | |
| Changes in Expenses and Other: | |
| Other Operation and Maintenance | (7.2 ) |
| Depreciation and Amortization | (2.1 ) |
| Taxes Other Than Income Taxes | 0.2 |
| Carrying Costs Income | (4.6 ) |
| Other Income | (1.1 ) |
| Interest Expense | 1.0 |
| Total Change in Expenses and Other | (13.8 ) |
| | |
| Income Tax Expense | (1.6 ) |
| | |
| First Quarter of 2016 | $70.2 |

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 $56 million primarily due to the following:
- A $54 million increase in transmission and PJM revenues primarily due to the energy supplied as a result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
- A $6 million increase in revenues associated with the Distribution Investment Rider.
- A $5 million increase in carrying charges primarily due to the collection of carrying costs on deferred capacity charges beginning June 2015.

These increases were partially offset by:

- A $14 million decrease in revenues associated with the recovery of 2012 storm costs under the Storm Damage Recovery Rider which ended in April 2015. This decrease in Retail Margins is primarily offset by a decrease in Other Operation and Maintenance expenses below.
- Margins from Off-system Sales decreased $9 million primarily due to losses from a power contract with OVEC.
- Transmission Revenues decreased $30 million primarily due to a decrease in Network Integrated Transmission Service revenue primarily due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, partially offset by a corresponding increase in Retail Margins above.

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

- Other Operation and Maintenance expenses increased $7 million primarily due to the following:
  - A $14 million increase in recoverable PJM expenses.
  - A $7 million increase in recoverable gridSMART® expenses.
  - A $4 million increase in employee-related expenses.

  These increases were partially offset by:
  - A $13 million decrease due to the completion of the amortization of 2012 deferred storm expenses in April 2015. This decrease was offset by a corresponding decrease in Retail Margins above.
  - A $6 million decrease due to a PUCO ordered contribution to the Ohio Growth Fund recorded in 2015.
- Carrying Costs Income decreased $5 million primarily due to the collection of carrying costs on deferred capacity charges beginning June 2015.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| REVENUES | | |
| Electricity, Transmission and Distribution | $756.7 | $874.2 |
| Sales to AEP Affiliates | 4.8 | 42.1 |
| Other Revenues | 2.1 | 2.1 |
| TOTAL REVENUES | 763.6 | 918.4 |
| | | |
| EXPENSES | | |
| Purchased Electricity for Resale | 164.9 | 142.1 |
| Purchased Electricity from AEP Affiliates | 49.1 | 270.6 |
| Amortization of Generation Deferrals | 55.1 | 31.4 |
| Other Operation | 167.9 | 146.8 |
| Maintenance | 33.7 | 47.6 |
| Depreciation and Amortization | 61.3 | 59.2 |
| Taxes Other Than Income Taxes | 97.6 | 97.8 |
| TOTAL EXPENSES | 629.6 | 795.5 |
| | | |
| OPERATING INCOME | 134.0 | 122.9 |
| | | |
| Other Income (Expense): | | |
| Interest Income | 1.5 | 1.9 |
| Carrying Costs Income | 1.9 | 6.5 |
| Allowance for Equity Funds Used During Construction | 1.7 | 2.4 |
| Interest Expense | (31.4 ) | (32.4 ) |
| | | |
| INCOME BEFORE INCOME TAX EXPENSE | 107.7 | 101.3 |
| | | |
| Income Tax Expense | 37.5 | 35.9 |
| | | |
| NET INCOME | $70.2 | $65.4 |

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| Net Income | $70.2 | $65.4 |
| | | |
| OTHER COMPREHENSIVE LOSS, NET OF TAXES | | |
| Cash Flow Hedges, Net of Tax of $(0.2) and $(0.2) in 2016 and 2015, Respectively | (0.4) | (0.3) |
| | | |
| TOTAL COMPREHENSIVE INCOME | $69.8 | $65.1 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

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OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2014 | $ 321.2 | $ 838.8 | $ 814.6 | $ 5.6 | $ 1,980.2 |
| Common Stock Dividends | | | (37.5) | | (37.5) |
| Net Income | | | 65.4 | | 65.4 |
| Other Comprehensive Loss | | | | (0.3) | (0.3) |
| TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2015 | $ 321.2 | $ 838.8 | $ 842.5 | $ 5.3 | $ 2,007.8 |
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2015 | $ 321.2 | $ 838.8 | $ 822.3 | $ 4.3 | $ 1,986.6 |
| Common Stock Dividends | | | (75.0) | | (75.0) |
| Net Income | | | 70.2 | | 70.2 |
| Other Comprehensive Loss | | | | (0.4) | (0.4) |
| TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2016 | $ 321.2 | $ 838.8 | $ 817.5 | $ 3.9 | $ 1,981.4 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2016 and December 31, 2015
(in millions)
(Unaudited)

| | March 31, 2016 | December 31, 2015 |
|---|---|---|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | $9.3 | $ 3.1 |
| Restricted Cash for Securitized Funding | 16.2 | 27.7 |
| Advances to Affiliates | 221.9 | 331.1 |
| Accounts Receivable: | | |
| Customers | 43.0 | 46.4 |
| Affiliated Companies | 60.0 | 64.3 |
| Accrued Unbilled Revenues | 13.3 | 1.4 |
| Miscellaneous | 1.1 | 0.4 |
| Allowance for Uncollectible Accounts | (0.4) | (0.2) |
| Total Accounts Receivable | 117.0 | 112.3 |
| Materials and Supplies | 71.0 | 86.1 |
| Prepayments and Other Current Assets | 12.1 | 12.9 |
| TOTAL CURRENT ASSETS | 447.5 | 573.2 |
| | | |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Transmission | 2,267.1 | 2,235.6 |
| Distribution | 4,324.8 | 4,287.7 |
| Other Property, Plant and Equipment | 423.1 | 408.2 |
| Construction Work in Progress | 160.2 | 171.9 |
| Total Property, Plant and Equipment | 7,175.2 | 7,103.4 |
| Accumulated Depreciation and Amortization | 2,070.4 | 2,048.7 |
| TOTAL PROPERTY, PLANT AND EQUIPMENT – NET | 5,104.8 | 5,054.7 |
| | | |
| OTHER NONCURRENT ASSETS | | |
| Notes Receivable – Affiliated | 32.3 | 32.3 |
| Regulatory Assets | 1,056.5 | 1,113.0 |
| Securitized Assets | 79.9 | 85.9 |
| Long-term Risk Management Assets | — | 19.2 |
| Deferred Charges and Other Noncurrent Assets | 225.9 | 259.6 |
| TOTAL OTHER NONCURRENT ASSETS | 1,394.6 | 1,510.0 |
| | | |
| TOTAL ASSETS | $6,946.9 | $ 7,137.9 |

See Condensed Notes to Condensed Financial Statements

of
Registrants
beginning
on page 90.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2016 and December 31, 2015
(dollars in millions)
(Unaudited)

| | March 31, 2016 | December 31, 2015 |
|---|---|---|
| CURRENT LIABILITIES | | |
| Accounts Payable: | | |
| General | $131.5 | $ 156.4 |
| Affiliated Companies | 74.6 | 88.7 |
| Long-term Debt Due Within One Year – Nonaffiliated (March 31, 2016 and December 31, 2015 Amounts Include $45.6 and $45.9, Respectively, Related to Ohio Phase-in-Recovery Funding) | 395.6 | 395.9 |
| Risk Management Liabilities | 5.5 | 3.6 |
| Customer Deposits | 89.4 | 65.4 |
| Accrued Taxes | 379.1 | 528.3 |
| Accrued Interest | 45.4 | 33.0 |
| Other Current Liabilities | 118.8 | 154.3 |
| TOTAL CURRENT LIABILITIES | 1,239.9 | 1,425.6 |
| | | |
| NONCURRENT LIABILITIES | | |
| Long-term Debt – Nonaffiliated (March 31, 2016 and December 31, 2015 Amounts Include $117.2 and $139.4, Respectively, Related to Ohio Phase-in-Recovery Funding) | 1,739.9 | 1,761.8 |
| Long-term Risk Management Liabilities | 5.8 | — |
| Deferred Income Taxes | 1,395.1 | 1,383.2 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 521.2 | 514.2 |
| Employee Benefits and Pension Obligations | 35.6 | 35.8 |
| Deferred Credits and Other Noncurrent Liabilities | 28.0 | 30.7 |
| TOTAL NONCURRENT LIABILITIES | 3,725.6 | 3,725.7 |
| | | |
| TOTAL LIABILITIES | 4,965.5 | 5,151.3 |
| | | |
| Rate Matters (Note 4) | | |
| Commitments and Contingencies (Note 5) | | |
| | | |
| COMMON SHAREHOLDER'S EQUITY | | |
| Common Stock – No Par Value: | | |
| Authorized – 40,000,000 Shares | | |
| Outstanding – 27,952,473 Shares | 321.2 | 321.2 |
| Paid-in Capital | 838.8 | 838.8 |
| Retained Earnings | 817.5 | 822.3 |
| Accumulated Other Comprehensive Income (Loss) | 3.9 | 4.3 |
| TOTAL COMMON SHAREHOLDER'S EQUITY | 1,981.4 | 1,986.6 |
| | | |
| TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY | $6,946.9 | $ 7,137.9 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, 2016 | 2015 |
|---|---|---|
| OPERATING ACTIVITIES | | |
| Net Income | $ 70.2 | $ 65.4 |
| Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities: | | |
| Depreciation and Amortization | 61.3 | 59.2 |
| Amortization of Generation Deferrals | 55.1 | 31.4 |
| Deferred Income Taxes | 7.3 | 1.7 |
| Carrying Costs Income | (1.9) | (6.5) |
| Allowance for Equity Funds Used During Construction | (1.7) | (2.4) |
| Mark-to-Market of Risk Management Contracts | 26.9 | 1.5 |
| Property Taxes | 56.0 | 49.8 |
| Deferral of Ohio Capacity Costs, Net | — | (18.2) |
| Change in Other Noncurrent Assets | (16.2) | 32.6 |
| Change in Other Noncurrent Liabilities | 6.5 | 25.4 |
| Changes in Certain Components of Working Capital: | | |
| Accounts Receivable, Net | (4.7) | 4.7 |
| Materials and Supplies | (3.0) | (7.3) |
| Accounts Payable | (30.4) | (25.2) |
| Customer Deposits | 24.0 | 0.9 |
| Accrued Taxes, Net | (148.4) | (59.5) |
| Other Current Assets | (0.4) | (1.2) |
| Other Current Liabilities | (20.7) | (7.2) |
| Net Cash Flows from Operating Activities | 79.9 | 145.1 |
| | | |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (99.2) | (119.7) |
| Change in Restricted Cash for Securitized Funding | 11.5 | 11.6 |
| Change in Advances to Affiliates, Net | 109.2 | 21.2 |

| | | |
|---|---|---|
| Other Investing Activities | 3.1 | 2.8 |
| Net Cash Flows from (Used for) Investing Activities | 24.6 | (84.1) |
| | | |
| FINANCING ACTIVITIES | | |
| Retirement of Long-term Debt – Nonaffiliated | (22.8) | (22.2) |
| Principal Payments for Capital Lease Obligations | (1.0) | (0.9) |
| Dividends Paid on Common Stock | (75.0) | (37.5) |
| Other Financing Activities | 0.5 | 1.1 |
| Net Cash Flows Used for Financing Activities | (98.3) | (59.5) |
| | | |
| Net Increase in Cash and Cash Equivalents | 6.2 | 1.5 |
| Cash and Cash Equivalents at Beginning of Period | 3.1 | 2.9 |
| Cash and Cash Equivalents at End of Period | $ 9.3 | $ 4.4 |
| | | |
| SUPPLEMENTARY INFORMATION | | |
| Cash Paid for Interest, Net of Capitalized Amounts | $ 17.8 | $ 18.8 |
| Net Cash Paid for Income Taxes | 72.5 | — |
| Noncash Acquisitions Under Capital Leases | 0.8 | 1.6 |
| Construction Expenditures Included in Current Liabilities as of March 31, | 23.1 | 42.9 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

PUBLIC SERVICE COMPANY OF OKLAHOMA

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in millions of KWhs) | |
| Retail: | | |
| Residential | 1,366 | 1,516 |
| Commercial | 1,155 | 1,131 |
| Industrial | 1,270 | 1,254 |
| Miscellaneous | 270 | 276 |
| Total Retail | 4,061 | 4,177 |
| Wholesale | 67 | 91 |
| Total KWhs | 4,128 | 4,268 |

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

Summary of Heating and Cooling Degree Days

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in degree days) | |
| Actual – Heating (a) | 778 | 1,166 |
| Normal – Heating (b) | 1,063 | 1,047 |
| Actual – Cooling (c) | 18 | 13 |
| Normal – Cooling (b) | 14 | 14 |

(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) Cooling degree days are calculated on a 65 degree temperature base.

First Quarter of 2016 Compared to First Quarter of 2015
Reconciliation of First Quarter of 2015 to First Quarter of 2016
Net Income
(in millions)

| | |
|---|---|
| First Quarter of 2015 | $13.7 |
| | |
| Changes in Gross Margin: | |
| Retail Margins (a) | 9.0 |
| Off-system Sales | (0.1 ) |
| Other Revenues | 0.9 |
| Total Change in Gross Margin | 9.8 |
| | |
| Changes in Expenses and Other: | |
| Other Operation and Maintenance | (2.7 ) |
| Depreciation and Amortization | (5.8 ) |
| Taxes Other Than Income Taxes | (0.4 ) |
| Interest Income | 0.1 |
| Allowance for Equity Funds Used During Construction | 1.0 |
| Interest Expense | 0.2 |
| Total Change in Expenses and Other | (7.6 ) |
| | |
| Income Tax Expense | (0.2 ) |
| | |
| First Quarter of 2016 | $15.7 |

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

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

- Retail Margins increased $9 million primarily due to the following:
  - A $10 million increase in weather-normalized retail margins.
  - A $4 million increase primarily due to interim base rate increases. This increase in retail margins has increases in other items below.

  These increases were partially offset by:
  - A $6 million decrease in weather-related usage primarily due to a 33% decrease in heating degree days.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $3 million primarily due to the following:
  - A $2 million increase in general and administrative expenses.
  - A $2 million increase in generation plant maintenance expenses primarily due to planned outages at Northeastern Plant.
- Depreciation and Amortization expenses increased $6 million primarily due to a higher depreciable base.

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PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| REVENUES | | |
| Electric Generation, Transmission and Distribution | $271.8 | $304.7 |
| Sales to AEP Affiliates | 1.0 | 1.3 |
| Other Revenues | 1.5 | 0.8 |
| TOTAL REVENUES | 274.3 | 306.8 |
| | | |
| EXPENSES | | |
| Fuel and Other Consumables Used for Electric Generation | 15.5 | 85.6 |
| Purchased Electricity for Resale | 93.3 | 65.5 |
| Other Operation | 62.9 | 60.8 |
| Maintenance | 21.8 | 21.2 |
| Depreciation and Amortization | 35.3 | 29.5 |
| Taxes Other Than Income Taxes | 9.7 | 9.3 |
| TOTAL EXPENSES | 238.5 | 271.9 |
| | | |
| OPERATING INCOME | 35.8 | 34.9 |
| | | |
| Other Income (Expense): | | |
| Interest Income | 0.2 | 0.1 |
| Allowance for Equity Funds Used During Construction | 2.3 | 1.3 |
| Interest Expense | (14.4 ) | (14.6 ) |
| | | |
| INCOME BEFORE INCOME TAX EXPENSE | 23.9 | 21.7 |
| | | |
| Income Tax Expense | 8.2 | 8.0 |
| | | |
| NET INCOME | $15.7 | $13.7 |

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

See Condensed Notes to Condensed Financial Statements of Registrants

beginning on
page 90.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| Net Income | $ 15.7 | $ 13.7 |
| | | |
| OTHER COMPREHENSIVE LOSS, NET OF TAXES | | |
| Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) in 2016 and 2015, Respectively | (0.2 ) | (0.2 ) |
| | | |
| TOTAL COMPREHENSIVE INCOME | $ 15.5 | $ 13.5 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2014 | $ 157.2 | $ 364.0 | $ 502.0 | $ 5.0 | $ 1,028.2 |
| Net Income | | | 13.7 | | 13.7 |
| Other Comprehensive Loss | | | | (0.2) | (0.2) |
| TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2015 | $ 157.2 | $ 364.0 | $ 515.7 | $ 4.8 | $ 1,041.7 |
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2015 | $ 157.2 | $ 364.0 | $ 594.5 | $ 4.2 | $ 1,119.9 |
| Net Income | | | 15.7 | | 15.7 |
| Other Comprehensive Loss | | | | (0.2) | (0.2) |
| TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2016 | $ 157.2 | $ 364.0 | $ 610.2 | $ 4.0 | $ 1,135.4 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2016 and December 31, 2015
(in millions)
(Unaudited)

| | March 31, 2016 | December 31, 2015 |
|---|---|---|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | $3.2 | $ 1.4 |
| Advances to Affiliates | 8.4 | 80.6 |
| Accounts Receivable: | | |
| Customers | 26.5 | 26.0 |
| Affiliated Companies | 16.2 | 20.8 |
| Miscellaneous | 2.5 | 3.3 |
| Allowance for Uncollectible Accounts | (0.7) | (0.6) |
| Total Accounts Receivable | 44.5 | 49.5 |
| Fuel | 21.2 | 17.6 |
| Materials and Supplies | 51.8 | 51.9 |
| Risk Management Assets | 0.7 | 0.6 |
| Accrued Tax Benefits | 34.8 | 37.3 |
| Prepayments and Other Current Assets | 6.6 | 6.5 |
| TOTAL CURRENT ASSETS | 171.2 | 245.4 |
| | | |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Generation | 1,496.7 | 1,302.6 |
| Transmission | 822.4 | 815.4 |
| Distribution | 2,240.3 | 2,206.7 |
| Other Property, Plant and Equipment (Including Plant to be Retired) | 414.4 | 405.7 |
| Construction Work in Progress | 145.7 | 315.3 |
| Total Property, Plant and Equipment | 5,119.5 | 5,045.7 |
| Accumulated Depreciation and Amortization | 1,365.7 | 1,352.5 |
| TOTAL PROPERTY, PLANT AND EQUIPMENT – NET | 3,753.8 | 3,693.2 |
| | | |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 224.9 | 214.8 |
| Employee Benefits and Pension Assets | 11.1 | 10.6 |
| Deferred Charges and Other Noncurrent Assets | 32.1 | 6.4 |
| TOTAL OTHER NONCURRENT ASSETS | 268.1 | 231.8 |
| | | |
| TOTAL ASSETS | $4,193.1 | $ 4,170.4 |

See Condensed Notes to Condensed Financial Statements

of
Registrants
beginning
on page 90.

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PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2016 and December 31, 2015
(Unaudited)

| | March 31, 2016 | December 31, 2015 |
|---|---|---|
| | (in millions) | |
| CURRENT LIABILITIES | | |
| Accounts Payable: | | |
| General | $87.0 | $ 108.2 |
| Affiliated Companies | 43.2 | 51.5 |
| Long-term Debt Due Within One Year – Nonaffiliated | 275.4 | 275.4 |
| Risk Management Liabilities | 0.2 | 0.2 |
| Customer Deposits | 50.6 | 50.3 |
| Accrued Taxes | 38.7 | 23.6 |
| Accrued Interest | 14.5 | 15.1 |
| Regulatory Liability for Over-Recovered Fuel Costs | 67.8 | 76.1 |
| Other Current Liabilities | 60.8 | 64.4 |
| TOTAL CURRENT LIABILITIES | 638.2 | 664.8 |
| | | |
| NONCURRENT LIABILITIES | | |
| Long-term Debt – Nonaffiliated | 1,010.9 | 1,010.7 |
| Deferred Income Taxes | 1,005.1 | 971.8 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 335.8 | 335.1 |
| Asset Retirement Obligations | 40.5 | 39.9 |
| Employee Benefits and Pension Obligations | 15.0 | 14.5 |
| Deferred Credits and Other Noncurrent Liabilities | 12.2 | 13.7 |
| TOTAL NONCURRENT LIABILITIES | 2,419.5 | 2,385.7 |
| | | |
| TOTAL LIABILITIES | 3,057.7 | 3,050.5 |
| | | |
| Rate Matters (Note 4) | | |
| Commitments and Contingencies (Note 5) | | |
| | | |
| COMMON SHAREHOLDER'S EQUITY | | |
| Common Stock – Par Value – $15 Per Share: | | |
| Authorized – 11,000,000 Shares | | |
| Issued – 10,482,000 Shares | | |
| Outstanding – 9,013,000 Shares | 157.2 | 157.2 |
| Paid-in Capital | 364.0 | 364.0 |
| Retained Earnings | 610.2 | 594.5 |
| Accumulated Other Comprehensive Income (Loss) | 4.0 | 4.2 |
| TOTAL COMMON SHAREHOLDER'S EQUITY | 1,135.4 | 1,119.9 |
| | | |
| TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY | $4,193.1 | $ 4,170.4 |

See
Condensed

Notes to Condensed Financial Statements of Registrants beginning on page 90.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, 2016 | | 2015 | |
|---|---|---|---|---|
| OPERATING ACTIVITIES | | | | |
| Net Income | $ 15.7 | | $ 13.7 | |
| Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities: | | | | |
| Depreciation and Amortization | 35.3 | | 29.5 | |
| Deferred Income Taxes | 30.5 | | 8.9 | |
| Allowance for Equity Funds Used During Construction | (2.3 | ) | (1.3 | ) |
| Mark-to-Market of Risk Management Contracts | — | | (0.2 | ) |
| Property Taxes | (24.1 | ) | (24.2 | ) |
| Fuel Over/Under-Recovery, Net | (8.3 | ) | 25.0 | |
| Change in Regulatory Assets | (3.9 | ) | 0.1 | |
| Change in Regulatory Liabilities | (1.1 | ) | 8.1 | |
| Change in Other Noncurrent Assets | (6.3 | ) | (5.1 | ) |
| Change in Other Noncurrent Liabilities | (0.4 | ) | 8.5 | |
| Changes in Certain Components of Working Capital: | | | | |
| Accounts Receivable, Net | 5.0 | | 4.5 | |
| Fuel, Materials and Supplies | (3.5 | ) | (2.0 | ) |
| Accounts Payable | (17.6 | ) | (6.8 | ) |
| Accrued Taxes, Net | 17.6 | | 14.8 | |
| Other Current Assets | (0.2 | ) | (9.0 | ) |
| Other Current Liabilities | (4.0 | ) | (7.3 | ) |
| Net Cash Flows from Operating Activities | 32.4 | | 57.2 | |
| | | | | |
| INVESTING ACTIVITIES | | | | |
| Construction Expenditures | (104.1 | ) | (90.2 | ) |
| Change in Advances to Affiliates, Net | 72.2 | | (62.3 | ) |
| Other Investing Activities | 2.1 | | 1.2 | |
| Net Cash Flows Used for Investing Activities | (29.8 | ) | (151.3 | ) |

| | | |
|---|---|---|
| FINANCING ACTIVITIES | | |
| Issuance of Long-term Debt – Nonaffiliated | — | 248.8 |
| Change in Advances from Affiliates, Net | — | (154.2) |
| Retirement of Long-term Debt – Nonaffiliated | (0.1) | (0.1) |
| Principal Payments for Capital Lease Obligations | (1.0) | (1.0) |
| Other Financing Activities | 0.3 | 0.7 |
| Net Cash Flows from (Used for) Financing Activities | (0.8) | 94.2 |
| | | |
| Net Increase in Cash and Cash Equivalents | 1.8 | 0.1 |
| Cash and Cash Equivalents at Beginning of Period | 1.4 | 1.3 |
| Cash and Cash Equivalents at End of Period | $ 3.2 | $ 1.4 |
| | | |
| SUPPLEMENTARY INFORMATION | | |
| Cash Paid for Interest, Net of Capitalized Amounts | $ 15.1 | $ 11.0 |
| Net Cash Paid (Received) for Income Taxes | (23.2) | — |
| Noncash Acquisitions Under Capital Leases | 1.4 | 0.9 |
| Construction Expenditures Included in Current Liabilities as of March 31, | 35.7 | 30.8 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in millions of KWhs) | |
| Retail: | | |
| Residential | 1,395 | 1,706 |
| Commercial | 1,301 | 1,366 |
| Industrial | 1,248 | 1,246 |
| Miscellaneous | 20 | 19 |
| Total Retail | 3,964 | 4,337 |
| Wholesale | 1,934 | 2,782 |
| Total KWhs | 5,898 | 7,119 |

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

Summary of Heating and Cooling Degree Days

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in degree days) | |
| Actual – Heating (a) | 576 | 912 |
| Normal – Heating (b) | 720 | 706 |
| Actual – Cooling (c) | 43 | 16 |
| Normal – Cooling (b) | 32 | 33 |

(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) Cooling degree days are calculated on a 65 degree temperature base.

