APPALACHIAN POWER CO
Form 10-Q
April 23, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended March 31, 2015
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

| Commission File Number | Registrants; States of Incorporation; Address and Telephone Number | I.R.S. Employer Identification Nos. |
|---|---|---|
| 1-3525 | AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation) | 13-4922640 |
| 1-3457 | APPALACHIAN POWER COMPANY (A Virginia Corporation) | 54-0124790 |
| 1-3570 | INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation) | 35-0410455 |
| 1-6543 | OHIO POWER COMPANY (An Ohio Corporation) | 31-4271000 |
| 0-343 | PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation) | 73-0410895 |
| 1-3146 | SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation) | 72-0323455 |
| | 1 Riverside Plaza, Columbus, Ohio 43215-2373 | |
| | Telephone (614) 716-1000 | |

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

Yes X No

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

Yes X No

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer X Accelerated filer

Non-accelerated filer Smaller reporting company

Indicate by check mark whether Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, non-accelerated filers or smaller reporting companies. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

| | |
|---|---|
| Large accelerated filer | Accelerated filer |
| Non-accelerated filer X | Smaller reporting company |

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act).

| | |
|---|---|
| Yes | No X |

Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

| | Number of shares of common stock outstanding of the registrants as of April 23, 2015 |
|---|---|
| American Electric Power Company, Inc. | 489,941,950 ($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, 2015

Part II. OTHER INFORMATION



This combined Form 10-Q is separately filed by American Electric Power Company, Inc., Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

| Term | Meaning |
|---|---|
| AEGCo | AEP Generating Company, an AEP electric utility subsidiary. |
| AEP or Parent | American Electric Power Company, Inc., an electric utility holding company. |
| AEP Consolidated | AEP and its majority owned consolidated subsidiaries and consolidated affiliates. |
| AEP Credit | AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies. |
| AEP Energy | AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. |
| AEP System | American Electric Power System, an electric system, owned and operated by AEP subsidiaries. |
| AEP Transmission Holdco | AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP. |
| AEPSC | American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries. |
| AEPTCo | AEP Transmission Company, LLC, a subsidiary of AEP Transmission Holdco and an intermediate holding company that owns seven wholly-owned transmission companies. |
| AGR | AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation & Marketing segment. |
| AFUDC | Allowance for Funds Used During Construction. |
| AOCI | Accumulated Other Comprehensive Income. |
| APCo | Appalachian Power Company, an AEP electric utility subsidiary. |
| Appalachian Consumer Rate Relief Funding | Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance. |
| APSC | Arkansas Public Service Commission. |
| ASU | Accounting Standards Update. |
| CAA | Clean Air Act. |
| CLECO | Central Louisiana Electric Company, a nonaffiliated utility company. |
| $CO_2$ | Carbon dioxide and other greenhouse gases. |
| Cook Plant | Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M. |
| CRES provider | Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service. |
| CWIP | Construction Work in Progress. |
| DCC Fuel | DCC Fuel IV LLC, DCC Fuel V LLC and DCC Fuel VI LLC, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. |
| DHLC | Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo. |
| EIS | Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP. |
| ENEC | Expanded Net Energy Charge. |
| Energy Supply | AEP Energy Supply LLC, a nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP. |
| ERCOT | Electric Reliability Council of Texas regional transmission organization. |
| ESP | Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO. |