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First Quarter of 2016 Compared to First Quarter of 2015
Reconciliation of First Quarter of 2015 to First Quarter of 2016
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

| | |
|---|---|
| First Quarter of 2015 | $45.7 |
| | |
| Changes in Gross Margin: | |
| Retail Margins (a) | (25.4 ) |
| Off-system Sales | (1.0 ) |
| Transmission Revenues | 1.5 |
| Other Revenues | (0.1 ) |
| Total Change in Gross Margin | (25.0 ) |
| | |
| Changes in Expenses and Other: | |
| Other Operation and Maintenance | (15.2 ) |
| Depreciation and Amortization | (0.5 ) |
| Taxes Other Than Income Taxes | (0.2 ) |
| Other Income | 2.2 |
| Interest Expense | 2.3 |
| Total Change in Expenses and Other | (11.4 ) |
| | |
| Income Tax Expense | 13.8 |
| Equity Earnings of Unconsolidated Subsidiary | 0.4 |
| Net Income Attributable to Noncontrolling Interest | (0.1 ) |
| | |
| First Quarter of 2016 | $23.4 |

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

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

- Retail Margins decreased $25 million primarily due to the following:
  - A $14 million decrease in weather-related usage primarily due to a 37% decrease in heating degree days.
  - A $13 million decrease primarily due to fuel cost recovery adjustments in 2015.

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

- Other Operation and Maintenance expenses increased $15 million primarily due to the following:
  - A $7 million increase in general and administrative expenses.
  - A $7 million increase in generation plant expenses.
- Income Tax Expense decreased $14 million primarily due to a decrease in pretax book income and the recording of federal and state income tax adjustments, partially offset by other book/tax differences which are accounted for on a flow-through basis.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| REVENUES | | |
| Electric Generation, Transmission and Distribution | $375.4 | $428.5 |
| Sales to AEP Affiliates | 3.1 | 2.7 |
| Other Revenues | 0.5 | 0.5 |
| TOTAL REVENUES | 379.0 | 431.7 |
| | | |
| EXPENSES | | |
| Fuel and Other Consumables Used for Electric Generation | 121.9 | 157.7 |
| Purchased Electricity for Resale | 28.1 | 20.0 |
| Other Operation | 77.1 | 65.6 |
| Maintenance | 31.1 | 27.4 |
| Depreciation and Amortization | 47.5 | 47.0 |
| Taxes Other Than Income Taxes | 21.9 | 21.7 |
| TOTAL EXPENSES | 327.6 | 339.4 |
| | | |
| OPERATING INCOME | 51.4 | 92.3 |
| | | |
| Other Income (Expense): | | |
| Other Income | 7.4 | 5.2 |
| Interest Expense | (27.9) | (30.2) |
| | | |
| INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS | 30.9 | 67.3 |
| | | |
| Income Tax Expense | 7.4 | 21.2 |
| Equity Earnings of Unconsolidated Subsidiary | 1.0 | 0.6 |
| | | |
| NET INCOME | 24.5 | 46.7 |
| | | |
| Net Income Attributable to Noncontrolling Interest | 1.1 | 1.0 |
| | | |
| EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER | $23.4 | $45.7 |

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

See Condensed Notes to

Condensed Financial Statements of Registrants beginning on page 90.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| Net Income | $24.5 | $46.7 |
| | | |
| OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES | | |
| Cash Flow Hedges, Net of Tax of $0.2 and $0.3 in 2016 and 2015, Respectively | 0.5 | 0.6 |
| Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) in 2016 and 2015, Respectively | (0.2) | (0.3) |
| | | |
| TOTAL OTHER COMPREHENSIVE INCOME | 0.3 | 0.3 |
| | | |
| TOTAL COMPREHENSIVE INCOME | 24.8 | 47.0 |
| | | |
| Total Comprehensive Income Attributable to Noncontrolling Interest | 1.1 | 1.0 |
| | | |
| TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER | $23.7 | $46.0 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | SWEPCo Common Shareholder | | | | | |
|---|---|---|---|---|---|---|
| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Noncontrolling Interest | Total |
| TOTAL EQUITY – DECEMBER 31, 2014 | $135.7 | $674.6 | $1,294.0 | $ (7.5 ) | $ 0.4 | $2,097.2 |
| | | | | | | |
| Common Stock Dividends | | | (30.0 ) | | | (30.0 ) |
| Common Stock Dividends – Nonaffiliated | | | | | (1.0 ) | (1.0 ) |
| Net Income | | | 45.7 | | 1.0 | 46.7 |
| Other Comprehensive Income | | | | 0.3 | | 0.3 |
| TOTAL EQUITY – MARCH 31, 2015 | $135.7 | $674.6 | $1,309.7 | $ (7.2 ) | $ 0.4 | $2,113.2 |
| | | | | | | |
| TOTAL EQUITY – DECEMBER 31, 2015 | $135.7 | $676.6 | $1,366.3 | $ (9.4 ) | $ 0.5 | $2,169.7 |
| | | | | | | |
| Common Stock Dividends | | | (30.0 ) | | | (30.0 ) |
| Common Stock Dividends – Nonaffiliated | | | | | (1.2 ) | (1.2 ) |
| Net Income | | | 23.4 | | 1.1 | 24.5 |
| Other Comprehensive Income | | | | 0.3 | | 0.3 |
| TOTAL EQUITY – MARCH 31, 2016 | $135.7 | $676.6 | $1,359.7 | $ (9.1 ) | $ 0.4 | $2,163.3 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2016 and December 31, 2015
(in millions)
(Unaudited)

| | March 31, 2016 | December 31, 2015 |
|---|---|---|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | | |
| (March 31, 2016 and December 31, 2015 Amounts Include $9.4 and $3.7, Respectively, Related to Sabine) | $ 12.3 | $ 5.2 |
| Advances to Affiliates | 2.0 | 2.0 |
| Accounts Receivable: | | |
| Customers | 45.9 | 40.2 |
| Affiliated Companies | 20.0 | 22.0 |
| Miscellaneous | 21.3 | 27.1 |
| Allowance for Uncollectible Accounts | (1.4 ) | (0.9 ) |
| Total Accounts Receivable | 85.8 | 88.4 |
| Fuel | | |
| (March 31, 2016 and December 31, 2015 Amounts Include $36.1 and $40.4, Respectively, Related to Sabine) | 129.3 | 142.1 |
| Materials and Supplies | 70.6 | 71.5 |
| Risk Management Assets | 0.8 | 0.8 |
| Accrued Tax Benefits | 37.3 | — |
| Regulatory Asset for Under-Recovered Fuel Costs | 2.5 | 4.1 |
| Prepayments and Other Current Assets | 27.8 | 21.2 |
| TOTAL CURRENT ASSETS | 368.4 | 335.3 |
| | | |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Generation | 4,190.5 | 3,943.5 |
| Transmission | 1,396.4 | 1,387.8 |
| Distribution | 1,966.6 | 1,957.3 |
| Other Property, Plant and Equipment (Including Plant to be Retired) | | |
| (March 31, 2016 and December 31, 2015 Amounts Include $300.5 and $297.7, Respectively, Related to Sabine) | 893.2 | 883.5 |
| Construction Work in Progress | 562.8 | 751.3 |
| Total Property, Plant and Equipment | 9,009.5 | 8,923.4 |
| Accumulated Depreciation and Amortization | | |
| (March 31, 2016 and December 31, 2015 Amounts Include $161.1 and $157.3, Respectively, Related to Sabine) | 2,620.9 | 2,602.3 |
| TOTAL PROPERTY, PLANT AND EQUIPMENT – NET | 6,388.6 | 6,321.1 |
| | | |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 422.0 | 415.8 |
| Deferred Charges and Other Noncurrent Assets | 120.4 | 75.8 |
| TOTAL OTHER NONCURRENT ASSETS | 542.4 | 491.6 |

| | | |
|---|---|---|
| TOTAL ASSETS | $7,299.4 | $ 7,148.0 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
March 31, 2016 and December 31, 2015
(Unaudited)

| | March 31, 2016 | December 31, 2015 |
|---|---|---|
| | (in millions) | |
| CURRENT LIABILITIES | | |
| Advances from Affiliates | $217.8 | $ 58.3 |
| Accounts Payable: | | |
| General | 140.3 | 150.4 |
| Affiliated Companies | 61.0 | 78.8 |
| Long-term Debt Due Within One Year – Nonaffiliated | 253.3 | 3.3 |
| Risk Management Liabilities | 3.5 | 3.1 |
| Customer Deposits | 62.5 | 61.4 |
| Accrued Taxes | 82.4 | 58.3 |
| Accrued Interest | 22.2 | 43.0 |
| Obligations Under Capital Leases | 25.3 | 21.9 |
| Other Current Liabilities | 86.6 | 110.7 |
| TOTAL CURRENT LIABILITIES | 954.9 | 589.2 |
| | | |
| NONCURRENT LIABILITIES | | |
| Long-term Debt – Nonaffiliated | 2,019.1 | 2,270.2 |
| Long-term Risk Management Liabilities | 1.8 | 2.1 |
| Deferred Income Taxes | 1,455.1 | 1,399.8 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 447.0 | 448.8 |
| Asset Retirement Obligations | 114.4 | 117.5 |
| Employee Benefits and Pension Obligations | 28.1 | 25.8 |
| Obligations Under Capital Leases | 73.6 | 75.6 |
| Deferred Credits and Other Noncurrent Liabilities | 42.1 | 49.3 |
| TOTAL NONCURRENT LIABILITIES | 4,181.2 | 4,389.1 |
| | | |
| TOTAL LIABILITIES | 5,136.1 | 4,978.3 |
| | | |
| Rate Matters (Note 4) | | |
| Commitments and Contingencies (Note 5) | | |
| | | |
| EQUITY | | |
| Common Stock – Par Value – $18 Per Share: | | |
| Authorized – 7,600,000 Shares | | |
| Outstanding – 7,536,640 Shares | 135.7 | 135.7 |
| Paid-in Capital | 676.6 | 676.6 |
| Retained Earnings | 1,359.7 | 1,366.3 |
| Accumulated Other Comprehensive Income (Loss) | (9.1) | (9.4) |
| TOTAL COMMON SHAREHOLDER’S EQUITY | 2,162.9 | 2,169.2 |
| | | |
| Noncontrolling Interest | 0.4 | 0.5 |

| | | |
|---|---|---|
| TOTAL EQUITY | 2,163.3 | 2,169.7 |
| TOTAL LIABILITIES AND EQUITY | $7,299.4 | $ 7,148.0 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2016 and 2015
(in millions)
(Unaudited)

| | Three Months Ended March 31, 2016 | | 2015 | |
|---|---|---|---|---|
| OPERATING ACTIVITIES | | | | |
| Net Income | $ 24.5 | | $ 46.7 | |
| Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities: | | | | |
| Depreciation and Amortization | 47.5 | | 47.0 | |
| Deferred Income Taxes | 44.6 | | 18.8 | |
| Allowance for Equity Funds Used During Construction | (7.4 | ) | (5.2 | ) |
| Mark-to-Market of Risk Management Contracts | 0.1 | | 3.1 | |
| Property Taxes | (41.4 | ) | (39.4 | ) |
| Fuel Over/Under-Recovery, Net | 3.7 | | 2.8 | |
| Change in Other Noncurrent Assets | 5.3 | | (0.9 | ) |
| Change in Other Noncurrent Liabilities | (1.9 | ) | (2.9 | ) |
| Changes in Certain Components of Working Capital: | | | | |
| Accounts Receivable, Net | 2.6 | | 26.0 | |
| Fuel, Materials and Supplies | 13.7 | | (0.5 | ) |
| Accounts Payable | (19.9 | ) | (28.3 | ) |
| Accrued Taxes, Net | (13.2 | ) | 43.1 | |
| Accrued Interest | (20.8 | ) | (25.5 | ) |
| Other Current Assets | (1.7 | ) | (11.4 | ) |
| Other Current Liabilities | (28.2 | ) | (44.1 | ) |
| Net Cash Flows from Operating Activities | 7.5 | | 29.3 | |
| | | | | |
| INVESTING ACTIVITIES | | | | |
| Construction Expenditures | (116.6 | ) | (138.1 | ) |
| Change in Advances to Affiliates, Net | — | | (252.3 | ) |
| Other Investing Activities | (7.0 | ) | (1.4 | ) |
| Net Cash Flows Used for Investing Activities | (123.6 | ) | (391.8 | ) |
| | | | | |
| FINANCING ACTIVITIES | | | | |
| | — | | 446.0 | |

| | | |
|---|---|---|
| Issuance of Long-term Debt – Nonaffiliated | | |
| Change in Advances from Affiliates, Net | 159.5 | — |
| Retirement of Long-term Debt – Nonaffiliated | (1.6) | (55.1) |
| Principal Payments for Capital Lease Obligations | (4.5) | (4.5) |
| Dividends Paid on Common Stock | (30.0) | (30.0) |
| Dividends Paid on Common Stock – Nonaffiliated | (1.2) | (1.0) |
| Other Financing Activities | 1.0 | 0.7 |
| Net Cash Flows from Financing Activities | 123.2 | 356.1 |
| | | |
| Net Increase (Decrease) in Cash and Cash Equivalents | 7.1 | (6.4) |
| Cash and Cash Equivalents at Beginning of Period | 5.2 | 14.4 |
| Cash and Cash Equivalents at End of Period | $ 12.3 | $ 8.0 |
| | | |
| SUPPLEMENTARY INFORMATION | | |
| Cash Paid for Interest, Net of Capitalized Amounts | $ 47.7 | $ 53.4 |
| Net Cash Paid (Received) for Income Taxes | 14.0 | (0.9) |
| Noncash Acquisitions Under Capital Leases | 4.9 | 0.9 |
| Construction Expenditures Included in Current Liabilities as of March 31, | 83.7 | 80.2 |

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 90.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANTS

The condensed notes to condensed financial statements are a combined presentation for the Registrants. The following list indicates Registrants to which the notes apply. Specific disclosures within each note apply to all Registrants unless indicated otherwise.

1. SIGNIFICANT ACCOUNTING MATTERS

The disclosures in this note apply to all Registrants unless indicated otherwise.

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods for each Registrant. Net income for the three months ended March 31, 2016 is not necessarily indicative of results that may be expected for the year ending December 31, 2016. The condensed financial statements are unaudited and should be read in conjunction with the audited 2015 financial statements and notes thereto, which are included in the Registrant's Annual Reports on Form 10-K as filed with the SEC on February 23, 2016.

Earnings Per Share (EPS) (Applies to AEP)

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 table presents AEP's basic and diluted EPS calculations included on the condensed statements of income:

| | Three Months Ended March 31, | | | |
|---|---|---|---|---|
| | 2016 | | 2015 | |
| | (in millions, except per share data) | | | |
| | | $/share | | $/share |
| Income from Continuing Operations | $503.1 | | $620.2 | |
| Less: Net Income Attributable to Noncontrolling Interests | 1.9 | | 1.5 | |
| Earnings Attributable to AEP Common Shareholders from Continuing Operations | $501.2 | | $618.7 | |
| | | | | |
| Weighted Average Number of Basic Shares Outstanding | 491.1 | $ 1.02 | 489.6 | $ 1.27 |
| Weighted Average Dilutive Effect of Restricted Stock Units | 0.2 | — | 0.3 | — |
| Weighted Average Number of Diluted Shares Outstanding | 491.3 | $ 1.02 | 489.9 | $ 1.27 |

There were no antidilutive shares outstanding as of March 31, 2016 and 2015.

## 2. NEW ACCOUNTING PRONOUNCEMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

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

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

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

The FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, "Revenue from Contracts with Customers (Topic: 606): Deferral of the Effective Date." The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted for annual periods beginning after December 15, 2016. As applicable, this standard may change the amount of revenue recognized on the statements of income in each reporting period. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2018.

ASU 2015-11 "Simplifying the Measurement of Inventory" (ASU 2015-11)

In July 2015, the FASB issued ASU 2015-11 simplifying the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first-out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. Management does not expect the new standard to impact the Registrants' results of operations, financial position or cash flows. Management plans to adopt ASU 2015-11 prospectively, effective January 1, 2017.

ASU 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" (ASU 2016-01)

In January 2016, the FASB issued ASU 2016-01 enhancing the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance sheet or the accompanying notes to the financial statements. The amendments also clarify that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for sale securities in combination with the entity's other deferred tax assets.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted. The amendments will be applied by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-01 effective January 1, 2018.

ASU 2016-02 “Accounting for Leases” (ASU 2016-02)

In February 2016, the FASB issued ASU 2016-02 increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, a capital lease will be known as a finance lease going forward. Leases with lease terms of 12 months or longer will be subject to the new requirements. Fundamentally, the criteria used to determine lease classification will remain the same, but will be more subjective under the new standard.

The new accounting guidance is effective for annual periods beginning after December 15, 2018 with early adoption permitted. The guidance will be applied by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented as well as a number of optional practical expedients that entities may elect to apply. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption. Management expects the new standard to impact the Registrants’ financial position, but not the Registrants’ results of operations or cash flows. Management plans to adopt ASU 2016-02 effective January 1, 2019.

ASU 2016-09 “Compensation – Stock Compensation” (ASU 2016-09)

In March 2016, the FASB issued ASU 2016-09 simplifying the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities and classification on the statements of cash flows. Under the new standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit on the statements of income. Under current GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income.

The new accounting guidance is effective for annual periods beginning after December 15, 2016. Early adoption is permitted in any interim or annual period. Certain provisions require retrospective/modified retrospective transition while others are to be applied prospectively. Management plans to adopt ASU 2016-09 effective January 1, 2017.

3. COMPREHENSIVE INCOME

The disclosures in this note apply to all Registrants unless indicated otherwise.

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the three months ended March 31, 2016 and 2015. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 for additional details.

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2016

| | 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, 2015 | $(5.2) | $(17.2) | $ 7.1 | $(111.8) | $(127.1) |
| Change in Fair Value Recognized in AOCI | (8.1) | — | 0.6 | — | (7.5) |
| Amount of (Gain) Loss Reclassified from AOCI | | | | | |
| Generation & Marketing Revenues | (8.6) | — | — | — | (8.6) |
| Purchased Electricity for Resale | 9.2 | — | — | — | 9.2 |
| Interest Expense | — | 0.5 | — | — | 0.5 |
| Amortization of Prior Service Cost (Credit) | — | — | — | (4.9) | (4.9) |
| Amortization of Actuarial (Gains)/Losses | — | — | — | 5.1 | 5.1 |
| Reclassifications from AOCI, before Income Tax (Expense) Credit | 0.6 | 0.5 | — | 0.2 | 1.3 |
| Income Tax (Expense) Credit | 0.2 | 0.2 | — | 0.1 | 0.5 |
| Reclassifications from AOCI, Net of Income Tax (Expense) Credit | 0.4 | 0.3 | — | 0.1 | 0.8 |
| Net Current Period Other Comprehensive Income (Loss) | (7.7) | 0.3 | 0.6 | 0.1 | (6.7) |
| Balance in AOCI as of March 31, 2016 | $(12.9) | $(16.9) | $ 7.7 | $(111.7) | $(133.8) |

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 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 | $1.6 | $(19.1) | $ 7.7 | $(93.3) | $(103.1) |
| Change in Fair Value Recognized in AOCI | 0.7 | (0.1) | 0.5 | — | 1.1 |
| Amount of (Gain) Loss Reclassified from AOCI | | | | | |
| Generation & Marketing Revenues | (12.7) | — | — | — | (12.7) |

| | | | | | |
|---|---|---|---|---|---|
| Purchased Electricity for Resale | 0.7 | — | — | — | 0.7 |
| Interest Expense | — | 1.2 | — | — | 1.2 |
| Amortization of Prior Service Cost (Credit) | — | — | — | (4.8 ) | (4.8 ) |
| Amortization of Actuarial (Gains)/Losses | — | — | — | 5.3 | 5.3 |
| Reclassifications from AOCI, before Income Tax (Expense) Credit | (12.0 ) | 1.2 | — | 0.5 | (10.3 ) |
| Income Tax (Expense) Credit | (4.2 ) | 0.4 | — | 0.1 | (3.7 ) |
| Reclassifications from AOCI, Net of Income Tax (Expense) Credit | (7.8 ) | 0.8 | — | 0.4 | (6.6 ) |
| Net Current Period Other Comprehensive Income (Loss) | (7.1 ) | 0.7 | 0.5 | 0.4 | (5.5 ) |
| Pension and OPEB Adjustment Related to Mitchell Plant | — | — | — | 5.1 | 5.1 |
| Balance in AOCI as of March 31, 2015 | $(5.5) | $ (18.4 ) | $ 8.2 | $(87.8) | $(103.5) |

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2016

| | Cash Flow Hedges Interest Rate and Foreign Currency | Pension and OPEB | Total |
|---|---|---|---|
| | (in millions) | | |
| Balance in AOCI as of December 31, 2015 | $3.6 | $(6.4) | $(2.8) |
| Change in Fair Value Recognized in AOCI | — | — | — |
| Amount of (Gain) Loss Reclassified from AOCI | | | |
| Interest Expense | (0.3) | — | (0.3) |
| Amortization of Prior Service Cost (Credit) | — | (1.2) | (1.2) |
| Amortization of Actuarial (Gains)/Losses | — | 0.7 | 0.7 |
| Reclassifications from AOCI, before Income Tax (Expense) Credit | (0.3) | (0.5) | (0.8) |
| Income Tax (Expense) Credit | (0.1) | (0.2) | (0.3) |
| Reclassifications from AOCI, Net of Income Tax (Expense) Credit | (0.2) | (0.3) | (0.5) |
| Net Current Period Other Comprehensive Income (Loss) | (0.2) | (0.3) | (0.5) |
| Balance in AOCI as of March 31, 2016 | $3.4 | $(6.7) | $(3.3) |

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2015

| | Cash Flow Hedges Interest Rate and Foreign Currency | Pension and OPEB | Total |
|---|---|---|---|
| | (in millions) | | |
| Balance in AOCI as of December 31, 2014 | $3.9 | $1.1 | $5.0 |
| Change in Fair Value Recognized in AOCI | — | — | — |
| Amount of (Gain) Loss Reclassified from AOCI | | | |
| Interest Expense | 0.2 | — | 0.2 |
| Amortization of Prior Service Cost (Credit) | — | (1.3) | (1.3) |
| Amortization of Actuarial (Gains)/Losses | — | 0.6 | 0.6 |
| Reclassifications from AOCI, before Income Tax (Expense) Credit | 0.2 | (0.7) | (0.5) |
| Income Tax (Expense) Credit | 0.1 | (0.3) | (0.2) |
| Reclassifications from AOCI, Net of Income Tax (Expense) Credit | 0.1 | (0.4) | (0.3) |
| Net Current Period Other Comprehensive Income (Loss) | 0.1 | (0.4) | (0.3) |
| Balance in AOCI as of March 31, 2015 | $4.0 | $0.7 | $4.7 |

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2016

| | Cash Flow Hedges Interest Rate and Foreign Currency | Pension and OPEB | Total |
|---|---|---|---|
| | (in millions) | | |
| Balance in AOCI as of December 31, 2015 | $(13.3) | $ (3.4 ) | $(16.7) |
| Change in Fair Value Recognized in AOCI | — | — | — |
| Amount of (Gain) Loss Reclassified from AOCI | | | |
| Interest Expense | 0.5 | — | 0.5 |
| Amortization of Prior Service Cost (Credit) | — | (0.2 ) | (0.2 ) |
| Amortization of Actuarial (Gains)/Losses | — | 0.2 | 0.2 |
| Reclassifications from AOCI, before Income Tax (Expense) Credit | 0.5 | — | 0.5 |
| Income Tax (Expense) Credit | 0.1 | — | 0.1 |
| Reclassifications from AOCI, Net of Income Tax (Expense) Credit | 0.4 | — | 0.4 |
| Net Current Period Other Comprehensive Income (Loss) | 0.4 | — | 0.4 |
| Balance in AOCI as of March 31, 2016 | $(12.9) | $ (3.4 ) | $(16.3) |

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2015

| | Cash Flow Hedges Interest Rate and Foreign Currency | Pension and OPEB | Total |
|---|---|---|---|
| | (in millions) | | |
| Balance in AOCI as of December 31, 2014 | $(14.4) | $ 0.1 | $(14.3) |
| Change in Fair Value Recognized in AOCI | — | — | — |
| Amount of (Gain) Loss Reclassified from AOCI | | | |
| Interest Expense | 0.4 | — | 0.4 |
| Amortization of Prior Service Cost (Credit) | — | (0.2 ) | (0.2 ) |
| Amortization of Actuarial (Gains)/Losses | — | 0.2 | 0.2 |
| Reclassifications from AOCI, before Income Tax (Expense) Credit | 0.4 | — | 0.4 |
| Income Tax (Expense) Credit | 0.1 | — | 0.1 |
| Reclassifications from AOCI, Net of Income Tax (Expense) Credit | 0.3 | — | 0.3 |
| Net Current Period Other Comprehensive Income (Loss) | 0.3 | — | 0.3 |
| Balance in AOCI as of March 31, 2015 | $(14.1) | $ 0.1 | $(14.0) |

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OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2016

| | Cash Flow Hedges Interest Rate and Foreign Currency (in millions) |
|---|---|
| Balance in AOCI as of December 31, 2015 | $ 4.3 |
| Change in Fair Value Recognized in AOCI | — |
| Amount of (Gain) Loss Reclassified from AOCI | |
| Interest Expense | (0.5 ) |
| Reclassifications from AOCI, before Income Tax (Expense) Credit | (0.5 ) |
| Income Tax (Expense) Credit | (0.1 ) |
| Reclassifications from AOCI, Net of Income Tax (Expense) Credit | (0.4 ) |
| Net Current Period Other Comprehensive Loss | (0.4 ) |
| Balance in AOCI as of March 31, 2016 | $ 3.9 |

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2015

| | Cash Flow Hedges Interest Rate and Foreign Currency (in millions) |
|---|---|
| Balance in AOCI as of December 31, 2014 | $ 5.6 |
| Change in Fair Value Recognized in AOCI | — |
| Amount of (Gain) Loss Reclassified from AOCI | |
| Interest Expense | (0.5 ) |
| Reclassifications from AOCI, before Income Tax (Expense) Credit | (0.5 ) |
| Income Tax (Expense) Credit | (0.2 ) |
| Reclassifications from AOCI, Net of Income Tax (Expense) Credit | (0.3 ) |
| Net Current Period Other Comprehensive Loss | (0.3 ) |
| Balance in AOCI as of March 31, 2015 | $ 5.3 |

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2016

| | Cash Flow Hedges Interest Rate and Foreign Currency (in millions) |
|---|---|
| Balance in AOCI as of December 31, 2015 | $ 4.2 |
| Change in Fair Value Recognized in AOCI | — |
| Amount of (Gain) Loss Reclassified from AOCI | |
| Interest Expense | (0.3 ) |
| Reclassifications from AOCI, before Income Tax (Expense) Credit | (0.3 ) |
| Income Tax (Expense) Credit | (0.1 ) |
| Reclassifications from AOCI, Net of Income Tax (Expense) Credit | (0.2 ) |
| Net Current Period Other Comprehensive Loss | (0.2 ) |
| Balance in AOCI as of March 31, 2016 | $ 4.0 |

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2015

| | Cash Flow Hedges Interest Rate and Foreign Currency (in millions) |
|---|---|
| Balance in AOCI as of December 31, 2014 | $ 5.0 |
| Change in Fair Value Recognized in AOCI | — |
| Amount of (Gain) Loss Reclassified from AOCI | |
| Interest Expense | (0.3 ) |
| Reclassifications from AOCI, before Income Tax (Expense) Credit | (0.3 ) |
| Income Tax (Expense) Credit | (0.1 ) |
| Reclassifications from AOCI, Net of Income Tax (Expense) Credit | (0.2 ) |
| Net Current Period Other Comprehensive Loss | (0.2 ) |
| Balance in AOCI as of March 31, 2015 | $ 4.8 |

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2016

| | Cash Flow Hedges Interest Rate and Foreign Currency | Pension and OPEB | Total |
|---|---|---|---|
| | (in millions) | | |
| Balance in AOCI as of December 31, 2015 | $(9.1) | $(0.3) | $(9.4) |
| Change in Fair Value Recognized in AOCI | — | — | — |
| Amount of (Gain) Loss Reclassified from AOCI | | | |
| Interest Expense | 0.7 | — | 0.7 |
| Amortization of Prior Service Cost (Credit) | — | (0.5) | (0.5) |
| Amortization of Actuarial (Gains)/Losses | — | 0.2 | 0.2 |
| Reclassifications from AOCI, before Income Tax (Expense) Credit | 0.7 | (0.3) | 0.4 |
| Income Tax (Expense) Credit | 0.2 | (0.1) | 0.1 |
| Reclassifications from AOCI, Net of Income Tax (Expense) Credit | 0.5 | (0.2) | 0.3 |
| Net Current Period Other Comprehensive Income (Loss) | 0.5 | (0.2) | 0.3 |
| Balance in AOCI as of March 31, 2016 | $(8.6) | $(0.5) | $(9.1) |

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2015

| | Cash Flow Hedges Interest Rate and Foreign Currency | Pension and OPEB | Total |
|---|---|---|---|
| | (in millions) | | |
| Balance in AOCI as of December 31, 2014 | $(11.1) | $ 3.6 | $(7.5) |
| Change in Fair Value Recognized in AOCI | — | — | — |
| Amount of (Gain) Loss Reclassified from AOCI | | | |
| Interest Expense | 0.9 | — | 0.9 |
| Amortization of Prior Service Cost (Credit) | — | (0.5) | (0.5) |
| Amortization of Actuarial (Gains)/Losses | — | 0.1 | 0.1 |
| Reclassifications from AOCI, before Income Tax (Expense) Credit | 0.9 | (0.4) | 0.5 |
| Income Tax (Expense) Credit | 0.3 | (0.1) | 0.2 |
| Reclassifications from AOCI, Net of Income Tax (Expense) Credit | 0.6 | (0.3) | 0.3 |
| Net Current Period Other Comprehensive Income (Loss) | 0.6 | (0.3) | 0.3 |
| Balance in AOCI as of March 31, 2015 | $(10.5) | $ 3.3 | $(7.2) |

## 4. RATE MATTERS

The disclosures in this note apply to all Registrants unless indicated otherwise.

As discussed in the 2015 Annual Report, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2015 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 2016 and updates the 2015 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

| | AEP | |
|---|---|---|
| | March 31, 2016 | December 31, 2015 |
| Noncurrent Regulatory Assets | (in millions) | |
| Regulatory Assets Currently Earning a Return | | |
| Storm Related Costs | $24.8 | $ 24.2 |
| Plant Retirement Costs - Materials and Supplies | 20.8 | 20.9 |
| Regulatory Assets Currently Not Earning a Return | | |
| Plant Retirement Costs - Asset Retirement Obligation Costs | 59.8 | 59.8 |
| Storm Related Costs | 23.2 | 18.2 |
| Peak Demand Reduction/Energy Efficiency | 14.1 | 13.1 |
| Other Regulatory Assets Pending Final Regulatory Approval | 35.4 | 31.7 |
| Total Regulatory Assets Pending Final Regulatory Approval | $178.1 | $ 167.9 |

| | APCo | |
|---|---|---|
| | March 31, 2016 | December 31, 2015 |
| Noncurrent Regulatory Assets | (in millions) | |
| Regulatory Assets Currently Earning a Return | | |
| Plant Retirement Costs - Materials and Supplies | $9.2 | $ 9.3 |
| Regulatory Assets Currently Not Earning a Return | | |
| Plant Retirement Costs - Asset Retirement Obligation Costs | 32.7 | 32.7 |
| Peak Demand Reduction/Energy Efficiency - Virginia | 13.6 | 12.7 |
| Amos Plant Transfer Costs - West Virginia | 2.0 | 2.0 |
| Other Regulatory Assets Pending Final Regulatory Approval | 0.6 | 0.6 |
| Total Regulatory Assets Pending Final Regulatory Approval | $58.1 | $ 57.3 |

| | I&M | |
|---|---|---|
| | March 31, 2016 | December 31, 2015 |
| Noncurrent Regulatory Assets | (in millions) | |
| | | |
| Regulatory Assets Currently Earning a Return | | |
| Plant Retirement Costs - Materials and Supplies | $11.6 | $ 11.6 |
| Regulatory Assets Currently Not Earning a Return | | |
| Plant Retirement Costs - Asset Retirement Obligation Costs - Indiana | 27.1 | 27.1 |
| Cook Plant Turbine | 10.4 | 9.7 |
| Deferred Cook Plant Life Cycle Management Project Costs - Michigan | 5.4 | 4.2 |
| Stranded Costs on Abandoned Plants | 3.9 | 3.9 |
| Rockport Dry Sorbent Injection System - Indiana | 3.6 | 2.8 |
| Other Regulatory Assets Pending Final Regulatory Approval | 0.2 | — |
| Total Regulatory Assets Pending Final Regulatory Approval | $62.2 | $ 59.3 |

| | OPCo | |
|---|---|---|
| | March 31, 2016 | December 31, 2015 |
| Noncurrent Regulatory Assets | (in millions) | |
| | | |
| Regulatory Assets Currently Not Earning a Return | | |
| gridSMART® Costs | $1.8 | $ 1.3 |
| Total Regulatory Assets Pending Final Regulatory Approval | $1.8 | $ 1.3 |

| | PSO | |
|---|---|---|
| | March 31, 2016 | December 31, 2015 |
| Noncurrent Regulatory Assets | (in millions) | |
| | | |
| Regulatory Assets Currently Not Earning a Return | | |
| Storm Related Costs | $17.0 | $ 12.3 |
| Other Regulatory Assets Pending Final Regulatory Approval | 1.1 | 1.1 |
| Total Regulatory Assets Pending Final Regulatory Approval | $18.1 | $ 13.4 |

| | SWEPCo | |
|---|---|---|
| | March 31, 2016 | December 31, 2015 |
| Noncurrent Regulatory Assets | (in millions) | |
| | | |
| Regulatory Assets Currently Not Earning a Return | | |
| Shipe Road Transmission Project - FERC | $3.1 | $ 3.1 |
| Asset Retirement Obligation - Arkansas, Louisiana | 1.9 | 1.7 |
| Other Regulatory Assets Pending Final Regulatory Approval | 1.4 | 1.1 |
| Total Regulatory Assets Pending Final Regulatory Approval | $6.4 | $ 5.9 |

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

APCo and WPCo Rate Matters (Applies to AEP and APCo)

2016 West Virginia Expanded Net Energy Charge Filing

In March 2016, APCo and WPCo filed their combined annual ENEC filing with the WVPSC which requested an increase in ENEC rates of $108 million ($86 million related to APCo) to be effective July 2016. The increase primarily relates to recovery of the December 2015 under-recovered ENEC deferral balance and the recovery of costs associated with the continuation and expansion of certain transmission and generation construction projects. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

West Virginia Deferred Base Rate Increase

In May 2015, the WVPSC issued an order on APCo and WPCo's combined base rate case. The order included a delayed billing of $25 million ($22 million related to APCo) 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 (WACC) rate for the $25 million annual delayed billing through June 2016, and stated recovery would be addressed concurrent with the next ENEC change in rates. In February 2016, APCo and WPCo filed a petition with the WVPSC to implement recovery of the unrecognized delayed billing totaling $29 million ($26 million related to APCo), which includes carrying charges through June 2016. Recovery of the delayed billing was requested over two years, beginning July 2016, with the unpaid principal subject to carrying charges. An order from the WVPSC is pending.

2015 Virginia Regulatory Asset Proceeding

In 2015, the Virginia SCC initiated a proceeding to address the proper treatment of APCo's authorized regulatory assets. Briefs related to this proceeding were filed by various parties. The Virginia SCC has no statutory deadline to issue its decision in this proceeding. As of March 31, 2016, APCo's authorized regulatory assets under review in this proceeding were $8 million. If any of these costs, or any additional costs that may be subject to review, are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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 amendments provide that APCo will absorb its Virginia jurisdictional share of incremental generation and distribution costs incurred during 2014 through 2017 that are associated with severe weather events and/or natural disasters and costs associated with potential asset impairments related to new carbon emission guidelines issued by the Federal EPA.

In February 2016, certain APCo industrial customers filed a petition with the Virginia SCC requesting the issuance of a declaratory order that finds the amendments to Virginia law suspending biennial reviews unconstitutional and, accordingly, directs APCo to make biennial review filings beginning in 2016. In February 2016, APCo filed a motion to stay the Virginia SCC's consideration of the petition due to a pending appeal at the Supreme Court of Virginia by industrial customers of a non-related utility regarding the constitutionality of the amendments. APCo and other parties have filed their responses to the petition. Oral arguments at the Virginia SCC were held in March 2016. Management is unable to predict the outcome of these challenges. If the biennial review process is reinstated in advance of March 2020, it could reduce future net income and cash flows and impact financial condition.

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ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

Parent has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next filed base rate proceeding. As of March 31, 2016, AEP's share of ETT's cumulative revenues, subject to review, is estimated to be $468 million based upon interim rate increases received from 2009 through 2015. In November 2015, the PUCT ordered ETT to file a base rate case by February 2017. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. Management is unable to determine a range of potential losses that are reasonably possible of occurring. A refund of interim transmission rates could reduce future net income and cash flows and impact financial condition.

KGPCo Rate Matters (Applies to AEP)

Kingsport Base Rate Case

In January 2016, KGPCo filed a request with the TRA to increase base rates by $12 million annually based upon a proposed return on common equity of 10.66%. A hearing at the TRA is scheduled for August 2016. If KGPCo does not recover its costs, it could reduce future net income and cash flows and impact financial condition.

OPCo Rate Matters (Applies to AEP and OPCo)

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 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 WACC rate. In June 2015, the Supreme Court of Ohio issued a decision that reversed the PUCO order on the carrying cost rate issue. In October 2015 this matter was remanded back to the PUCO for reinstatement of the WACC rate. A decision from the PUCO is pending.

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. In 2013, this ruling was generally upheld in rehearing orders.

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 included 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. Oral arguments at the Supreme Court of Ohio were held in December 2015.

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In April 2015, the PUCO issued an order that approved, with modifications, OPCo's July 2014 application to collect the unrecovered portion of the deferred capacity costs. The order included approval to continue the collection of deferred capacity costs at a rate of $4.00/MWh beginning June 1, 2015 for approximately 32 months, with carrying costs at a long-term cost of debt rate. Additionally, the order stated that an audit will be conducted of the May 31, 2015 capacity deferral balance, which was $444 million. In May 2015, the PUCO granted intervenors requests for rehearing. As of March 31, 2016, OPCo's net deferred capacity costs balance of $320 million, including debt carrying costs, was recorded in Regulatory Assets on the balance sheet. Through March 31, 2016, OPCo has collected $266 million in deferred capacity costs, and related carrying charges.

In 2013, the PUCO issued its Orders on Rehearing for the ESP which generally upheld its August 2012 order. The PUCO clarified that a final reconciliation of revenues and expenses would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket related to the competitive bid process (CBP). In 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order. Oral arguments at the Supreme Court of Ohio were held in May 2015.

In November 2013, the PUCO issued an order approving OPCo's CBP with modifications. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings.

In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC. In March 2014, the PUCO approved OPCo's request to implement riders related to the unbundling of the FAC. In October 2014, the independent auditor, selected by the PUCO, filed its report with the PUCO for the period August 2012 through May 2015. 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.

In April 2016, the Supreme Court of Ohio issued two opinions related to the deferral of OPCo's capacity charges. The Supreme Court of Ohio ruled that the PUCO must reconsider an energy credit that was used to determine OPCo's authorized capacity deferral threshold of $188.88/MW day during the August 2012 through May 2015 period. The PUCO reduced OPCo's authorized capacity deferral threshold to $188.88/MW day largely due to an offset for an energy credit of $147.41/MW day. The Supreme Court of Ohio directed the PUCO to substantively address OPCo's arguments that the $147.41/MW day credit was overstated by approximately $100.00/MW day due to various inaccuracies affecting input data and assumptions.

The Supreme Court of Ohio also rejected a portion of OPCo's RSR revenues collected during the period September 2012 through May 2015 and directed the PUCO to apply these RSR revenues against OPCo's deferred capacity costs. The Supreme Court of Ohio was not able to determine the amount of the reduction to OPCo's deferred capacity costs and remanded the issue to the PUCO to determine the appropriate reduction.

Due to the interrelated nature of these two Supreme Court of Ohio opinions that directly relate to OPCo's deferred capacity costs, management believes that the PUCO will rule upon both issues together. Further, management believes that the net impact of these issues will largely offset and will not result in a material future reduction of OPCo's net income.

Additionally, the Supreme Court of Ohio agreed with OPCo's cross-appeal assertion that the 12% threshold was not based on a comparison of OPCo's return on equity to the returns during the same period of comparable publicly traded companies, including utilities, that face comparable business and financial risk. The Supreme Court of Ohio reversed the 12% threshold and remanded this issue to the PUCO. See "Significantly Excessive Earnings Test Filings" section below.

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

June 2015 - May 2018 ESP Including PPA Application

In December 2013, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments and the continuation and modification of certain existing riders, including the Distribution Investment Rider (DIR), effective June 2015 through May 2018. The proposal also included a PPA rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based PPA. The PPA would initially be based upon the OVEC contractual entitlement and could, upon further approval, be expanded to include other contracts involving other Ohio legacy generation assets.

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

In May 2015, OPCo filed an amended PPA application that (a) included OPCo’s OVEC contractual entitlement, (b) addressed the PPA requirements set forth in the PUCO’s February 2015 order, (c) updated supporting testimony to reflect a current analysis of the PPA proposal and (d) included the 2,671 MW to be available for capacity, energy and ancillary services, produced by AGR over the lives of the respective generating units.

In December 2015, a contested stipulation agreement related to the PPA rider application was filed with the PUCO. The stipulation agreement provided for a 10.38% return on common equity, for AGR, with the PPA rider term extending through May 2024. The stipulation agreement included (a) an affiliate PPA between OPCo and AGR to be included in the PPA rider, (b) OPCo’s OVEC contractual entitlement to be included in the PPA rider, (c) potential additional contingent customer credits of up to $100 million to be included in the PPA rider over the final four years of the PPA rider, (d) annual compliance reviews before the PUCO, (e) an agreement to retire, refuel or repower to 100% natural gas, Conesville Plant, Units 5 and 6 and Cardinal Plant, Unit 1 by 2029 and 2030, respectively, and (f) a commitment by OPCo to submit an amended ESP filing by April 30, 2016 which would extend all ESP riders through May 2024. Additionally, subject to cost recovery and PUCO approval, OPCo agreed to develop and implement, by 2021, a solar energy project(s) of at least 400 MW and a wind energy project(s) of at least 500 MW, with 100% of all output to be received by OPCo. AEP affiliates could own up to 50% of these solar and wind projects. OPCo agreed to file a carbon reduction plan with the PUCO by December 2016 that will focus on fuel diversification and carbon emission reductions.