i

| Term | Meaning |
|---|---|
| ETT | Electric Transmission Texas, LLC, an equity interest joint venture between AEP and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT. |
| FAC | Fuel Adjustment Clause. |
| FASB | Financial Accounting Standards Board. |
| Federal EPA | United States Environmental Protection Agency. |
| FERC | Federal Energy Regulatory Commission. |
| FGD | Flue Gas Desulfurization or scrubbers. |
| FTR | Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices. |
| GAAP | Accounting Principles Generally Accepted in the United States of America. |
| I&M | Indiana Michigan Power Company, an AEP electric utility subsidiary. |
| IEU | Industrial Energy Users-Ohio. |
| IGCC | Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas. |
| Interconnection Agreement | An agreement by and among APCo, I&M, KPCo and OPCo, which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014. |
| IRS | Internal Revenue Service. |
| IURC | Indiana Utility Regulatory Commission. |
| KGPCo | Kingsport Power Company, an AEP electric utility subsidiary. |
| KPCo | Kentucky Power Company, an AEP electric utility subsidiary. |
| KPSC | Kentucky Public Service Commission. |
| KWh | Kilowatthour. |
| LPSC | Louisiana Public Service Commission. |
| MISO | Midwest Independent Transmission System Operator. |
| MMBtu | Million British Thermal Units. |
| MPSC | Michigan Public Service Commission. |
| MTM | Mark-to-Market. |
| MW | Megawatt. |
| MWh | Megawatthour. |
| $NO_x$ | Nitrogen oxide. |
| Nonutility Money Pool | Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries. |
| NSR | New Source Review. |
| OCC | Corporation Commission of the State of Oklahoma. |
| Ohio Phase-in-Recovery Funding | Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property. |
| OPCo | Ohio Power Company, an AEP electric utility subsidiary. |
| OPEB | Other Postretirement Benefit Plans. |
| OTC | Over the counter. |
| OVEC | Ohio Valley Electric Corporation, which is 43.47% owned by AEP. |
| PIRR | Phase-In Recovery Rider. |
| PJM | Pennsylvania – New Jersey – Maryland regional transmission organization. |
| PM | Particulate Matter. |

| | |
|---|---|
| PSO | Public Service Company of Oklahoma, an AEP electric utility subsidiary. |
| PUCO | Public Utilities Commission of Ohio. |
| PUCT | Public Utility Commission of Texas. |
| Registrant Subsidiaries | AEP subsidiaries which are SEC registrants; APCo, I&M, OPCo, PSO and SWEPCo. |
| Risk Management Contracts | Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges. |

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

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in “Item 7 – Management’s Discussion and Analysis of Financial Condition and Results of Operations” of the 2014 Annual Report, but there are others throughout this document which may be identified by words such as “expect,” “anticipate,” “intend,” “plan,” “believe,” “will,” “should,” “could,” “would,” “project,” “continue” and similar expressions, and include statements ref future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate, growth or contraction within and changes in market demand and demographic patterns in our service territory.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of competition, including competition for retail customers.
- Weather conditions, including storms and drought conditions, and our ability to recover significant storm restoration costs.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generation capacity and the performance of our generation plants.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generation capacity and transmission lines and facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs.
- New legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation, cost recovery and/or profitability of our generation plants and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- A reduction in the federal statutory tax rate could result in an accelerated return of deferred federal income taxes to customers.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- Our ability to constrain operation and maintenance costs.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity and other energy-related commodities.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing, alternative or distributed sources of generation.

Our ability to recover through rates or market prices any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.
Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas and capacity auction returns.
Changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP.

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

The forward looking statements of AEP and its Registrant Subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see “Risk Factors” in Part I of the 2014 Annual Report and in Part II of this report.

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

EXECUTIVE OVERVIEW

Customer Demand

Our weather-normalized retail sales volumes for the first quarter of 2015 decreased by 1.3% from the first quarter of 2014. Our first quarter 2015 industrial sales increased 1.2% compared to the first quarter of 2014 primarily due to increased sales to customers in oil and gas related sectors. Residential and commercial sales decreased 4% and 0.4% in the first quarter of 2015, respectively, from the first quarter of 2014.

Merchant Fleet Alternatives

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

AEP River Operations Alternatives

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

Merchant Portion of Turk Plant

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

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.

1

Ohio Electric Security Plan Filings

2009 - 2011 ESP

In August 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover OPCo’s deferred fuel costs in rates beginning September 2012. Oral arguments at the Supreme Court of Ohio were held in February 2015. OPCo presented arguments to reinstate a weighted average cost of capital carrying charge and to defend against an intervenor argument that the carrying charges should be reduced due to an accumulated deferred income tax credit.

June 2012 - May 2015 Ohio ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that established base generation rates through May 2015. This ruling was generally upheld in PUCO rehearing orders in January and March 2013.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the RPM price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The OPCo RPM price collected from CRES providers, which includes reserve margins, was approximately $34/MW day through May 2014 and is $150/MW day from June 2014 through May 2015. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and is currently collected at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In April and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO’s ESP order, including the RSR. In July 2014, OPCo submitted a separate application to continue the RSR to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh, until the balance of the capacity deferrals has been collected. In April 2015, the PUCO issued an order approving the application to continue the RSR, with modifications. As of March 31, 2015, OPCo’s incurred deferred capacity costs balance was $434 million, including debt carrying costs.