In March 2016, the PUCO modified and approved the stipulation agreement. The PPA is effective April 2016 through May 2024, with quarterly PPA rider reconciliations to actual PPA costs compared to PJM market revenues, subject to audit and review by the PUCO. PUCO modifications to the stipulation agreement included (a) a temporary customer-specific rate impact cap of 5% through May 2018, (b) a directive that OPCo will not seek recovery from customers for any costs associated with the retirement, refueling, co-firing or repowering of PPA units, (c) the limitation that OPCo will not flow through any capacity performance penalties or bonuses through the PPA rider, (d) the right for the PUCO to exclude costs associated with a forced outage lasting longer than 90 days, (e) the limitation that OPCo will not flow through any net costs or revenues associated with AGR’s obligations or entitlements related to Cardinal Plant, Units 2 and 3 and (f) the right for the PUCO to re-evaluate or modify the PPA rider if there is a change to PJM’s tariffs or rules that prohibits the PPA units from being bid into PJM auctions.

The PUCO order did not modify OPCo's agreement to provide potential additional customer credits of up to $100 million during the final four years of the PPA rider, which are shown in the following table:

| PJM Planning Year | Potential Credit |
|---|---|
| June 2020 through May 2021 | $10 million |
| June 2021 through May 2022 | $20 million |
| June 2022 through May 2023 | $30 million |
| June 2023 through May 2024 | $40 million |

In accordance with accounting guidance for "Contingencies," management will perform ongoing reviews of projected PPA plant costs compared to related market prices for energy and capacity to determine if additional credits to customers are probable. Management is unable to determine a range of potential losses that are reasonably possible of occurring. Potential PPA credits could reduce future net income and cash flows and impact financial condition.

In January 2016, a complaint was filed at the FERC against AGR and OPCo related to the PPA. The complaint asserts that the affiliate PPA between AGR and OPCo is reviewable by the FERC under its standards for affiliate transactions. In March 2016, a group of merchant generation owners filed a complaint at the FERC against PJM seeking revisions to the Minimum Offer Price Rule (MOPR) in PJM's tariff. The complaint against PJM requested the FERC act in advance of the May 2016 Base Residual Auction for the 2019/2020 delivery year to expand the MOPR to certain existing generating units that receive revenues from sources other than the PJM market and are entered into on or after January 1, 2016. If approved as proposed, the revised MOPR would apply to the PPA units and could affect bidding into PJM.

In April 2016, the FERC issued an order granting the January 2016 complaint filed against AGR and OPCo. The FERC order rescinded the waivers of the FERC's affiliate rules as to the affiliate PPA between AGR and OPCo. As a result, AGR and OPCo are required to submit the affiliate PPA to the FERC for review in accordance with FERC's rules governing affiliate transactions. The affiliate PPA is not effective until the FERC review is completed and the affiliate PPA is approved. Management is evaluating its alternatives in response to this order.

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 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 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® (gridSMART® Phase II) program was filed with the PUCO which included a proposed project to satisfy the PUCO 2009 SEET directive. In April 2016, a stipulation agreement related to the gridSMART® Phase II program was filed with the PUCO. As part of the stipulation agreement, OPCo will invest at least $20 million over a six-year period for the installation of Volt VAR Optimization (VVO) technology on selected circuits throughout OPCo's service territory. All parties to the stipulation agree that OPCo's proposed VVO investment resolves OPCo's outstanding obligation for renewable or similar investment associated with the PUCO's 2009 SEET directive. A decision from the PUCO is pending.

In June 2015, OPCo submitted its 2014 SEET filing with the PUCO. Management believes its financial statements adequately address the impact of 2014 SEET requirements.

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. In OPCo's 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 filing to approve recovery of the deferral under the interim agreement.

To the extent amounts discussed above are refunded to customers, it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters (Applies to AEP and PSO)

2015 Oklahoma Base Rate Case

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

effective in January 2016. The proposed $44 million increase related to environmental investments was effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls were placed 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 March 31, 2016, PSO had incurred costs of $208 million related to these projects, including AFUDC.

In addition, the filing also notified the OCC that the incremental replacement capacity and energy costs, including the first year effects of new PPAs, estimated to be $35 million, will be incurred related to the environmental compliance plan due to the closure of Northeastern Plant, Unit 4, which would be recovered through the FAC. As of March 31, 2016, the net book value of Northeastern Plant, Unit 4 was $94 million, before cost of removal, including materials and supplies inventory and CWIP. Northeastern Plant, Unit 4 was considered probable of abandonment and was retired in April 2016.

In October 2015, testimony was filed by OCC staff and intervenors with recommendations that included increases to base rates and/or the proposed environmental rider ranging from $10 million to $31 million, based upon returns on common equity ranging from 8.75% to 9.3%, and increases to depreciation expense ranging from $23 million to $46 million. Additionally, recommendations by certain intervenors included (a) no recovery of PSO's investment in Northeastern Plant, Unit 3 environmental controls, (b) no recovery of the plant balances at the time the units are retired in 2016 and 2026, (c) denial of returns on the book values after the retirement dates, or to be set at only the cost of debt, and (d) the disallowance of the capacity costs associated with the PPAs. Additionally, some intervenors recommended no change in depreciation rates for Northeastern Plant, Units 3 and 4. These units are currently being depreciated through 2040. Hearings at the OCC were held in December 2015. In January 2016, PSO implemented an interim annual base rate increase of $75 million. These interim rates are subject to refund pending a final order from the OCC related to the initial $137 million request. An order from the OCC is anticipated by the end of the third quarter of 2016.

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

SWEPCo Rate Matters (Applies to AEP and SWEPCo)

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.

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

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, 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 prudency review of the Turk Plant. The settlement also provided that the LPSC would review base rates in 2014 and 2015 and that SWEPCo would 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. A hearing at the LPSC related to the Turk Plant prudence review is scheduled for November 2016. 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 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 used to serve Louisiana customers in 2015 due to the expiration of a purchased power agreement attributable to Louisiana customers. In December 2014, the LPSC approved a partial settlement agreement that included the implementation of the $15 million annual increase in rates effective January 2015. These increases are subject to LPSC staff review and are subject to refund. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2015 Louisiana Formula Rate Filing

In April 2015, SWEPCo filed its formula rate plan for test year 2014 with the LPSC. The filing included a $14 million annual increase, which was effective August 2015. This increase is subject to LPSC staff review and is subject to refund. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Welsh Plant - Environmental Impact

Management currently estimates that the investment necessary to meet proposed environmental regulations through 2025 for Welsh Plant, Units 1 and 3 could cost approximately $900 million, excluding AFUDC. As part of this investment, 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 $400 million, excluding AFUDC. As of March 31, 2016, SWEPCo had incurred costs of $372 million, including AFUDC, and had remaining contractual construction obligations of $28 million related to these projects. In March 2016, SWEPCo filed a request with the APSC to recover $69 million in environmental costs related to the Arkansas retail jurisdictional share of Welsh Plant, Units 1 and 3. SWEPCo began recovering the Arkansas jurisdictional share of these costs in March 2016, subject to review in the next filed base rate proceeding. SWEPCo will seek recovery of the remaining project costs from customers at the state commissions and the FERC. Management continues to evaluate the impact of environmental rules and related project cost estimates.

As of March 31, 2016, the net book value of Welsh Plant, Units 1 and 3 was $606 million, before cost of removal, including materials and supplies inventory and CWIP. As of March 31, 2016, the net book value of Welsh Plant, Unit 2 was $84 million, before cost of removal, including materials and supplies inventory and CWIP. Welsh Plant, Unit 2 was considered probable of abandonment and was retired in April 2016.

If any of these costs are not recoverable, including retirement-related costs for Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition.

TCC Rate Matters (Applies to AEP)

TCC Distribution Cost Recovery Factor (DCRF)

In April 2016, TCC filed a request with the PUCT for approval of a DCRF rider to allow recovery of eligible net distribution investments. The request included a revenue requirement of $54 million to be effective September 2016. Amounts approved would be subject to refund based upon a prudence review of the investments in TCC's next base rate case. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

TNC Rate Matters (Applies to AEP)

TNC Distribution Cost Recovery Factor (DCRF)

In April 2016, TNC filed a request with the PUCT for approval of a DCRF rider to allow recovery of eligible net distribution investments. The request included a revenue requirement of $16 million to be effective September 2016. Amounts approved would be subject to refund based upon a prudence review of the investments in TNC's next base rate case. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Other Rate Matters (Applies to AEP, PSO and SWEPCo)

SPP Open Access Transmission Tariff (OATT) Upgrade Costs
Under the SPP OATT, costs of participant-funded transmission upgrades may be recovered, in part, from SPP customers whose transmission service is dependent upon capacity enabled by the upgrades. SPP has not charged its customers any amounts attributable to these upgrades. SPP indicated that the impact to customers will be quantified and charges will be implemented in the fourth quarter of 2016, including amounts for prior periods. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

The Registrants are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Registrants' business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against the Registrants cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2015 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letters of Credit (Applies to AEP, APCo, I&M and OPCo)

Standby letters of credit are entered into with third parties. These letters of credit are issued in the ordinary course of business and cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

AEP has two revolving credit facilities totaling $3.5 billion, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of March 31, 2016, AEP's maximum future payments for letters of credit issued under the revolving credit facilities were $2 million with maturities ranging from October 2016 to December 2016.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP also issues letters of credit on behalf of subsidiaries under three uncommitted facilities totaling $225 million. As of March 31, 2016, the Registrants' maximum future payments for letters of credit issued under the uncommitted facilities were as follows:

| Company | Amount (in millions) | Maturity |
|---|---|---|
| AEP | $ 190.2 | June 2016 to March 2017 |
| OPCo | 4.2 | September 2016 |

The Registrants have $351 million of variable rate Pollution Control Bonds supported by $355 million of bilateral letters of credit as follows:

| Company | Pollution | Bilateral Letters | Maturity of Bilateral Letters of Credit |
|---|---|---|---|

| | Control of Bonds | Credit | |
|---|---|---|---|
| | (in millions) | | |
| AEP | $ 351.4 | $ 355.4 | June 2016 to July 2017 |
| APCo | 104.4 | 105.6 | March 2017 |
| I&M | 77.0 | 77.9 | March 2017 |

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Guarantees of Third-Party Obligations (Applies to AEP and SWEPCo)

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million.  Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine.  This guarantee ends upon depletion of reserves and completion of final reclamation.  Based on the latest study completed in 2010, it is estimated the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of $58 million.  Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation.  As of March 31, 2016, SWEPCo has collected $67 million through a rider for final mine closure and reclamation costs, of which $15 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $52 million is recorded in Asset Retirement Obligations on SWEPCo’s condensed balance sheet.

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

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications.  Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements.  Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters.  With respect to sale agreements, exposure generally does not exceed the sale price.  As of March 31, 2016, there were no material liabilities recorded for any indemnifications.

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

Master Lease Agreements

The Registrants lease certain equipment under master lease agreements.  Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term.  If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrants are committed to pay the difference between the actual fair value and the residual value guarantee.  Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.  As of March 31, 2016, the maximum potential loss by Registrants for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term is as follows:

| Company | Maximum Potential Loss (in millions) |
|---|---|
| AEP | $ 33.6 |
| APCo | 4.9 |
| I&M | 3.0 |
| OPCo | 5.3 |
| PSO | 2.8 |
| SWEPCo | 3.1 |

Railcar Lease (Applies to AEP, I&M and SWEPCo)

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignments are accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $9 million and $11 million for I&M and SWEPCo, respectively, for the remaining railcars as of March 31, 2016.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from 83% of the projected fair value of the equipment under the current five year lease term to 77% at the end of the 20-year term. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. The maximum potential losses related to the guarantee are $9 million and $10 million for I&M and SWEPCo, respectively, as of March 31, 2016, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair value would produce a sufficient sales price to avoid any loss.

AEPRO Boat and Barge Leases (Applies to AEP)

In October 2015, AEP signed a Purchase and Sale Agreement to sell its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. The sale closed in November 2015. See “AEPRO (Corporate and Other)” section of Note 6. Certain of the boat and barge leases acquired by the nonaffiliated party are subject to an AEP guarantee in favor of the lessor, ensuring future payments under such leases with maturities up to 2027. As of March 31, 2016, the maximum potential amount of future payments required under the guaranteed leases was $93 million. In certain instances, AEP has no recourse against the nonaffiliated party if required to pay a lessor under a guarantee, but AEP would have access to sell the leased assets in order to recover payments made by AEP under the guarantee. As of March 31, 2016, AEP’s boat and barge lease guarantee liability was $15 million.

ENVIRONMENTAL CONTINGENCIES

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

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

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. In 2014, I&M recorded an accrual for remediation at certain additional sites in Michigan. As a result of receiving approval of completed remediation work from the MDEQ in March 2015, I&M’s accrual was reduced. As of March 31, 2016, I&M’s accrual for all of these sites is $8 million. As the remediation work is completed, I&M’s cost may change as new information becomes available concerning either the level of contamination at the sites or changes in the scope of remediation. Management cannot predict the amount of additional cost, if any.

NUCLEAR CONTINGENCIES (APPLIES TO AEP AND I&M)

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

OPERATIONAL CONTINGENCIES

Rockport Plant Litigation (Applies to AEP and I&M)

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022.  The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit.  The plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement.  The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff.  The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio.  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 plaintiff's claims. Several claims remained, 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. The plaintiff subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. In November 2015, AEGCo and I&M filed a motion to strike the plaintiff's motion for partial judgment and filed a motion to dismiss the case for failure to state a claim. In March 2016, the court entered an opinion and order in favor of AEGCo and I&M, dismissing certain of the plaintiffs' claims for breach of contract and dismissing claims for breach of implied covenant of good faith and fair dealing, and further dismissing plaintiffs' claim for indemnification of costs. By the same order, the court permitted plaintiffs to move forward with their claim that AEGCo and I&M failed to exercise prudent utility practices in the maintenance and operation of Rockport Plant, Unit 2. In April 2016, the plaintiffs filed a notice of voluntary dismissal of the other remaining claims with prejudice and the court subsequently entered a final judgment. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Natural Gas Markets Lawsuits (Applies to AEP)

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity.  AEP was dismissed from the case.  A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies.  AEP (or a subsidiary) is among the companies named as defendants in some of these cases.  AEP settled, received summary judgment or was dismissed from all of these cases.  The plaintiffs appealed the Nevada federal district court's dismissal of several cases involving AEP companies to the U.S. Court of Appeals for the Ninth Circuit.  In April 2013, the appellate court reversed in part, and affirmed in part, the district court's orders in these cases.  The appellate court reversed the district court's holding that the state antitrust claims were preempted by the Natural Gas Act and the order dismissing AEP from two of the cases on personal jurisdiction grounds and affirmed the decision denying leave to the plaintiffs to amend their complaints in two of the cases.  Defendants in these cases, including AEP, filed a petition seeking further review with the U.S. Supreme Court on the preemption issue. AEP also subsequently filed a separate petition with the U.S. Supreme Court seeking review of the personal jurisdiction issue. In July 2014, the U.S. Supreme Court granted the defendants' previously filed petition for further review with the U.S. Supreme Court on the preemption issue. Oral argument occurred in January 2015. In April 2015, the U.S. Supreme Court affirmed the judgment of the U.S. Court of Appeals for the Ninth Circuit on the preemption issue, holding that the plaintiffs' state antitrust claims were not preempted by the Natural Gas Act. The U.S. Supreme Court denied AEP's petition for review of the personal jurisdiction issue shortly thereafter. The cases were remanded to the district court for further proceedings. There are four pending cases, of which three are class actions and one is a single plaintiff case. A tentative settlement has been reached in the three class actions. This settlement, once finalized, will be subject to court approval. Management will continue to defend the remaining case. Management is unable to determine the amount of potential additional loss that is reasonably possible of occurring.

Wage and Hours Lawsuit (Applies to AEP and PSO)

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

In March 2014, the federal court granted plaintiffs’ motion to conditionally certify the action as a class action.  Notice was given to all potential class members and an additional 44 individuals opted in to the class, bringing the plaintiff class to 80 current and former employees. Two plaintiffs have since dismissed their claims without prejudice, leaving 78 plaintiffs. In February 2016, PSO filed a motion for summary judgment. In April 2016, by opinion and order, the court granted PSO’s motion for summary judgment and dismissed the case. Management does not believe a loss is probable. If there is an unfavorable outcome contrary to expectations, management estimates possible losses of up to $30 million.

Gavin Landfill Litigation (Applies to AEP and OPCo)

In August 2014, a complaint was filed in the Mason County, West Virginia Circuit Court against AEP, AEPSC, OPCo and an individual supervisor alleging wrongful death and personal injury/illness claims arising out of purported exposure to coal combustion by-product waste at the Gavin Plant landfill.  As a result of OPCo transferring its generation assets to AGR, the outcome of this complaint will be the responsibility of AGR. The lawsuit was filed on behalf of 77 plaintiffs, consisting of 39 current and former contractors of the landfill and 38 family members of those contractors.  Eleven of the family members are pursuing personal injury/illness claims and the remainder are pursuing loss of consortium claims.  The plaintiffs seek compensatory and punitive damages, as well as medical monitoring.  In September 2014, management filed a motion to dismiss the complaint, contending the case should be filed in Ohio. In August 2015, the court denied the motion. Management appealed that decision to the West Virginia Supreme Court.  In February 2016, a decision was issued by the court denying the appeal and remanding the case to the West Virginia Mass Litigation Panel, which typically handles multi-plaintiff cases, rather than back to the Mason County, West Virginia Circuit Court. Defendants’ petition for rehearing was denied by the West Virginia Supreme Court.  Management will continue to defend against the claims.  Management is unable to determine a range of potential losses that are reasonably possible of occurring.

6. DISPOSITION

The disclosures in this note apply to AEP only.

2015

AEPRO (Corporate and Other)

In October 2015, AEP signed a Purchase and Sale Agreement to sell its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. The sale closed in November 2015. The nonaffiliated party acquired AEPRO by purchasing all of the common stock of AEP Resources, Inc., the parent company of AEPRO. The nonaffiliated party assumed certain assets and liabilities of AEPRO, excluding the equity method investment in International Marine Terminals, LLC, pension and benefit assets and liabilities and debt obligations. Prior to the closing of the sale, AEP retired the debt obligations of AEPRO. AEP retained ownership of its captive barge fleet that delivers coal to the company's regulated coal-fueled power plant units owned or leased by AEGCo, APCo, I&M, KPCo and WPCo. AEP signed a contract with the nonaffiliated party to dispatch and schedule its captive barge fleet for the company's regulated coal-fueled power plant units. AEP also has a separate contract with the nonaffiliated party to barge coal for AGR. These agreements with the nonaffiliated party extend through the end of 2016.

Results of operations of AEPRO have been classified as discontinued operations on AEP's statements of income for the three months ended March 31, 2015, as shown in the following table:

| | Three Months Ended March 31, 2015 (in millions) |
|---|---|
| Other Revenues | $ 127.7 |
| | |
| Other Operation Expense | 85.0 |
| Maintenance Expense | 8.3 |
| Depreciation and Amortization Expense | 9.1 |
| Taxes Other Than Income Taxes | 4.0 |
| Total Expenses | 106.4 |
| | |
| Other Income (Expense) | (4.4 ) |
| | |
| Pretax Income of Discontinued Operations | 16.9 |
| Income Tax Expense | 6.3 |
| Equity Earnings of Unconsolidated Subsidiaries | (0.1 ) |
| Total Income on Discontinued Operations as Presented on the Statements of Income | $ 10.5 |

## 7. BENEFIT PLANS

The disclosures in this note apply to all Registrants unless indicated otherwise.

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

Components of Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost (credit) by Registrant for the plans for the three months ended March 31, 2016 and 2015:

AEP

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---|---|---|---|---|
| | Three Months Ended March 31, | | Three Months Ended March 31, | |
| | 2016 | 2015 | 2016 | 2015 |
| | (in millions) | | | |
| Service Cost | $21.4 | $23.3 | $2.6 | $3.1 |
| Interest Cost | 52.9 | 51.3 | 15.2 | 14.2 |
| Expected Return on Plan Assets | (70.1 ) | (68.7 ) | (26.8 ) | (27.8 ) |
| Amortization of Prior Service Cost (Credit) | 0.6 | 0.6 | (17.3 ) | (17.3 ) |
| Amortization of Net Actuarial Loss | 21.0 | 26.8 | 7.9 | 4.7 |
| Net Periodic Benefit Cost (Credit) | $25.8 | $33.3 | $(18.4) | $(23.1) |

APCo

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---|---|---|---|---|
| | Three Months Ended March 31, | | Three Months Ended March 31, | |
| | 2016 | 2015 | 2016 | 2015 |
| | (in millions) | | | |
| Service Cost | $2.0 | $2.2 | $0.2 | $0.3 |
| Interest Cost | 6.8 | 6.7 | 2.7 | 2.6 |
| Expected Return on Plan Assets | (8.8 ) | (8.8 ) | (4.3 ) | (4.6 ) |
| Amortization of Prior Service Credit | — | — | (2.5 ) | (2.5 ) |
| Amortization of Net Actuarial Loss | 2.7 | 3.5 | 1.4 | 0.9 |
| Net Periodic Benefit Cost (Credit) | $2.7 | $3.6 | $(2.5 ) | $(3.3 ) |

I&M

| | Pension Plans | Other Postretirement |
|---|---|---|

| | Three Months Ended March 31, | | Benefit Plans Three Months Ended March 31, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| | (in millions) | | | |
| Service Cost | $3.0 | $3.2 | $0.4 | $0.4 |
| Interest Cost | 6.3 | 6.1 | 1.8 | 1.6 |
| Expected Return on Plan Assets | (8.4 ) | (8.1 ) | (3.2 ) | (3.3 ) |
| Amortization of Prior Service Cost (Credit) | 0.1 | — | (2.4 ) | (2.4 ) |
| Amortization of Net Actuarial Loss | 2.5 | 3.2 | 0.9 | 0.5 |
| Net Periodic Benefit Cost (Credit) | $3.5 | $4.4 | $(2.5 ) | $(3.2 ) |

OPCo

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---|---|---|---|---|
| | Three Months Ended March 31, | | Three Months Ended March 31, | |
| | 2016 | 2015 | 2016 | 2015 |
| | (in millions) | | | |
| Service Cost | $1.6 | $1.7 | $0.2 | $0.2 |
| Interest Cost | 5.2 | 5.1 | 1.7 | 1.6 |
| Expected Return on Plan Assets | (6.9 ) | (6.9 ) | (3.2 ) | (3.4 ) |
| Amortization of Prior Service Credit | — | — | (1.7 ) | (1.7 ) |
| Amortization of Net Actuarial Loss | 2.0 | 2.6 | 0.9 | 0.5 |
| Net Periodic Benefit Cost (Credit) | $1.9 | $2.5 | $(2.1 ) | $(2.8 ) |

PSO

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---|---|---|---|---|
| | Three Months Ended March 31, | | Three Months Ended March 31, | |
| | 2016 | 2015 | 2016 | 2015 |
| | (in millions) | | | |
| Service Cost | $1.5 | $1.6 | $0.2 | $0.2 |
| Interest Cost | 2.8 | 2.7 | 0.8 | 0.8 |
| Expected Return on Plan Assets | (3.9 ) | (3.8 ) | (1.5 ) | (1.6 ) |
| Amortization of Prior Service Cost (Credit) | 0.1 | 0.1 | (1.1 ) | (1.1 ) |
| Amortization of Net Actuarial Loss | 1.1 | 1.4 | 0.4 | 0.2 |
| Net Periodic Benefit Cost (Credit) | $1.6 | $2.0 | $(1.2 ) | $(1.5 ) |

SWEPCo

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---|---|---|---|---|
| | Three Months Ended March 31, | | Three Months Ended March 31, | |
| | 2016 | 2015 | 2016 | 2015 |
| | (in millions) | | | |
| Service Cost | $2.0 | $2.1 | $0.2 | $0.2 |
| Interest Cost | 3.1 | 2.9 | 0.9 | 0.8 |
| Expected Return on Plan Assets | (4.1 ) | (4.0 ) | (1.7 ) | (1.7 ) |
| Amortization of Prior Service Cost (Credit) | 0.1 | 0.1 | (1.3 ) | (1.3 ) |
| Amortization of Net Actuarial Loss | 1.2 | 1.5 | 0.5 | 0.3 |

| | | | | |
|---|---|---|---|---|
| Net Periodic Benefit Cost (Credit) | $2.3 | $2.6 | $(1.4 ) | $(1.7 ) |

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8. BUSINESS SEGMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

AEP's Reportable Segments

AEP's primary business is the generation, transmission and distribution of electricity. Within its Vertically Integrated Utilities segment, AEP centrally dispatches generation assets and manages its 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.

AEP's 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 AEP's wholly-owned transmission-only subsidiaries and transmission-only joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

Generation & Marketing

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

The remainder of AEP's activities is presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries, Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs. With the sale of AEPRO in November 2015, the activities related to the AEP River Operations segment have been moved to Corporate and Other for the periods presented. See "AEPRO (Corporate and Other)" section of Note 6 for additional information.

The tables below present AEP's reportable segment income statement information for the three months ended March 31, 2016 and 2015 and reportable segment balance sheet information as of March 31, 2016 and December 31, 2015. These amounts include certain estimates and allocations where necessary.

| | Vertically Integrated Utilities | Transmission and Distribution Utilities | AEP Transmission Holdco | Generation & Marketing | Corporate and Other (a) | Reconciling Adjustments | Consolidated |
|---|---|---|---|---|---|---|---|
| | (in millions) | | | | | | |
| Three Months Ended March 31, 2016 | | | | | | | |
| Revenues from: | | | | | | | |
| External Customers | $2,218.1 | $ 1,077.3 | $ 29.3 | $ 713.9 | $ 6.3 | $ — | $ 4,044.9 |
| Other Operating Segments | 27.5 | 19.5 | 59.3 | 34.1 | 18.1 | (158.5 ) | — |
| Total Revenues | $2,245.6 | $ 1,096.8 | $ 88.6 | $ 748.0 | $ 24.4 | $ (158.5 ) | $ 4,044.9 |
| | | | | | | | |
| Income from Continuing Operations | $278.7 | $ 108.0 | $ 44.7 | $ 70.7 | $ 1.0 | $ — | $ 503.1 |
| Income from Discontinued Operations, Net of Tax | — | — | — | — | — | — | — |
| Net Income | $278.7 | $ 108.0 | $ 44.7 | $ 70.7 | $ 1.0 | $ — | $ 503.1 |

| | Vertically Integrated Utilities | Transmission and Distribution Utilities | AEP Transmission Holdco | Generation & Marketing | Corporate and Other (a) | Reconciling Adjustments | Consolidated |
|---|---|---|---|---|---|---|---|
| | (in millions) | | | | | | |
| Three Months Ended March 31, 2015 | | | | | | | |
| Revenues from: | | | | | | | |
| External Customers | $2,487.4 | $ 1,206.3 | $ 21.7 | $ 859.2 | $ 5.8 | $ — | $ 4,580.4 |
| Other Operating Segments | 17.7 | 63.8 | 36.2 | 311.3 | 20.4 | (449.4 ) | — |
| Total Revenues | $2,505.1 | $ 1,270.1 | $ 57.9 | $ 1,170.5 | $ 26.2 | $ (449.4 ) | $ 4,580.4 |
| | | | | | | | |
| Income (Loss) from Continuing Operations | $300.3 | $ 97.2 | $ 36.3 | $ 187.4 | $ (1.0 ) | $ — | $ 620.2 |
| Income from Discontinued Operations, Net of Tax | — | — | — | — | 10.5 | — | 10.5 |
| Net Income | $300.3 | $ 97.2 | $ 36.3 | $ 187.4 | $ 9.5 | $ — | $ 630.7 |

| | Vertically Integrated Utilities | Transmission and Distribution Utilities | AEP Transmission Holdco | Generation & Marketing | Corporate and Other (a) | Reconciling Adjustments | | Consolidated |
|---|---|---|---|---|---|---|---|---|
| | (in millions) | | | | | | | |
| March 31, 2016 | | | | | | | | |
| Total Property, Plant and Equipment | $40,599.7 | $ 14,029.4 | $ 4,230.5 | $ 7,510.9 | $357.3 | $ (297.6 | ) (b) | $ 66,430.2 |
| Accumulated Depreciation and Amortization | 12,485.3 | 3,573.5 | 63.9 | 3,409.8 | 180.8 | (116.0 | ) (b) | 19,597.3 |
| Total Property Plant and Equipment - Net | $28,114.4 | $ 10,455.9 | $ 4,166.6 | $ 4,101.1 | $176.5 | $ (181.6 | ) (b) | $ 46,832.9 |
| Total Assets | $36,197.0 | $ 14,341.3 | $ 5,152.7 | $ 5,400.2 | $21,962.1 | $ (20,566.8 | ) (b) (c) | $ 62,486.5 |
| Long-term Debt Due Within One Year: | | | | | | | | |
| Affiliated | $— | $ — | $ — | $ — | $— | $— | | $ — |
| Non-Affiliated | 1,174.3 | 786.3 | — | 71.7 | 1.0 | — | | 2,033.3 |
| Long-term Debt: | | | | | | | | |
| Affiliated | 20.0 | — | — | 32.2 | — | (52.2 | ) | — |
| Non-Affiliated | 9,948.1 | 4,665.6 | 1,654.1 | 635.3 | 846.2 | — | | 17,749.3 |
| Total Long-term Debt | $11,142.4 | $ 5,451.9 | $ 1,654.1 | $ 739.2 | $847.2 | $ (52.2 | ) | $ 19,782.6 |

| | Vertically Integrated Utilities | Transmission and Distribution Utilities | AEP Transmission Holdco | Generation & Marketing | Corporate and Other (a) | Reconciling Adjustments | | Consolidated |
|---|---|---|---|---|---|---|---|---|
| | (in millions) | | | | | | | |
| December 31, 2015 | | | | | | | | |
| Total Property, Plant and Equipment | $40,130.3 | $ 13,840.5 | $ 3,977.6 | $ 7,461.3 | $350.9 | $ (279.2 | ) (b) | $ 65,481.4 |
| Accumulated Depreciation and Amortization | 12,335.0 | 3,529.2 | 52.3 | 3,367.0 | 176.9 | (112.2 | ) (b) | 19,348.2 |
| Total Property Plant and Equipment - Net | $27,795.3 | $ 10,311.3 | $ 3,925.3 | $ 4,094.3 | $174.0 | $ (167.0 | ) (b) | $ 46,133.2 |
| Total Assets | $35,792.3 | $ 14,640.2 | $ 5,012.1 | $ 5,414.5 | $21,907.4 | $ (21,083.4 | ) (b) (c) | $ 61,683.1 |
| Long-term Debt Due Within One Year: | | | | | | | | |
| Affiliated | $— | $ — | $ — | $ — | $— | $— | | $ — |
| Non-Affiliated | 935.4 | 824.7 | — | 71.6 | 0.1 | — | | 1,831.8 |
| Long-term Debt: | | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Affiliated | 20.0 | — | — | 32.2 | — | (52.2 ) | — |
| Non-Affiliated | 9,833.0 | 4,776.8 | 1,648.4 | 639.5 | 843.2 | — | 17,740.9 |
| Total Long-term Debt | $10,788.4 | $5,601.5 | $1,648.4 | $743.3 | $843.3 | $(52.2 ) | $19,572.7 |

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent’s guarantee revenue received from affiliates, investment income, interest income, interest expense and discontinued operations of AEPRO and other nonallocated costs.
(b) Includes eliminations due to an intercompany capital lease.
(c) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP’s investments in subsidiary companies.

Registrant Subsidiaries' Reportable Segments

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

## 9. DERIVATIVES AND HEDGING

The disclosures in this note apply to all Registrants unless indicated otherwise.

### OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of AEP subsidiaries, including the Registrant Subsidiaries. AEPEP is agent for and transacts on behalf of other AEP subsidiaries.

The Registrants are exposed to certain market risks as major power producers and participants in the electricity, capacity, natural gas, coal and emission allowance markets. These risks include commodity price risks which may be subject to capacity risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact the Registrants due to changes in the underlying market prices or rates. Management utilizes derivative instruments to manage these risks.

### STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

#### Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, the Registrants primarily employ risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for “Derivatives and Hedging.” Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

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

The following tables represent the gross notional volume of the Registrants' outstanding derivative contracts as of March 31, 2016 and December 31, 2015:

Notional Volume of Derivative Instruments
March 31, 2016

| Primary Risk Exposure | Unit of Measure | AEP | APCo | I&M | OPCo | PSO | SWEPCo |
|---|---|---|---|---|---|---|---|
| | | (in millions) | | | | | |
| Commodity: | | | | | | | |
| Power | MWhs | 272.7 | 25.0 | 13.9 | 11.6 | 4.8 | 5.9 |
| Coal | Tons | 3.4 | — | 1.1 | — | — | 2.3 |
| Natural Gas | MMBtus | 42.7 | 0.3 | 0.2 | — | 0.2 | 0.2 |
| Heating Oil and Gasoline | Gallons | 6.9 | 1.3 | 0.6 | 1.5 | 0.8 | 0.9 |
| Interest Rate | USD | $101.9 | $ 1.2 | $0.8 | $ — | $ — | $ — |
| Interest Rate and Foreign Currency | USD | $559.3 | $ — | $— | $ — | $ — | $ — |

Notional Volume of Derivative Instruments
December 31, 2015

| Primary Risk Exposure | Unit of Measure | AEP | APCo | I&M | OPCo | PSO | SWEPCo |
|---|---|---|---|---|---|---|---|
| | | (in millions) | | | | | |
| Commodity: | | | | | | | |
| Power | MWhs | 317.8 | 40.9 | 22.8 | 13.3 | 11.3 | 14.0 |
| Coal | Tons | 4.4 | — | 1.6 | — | — | 2.8 |
| Natural Gas | MMBtus | 38.2 | 0.3 | 0.2 | — | 0.2 | 0.2 |
| Heating Oil and Gasoline | Gallons | 7.4 | 1.4 | 0.7 | 1.6 | 0.8 | 0.9 |
| Interest Rate | USD | $113.5 | $ 2.4 | $1.6 | $ — | $ — | $ — |
| Interest Rate and Foreign Currency | USD | $560.3 | $ — | $— | $ — | $ — | $ — |

Fair Value Hedging Strategies (Applies to AEP)

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

Cash Flow Hedging Strategies

The Registrants utilize cash flow hedges on certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. The Registrants do not hedge all commodity price risk.

The Registrants utilize a variety of interest rate derivative transactions in order to manage interest rate risk exposure. The Registrants also utilize interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The Registrants do not hedge all interest rate exposure.

At times, the Registrants are exposed to foreign currency exchange rate risks primarily when some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, the Registrants may utilize foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. The Registrants do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

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

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

According to the accounting guidance for “Derivatives and Hedging,” the Registrants reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrants are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2016 and December 31, 2015 condensed balance sheets, the Registrants netted cash collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

| Company | March 31, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| | Cash Collateral Received Netted Against Risk Management Assets | Cash Collateral Paid Netted Against Risk Management Liabilities | Cash Collateral Received Netted Against Risk Management Assets | Cash Collateral Paid Netted Against Risk Management Liabilities |
| | (in millions) | | | |
| AEP | $ 11.8 | $ 43.0 | $ 5.8 | $ 44.4 |
| APCo | — | 0.6 | — | 3.1 |
| I&M | — | 0.1 | — | 0.6 |
| OPCo | — | 0.2 | — | 0.5 |
| PSO | — | 0.1 | — | 0.3 |
| SWEPCo | — | 0.2 | — | 0.3 |

The following tables represent the gross fair value of the Registrants' derivative activity on the condensed balance sheets as of March 31, 2016 and December 31, 2015:

AEP

Fair Value of Derivative Instruments
March 31, 2016

| Balance Sheet Location | Risk Management Contracts Commodity (a) | Hedging Contracts Commodity (a) | Interest Rate and Foreign Currency (a) | Gross Amounts of Risk Management Assets/ Liabilities Recognized | Gross Amounts Offset in the Statement of Financial Position (b) | Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c) |
|---|---|---|---|---|---|---|
| | (in millions) | | | | | |
| Current Risk Management Assets | $425.9 | $9.8 | $ 0.9 | $ 436.6 | $(292.8 ) | $ 143.8 |
| Long-term Risk Management Assets | 390.1 | 13.5 | — | 403.6 | (74.7 ) | 328.9 |
| Total Assets | 816.0 | 23.3 | 0.9 | 840.2 | (367.5 ) | 472.7 |
| | | | | | | |
| Current Risk Management Liabilities | 401.6 | 12.6 | 0.3 | 414.5 | (310.2 ) | 104.3 |
| Long-term Risk Management Liabilities | 264.6 | 31.0 | 0.5 | 296.1 | (88.5 ) | 207.6 |
| Total Liabilities | 666.2 | 43.6 | 0.8 | 710.6 | (398.7 ) | 311.9 |
| | | | | | | |
| Total MTM Derivative Contract Net Assets (Liabilities) | $149.8 | $(20.3) | $ 0.1 | $ 129.6 | $31.2 | $ 160.8 |

AEP

Fair Value of Derivative Instruments
December 31, 2015

| Balance Sheet Location | Risk Management Contracts Commodity (a) | Hedging Contracts Commodity (a) | Interest Rate and Foreign Currency (a) | Gross Amounts of Risk Management Assets/ Liabilities Recognized | Gross Amounts Offset in the Statement of Financial Position (b) | Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c) |
|---|---|---|---|---|---|---|
| | (in millions) | | | | | |
| Current Risk Management Assets | $368.8 | $8.2 | $ 0.1 | $ 377.1 | $(242.7 ) | $ 134.4 |
| Long-term Risk Management Assets | 364.8 | 11.7 | — | 376.5 | (54.7 ) | 321.8 |
| Total Assets | 733.6 | 19.9 | 0.1 | 753.6 | (297.4 ) | 456.2 |
| | | | | | | |
| Current Risk Management Liabilities | 347.0 | 9.1 | 0.3 | 356.4 | (269.3 ) | 87.1 |
| Long-term Risk Management Liabilities | 223.3 | 19.3 | 3.2 | 245.8 | (66.7 ) | 179.1 |
| Total Liabilities | 570.3 | 28.4 | 3.5 | 602.2 | (336.0 ) | 266.2 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total MTM Derivative Contract Net Assets (Liabilities) | $163.3 | $(8.5) | $ (3.4 ) | $ 151.4 | $38.6 | $ 190.0 |

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

APCo

Fair Value of Derivative Instruments
March 31, 2016

| Balance Sheet Location | Risk Management Contracts - Commodity (a) | Gross Amounts Offset in the Statement of Financial Position (b) | Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c) |
|---|---|---|---|
| | (in millions) | | |
| Current Risk Management Assets - Nonaffiliated and Affiliated | $24.1 | $ (12.2 ) | $ 11.9 |
| Long-term Risk Management Assets - Nonaffiliated | 1.0 | (0.7 ) | 0.3 |
| Total Assets | 25.1 | (12.9 ) | 12.2 |
| | | | |
| Current Risk Management Liabilities - Nonaffiliated | 23.2 | (12.8 ) | 10.4 |
| Long-term Risk Management Liabilities - Nonaffiliated | 0.8 | (0.7 ) | 0.1 |
| Total Liabilities | 24.0 | (13.5 ) | 10.5 |
| | | | |
| Total MTM Derivative Contract Net Assets | $1.1 | $ 0.6 | $ 1.7 |

APCo

Fair Value of Derivative Instruments
December 31, 2015

| Balance Sheet Location | Risk Management Contracts - Commodity (a) | Gross Amounts Offset in the Statement of Financial Position (b) | Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c) |
|---|---|---|---|
| | (in millions) | | |
| Current Risk Management Assets - Nonaffiliated and Affiliated | $25.9 | $ (10.3 ) | $ 15.6 |
| Long-term Risk Management Assets - Nonaffiliated | 0.3 | (0.2 ) | 0.1 |
| Total Assets | 26.2 | (10.5 ) | 15.7 |
| | | | |
| Current Risk Management Liabilities - Nonaffiliated | 18.1 | (13.3 ) | 4.8 |
| Long-term Risk Management Liabilities - Nonaffiliated | 0.3 | (0.2 ) | 0.1 |
| Total Liabilities | 18.4 | (13.5 ) | 4.9 |
| | | | |
| Total MTM Derivative Contract Net Assets | $7.8 | $ 3.0 | $ 10.8 |

(a)

Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for “Derivatives and Hedging.”

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

(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

I&M

Fair Value of Derivative Instruments
March 31, 2016

| Balance Sheet Location | Risk Management Contracts - Commodity (a) | Gross Amounts Offset in the Statement of Financial Position (b) | Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c) |
|---|---|---|---|
| | (in millions) | | |
| Current Risk Management Assets - Nonaffiliated and Affiliated | $17.6 | $ (8.5 ) | $ 9.1 |
| Long-term Risk Management Assets - Nonaffiliated | 0.9 | (0.5 ) | 0.4 |
| Total Assets | 18.5 | (9.0 ) | 9.5 |
| | | | |
| Current Risk Management Liabilities - Nonaffiliated | 15.0 | (8.6 ) | 6.4 |
| Long-term Risk Management Liabilities - Nonaffiliated | 1.5 | (0.5 ) | 1.0 |
| Total Liabilities | 16.5 | (9.1 ) | 7.4 |
| | | | |
| Total MTM Derivative Contract Net Assets | $2.0 | $ 0.1 | $ 2.1 |

I&M

Fair Value of Derivative Instruments
December 31, 2015

| Balance Sheet Location | Risk Management Contracts - Commodity (a) | Gross Amounts Offset in the Statement of Financial Position (b) | Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c) |
|---|---|---|---|
| | (in millions) | | |
| Current Risk Management Assets - Nonaffiliated and Affiliated | $22.8 | $ (10.5 ) | $ 12.3 |
| Long-term Risk Management Assets - Nonaffiliated | 0.6 | (0.6 ) | — |
| Total Assets | 23.4 | (11.1 ) | 12.3 |
| | | | |
| Current Risk Management Liabilities - Nonaffiliated | 17.0 | (10.7 ) | 6.3 |
| Long-term Risk Management Liabilities - Nonaffiliated | 2.6 | (1.0 ) | 1.6 |
| Total Liabilities | 19.6 | (11.7 ) | 7.9 |
| | | | |
| Total MTM Derivative Contract Net Assets | $3.8 | $ 0.6 | $ 4.4 |

(a)

Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

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

(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

OPCo

Fair Value of Derivative Instruments
March 31, 2016

| Balance Sheet Location | Risk Management Contracts - Commodity (a) | Gross Amounts Offset in the Statement of Financial Position (b) | Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c) |
|---|---|---|---|
| | (in millions) | | |
| Current Risk Management Assets | $— | $ — | $ — |
| Long-term Risk Management Assets | — | — | — |
| Total Assets | — | — | — |
| | | | |
| Current Risk Management Liabilities | 5.7 | (0.2 ) | 5.5 |
| Long-term Risk Management Liabilities | 5.8 | — | 5.8 |
| Total Liabilities | 11.5 | (0.2 ) | 11.3 |
| | | | |
| Total MTM Derivative Contract Net Assets (Liabilities) | $(11.5) | $ 0.2 | $ (11.3 ) |

OPCo

Fair Value of Derivative Instruments
December 31, 2015

| Balance Sheet Location | Risk Management Contracts - Commodity (a) | Gross Amounts Offset in the Statement of Financial Position (b) | Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c) |
|---|---|---|---|
| | (in millions) | | |
| Current Risk Management Assets | $— | $ — | $ — |
| Long-term Risk Management Assets | 19.2 | — | 19.2 |
| Total Assets | 19.2 | — | 19.2 |
| | | | |
| Current Risk Management Liabilities | 4.1 | (0.5 ) | 3.6 |
| Long-term Risk Management Liabilities | — | — | — |
| Total Liabilities | 4.1 | (0.5 ) | 3.6 |
| | | | |
| Total MTM Derivative Contract Net Assets | $15.1 | $ 0.5 | $ 15.6 |

(a)

Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for “Derivatives and Hedging.”