In November 2013, the PUCO issued an order approving OPCo’s competitive bid process with modifications. As ordered, in 2014, OPCo conducted multiple energy-only auctions for a total of 100% of the SSO load with delivery beginning April 2014 through May 2015. For delivery starting in June 2015, OPCo will conduct energy and capacity auctions for its entire SSO load. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit.

In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC. In March 2014, the PUCO approved OPCo’s request to implement riders related to the unbundling of the FAC. In October 2014, the independent auditor, selected by the PUCO, filed its report for the period August 2012 through May 2015 with the PUCO. If the PUCO ultimately concludes that a portion of the fixed fuel costs are also recovered through OPCo's $188.88 capacity charge, the independent auditor recommends a methodology for calculating a refund of a portion of certain fixed fuel costs. The retail share of these fixed fuel costs is approximately $90 million annually. A hearing related to this matter has not been scheduled. Management believes that no over-recovery of costs has occurred and intends to oppose the findings in the audit report.

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

2

June 2015 - May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments and the continuation and modification of certain existing riders effective June 2015 through May 2018. The proposal included a return on common equity of 10.65% on capital costs for certain riders. The proposal also included a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based purchase power agreement.

In October 2014, OPCo filed a separate application with the PUCO to propose a new extended PPA for inclusion in the PPA rider, discussed above. The new PPA would include an additional 2,671 MW to be purchased from AGR over the life of the respective generating units.

In February 2015, the PUCO issued an order approving OPCo's ESP application, subject to certain modifications, with a return on common equity of 10.2% on capital costs for certain riders. The order included (a) approval of the Distribution Investment Rider 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 April 2015, the PUCO issued an order that granted applications for rehearing for further consideration filed by OPCo and various intervenors.

If OPCo is ultimately not permitted to fully collect all components of its ESP rates, it could reduce future net income and cash flows and impact financial condition. See “Ohio Electric Security Plan Filings” section of Note 4.

2012 Texas Base Rate Case

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

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share of the Turk Plant. In February 2013, a settlement was approved by the LPSC that increased SWEPCo's Louisiana total rates by approximately $2 million annually, effective March 2013. The March 2013 base rates are based upon a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. In December 2014, the LPSC approved a settlement agreement related to the staff review of the cost of service. The settlement agreement reduced the requested revenue increase by $3 million, primarily due to the timing of both the allowed recovery of certain existing regulatory assets and the establishment of a regulatory asset for certain previously expensed costs. See the “2012 Louisiana Formula Rate Filing” section of Note 4.

2014 Oklahoma Base Rate Case

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

In June 2014, a non-unanimous stipulation agreement between PSO, the OCC staff and certain intervenors was filed with the OCC. The parties to the stipulation recommended no overall change to the transmission rider or to annual revenues, other than additional revenues through a separate rider related to advanced metering costs, and that the terms of the stipulation be effective November 2014. The advanced metering rider would provide $24 million of revenues over 14 months beginning in November 2014 and increase to $27 million in 2016. New depreciation rates are recommended for advanced metering investments and existing meters, also to be effective November 2014. Additionally, the stipulation recommends recovery of regulatory assets for 2013 storms and regulatory case expenses. In July 2014, the Attorney General joined in the stipulation agreement. In April 2015, the OCC issued an order that approved the stipulation agreement. See the “2014 Oklahoma Base Rate Case” section of Note 4.

2014 West Virginia Base Rate Case

In June 2014, APCo and WPCo filed a request with the WVPSC to increase annual base rates by $181 million, based upon a 10.62% return on common equity, to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates primarily due to the increase in plant investment and changes in the expected service lives of various generating units. The filing also requested recovery of $89 million in regulatory assets over five years related to 2012 West Virginia storm costs, IGCC and other deferred costs. The filing also included a request to implement a rider of approximately $45 million annually to recover vegetation management costs, including a return on capital investment. In December 2014 and January 2015, intervenors filed testimony which proposed total annual revenue increases ranging from $35 million to $59 million based upon returns on common equity ranging from 9% to 10% and regulatory asset disallowances ranging from $7 million to $9 million. Additionally, other intervenors proposed that the revenue requirement be based on a return on common equity of 8.7% and that $89 million of regulatory assets be disallowed. Intervenors also recommended a disallowance of approximately $44 million related to the December 2013 transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo. Hearings at the WVPSC were held in January 2015. An order is anticipated in the second quarter of 2015. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “2014 West Virginia Base Rate Case” section of Note 4.