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

(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

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PSO

Fair Value of Derivative Instruments
March 31, 2016

| Balance Sheet Location | Risk Management Contracts - Commodity (a) | Gross Amounts Offset in the Statement of Financial Position (b) | Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c) |
|---|---|---|---|
| | (in millions) | | |
| Current Risk Management Assets | $0.7 | $ — | $ 0.7 |
| Long-term Risk Management Assets | — | — | — |
| Total Assets | 0.7 | — | 0.7 |
| | | | |
| Current Risk Management Liabilities | 0.3 | (0.1 ) | 0.2 |
| Long-term Risk Management Liabilities | — | — | — |
| Total Liabilities | 0.3 | (0.1 ) | 0.2 |
| | | | |
| Total MTM Derivative Contract Net Assets | $0.4 | $ 0.1 | $ 0.5 |

PSO

Fair Value of Derivative Instruments
December 31, 2015

| Balance Sheet Location | Risk Management Contracts - Commodity (a) | Gross Amounts Offset in the Statement of Financial Position (b) | Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c) |
|---|---|---|---|
| | (in millions) | | |
| Current Risk Management Assets | $0.6 | $ — | $ 0.6 |
| Long-term Risk Management Assets | — | — | — |
| Total Assets | 0.6 | — | 0.6 |
| | | | |
| Current Risk Management Liabilities | 0.5 | (0.3 ) | 0.2 |
| Long-term Risk Management Liabilities | — | — | — |
| Total Liabilities | 0.5 | (0.3 ) | 0.2 |
| | | | |
| Total MTM Derivative Contract Net Assets | $0.1 | $ 0.3 | $ 0.4 |

(a)

Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

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

(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

SWEPCo

Fair Value of Derivative Instruments
March 31, 2016

| Balance Sheet Location | Risk Management Contracts - Commodity (a) | Gross Amounts Offset in the Statement of Financial Position (b) | Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c) |
|---|---|---|---|
| | (in millions) | | |
| Current Risk Management Assets | $0.9 | $ (0.1 ) | $ 0.8 |
| Long-term Risk Management Assets | — | — | — |
| Total Assets | 0.9 | (0.1 ) | 0.8 |
| | | | |
| Current Risk Management Liabilities | 3.8 | (0.3 ) | 3.5 |
| Long-term Risk Management Liabilities | 1.8 | — | 1.8 |
| Total Liabilities | 5.6 | (0.3 ) | 5.3 |
| | | | |
| Total MTM Derivative Contract Net Assets (Liabilities) | $(4.7) | $ 0.2 | $ (4.5 ) |

SWEPCo

Fair Value of Derivative Instruments
December 31, 2015

| Balance Sheet Location | Risk Management Contracts - Commodity (a) | Gross Amounts Offset in the Statement of Financial Position (b) | Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c) |
|---|---|---|---|
| | (in millions) | | |
| Current Risk Management Assets | $0.8 | $ — | $ 0.8 |
| Long-term Risk Management Assets | — | — | — |
| Total Assets | 0.8 | — | 0.8 |
| | | | |
| Current Risk Management Liabilities | 3.4 | (0.3 ) | 3.1 |
| Long-term Risk Management Liabilities | 2.1 | — | 2.1 |
| Total Liabilities | 5.5 | (0.3 ) | 5.2 |
| | | | |
| Total MTM Derivative Contract Net Assets (Liabilities) | $(4.7) | $ 0.3 | $ (4.4 ) |

(a)

Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for “Derivatives and Hedging.”

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

(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

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The tables below present the Registrants' activity of derivative risk management contracts for the three months ended March 31, 2016 and 2015:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2016

| Location of Gain (Loss) | AEP | APCo | I&M | OPCo | PSO | SWEPCo |
|---|---|---|---|---|---|---|
| | (in millions) | | | | | |
| Vertically Integrated Utilities Revenues | $0.6 | $— | $— | $— | $— | $ — |
| Transmission and Distribution Utilities Revenues | (3.5 ) | — | — | — | — | — |
| Generation & Marketing Revenues | 19.8 | — | — | — | — | — |
| Electric Generation, Transmission and Distribution Revenues | — | (0.8 ) | 1.6 | (3.5 ) | — | — |
| Sales to AEP Affiliates | — | 1.1 | 4.0 | — | — | — |
| Purchased Electricity for Resale | 2.1 | 1.4 | 0.1 | — | — | — |
| Other Operation Expense | (0.7 ) | (0.1 ) | (0.1 ) | (0.1 ) | (0.1 ) | (0.1 ) |
| Maintenance Expense | (0.8 ) | (0.2 ) | (0.1 ) | (0.1 ) | (0.1 ) | (0.1 ) |
| Regulatory Assets (a) | (11.1 ) | 0.2 | 0.3 | (11.4 ) | (0.5 ) | 0.1 |
| Regulatory Liabilities (a) | 12.7 | 15.9 | 3.9 | (15.2 ) | — | 4.5 |
| Total Gain (Loss) on Risk Management Contracts | $19.1 | $17.5 | $9.7 | $(30.3) | $(0.7) | $ 4.4 |

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2015

| Location of Gain (Loss) | AEP | APCo | I&M | OPCo | PSO | SWEPCo |
|---|---|---|---|---|---|---|
| | (in millions) | | | | | |
| Vertically Integrated Utilities Revenues | $4.4 | $— | $— | $— | $— | $ — |
| Generation & Marketing Revenues | 48.8 | — | — | — | — | — |
| Electric Generation, Transmission and Distribution Revenues | — | 0.6 | 2.2 | — | — | — |
| Purchased Electricity for Resale | 3.3 | 0.7 | 0.3 | — | — | — |
| Other Operation Expense | (0.9 ) | (0.1 ) | (0.1 ) | (0.2 ) | (0.1 ) | (0.1 ) |
| Maintenance Expense | (0.8 ) | (0.2 ) | (0.1 ) | (0.1 ) | (0.1 ) | (0.1 ) |
| Regulatory Assets (a) | (4.1 ) | 0.7 | (0.5 ) | — | (0.8 ) | (3.5 ) |
| Regulatory Liabilities (a) | 3.9 | 1.7 | (3.0 ) | 4.7 | — | 3.9 |
| Total Gain (Loss) on Risk Management Contracts | $54.6 | $3.4 | $(1.2) | $4.4 | $(1.0) | $ 0.2 |

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the condensed statements of income depending on the relevant facts and circumstances.

Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the condensed statements of income as that of the associated risk. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015, see Note 4 - Rate Matters. These auctions resulted in a range of products, including 12-month, 24-month, and 36-month periods. The delivery period for each contract is scheduled to start on the first day of June of each year, immediately following the auction. Certain affiliated Vertically Integrated Utility and Generation & Marketing segment entities participated in the auction process and were awarded tranches of OPCo's SSO load. The underlying contracts are derivatives subject to the accounting guidance for "Derivatives and Hedging" and are accounted for using MTM accounting, unless the contract has been designated as a normal purchase or normal sale.

Accounting for Fair Value Hedging Strategies (Applies to AEP)

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

AEP records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on the condensed statements of income. The following table shows the results of hedging gains (losses) during the three months ended March 31, 2016 and 2015:

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in millions) | |
| Gain on Fair Value Hedging Instruments | $3.5 | $4.5 |
| Loss on Fair Value Portion of Long-term Debt | (3.5 ) | (4.5 ) |

During the three months ended March 31, 2016 and 2015, hedge ineffectiveness was immaterial.

Accounting for Cash Flow Hedging Strategies

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

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on the condensed statements of income or in Regulatory Assets or Regulatory Liabilities on the condensed balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2016 and 2015, AEP applied cash flow hedging to outstanding power derivatives. During the three months ended March 31, 2016 and 2015, the Registrant Subsidiaries did not apply cash flow hedging to outstanding power derivatives.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets into Interest Expense on the condensed statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2016 and 2015, AEP applied cash flow hedging to outstanding interest rate derivatives. During the three months ended March 31, 2016 and 2015, the Registrant Subsidiaries did not apply cash flow hedging to outstanding interest rate derivatives.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets into Depreciation and Amortization expense on the condensed statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three months ended March 31, 2016 and 2015, the Registrants did not apply cash flow hedging to any outstanding foreign currency derivatives as cash flow hedges.

During the three months ended March 31, 2016 and 2015, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

For details on effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets and the reasons for changes in cash flow hedges, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets as of March 31, 2016 and December 31, 2015 were:

Impact of Cash Flow Hedges on AEP's
Condensed Balance Sheets

| Company | March 31, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| | Commodity | Interest Rate and Foreign Currency | Commodity | Interest Rate and Foreign Currency |
| | (in millions) | | | |
| Hedging Assets (a) | $ 19.8 | $ — | $ 17.6 | $ — |
| Hedging Liabilities (a) | 40.1 | 0.4 | 26.1 | 0.4 |
| AOCI Loss Net of Tax | (12.9 ) | (16.9 ) | (5.2 ) | (17.2 ) |
| Portion Expected to be Reclassified to Net Income During the Next Twelve Months | (1.7 ) | (1.4 ) | (0.4 ) | (1.5 ) |

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

As of March 31, 2016 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 141 months.

Impact of Cash Flow Hedges on the Registrant Subsidiaries'
Condensed Balance Sheets

| Company | March 31, 2016 | December 31, 2015 |
|---|---|---|
| | Interest Rate and Foreign Currency | |

| | AOCI Gain (Loss) Net of Tax | Expected to be Reclassified to Net Income During the Next Twelve Months | AOCI Gain (Loss) Net of Tax | Expected to be Reclassified to Net Income During the Next Twelve Months |
|---|---|---|---|---|
| | (in millions) | | | |
| APCo | $3.4 | $ 0.7 | $3.6 | $ 0.7 |
| I&M | (12.9) | (1.3 ) | (13.3) | (1.3 ) |
| OPCo | 3.9 | 1.1 | 4.3 | 1.2 |
| PSO | 4.0 | 0.8 | 4.2 | 0.8 |
| SWEPCo | (8.6 ) | (1.7 ) | (9.1 ) | (1.7 ) |

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

Credit Risk

Management limits credit risk in 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. Management uses Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. A counterparty is required to post cash or letters of credit in the event exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Credit Downgrade Triggers (Applies to AEP, APCo, I&M, PSO and SWEPCo)

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, additional amounts of collateral are required if certain credit ratings decline below a specified rating threshold.  The amount of collateral required fluctuates based on market prices and total exposure.  On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts.  AEP, APCo, I&M, PSO and SWEPCo have not experienced a downgrade below a specified rating threshold that would require the posting of additional collateral.  There is no exposure relating to derivative contracts, however, there is exposure relating to RTOs, ISOs and non-derivative contracts. The following table represents the exposure if credit ratings were to decline below a specified rating threshold as of March 31, 2016 and December 31, 2015:

| Company | March 31, 2016 Amount of Collateral That Would Have Been Required to Post Attributable to RTOs and ISOs | March 31, 2016 Amount of Collateral Attributable to Other Contracts | | December 31, 2015 Amount of Collateral That Would Have Been Required to Post Attributable to RTOs and ISOs | December 31, 2015 Amount of Collateral Attributable to Other Contracts | |
|---|---|---|---|---|---|---|
| | (in millions) | | | | | |
| AEP | $23.6 | $ 298.3 | (a) | $17.5 | $ 297.8 | (a) |

| | | | | |
|---|---|---|---|---|
| APCo | 2.2 | 0.1 | 4.9 | 0.1 |
| I&M | 1.4 | — | 3.3 | 0.1 |
| PSO | 2.1 | 3.2 | — | 3.2 |
| SWEPCo | 2.7 | 0.1 | — | 0.1 |

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

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Cross-Default Triggers (Applies to AEP, APCo and I&M)

In addition, a majority of non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following tables represent: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount that the exposure has been reduced by cash collateral posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements as of March 31, 2016 and December 31, 2015:

| | March 31, 2016 | | |
|---|---|---|---|
| Company | Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements | Amount of Cash Collateral Posted | Additional Settlement Liability if Cross Default Provision is Triggered |
| | (in millions) | | |
| AEP | $ 328.8 | $ — | $ 276.2 |
| APCo | 3.8 | — | 3.8 |
| I&M | 2.6 | — | 2.6 |

| | December 31, 2015 | | |
|---|---|---|---|
| Company | Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements | Amount of Cash Collateral Posted | Additional Settlement Liability if Cross Default Provision is Triggered |
| | (in millions) | | |
| AEP | $ 300.1 | $ 0.8 | $ 240.6 |
| APCo | 3.7 | — | 3.7 |
| I&M | 2.5 | — | 2.5 |

## 10. FAIR VALUE MEASUREMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

### Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer and Chief Risk Officer in addition to Energy Supply's President and Vice President.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the nuclear trusts, Cash and Cash Equivalents, Other Temporary Investments and Restricted Cash for Securitized Funding are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalent funds.  Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data.  Pricing vendors calculate bond valuations using financial models and matrices.  The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation.  Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments.  Investments with unobservable valuation inputs are classified as Level 3 investments.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs.  These instruments are not marked-to-market.  The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt for the Registrants as of March 31, 2016 and December 31, 2015 are summarized in the following table:

| Company | March 31, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| | Book Value | Fair Value | Book Value | Fair Value |
| | (in millions) | | | |
| AEP | $19,782.6 | $22,052.8 | $19,572.7 | $21,201.3 |
| APCo | 3,919.3 | 4,597.8 | 3,930.7 | 4,416.7 |
| I&M | 2,366.6 | 2,595.4 | 2,000.0 | 2,193.6 |
| OPCo | 2,135.5 | 2,515.4 | 2,157.7 | 2,472.7 |
| PSO | 1,286.3 | 1,463.6 | 1,286.1 | 1,402.9 |
| SWEPCo | 2,272.4 | 2,483.4 | 2,273.5 | 2,417.2 |

Fair Value Measurements of Other Temporary Investments (Applies to AEP)

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds and securities available for sale, including marketable securities that management intends to hold for less than one year and investments by its protected cell of EIS.

The following is a summary of Other Temporary Investments:

| Other Temporary Investments | March 31, 2016 | | | |
|---|---|---|---|---|
| | Cost | Gross Unrealized Gains | Gross Unrealized Losses | Fair Value |
| | (in millions) | | | |
| Restricted Cash (a) | $147.4 | $ — | $ — | $147.4 |
| Fixed Income Securities – Mutual Funds | 91.4 | 0.1 | — | 91.5 |
| Equity Securities – Mutual Funds | 13.9 | 11.7 | — | 25.6 |
| Total Other Temporary Investments | $252.7 | $ 11.8 | $ — | $264.5 |

| | December 31, 2015 | | | |
|---|---|---|---|---|
| Other Temporary Investments | Cost | Gross Unrealized Gains | Gross Unrealized Losses | Fair Value |
| | (in millions) | | | |
| Restricted Cash (a) | $271.0 | $ — | $ — | $271.0 |
| Fixed Income Securities – Mutual Funds | 91.1 | — | (0.7) | 90.4 |
| Equity Securities – Mutual Funds | 13.7 | 11.7 | — | 25.4 |
| Total Other Temporary Investments | $375.8 | $ 11.7 | $ (0.7) | $386.8 |

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

The following table provides the activity for fixed income and equity securities within Other Temporary Investments for the three months ended March 31, 2016 and 2015:

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in millions) | |
| Proceeds from Investment Sales | $ — | $ — |
| Purchases of Investments | 0.4 | 0.4 |
| Gross Realized Gains on Investment Sales | — | — |
| Gross Realized Losses on Investment Sales | — | — |

As of March 31, 2016 and December 31, 2015, AEP had no Other Temporary Investments with an unrealized loss position. As of March 31, 2016, fixed income securities were primarily debt based mutual funds with short and intermediate maturities. Mutual funds may be sold and do not contain maturity dates.

For details of the reasons for changes in Securities Available for Sale included in Accumulated Other Comprehensive Income (Loss) for the three months ended March 31, 2016 and 2015, see Note 3.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal (Applies to AEP and I&M)

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

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

I&M maintains trust records for each regulatory jurisdiction. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

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

The following is a summary of nuclear trust fund investments as of March 31, 2016 and December 31, 2015:

| | March 31, 2016 | | | December 31, 2015 | | |
|---|---|---|---|---|---|---|
| | Fair Value | Gross Unrealized Gains | Other-Than-Temporary Impairments | Fair Value | Gross Unrealized Gains | Other-Than-Temporary Impairments |
| | (in millions) | | | | | |
| Cash and Cash Equivalents | $142.0 | $ — | $ — | $168.3 | $ — | $ — |
| Fixed Income Securities: | | | | | | |
| United States Government | 761.1 | 52.3 | (2.1) | 731.1 | 35.9 | (2.6) |
| Corporate Debt | 68.9 | 4.9 | (1.0) | 57.9 | 3.2 | (1.1) |
| State and Local Government | 29.0 | 1.2 | (0.3) | 22.2 | 1.1 | (0.3) |
| Subtotal Fixed Income Securities | 859.0 | 58.4 | (3.4) | 811.2 | 40.2 | (4.0) |
| Equity Securities - Domestic | 1,151.4 | 583.5 | (78.9) | 1,126.9 | 571.6 | (79.3) |
| Spent Nuclear Fuel and Decommissioning Trusts | $2,152.4 | $ 641.9 | $ (82.3) | $2,106.4 | $ 611.8 | $ (83.3) |

The following table provides the securities activity within the decommissioning and SNF trusts for the three months ended March 31, 2016 and 2015:

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (in millions) | |
| Proceeds from Investment Sales | $1,137.7 | $228.2 |
| Purchases of Investments | 1,151.6 | 245.8 |
| Gross Realized Gains on Investment Sales | 15.8 | 11.2 |
| Gross Realized Losses on Investment Sales | 7.8 | 3.8 |

The adjusted cost of fixed income securities was $801 million and $771 million as of March 31, 2016 and December 31, 2015, respectively. The adjusted cost of equity securities was $568 million and $555 million as of March 31, 2016 and December 31, 2015, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of March 31, 2016 was as follows:

| | Fair Value of Fixed Income Securities |
|---|---|
| | (in millions) |
| Within 1 year | $ 175.4 |
| 1 year – 5 years | 369.6 |
| 5 years – 10 years | 133.0 |
| After 10 years | 181.0 |
| Total | $ 859.0 |

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, the Registrants' financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2016 and December 31, 2015. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2016

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|---|---|---|---|---|
| Assets: | (in millions) | | | | |
| Cash and Cash Equivalents (a) | $9.6 | $4.4 | $— | $176.4 | $190.4 |
| Other Temporary Investments | | | | | |
| Restricted Cash (a) | 129.2 | 7.6 | — | 10.6 | 147.4 |
| Fixed Income Securities – Mutual Funds | 91.5 | — | — | — | 91.5 |
| Equity Securities – Mutual Funds (b) | 25.6 | — | — | — | 25.6 |
| Total Other Temporary Investments | 246.3 | 7.6 | — | 10.6 | 264.5 |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (c) (d) | 10.7 | 585.5 | 201.8 | (346.0 ) | 452.0 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (c) | — | 11.4 | 8.1 | 0.3 | 19.8 |
| Fair Value Hedges | — | 0.5 | — | 0.4 | 0.9 |
| Total Risk Management Assets | 10.7 | 597.4 | 209.9 | (345.3 ) | 472.7 |
| Spent Nuclear Fuel and Decommissioning Trusts | | | | | |
| Cash and Cash Equivalents (e) | 135.3 | — | — | 6.7 | 142.0 |
| Fixed Income Securities: | | | | | |
| United States Government | — | 761.1 | — | — | 761.1 |
| Corporate Debt | — | 68.9 | — | — | 68.9 |
| State and Local Government | — | 29.0 | — | — | 29.0 |
| Subtotal Fixed Income Securities | — | 859.0 | — | — | 859.0 |
| Equity Securities – Domestic (b) | 1,151.4 | — | — | — | 1,151.4 |
| Total Spent Nuclear Fuel and Decommissioning Trusts | 1,286.7 | 859.0 | — | 6.7 | 2,152.4 |
| Total Assets | $1,553.3 | $1,468.4 | $209.9 | $(151.6) | $3,080.0 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts (c) (d) | $20.5 | $569.2 | $58.5 | $(377.2) | $271.0 |

| | | | | | |
|---|---|---|---|---|---|
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (c) | — | 29.7 | 10.1 | 0.3 | 40.1 |
| Interest Rate/Foreign Currency Hedges | — | 0.4 | — | — | 0.4 |
| Fair Value Hedges | — | — | — | 0.4 | 0.4 |
| Total Risk Management Liabilities | $20.5 | $599.3 | $68.6 | $(376.5) | $311.9 |

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|---|---|---|---|---|
| Assets: | (in millions) | | | | |
| Cash and Cash Equivalents (a) | $3.9 | $4.3 | $— | $168.2 | $176.4 |
| Other Temporary Investments | | | | | |
| Restricted Cash (a) | 230.0 | 7.7 | — | 33.3 | 271.0 |
| Fixed Income Securities – Mutual Funds | 90.4 | — | — | — | 90.4 |
| Equity Securities – Mutual Funds (b) | 25.4 | — | — | — | 25.4 |
| Total Other Temporary Investments | 345.8 | 7.7 | — | 33.3 | 386.8 |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (c) (f) | 11.5 | 495.0 | 219.7 | (287.7 ) | 438.5 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (c) | — | 15.9 | 1.0 | 0.7 | 17.6 |
| Fair Value Hedges | — | — | — | 0.1 | 0.1 |
| Total Risk Management Assets | 11.5 | 510.9 | 220.7 | (286.9 ) | 456.2 |
| Spent Nuclear Fuel and Decommissioning Trusts | | | | | |
| Cash and Cash Equivalents (e) | 160.5 | — | — | 7.8 | 168.3 |
| Fixed Income Securities: | | | | | |
| United States Government | — | 731.1 | — | — | 731.1 |
| Corporate Debt | — | 57.9 | — | — | 57.9 |
| State and Local Government | — | 22.2 | — | — | 22.2 |
| Subtotal Fixed Income Securities | — | 811.2 | — | — | 811.2 |
| Equity Securities – Domestic (b) | 1,126.9 | — | — | — | 1,126.9 |
| Total Spent Nuclear Fuel and Decommissioning Trusts | 1,287.4 | 811.2 | — | 7.8 | 2,106.4 |
| Total Assets | $1,648.6 | $1,334.1 | $220.7 | $(77.6 ) | $3,125.8 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts (c) (f) | $24.1 | $471.5 | $67.3 | $(326.3) | $236.6 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (c) | — | 18.9 | 6.5 | 0.7 | 26.1 |
| Interest Rate/Foreign Currency Hedges | — | 0.4 | — | — | 0.4 |
| Fair Value Hedges | — | 3.0 | — | 0.1 | 3.1 |
| Total Risk Management Liabilities | $24.1 | $493.8 | $73.8 | $(325.5) | $266.2 |