New Virginia Legislation Affecting Biennial Reviews

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

4

Kentucky Fuel Adjustment Clause Review

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. In January 2015, the KPSC issued an order disallowing certain FAC costs during the period of January 2014 through May 2015 while KPCo owns and operates both Big Sandy Plant, Unit 2 and its one-half interest in the Mitchell Plant. As a result of this order, KPCo recorded a regulatory disallowance of $36 million in December 2014. In February 2015, KPCo filed an appeal of this order with the Franklin County Circuit Court. In April 2015, the Franklin County Circuit Court issued an order approving intervenors request to hold this case in abeyance until the KPSC issues a final order in KPCo’s two-year FAC review case for the period November 1, 2012 through October 31, 2014. See the “Kentucky Fuel Adjustment Clause Review” section of Note 4.

2014 Kentucky Base Rate Case

In December 2014, KPCo filed a request with the KPSC for a net increase in rates of $70 million, which consists of a $75 million increase in rider rates, offset by a $5 million decrease in annual base rates, to be effective July 2015 based upon a 10.62% return on common equity. In March 2015, intervenors filed testimony which recommended net increases in rates ranging from $20 million to $26 million. These increases consist of proposed increases in rider rates ranging from $55 million to $63 million, offset by decreases in annual base rates ranging from $35 million to $37 million and based upon returns on common equity ranging from 8.65% to 8.75%. Hearings at the KPSC are scheduled for May 2015. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See the “2014 Kentucky Base Rate Case” section of Note 4.

PJM Capacity Market

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

Through May 2015, AGR will provide generation capacity to OPCo for both switched and non-switched OPCo generation customers. For switched customers, OPCo pays AGR $188.88/MW day for capacity. For non-switched OPCo generation customers, OPCo pays AGR its blended tariff rate for capacity consisting of $188.88/MW day for auctioned load and the non-fuel generation portion of its base rate for non-auctioned load. AGR’s excess capacity is subject to the PJM RPM auction. After May 2015, AGR's generation assets will be subject to PJM capacity prices. Shown below are the current auction prices for capacity, as announced/settled by PJM:

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

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

In conjunction with other utility companies, we continue to address mutual concerns related to the PJM capacity auction process. Through this advocacy effort, the FERC has accepted PJM recommendations including: (a) assuring that capacity imports have firm transmission and can be readily dispatched by PJM, (b) placing limits on the number of MWs of summer-only demand response to assure more year-round reliability, (c) modification and enforcement of the dispatch of demand response to better reflect real-time capacity requirements, and (d) redesigning the auction demand curve so that it is less steep, all which should have the impact of reducing capacity price volatility beginning in the June 2018 time period.

In December 2014, PJM filed with FERC for approval of a new type of capacity product, the Capacity Performance Product (CP). The intent of the filing is to raise the level of capacity performance and reliability during emergency events by: (a) assessing higher penalties for non-performance during these events, (b) allowing higher price offers into the auction and (c) requiring generating units to provide fuel and operational assurances that they can perform reliably during emergency events.

In this same filing, PJM proposed with FERC supplemental capacity auctions for the June 2016 through May 2017 and June 2017 through May 2018 auction periods. These supplemental auctions would address capacity performance and reliability issues in these interim years, and if accepted, would allow AGR to re-offer at least part of the capacity already cleared for these years at a higher price.

On March 31, 2015, FERC issued a deficiency letter to PJM regarding their capacity performance filing.  FERC directed PJM to respond within 30 days.

Due to the FERC deficiency letter, PJM filed a waiver request at FERC seeking authority to delay the June 2018 through May 2019 base residual auction, scheduled for May 2015, until FERC issues an order on the merits in the CP docket. PJM requested FERC to rule on its request by April 24, 2015. Absent a ruling, PJM will withdraw its previously filed CP proposal and hold the May auction under its current tariff. If this occurs, the June 2016 through May 2017 and June 2017 through May 2018 supplemental capacity auctions will not be held.