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2016

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|---|---|---|---|---|
| Assets: | (in millions) | | | | |
| Restricted Cash for Securitized Funding (a) | $7.5 | $— | $— | $0.1 | $7.6 |
| Risk Management Assets - Nonaffiliated and Affiliated | | | | | |
| Risk Management Commodity Contracts (c) (g) | 0.2 | 16.2 | 8.2 | (12.4 ) | 12.2 |
| Total Assets: | $7.7 | $16.2 | $8.2 | $(12.3) | $19.8 |
| Liabilities: | | | | | |
| Risk Management Liabilities - Nonaffiliated | | | | | |
| Risk Management Commodity Contracts (c) (g) | $0.2 | $17.7 | $5.6 | $(13.0) | $10.5 |

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|---|---|---|---|---|
| Assets: | (in millions) | | | | |
| Restricted Cash for Securitized Funding (a) | $14.8 | $— | $— | $0.1 | $14.9 |
| Risk Management Assets - Nonaffiliated and Affiliated | | | | | |
| Risk Management Commodity Contracts (c) (g) | 0.2 | 13.9 | 12.2 | (10.6 ) | 15.7 |
| Total Assets: | $15.0 | $13.9 | $12.2 | $(10.5) | $30.6 |
| Liabilities: | | | | | |
| Risk Management Liabilities - Nonaffiliated | | | | | |
| Risk Management Commodity Contracts (c) (g) | $0.2 | $17.8 | $0.5 | $(13.6) | $4.9 |

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2016

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|---|---|---|---|---|
| Assets: | (in millions) | | | | |
| Risk Management Assets - Nonaffiliated and Affiliated | | | | | |
| Risk Management Commodity Contracts (c) (g) | $0.1 | $12.5 | $5.5 | $(8.6) | $9.5 |
| Spent Nuclear Fuel and Decommissioning Trusts | | | | | |
| Cash and Cash Equivalents (e) | 135.3 | — | — | 6.7 | 142.0 |
| Fixed Income Securities: | | | | | |
| United States Government | — | 761.1 | — | — | 761.1 |
| Corporate Debt | — | 68.9 | — | — | 68.9 |
| State and Local Government | — | 29.0 | — | — | 29.0 |
| Subtotal Fixed Income Securities | — | 859.0 | — | — | 859.0 |
| Equity Securities - Domestic (b) | 1,151.4 | — | — | — | 1,151.4 |
| Total Spent Nuclear Fuel and Decommissioning Trusts | 1,286.7 | 859.0 | — | 6.7 | 2,152.4 |
| Total Assets | $1,286.8 | $871.5 | $5.5 | $(1.9) | $2,161.9 |
| Liabilities: | | | | | |
| Risk Management Liabilities - Nonaffiliated | | | | | |
| Risk Management Commodity Contracts (c) (g) | $0.1 | $14.2 | $1.8 | $(8.7) | $7.4 |

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|---|---|---|---|---|
| Assets: | (in millions) | | | | |
| Risk Management Assets - Nonaffiliated and Affiliated | | | | | |
| Risk Management Commodity Contracts (c) (g) | $0.1 | $17.0 | $6.3 | $(11.1) | $12.3 |
| Spent Nuclear Fuel and Decommissioning Trusts | | | | | |
| Cash and Cash Equivalents (e) | 160.5 | — | — | 7.8 | 168.3 |
| Fixed Income Securities: | | | | | |
| United States Government | — | 731.1 | — | — | 731.1 |
| Corporate Debt | — | 57.9 | — | — | 57.9 |
| State and Local Government | — | 22.2 | — | — | 22.2 |
| Subtotal Fixed Income Securities | — | 811.2 | — | — | 811.2 |
| Equity Securities - Domestic (b) | 1,126.9 | — | — | — | 1,126.9 |
| Total Spent Nuclear Fuel and Decommissioning Trusts | 1,287.4 | 811.2 | — | 7.8 | 2,106.4 |

| | | | | | |
|---|---|---|---|---|---|
| Total Assets | $1,287.5 | $828.2 | $6.3 | $(3.3) | $2,118.7 |
| Liabilities: | | | | | |
| Risk Management Liabilities - Nonaffiliated | | | | | |
| Risk Management Commodity Contracts (c) (g) | $0.1 | $17.5 | $2.0 | $(11.7) | $7.9 |

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OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2016

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|---|---|---|---|---|
| Assets: | (in millions) | | | | |
| Restricted Cash for Securitized Funding (a) | $16.2 | $— | $— | $— | $16.2 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts (c) (g) | $— | $0.6 | $10.9 | $(0.2) | $11.3 |

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|---|---|---|---|---|
| Assets: | (in millions) | | | | |
| Restricted Cash for Securitized Funding (a) | $— | $— | $— | $27.7 | $27.7 |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (c) (g) | — | — | 16.0 | 3.2 | 19.2 |
| Total Assets | $— | $— | $16.0 | $30.9 | $46.9 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts (c) (g) | $— | $0.8 | $0.1 | $2.7 | $3.6 |

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2016

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|---|---|---|---|---|
| Assets: | (in millions) | | | | |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (c) (g) | $— | $0.1 | $0.7 | $(0.1) | $0.7 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts (c) (g) | $— | $0.3 | $0.1 | $(0.2) | $0.2 |

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|---|---|---|---|---|
| Assets: | (in millions) | | | | |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (c) (g) | $— | $— | $0.7 | $(0.1) | $0.6 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts (c) (g) | $— | $0.5 | $0.1 | $(0.4) | $0.2 |

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2016

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|---|---|---|---|---|
| Assets: | (in millions) | | | | |
| Cash and Cash Equivalents (a) | $9.4 | $— | $— | $2.9 | $12.3 |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (c) (g) | — | 0.1 | 0.8 | (0.1 ) | 0.8 |
| Total Assets | $9.4 | $0.1 | $0.8 | $2.8 | $13.1 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts (c) (g) | $— | $5.5 | $0.1 | $(0.3) | $5.3 |

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|---|---|---|---|---|
| Assets: | (in millions) | | | | |
| Cash and Cash Equivalents (a) | $3.6 | $— | $— | $1.6 | $5.2 |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (c) (g) | — | — | 0.9 | (0.1 ) | 0.8 |
| Total Assets | $3.6 | $— | $0.9 | $1.5 | $6.0 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts (c) (g) | $— | $5.5 | $0.1 | $(0.4) | $5.2 |

(a) Amounts in “Other’’ column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.
(b) Amounts represent publicly traded equity securities and equity-based mutual funds.
(c) Amounts in “Other’’ column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for “Derivatives and Hedging.’’
(d) The March 31, 2016 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $(5) million in 2016 and $(5) million in periods 2017-2019; Level 2 matures $3 million in 2016, $9 million in periods 2017-2019, $3 million in periods 2020-2021 and $1 million in periods 2022-2032; Level 3 matures $17 million in 2016, $37 million in periods 2017-2019, $21

million in periods 2020-2021 and $69 million in periods 2022-2032. Risk management commodity contracts are substantially comprised of power contracts.

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

(f) The December 31, 2015 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $(9) million in 2016 and $(4) million in periods 2017-2019; Level 2 matures $2 million in 2016, $18 million in periods 2017-2019 and $4 million in periods 2020-2021; Level 3 matures $28 million in 2016, $29 million in periods 2017-2019, $19 million in periods 2020-2021 and $76 million in periods 2022-2032. Risk management commodity contracts are substantially comprised of power contracts.

(g) Substantially comprised of power contracts for APCo, I&M and OPCo and coal contracts for PSO and SWEPCo.

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2016 and 2015.

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

| Three Months Ended March 31, 2016 | AEP | APCo (a) | I&M (a) | OPCo | PSO | SWEPCo |
|---|---|---|---|---|---|---|
| | (in millions) | | | | | |
| Balance as of December 31, 2015 | $146.9 | $11.7 | $4.3 | $15.9 | $0.6 | $ 0.8 |
| Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c) | 23.5 | 15.3 | 2.5 | (0.6 ) | (0.8 ) | 4.6 |
| Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b) | 21.9 | — | — | — | — | — |
| Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income | 1.3 | — | — | — | — | — |
| Purchases, Issuances and Settlements (d) | (42.7 ) | (27.7 ) | (4.6 ) | 1.4 | 0.5 | (4.9 ) |
| Transfers out of Level 3 (f) (g) | 10.9 | 0.1 | 0.1 | — | — | — |
| Changes in Fair Value Allocated to Regulated Jurisdictions (h) | (20.5 ) | 3.2 | 1.4 | (27.6 ) | 0.3 | 0.2 |
| Balance as of March 31, 2016 | $141.3 | $2.6 | $3.7 | $(10.9) | $0.6 | $ 0.7 |

| Three Months Ended March 31, 2015 | AEP | APCo | I&M | OPCo | PSO | SWEPCo |
|---|---|---|---|---|---|---|
| | (in millions) | | | | | |
| Balance as of December 31, 2014 | $150.8 | $15.8 | $14.7 | $48.4 | $(0.3) | $ (0.5 ) |
| Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c) | 8.6 | 2.2 | 0.1 | 0.2 | (0.3 ) | 5.8 |
| Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b) | 5.2 | — | — | — | — | — |
| Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income | (1.9 ) | — | — | — | — | — |
| Purchases, Issuances and Settlements (d) | (38.5 ) | (13.4 ) | (9.0 ) | (6.8 ) | 0.6 | (5.3 ) |
| Transfers into Level 3 (e) (f) | 15.3 | — | — | — | — | — |
| Transfers out of Level 3 (f) (g) | (12.4 ) | — | — | — | — | — |
| Changes in Fair Value Allocated to Regulated Jurisdictions (h) | 3.5 | 1.4 | (0.2 ) | 4.1 | (0.7 ) | (1.2 ) |
| Balance as of March 31, 2015 | $130.6 | $6.0 | $5.6 | $45.9 | $(0.7) | $ (1.2 ) |

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

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of March 31, 2016 and December 31, 2015:

Significant Unobservable Inputs
March 31, 2016
AEP

| | Fair Value | | Valuation | Significant | Input/Range | | |
|---|---|---|---|---|---|---|---|
| | Assets | Liabilities | Technique | Unobservable Input | Low | High | Weighted Average |
| | (in millions) | | | | | | |
| Energy Contracts | $207.6 | $ 59.5 | Discounted Cash Flow | Forward Market Price (a) | $8.77 | $162.36 | $ 45.45 |
| | | | | Counterparty Credit Risk (b) | 251 | 669 | NA |
| FTRs | 2.3 | 9.1 | Discounted Cash Flow | Forward Market Price (a) | $(17.72) | $10.50 | $ 0.60 |
| Total | $209.9 | $ 68.6 | | | | | |

Significant Unobservable Inputs
December 31, 2015
AEP

| | Fair Value | | Valuation | Significant | Input/Range | | |
|---|---|---|---|---|---|---|---|
| | Assets | Liabilities | Technique | Unobservable Input | Low | High | Weighted Average |
| | (in millions) | | | | | | |
| Energy Contracts | $212.3 | $ 70.3 | Discounted Cash Flow | Forward Market Price (a) | $9.69 | $165.36 | $ 36.35 |
| | | | | Counterparty Credit Risk (b) | 670 | | |
| FTRs | 8.4 | 3.5 | Discounted Cash Flow | Forward Market Price (a) | $(6.99) | $10.34 | $ 1.10 |
| Total | $220.7 | $ 73.8 | | | | | |

Significant Unobservable Inputs
March 31, 2016
APCo

| | Fair Value | | Valuation | Significant | Forward Price Range | | |
|---|---|---|---|---|---|---|---|
| | | | | Unobservable | | | Weighted |
| | Assets | Liabilities | Technique | Input (a) | Low | High | Average |
| | (in millions) | | | | | | |
| Energy Contracts | $8.2 | $ 0.1 | Discounted Cash Flow | Forward Market Price | $8.77 | $47.05 | $ 29.14 |
| FTRs | — | 5.5 | Discounted Cash Flow | Forward Market Price | 0.42 | 5.58 | 1.90 |
| Total | $8.2 | $ 5.6 | | | | | |

Significant Unobservable Inputs
December 31, 2015
APCo

| | Fair Value | | Valuation | Significant | Forward Price Range | | |
|---|---|---|---|---|---|---|---|
| | | | | Unobservable | | | Weighted |
| | Assets | Liabilities | Technique | Input (a) | Low | High | Average |
| | (in millions) | | | | | | |
| Energy Contracts | $7.9 | $ 0.2 | Discounted Cash Flow | Forward Market Price | $12.61 | $47.24 | $ 32.38 |
| FTRs | 4.3 | 0.3 | Discounted Cash Flow | Forward Market Price | (6.96 ) | 8.43 | 1.34 |
| Total | $12.2 | $ 0.5 | | | | | |

Significant Unobservable Inputs
March 31, 2016
I&M

| | Fair Value | | Valuation | Significant | Forward Price Range | | |
|---|---|---|---|---|---|---|---|
| | Assets | Liabilities | Technique | Unobservable Input (a) | Low | High | Weighted Average |
| | (in millions) | | | | | | |
| Energy Contracts | $5.5 | $ 0.1 | Discounted Cash Flow | Forward Market Price | $8.77 | $47.05 | $ 29.14 |
| FTRs | — | 1.7 | Discounted Cash Flow | Forward Market Price | (0.07 ) | 5.58 | 0.42 |
| Total | $5.5 | $ 1.8 | | | | | |

Significant Unobservable Inputs
December 31, 2015
I&M

| | Fair Value | | Valuation | Significant | Forward Price Range | | |
|---|---|---|---|---|---|---|---|
| | Assets | Liabilities | Technique | Unobservable Input (a) | Low | High | Weighted Average |
| | (in millions) | | | | | | |
| Energy Contracts | $6.0 | $ 0.2 | Discounted Cash Flow | Forward Market Price | $12.61 | $47.24 | $ 32.38 |
| FTRs | 0.3 | 1.8 | Discounted Cash Flow | Forward Market Price | (6.96 ) | 8.43 | 1.34 |
| Total | $6.3 | $ 2.0 | | | | | |

Significant Unobservable Inputs
March 31, 2016
OPCo

| | Fair Value | | Valuation | Significant | Forward Price Range | | |
|---|---|---|---|---|---|---|---|
| | Assets | Liabilities | Technique | Unobservable Input | Low | High | Weighted Average |
| | (in millions) | | | | | | |
| Energy Contracts | $ — | $ 10.9 | Discounted Cash Flow | Forward Market Price (a) | $36.41 | $162.36 | $ 84.24 |
| | | | | Counterparty Credit Risk (b) | 251 | | |
| Total | $ — | $ 10.9 | | | | | |

Significant Unobservable Inputs
December 31, 2015
OPCo

| | Fair Value | | Valuation | Significant | Forward Price Range | | |
|---|---|---|---|---|---|---|---|
| | Assets | Liabilities | Technique | Unobservable Input (a) | Low | High | Weighted Average |
| | (in millions) | | | | | | |
| Energy Contracts | $16.0 | $ 0.1 | Discounted Cash Flow | Forward Market Price | $41.61 | $165.36 | $ 86.84 |

Significant Unobservable Inputs
March 31, 2016
PSO

| | Fair Value | | Valuation | Significant | Forward Price Range | | |
|---|---|---|---|---|---|---|---|
| | Assets | Liabilities | Technique | Unobservable Input (a) | Low | High | Weighted Average |
| | (in millions) | | | | | | |
| FTRs | $0.7 | $ 0.1 | Discounted Cash Flow | Forward Market Price | $(17.72) | $1.80 | $ (0.59) |

Significant Unobservable Inputs
December 31, 2015
PSO

| | Fair Value | | Valuation | Significant | Forward Price Range | | |
|---|---|---|---|---|---|---|---|
| | Assets | Liabilities | Technique | Unobservable Input (a) | Low | High | Weighted Average |
| | (in millions) | | | | | | |
| FTRs | $0.7 | $ 0.1 | Discounted Cash Flow | Forward Market Price | $(6.96) | $8.43 | $ 1.34 |

Significant Unobservable Inputs
March 31, 2016
SWEPCo

| | Fair Value | | Valuation | Significant | Forward Price Range | | |
|---|---|---|---|---|---|---|---|
| | Assets | Liabilities | Technique | Unobservable Input (a) | Low | High | Weighted Average |
| | (in millions) | | | | | | |
| FTRs | $ 0.8 | $ 0.1 | Discounted Cash Flow | Forward Market Price | $ (17.72) | $ 1.80 | $ (0.59) |

Significant Unobservable Inputs
December 31, 2015
SWEPCo

| | Fair Value | | Valuation | Significant | Forward Price Range | | |
|---|---|---|---|---|---|---|---|
| | Assets | Liabilities | Technique | Unobservable Input (a) | Low | High | Weighted Average |
| | (in millions) | | | | | | |
| FTRs | $ 0.9 | $ 0.1 | Discounted Cash Flow | Forward Market Price | $ (6.96) | $ 8.43 | $ 1.34 |

(a) Represents market prices in dollars per MWh.
(b) Represents average price of credit default swaps used to calculate counterparty credit risk, reported in basis points.
NA Not applicable.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs for the Registrants as of March 31, 2016 and December 31, 2015:

Sensitivity of Fair Value Measurements

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

11. INCOME TAXES

The disclosures in this note apply to all Registrants unless indicated otherwise.

AEP System Tax Allocation Agreement

AEP and subsidiaries join in the filing of a consolidated federal income tax return. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

Valuation Allowance (Applies to AEP)

AEP assesses available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that AEP will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount. Objective negative evidence evaluated includes whether AEP has a history of recognizing income of the character which can be offset by loss carryforwards. Other objective negative evidence evaluated is the impact recently enacted federal tax legislation will have on future taxable income and on AEP's ability to benefit from the carryforward of charitable contribution deductions. On the basis of this evaluation, AEP did not record a change in the valuation allowance in the first quarter of 2016.

A valuation allowance of $130 million has been recorded against AEP's deferred tax asset balance as of March 31, 2016. The valuation allowance reflects management's assessment of the amount of deferred tax assets that are more likely than not to be realized. The amount of the deferred tax assets realizable; however, could be adjusted if estimates of future taxable income are materially impacted during the carryforward period.

Federal and State Income Tax Audit Status

AEP and subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011, 2012 and 2013 started in April 2014. AEP and subsidiaries received a Revenue Agents Report in April 2016, completing the 2011 through 2013 audit cycle indicating an agreed upon audit. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, the Registrants accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

AEP and subsidiaries file income tax returns in various state, local or foreign jurisdictions. These taxing authorities routinely examine the tax returns. AEP and subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. The Registrants are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2009.

State Tax Legislation (Applies to AEP, PSO and SWEPCo)

In March 2016, the Texas Comptroller of Public Accounts issued clarifying guidance regarding the treatment of transmission and distribution expenses included in the computation of taxable income for purposes of calculating the Texas gross margins tax. The guidance clarified which specific transmission and distribution expenses are included in the computation of the cost of goods sold deduction. This guidance resulted in a net favorable adjustment to net income of $10 million, $1 million and $5 million for AEP, PSO and SWEPCo, respectively.

In March 2016, Louisiana enacted several tax bills impacting income taxes, franchise taxes and sales taxes. The income tax provisions limit the use of Louisiana net operating losses and the sales tax provisions increase the sales tax rate and suspend or eliminate certain exemptions. The legislation is not expected to materially impact net income or cash flows.

12. FINANCING ACTIVITIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

Long-term Debt Outstanding (Applies to AEP)

The following table details long-term debt outstanding as of March 31, 2016 and December 31, 2015:

| Type of Debt | March 31, 2016 | December 31, 2015 |
|---|---|---|
| | (in millions) | |
| Senior Unsecured Notes | $14,026.2 | $ 13,629.1 |
| Pollution Control Bonds | 1,784.1 | 1,784.8 |
| Notes Payable | 233.6 | 264.7 |
| Securitization Bonds | 1,863.1 | 2,024.0 |
| Spent Nuclear Fuel Obligation (a) | 265.7 | 265.6 |
| Other Long-term Debt | 1,609.9 | 1,604.5 |
| Total Long-term Debt Outstanding | 19,782.6 | 19,572.7 |
| Long-term Debt Due Within One Year | 2,033.3 | 1,831.8 |
| Long-term Debt | $17,749.3 | $ 17,740.9 |

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M, a nuclear licensee, has an obligation to the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation were $309 million and $309 million as of March 31, 2016 and December 31, 2015, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the condensed balance sheets.

Long-term Debt Activity

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2016 are shown in the tables below:

| Company | Type of Debt | Principal Amount (a) | Interest Rate | Due Date |
|---|---|---|---|---|
| Issuances: | | (in millions) | (%) | |
| APCo | Pollution Control Bonds | $ 125.3 | Variable | 2016 |
| I&M | Senior Unsecured Notes | 400.0 | 4.55 | 2046 |
| | | | | |
| Non-Registrant: | | | | |
| Transource Missouri | Other Long-term Debt | 5.5 | Variable | 2018 |
| Total Issuances | | $ 530.8 | | |

(a) Amounts indicated on the statements of cash flows are net of issuance costs and premium or discount and will not tie to the issuance amounts.

| Company | Type of Debt | Principal Amount Paid | Interest Rate | Due Date |
|---|---|---|---|---|
| Retirements and Principal Payments: | | (in millions) | (%) | |
| APCo | Pollution Control Bonds | $ 125.3 | Variable | 2016 |
| APCo | Securitization Bonds | 11.2 | 2.008 | 2024 |
| I&M | Notes Payable | 0.4 | Variable | 2016 |
| I&M | Notes Payable | 0.3 | 2.12 | 2016 |
| I&M | Notes Payable | 6.9 | Variable | 2017 |
| I&M | Notes Payable | 10.2 | Variable | 2019 |
| I&M | Notes Payable | 10.7 | Variable | 2019 |
| I&M | Other Long-term Debt | 0.3 | 6.00 | 2025 |
| OPCo | Securitization Bonds | 22.8 | 0.958 | 2018 |
| PSO | Other Long-term Debt | 0.1 | 3.00 | 2027 |
| SWEPCo | Notes Payable | 1.6 | 4.58 | 2032 |
| | | | | |
| Non-Registrant: | | | | |
| AEGCo | Senior Unsecured Notes | 3.7 | 6.33 | 2037 |
| AEP Subsidiaries | Notes Payable | 1.0 | Variable | 2017 |
| TCC | Securitization Bonds | 44.2 | 6.25 | 2016 |
| TCC | Securitization Bonds | 83.7 | 5.17 | 2018 |
| Total Retirements and Principal Payments | | $ 322.4 | | |

In April 2016, I&M retired $13 million of Notes Payable related to DCC Fuel.

In April 2016, Transource Missouri drew $6 million on an existing variable rate credit facility due in 2018.

As of March 31, 2016, trustees held, on behalf of AEP, $554 million of their reacquired Pollution Control Bonds. Of this total, $40 million and $345 million related to I&M and OPCo, respectively.

Dividend Restrictions

Parent Restrictions (Applies to AEP)

The holders of AEP's common stock are entitled to receive the dividends declared by the Board of Directors provided funds are legally available for such dividends.  Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries.

Pursuant to the leverage restrictions in credit agreements, AEP must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%.  The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the company distributing the dividend.  The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements.  As of March 31, 2016, none of AEP's retained earnings were restricted for the purpose of the payment of dividends.

Utility Subsidiaries' Restrictions

AEP utility subsidiaries pay dividends to Parent provided funds are legally available.  Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to

Parent in the form of dividends.

Certain AEP subsidiaries have credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%.

The Federal Power Act prohibits the utility subsidiaries from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." As of March 31, 2016, this restriction did not limit the ability of the utility subsidiaries to pay dividends out of retained earnings.

Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to AGR, APCo and I&M.

Corporate Borrowing Program - AEP System (Applies to Registrant Subsidiaries)

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries, and a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of March 31, 2016 and December 31, 2015 are included in Advances to Affiliates and Advances from Affiliates, respectively, on each of the Registrant Subsidiaries' condensed balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits for the three months ended March 31, 2016 are described in the following table:

| Company | Maximum Borrowings from the Utility Money Pool | Maximum Loans to the Utility Money Pool | Average Borrowings from the Utility Money Pool | Average Loans to the Utility Money Pool | Net Loans to (Borrowings from) the Utility Money Pool as of March 31, 2016 | Authorized Short-term Borrowing Limit |
|---|---|---|---|---|---|---|
| | (in millions) | | | | | |
| APCo | $286.9 | $ 25.7 | $ 183.2 | $ 25.5 | $ (146.4) | $ 600.0 |
| I&M | 369.1 | 62.5 | 267.3 | 17.0 | 2.8 | 500.0 |
| OPCo | — | 379.2 | — | 304.7 | 221.9 | 400.0 |
| PSO | — | 91.0 | — | 48.7 | 8.4 | 300.0 |
| SWEPCo | 221.8 | — | 148.0 | — | (217.8) | 350.0 |

The activity in the above table does not include short-term lending activity of SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC, which is a participant in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of March 31, 2016 and December 31, 2015 are included in Advances to Affiliates on SWEPCo's condensed balance sheets. For the three months ended March 31, 2016, Mutual Energy SWEPCo, LLC had the following activity in the Nonutility Money Pool:

| Maximum Loans to the Nonutility Money Pool | Average Loans to the Nonutility Money Pool | Loans to the Nonutility Money Pool as of March 31, 2016 |
|---|---|---|
| (in millions) | | |
| $2.0 | $ 2.0 | $ 2.0 |

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| Maximum Interest Rate | 0.83% | 0.59% |
| Minimum Interest Rate | 0.69% | 0.39% |

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The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the three months ended March 31, 2016 and 2015 are summarized for all Registrant Subsidiaries in the following table:

| Company | Average Interest Rate for Funds Borrowed from the Utility Money Pool for Three Months Ended March 31, | | Average Interest Rate for Funds Loaned to the Utility Money Pool for Three Months Ended March 31, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| APCo | 0.73 % | — % | 0.73 % | 0.45 % |
| I&M | 0.72 % | 0.46 % | 0.74 % | 0.46 % |
| OPCo | — % | — % | 0.73 % | 0.46 % |
| PSO | — % | 0.49 % | 0.72 % | 0.44 % |
| SWEPCo | 0.73 % | 0.46 % | — % | 0.52 % |

Maximum, minimum and average interest rates for funds loaned to the Nonutility Money Pool for the three months ended March 31, 2016 are summarized for Mutual Energy SWEPCo, LLC in the following table:

| Three Months Ended March 31, | Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool | Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool | Average Interest Rate for Funds Loaned to the Nonutility Money Pool |
|---|---|---|---|
| 2016 | 0.83 % | 0.69 % | 0.73 % |

Short-term Debt (Applies to AEP)

Outstanding short-term debt was as follows:

| Type of Debt | March 31, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| | Outstanding Amount | Interest Rate (a) | Outstanding Amount | Interest Rate (a) |
| | (in millions) | | (in millions) | |
| Securitized Debt for Receivables (b) | $719.0 | 0.58 % | $675.0 | 0.30 % |
| Commercial Paper | 502.0 | 0.77 % | 125.0 | 0.81 % |
| Total Short-term Debt | $1,221.0 | | $800.0 | |

(a) Weighted average rate.

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

Credit Facilities

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

Sale of Receivables – AEP Credit (Applies to AEP)

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

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and expires in June 2017.

Accounts receivable information for AEP Credit is as follows:

| | Three Months Ended March 31, | |
|---|---|---|
| | 2016 | 2015 |
| | (dollars in millions) | |
| Effective Interest Rates on Securitization of Accounts Receivable | 0.58 % | 0.26 % |
| Net Uncollectible Accounts Receivable Written Off | $5.7 | $6.6 |

| | March 31, 2016 | December 31, 2015 |
|---|---|---|
| | (in millions) | |
| Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts | $849.8 | $ 924.8 |
| Total Principal Outstanding | 719.0 | 675.0 |
| Delinquent Securitized Accounts Receivable | 52.1 | 48.3 |
| Bad Debt Reserves Related to Securitization of Accounts Receivable | 20.9 | 17.5 |
| Unbilled Receivables Related to Securitization of Accounts Receivable | 264.0 | 357.8 |

AEP Credit's delinquent customer accounts receivable represent accounts greater than 30 days past due.

Sale of Receivables – AEP Credit (Applies to Registrant Subsidiaries)

Under this sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiary's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' condensed statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for the operating companies and retains the remainder.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement for each Registrant Subsidiary as of March 31, 2016 and December 31, 2015 was as follows:

| Company | March 31, 2016 | December 31, 2015 |
|---|---|---|
| | (in millions) | |
| APCo | $136.6 | $ 135.4 |
| I&M | 125.3 | 134.8 |
| OPCo | 339.0 | 351.4 |
| PSO | 94.5 | 116.1 |
| SWEPCo | 121.2 | 151.8 |

The fees paid by the Registrant Subsidiaries to AEP Credit for customer accounts receivable sold were:

| Company | Three Months Ended March 31, 2016 | 2015 |
|---|---|---|
| | (in millions) | |
| APCo | $ 1.8 | $ 2.5 |
| I&M | 1.9 | 2.4 |
| OPCo | 7.9 | 8.0 |
| PSO | 1.4 | 1.4 |
| SWEPCo | 1.5 | 1.7 |

The Registrant Subsidiaries' proceeds on the sale of receivables to AEP Credit were:

| Company | Three Months Ended March 31, 2016 | 2015 |
|---|---|---|
| | (in millions) | |
| APCo | $ 384.4 | $ 429.6 |
| I&M | 388.1 | 419.6 |
| OPCo | 646.6 | 715.0 |
| PSO | 272.1 | 302.5 |
| SWEPCo | 336.1 | 373.2 |

## 13. VARIABLE INTEREST ENTITIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

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

AEP is the primary beneficiary of Sabine, DCC Fuel, Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, AEP Credit, a protected cell of EIS and Transource Energy. In addition, AEP has not provided material financial or other support to any of these entities that was not previously contractually required. AEP holds a significant variable interest in DHLC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

### Consolidated Variable Interests Entities

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the three months ended March 31, 2016 and 2015 were $41 million and $42 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's condensed balance sheets.

I&M has nuclear fuel lease agreements with DCC Fuel, which was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each DCC Fuel entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the three months ended March 31, 2016 and 2015 were $29 million and $23 million, respectively. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on I&M's control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on I&M's condensed balance sheets.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. Management has concluded that TCC is the primary beneficiary of Transition Funding because TCC has the power to direct the most significant activities of the VIE and TCC's equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled $1.4 billion and $1.5 billion as of March 31, 2016 and December 31, 2015, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the condensed balance sheets. Transition Funding has securitized transition assets of $1.3 billion and $1.3 billion as of March 31, 2016 and December 31, 2015, respectively, which are presented separately on the face of the condensed balance sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the condensed balance sheets.

Ohio Phase-in-Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to phase-in recovery property. Management has concluded that OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding because OPCo has the power to direct the most significant activities of the VIE and OPCo's equity interest could potentially be significant. Therefore, OPCo is required to consolidate Ohio Phase-in-Recovery Funding. The securitized bonds totaled $163 million and $185 million as of March 31, 2016 and December 31, 2015, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the condensed balance sheets. Ohio Phase-in-Recovery Funding has securitized assets of $80 million and $86 million as of March 31, 2016 and December 31, 2015, respectively, which are presented separately on the face of the condensed balance sheets. The phase-in recovery property represents the right to impose and collect Ohio deferred distribution charges from customers receiving electric transmission and distribution service from OPCo under a recovery mechanism approved by the PUCO. In August 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to OPCo or any other AEP entity. OPCo acts as the servicer for Ohio Phase-in-Recovery Funding's securitized assets and remits all related amounts collected from customers to Ohio Phase-in-Recovery Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Ohio Phase-in-Recovery Funding's assets and liabilities on OPCo's condensed balance sheets.

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. The securitized bonds totaled $330 million and $342 million, as of March 31, 2016 and December 31, 2015, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the condensed balance sheets. Appalachian Consumer Rate Relief Funding has securitized assets of $322 million and $328 million, as of March 31, 2016 and December 31, 2015, respectively, which are presented separately on the face of the condensed balance sheets. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on APCo's condensed balance sheets.

AEP Credit is a wholly-owned subsidiary of Parent. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on AEP's control of AEP Credit, management concluded that AEP is the primary beneficiary and is required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the condensed balance sheets. See

"Sale of Receivables - AEP Credit" section of Note 12.

AEP's subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. AEP's subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on AEP's control and the structure of the protected cell of EIS, management concluded that AEP is the primary beneficiary of the protected cell and are required to consolidate the protected cell of EIS. The insurance premium expense to the protected cell for the three months ended March 31, 2016 and 2015 were $13 million and $14 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the condensed balance sheets.

Transource Energy was formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates. AEP has equity and voting ownership of 86.5% with the other owner having 13.5% interest. Management has concluded that Transource Energy is a VIE and that AEP is the primary beneficiary because AEP has the power to direct the most significant activities of the entity and AEP's equity interest could potentially be significant. Therefore, AEP is required to consolidate Transource Energy. In January 2014, Transource Missouri (a wholly-owned subsidiary of Transource Energy) acquired transmission assets from the non-controlling owner and issued debt and received a capital contribution to fund the acquisition. The majority of Transource Energy's activity resulted from the asset acquisition, construction projects, debt issuance and capital contribution. AEP has provided capital contributions to Transource Energy of $8 million and $47 million during the three months ended March 31, 2016 and the year ended December 31, 2015, respectively. AEP and the other owner of Transource Energy are required to ensure a specific equity level in Transource Missouri upon completion of projects or if a project is abandoned by the RTO. See the tables below for the classification of Transource Energy's assets and liabilities on the condensed balance sheets.

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

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
March 31, 2016

| | Registrant Subsidiaries | | | | Other Consolidated VIEs | | | |
|---|---|---|---|---|---|---|---|---|
| | SWEPCo Sabine | I&M DCC Fuel | OPCo Ohio Phase-in-Recovery Funding | APCo Appalachian Consumer Rate Relief Funding | AEP Credit | TCC Transition Funding | Protected Cell of EIS | Transource Energy |
| | (in millions) | | | | | | | |
| ASSETS | | | | | | | | |
| Current Assets | $59.6 | $79.6 | $ 18.8 | $ 10.8 | $850.4 | $ 139.4 | $ 172.5 | $ 13.6 |
| Net Property, Plant and Equipment | 140.4 | 129.0 | — | — | — | — | — | 253.1 |
| Other Noncurrent Assets | 62.8 | 67.7 | 150.6 (a) | 326.2 (b) | 7.6 | 1,316.8 (c) | 2.0 | 6.3 |
| Total Assets | $262.8 | $276.3 | $ 169.4 | $ 337.0 | $858.0 | $ 1,456.2 | $ 174.5 | $ 273.0 |
| | | | | | | | | |
| LIABILITIES AND EQUITY | | | | | | | | |
| Current Liabilities | $37.3 | $73.4 | $ 46.2 | $ 24.8 | $781.9 | $ 238.0 | $ 48.8 | $ 44.5 |
| Noncurrent Liabilities | 225.1 | 202.9 | 121.9 | 310.9 | 0.4 | 1,200.1 | 81.8 | 118.7 |
| Equity | 0.4 | — | 1.3 | 1.3 | 75.7 | 18.1 | 43.9 | 109.8 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Total Liabilities and Equity | $262.8 | $276.3 | $ 169.4 | $ 337.0 | $858.0 | $ 1,456.2 | $ 174.5 | $ 273.0 |

(a) Includes an intercompany item eliminated in consolidation of $70.7 million.
(b) Includes an intercompany item eliminated in consolidation of $3.9 million.
(c) Includes an intercompany item eliminated in consolidation of $66.6 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2015

| | Registrant Subsidiaries | | | | | Other Consolidated VIEs | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | SWEPCo Sabine | I&M DCC Fuel | OPCo Ohio Phase-in-Recovery Funding | | APCo Appalachian Consumer Rate Relief Funding | | AEP Credit | TCC Transition Funding | | Protected Cell of EIS | Transource Energy |
| | (in millions) | | | | | | | | | | |
| ASSETS | | | | | | | | | | | |
| Current Assets | $61.7 | $91.1 | $ 31.2 | | $ 18.5 | | $925.7 | $ 234.1 | | $ 165.3 | $ 10.8 |
| Net Property, Plant and Equipment | 147.0 | 159.9 | — | | — | | — | — | | — | 227.2 |
| Other Noncurrent Assets | 61.8 | 84.6 | 162.0 | (a) | 332.0 | (b) | 6.4 | 1,365.7 | (c) | 1.9 | 5.5 |
| Total Assets | $270.5 | $335.6 | $ 193.2 | | $ 350.5 | | $932.1 | $ 1,599.8 | | $ 167.2 | $ 243.5 |
| | | | | | | | | | | | |
| LIABILITIES AND EQUITY | | | | | | | | | | | |
| Current Liabilities | $47.7 | $84.8 | $ 47.3 | | $ 27.1 | | $855.1 | $ 291.7 | | $ 41.8 | $ 36.6 |
| Noncurrent Liabilities | 222.3 | 250.8 | 144.6 | | 321.5 | | 0.3 | 1,290.0 | | 83.9 | 113.0 |
| Equity | 0.5 | — | 1.3 | | 1.9 | | 76.7 | 18.1 | | 41.5 | 93.9 |
| Total Liabilities and Equity | $270.5 | $335.6 | $ 193.2 | | $ 350.5 | | $932.1 | $ 1,599.8 | | $ 167.2 | $ 243.5 |

(a) Includes an intercompany item eliminated in consolidation of $76.1 million.
(b) Includes an intercompany item eliminated in consolidation of $4.0 million.
(c) Includes an intercompany item eliminated in consolidation of $68.2 million.

Non-Consolidated Significant Variable Interests

DHLC is a mining operator which sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and voting rights equally. Each entity guarantees 50% of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the three months ended March 31, 2016 and 2015 were $15 million and $15 million, respectively. SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although SWEPCo holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's condensed balance sheets.

SWEPCo's investment in DHLC was:

| | March 31, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| | As Reported on the Balance Sheet | Maximum Exposure | As Reported on the Balance Sheet | Maximum Exposure |

| | | | | |
|---|---|---|---|---|
| | (in millions) | | | |
| Capital Contribution from SWEPCo | $7.6 | $ 7.6 | $7.6 | $ 7.6 |
| Retained Earnings | 8.7 | 8.7 | 7.7 | 7.7 |
| SWEPCo's Guarantee of Debt | — | 87.4 | — | 82.9 |
| Total Investment in DHLC | $16.3 | $ 103.7 | $15.3 | $ 98.2 |

AEP and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the “West Virginia Series (PATH-WV),” owned equally by subsidiaries of FirstEnergy and AEP, and the “Allegheny Series” which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. AEP has no interest or control in the “Allegheny Series”. AEP is not required to consolidate PATH-WV as AEP is not the primary beneficiary, although AEP holds a significant variable interest in PATH-WV. AEP’s equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the condensed balance sheets. AEP and FirstEnergy share the returns and losses equally in PATH-WV. AEP’s subsidiaries and FirstEnergy’s subsidiaries provide services to the PATH companies through service agreements. The entities recover costs through regulated rates.

In August 2012, the PJM board cancelled the PATH Project, the transmission project that PATH was intended to develop and removed it from the 2012 Regional Transmission Expansion Plan. In September 2012, the PATH Project companies submitted an application to the FERC requesting authority to recover prudently-incurred costs associated with the PATH Project. In November 2012, the FERC issued an order accepting the PATH Project’s abandonment cost recovery application, subject to settlement procedures and hearing. The parties to the case have been unable to reach a settlement agreement and in March 2014, settlement judge procedures were terminated. Hearings at FERC were held in March and April 2015. In April 2015, PATH filed a stipulation agreement with the FERC that agreed to a 50% debt and 50% equity capital structure and a 4.7% cost of long-term debt for the entire amortization period. In September 2015, the Administrative Law Judge who conducted the hearings issued an Initial Decision, which if adopted by the FERC, would deem certain costs not recoverable. The Initial Decision has no binding effect. Additional briefing was submitted during the fourth quarter of 2015. The case is currently pending before FERC. Depending on the outcome of this proceeding, PATH-WV may be required to refund certain amounts that have been collected under its formula rate. Management believes its financial statements adequately address the potential impact of this proceeding.

AEP’s investment in PATH-WV was:

| | March 31, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| | As Reported on the Balance Sheet | Maximum Exposure | As Reported on the Balance Sheet | Maximum Exposure |
| | (in millions) | | | |
| Capital Contribution from Parent | $18.8 | $ 18.8 | $18.8 | $ 18.8 |
| Retained Earnings | 2.2 | 2.2 | 2.2 | 2.2 |
| Total Investment in PATH-WV | $21.0 | $ 21.0 | $21.0 | $ 21.0 |

As of March 31, 2016, AEP’s $21 million investment in PATH-WV was included in Deferred Charges and Other Noncurrent Assets on the condensed balance sheet. If AEP cannot ultimately recover the investment related to PATH-WV, it could reduce future net income and cash flows.

AEPSC provides certain managerial and professional services to AEP’s subsidiaries. Parent is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC’s cost. AEP subsidiaries have not provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

| Company | Three Months Ended March 31, 2016 | 2015 |
|---|---|---|
| | (in millions) | |
| APCo | $56.6 | $48.2 |
| I&M | 35.0 | 33.5 |
| OPCo | 44.5 | 39.2 |
| PSO | 28.5 | 23.5 |
| SWEPCo | 36.7 | 31.5 |

The carrying amount and classification of variable interest in AEPSC's accounts payable are as follows:

| Company | March 31, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| | As Reported on the Balance Sheet | Maximum Exposure | As Reported on the Balance Sheet | Maximum Exposure |
| | (in millions) | | | |
| APCo | $21.1 | $ 21.1 | $25.8 | $ 25.8 |
| I&M | 11.6 | 11.6 | 16.6 | 16.6 |
| OPCo | 14.9 | 14.9 | 23.3 | 23.3 |
| PSO | 9.1 | 9.1 | 12.6 | 12.6 |
| SWEPCo | 12.6 | 12.6 | 16.4 | 16.4 |

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1, leases a 50% interest in Rockport Plant, Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEGCo has a Unit Power Agreement associated with the Lawrenceburg Generating Station which was assigned by OPCo to AGR effective January 1, 2014. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. I&M is considered to have a significant interest in AEGCo due to these transactions. I&M is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M and KPCo, this financing would be provided by AEP. Total billings to I&M from AEGCo for the three months ended March 31, 2016 and 2015 were $45 million and $55 million, respectively. The carrying amount of I&M's liabilities associated with AEGCo as of March 31, 2016 and December 31, 2015 was $13 million and $17 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability. For additional information regarding AEGCo's lease, see "Rockport Lease" section of Note 13 in the 2015 Annual Report.

CONTROLS AND PROCEDURES

During the first quarter of 2016, management, including the principal executive officer and principal financial officer of each of the Registrants, evaluated the Registrants’ disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants’ management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. As of March 31, 2016, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives.

There was no change in the Registrants’ internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the first quarter of 2016 that materially affected, or is reasonably likely to materially affect, the Registrants’ internal control over financial reporting.

## PART II. OTHER INFORMATION

### Item 1. Legal Proceedings

For a discussion of material legal proceedings, see “Commitments, Guarantees and Contingencies,” of Note 5 incorporated herein by reference.

### Item 1A. Risk Factors

The Annual Report on Form 10-K for the year ended December 31, 2015 includes a detailed discussion of risk factors. As of March 31, 2016, there have been no material changes to the risk factors previously disclosed in the 2015 Annual Report on Form 10-K.

### Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None

### Item 4. Mine Safety Disclosures

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of DHLC, and AGR and KPCo, through their former joint ownership of the Conner Run fly ash impoundment, were subject to the provisions of the Mine Act for the quarter ended March 31, 2016. Conner Run’s ownership was transferred to Consolidation Coal Company in the fourth quarter of 2015 and the federal mine identification number was transferred in the first quarter of 2016.

The Dodd-Frank Wall Street Reform and Consumer Protection Act and its related regulations require companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. Exhibit 95 contains the notices of violation and proposed assessments received by DHLC and Conner Run under the Mine Act for the quarter ended March 31, 2016.

### Item 5. Other Information

None

### Item 6. Exhibits

12 – Computation of Consolidated Ratio of Earnings to Fixed Charges

31(a) – Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31(b) – Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

32(a) – Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code
32(b) – Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

95 – Mine Safety Disclosures

101.INS – XBRL Instance Document
101.SCH – XBRL Taxonomy Extension Schema
101.CAL – XBRL Taxonomy Extension Calculation Linkbase
101.DEF – XBRL Taxonomy Extension Definition Linkbase
101.LAB – XBRL Taxonomy Extension Label Linkbase
101.PRE – XBRL Taxonomy Extension Presentation Linkbase

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

APPALACHIAN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: April 28, 2016