On April 10, 2015, PJM filed a response to the FERC deficiency letter. PJM proposed certain changes to the auction bidding process developed in conjunction with the PJM Market Monitor. The impact of these revisions to the auction clearing price cannot be estimated at this time. Although PJM did not ask for a specific response date from FERC, they reiterated their arguments in the waiver filing, asking FERC for minimal delays in issuing an order.

AEP, our coalition partners and the PJM supplier group made joint filings in support of the PJM proposal to delay the June 2018 through May 2019 base residual auction as well as PJM’s request that FERC rule on the CP docket without undue delay.  Additionally, we plan to provide comments on PJM's deficiency letter response by the April 24, 2015 deadline set by FERC.

Welsh Plant, Units 1 and 3 - Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet mercury and air toxics standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of March 31, 2015, SWEPCo has incurred costs of $211 million and has remaining contractual construction obligations of $84 million related to these projects.  SWEPCo will seek recovery of these project costs from customers through filings at the state commissions and the FERC. See "Climate Change, $CO_2$ Regulation and Energy Policy" section of “Environmental Issues” below.  As of March 31, 2015, the net book value of Welsh Plant, Units 1 and 3 was $431 million, before cost of removal, including materials and supplies inventory and CWIP.  If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 - Rate Matters, Note 6 - Commitments, Guarantees and Contingencies and the “Litigation” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2014 Annual Report. Additionally, see Note 4 - Rate Matters and Note 5 - Commitments, Guarantees and Contingencies included herein. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

6

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court granted our motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs' claims. Several claims remain, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. We will continue to defend against the remaining claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL ISSUES

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

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

See a complete discussion of these matters in the "Environmental Issues" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2014 Annual Report. We will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Environmental rules could result in accelerated depreciation, impairment of assets or regulatory disallowances. If we are unable to recover the costs of environmental compliance, it would reduce future net income and cash flows and impact financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. We continue to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of March 31, 2015, the AEP System had a total generating capacity of 37,600 MWs, of which 23,700 MWs are coal-fired. We continue to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on our generating facilities. Based upon our estimates, investment to meet these requirements ranges from approximately $2.8 billion to $3.3 billion through 2020. These amounts include investments to convert some of our coal generation to natural gas. If natural gas conversion is not completed, the units could be retired sooner than planned.

7

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

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

| Company | Plant Name and Unit | Expected Retirement Date | Generating Capacity (in MWs) |
|---|---|---|---|
| AGR | Kammer Plant | Second quarter of 2015 | 630 |
| AGR | Muskingum River Plant | Second quarter of 2015 | 1,440 |
| AGR | Picway Plant | Second quarter of 2015 | 100 |
| APCo | Clinch River Plant, Unit 3 | Second quarter of 2015 | 235 |
| APCo | Glen Lyn Plant | Second quarter of 2015 | 335 |
| APCo | Kanawha River Plant | Second quarter of 2015 | 400 |
| APCo/AGR | Sporn Plant | Second quarter of 2015 | 600 |
| I&M | Tanners Creek Plant | Second quarter of 2015 | 995 |
| KPCo | Big Sandy Plant, Unit 2 | Second quarter of 2015 | 800 |
| PSO | Northeastern Station, Unit 4 | 2016 | 470 |
| SWEPCo | Welsh Plant, Unit 2 | 2016 | 528 |
| Total | | | 6,533 |

As of March 31, 2015, the net book value of the AGR units listed above was zero. The net book value before cost of removal, including related material and supplies inventory and CWIP balances, of the regulated plants in the table above was $965 million.

In addition, we are in the process of obtaining permits following the KPSC's approval for the conversion of KPCo's 278 MW Big Sandy Plant, Unit 1 to natural gas.  As of March 31, 2015, the net book value before cost of removal, including related material and supplies inventory and CWIP balances, of Big Sandy Plant, Unit 1 was $109 million.

Volatility in fuel prices, pending environmental rules and other market factors could also have an adverse impact on the accounting evaluation of the recoverability of the net book values of coal-fired units. For regulated plants that we may close early, we are seeking regulatory recovery of remaining net book values. To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially reduce future net income and cash flows and impact financial condition.

Clean Air Act Requirements

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

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in $SO_2$ and $NO_x$ emissions from power plants. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. 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. All of the states in which our power plants are located are covered by CSAPR. See "Cross-State Air Pollution Rule (CSAPR)" section below.

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

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA’s requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through 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 2009, the Federal EPA issued a final mandatory reporting rule for $CO_2$ and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of $CO_2$ emissions per year. The Federal EPA issued a final endangerment finding for greenhouse gas emissions from new motor vehicles in 2009. The Federal EPA determined that greenhouse gas emissions from stationary sources will be subject to regulation under the CAA beginning January 2011 and finalized its proposed scheme to streamline and phase-in regulation of stationary source $CO_2$ emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, SIP calls and FIPs. This rule was overturned by the U.S. Supreme Court. The Federal EPA has proposed to include $CO_2$ emissions in standards that apply to new and existing electric utility units. See "Climate Change, $CO_2$ Regulation and Energy Policy" section below.

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

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

Cross-State Air Pollution Rule (CSAPR)

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

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. In 2012, the court issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the CAIR until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to “overcontrol” emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. The petition for review filed by the Federal EPA and other parties in the U.S. Supreme Court was granted in June 2013. In April 2014, the U.S. Supreme Court issued a decision reversing in part the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanding the case for further proceedings consistent with the opinion. The Federal EPA filed a motion to lift the stay and allow Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. The court granted the Federal EPA's motion. The parties have filed briefs, presented oral arguments and the case remains pending. Separate appeals of the Error Corrections Rule and the further revisions have been filed but no briefing schedules have been established. We cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metals) and hydrogen chloride (as a surrogate for acid gases) for units burning coal on a 30-day rolling average basis. In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. The effective date of the final rule was April 16, 2012 and compliance is required within three years. Petitions for administrative reconsideration and judicial review were filed. In 2012, the Federal EPA published a notice announcing that it would accept comments on its reconsideration of certain issues related to the new source standards, including clarification of the requirements that apply during periods of start-up and shut down, measurement issues and the application of variability factors that may have an impact on the level of the standards. The Federal EPA issued revisions to the new source standards consistent with the proposed rule, except the start-up and shut down provisions in March 2013. A final rule on reconsideration was issued in 2014 and a proposed rule containing technical corrections was issued in early 2015, but it has not yet been published in the Federal Register. 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.

The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and the revised rule provides alternative work practice standards for operators during start-up and shut down periods. We have obtained a one-year administrative extension at several units to facilitate the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades.  We remain concerned about the availability of compliance extensions, the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines and the lack of coordination among the Mercury and Air Toxics Standards schedule and other environmental requirements.

Climate Change, $CO_2$ Regulation and Energy Policy

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

Several states have adopted programs that directly regulate $CO_2$ emissions from power plants. The majority of the states where we have generating facilities have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements that can assist in reducing carbon emissions. We are taking steps to comply with these requirements, including increasing our wind power purchases and broadening our portfolio of energy efficiency programs.

In the absence of comprehensive federal climate change or energy policy legislation, President Obama issued a memorandum to the Administrator of the Federal EPA directing the agency to develop and issue a new proposal regulating carbon emissions from new electric generating units under the CAA. The new proposal was issued in September 2013 and requires new large natural gas units to meet a limit of 1,000 pounds of $CO_2$ per MWh of electricity generated and small natural gas units to meet a limit of 1,100 pounds of $CO_2$ per MWh. New coal-fired units are required to meet a limit of 1,100 pounds of $CO_2$ per MWh, with the option to meet a 1,000 pound per MWh limit if they choose to average emissions over multiple years. This proposal was published in the Federal Register in January 2014 and the comment period has closed.

The Federal EPA was also directed to develop and issue a separate proposal regulating carbon emissions from modified and reconstructed electric generating units (EGUs) and to issue guidelines for existing EGUs before June 2014, to finalize those standards by June 2015 and to require states to submit revisions to their implementation plans including such standards no later than June 2016. The Federal EPA issued guidelines for the development of standards for existing sources in June 2014. The guidelines use a “portfolio” approach to reducing emissions from existing sources that includes efficiency improvements at coal plants, displacing coal-fired generation with increased utilization of natural gas combined cycle units, expanding renewable generation resources and increasing customer energy efficiency. Comments were due in December 2014. The Federal EPA also issued proposed regulations governing emissions of $CO_2$ from modified and reconstructed EGUs in June 2014 and comments were due in October 2014. The standards for modified and reconstructed units include several options, including use of historic baselines or energy efficiency audits to establish source-specific $CO_2$ emission rates or to limit $CO_2$ emission rates which could be no less than 1,900 pounds per MWh at larger coal units and 2,100 pounds per MWh at smaller coal units. The Federal EPA announced in January 2015 that the schedule for finalizing its action on all of these standards will extend into the summer of 2015 and that it will develop and propose for public comment a model FIP that will be finalized for individual states that fail to submit a timely state plan to implement the existing source standards. We cannot currently predict the impact these programs may have on future resource plans or our existing generating fleet, but the costs may be substantial.

In 2012, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA’s endangerment finding, its regulatory program for $CO_2$ emissions from new motor vehicles and its plan to phase in regulation of $CO_2$ emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. In June 2014, the U.S. Supreme Court determined that the Federal EPA was not compelled to regulate $CO_2$ emissions from stationary sources under the Title V or PSD programs as a result of its adoption of the motor vehicle standards, but that sources otherwise required to obtain a PSD permit may be required to perform a Best Available Control Technology analysis for $CO_2$ emissions if they exceed a reasonable level.

Federal and state legislation or regulations that mandate limits on the emission of $CO_2$ could result in significant increases in capital expenditures and operating costs, which in turn, could lead to increased liquidity needs and higher financing costs.  Excessive costs to comply with future legislation or regulations might force our utility subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets.

11

Coal Combustion Residual Rule

In 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The proposed rule contained two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and existing unlined surface impoundments.

Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. To comply with a court-ordered deadline, the Federal EPA issued a prepublication copy of its final rule in December 2014. The final rule was published in the Federal Register in April 2015 and becomes effective six months after publication. We are in the process of evaluating the impact of this rule and have not yet determined an estimate of the expected increase in asset retirement obligations. Upon completion of the evaluation, we expect to record an increase in asset retirement obligations in the second quarter of 2015 due to this publication.

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

In February 2014, the Federal EPA completed a risk evaluation of the beneficial uses of coal fly ash in concrete and FGD gypsum in wallboard and concluded that the Federal EPA supports these beneficial uses. Currently, approximately 40% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Encapsulated beneficial uses are not materially impacted by the new rule but additional demonstrations may be required to continue land applications in significant amounts except in road construction projects.

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 have been filed by industry and environmental groups and are currently pending in the U.S. Court of Appeals for the Second Circuit.

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

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

RESULTS OF OPERATIONS

SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. Within our Vertically Integrated Utilities segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

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

AEP Transmission Holdco

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

13

Generation & Marketing

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

AEP River Operations

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

The table below presents Earnings Attributable to AEP Common Shareholders by segment for the three months ended March 31, 2015 and 2014.

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (in millions) | |
| Vertically Integrated Utilities | $299 | $278 |
| Transmission and Distribution Utilities | 97 | 97 |
| AEP Transmission Holdco | 36 | 24 |
| Generation & Marketing | 187 | 163 |
| AEP River Operations | 11 | 3 |
| Corporate and Other (a) | (1) | (5) |
| Earnings Attributable to AEP Common Shareholders | $629 | $560 |

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

AEP CONSOLIDATED

First Quarter of 2015 Compared to First Quarter of 2014

Earnings Attributable to AEP Common Shareholders increased from $560 million in 2014 to $629 million in 2015 primarily due to:

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

These increases were partially offset by:

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

Our results of operations by operating segment are discussed below.

VERTICALLY INTEGRATED UTILITIES

| Vertically Integrated Utilities | Three Months Ended March 31, 2015 | 2014 |
|---|---|---|
| | (in millions) | |
| Revenues | $2,505 | $2,586 |
| Fuel and Purchased Electricity | 983 | 1,094 |
| Gross Margin | 1,522 | 1,492 |
| Other Operation and Maintenance | 576 | 576 |
| Depreciation and Amortization | 272 | 263 |
| Taxes Other Than Income Taxes | 97 | 96 |
| Operating Income | 577 | 557 |
| Interest and Investment Income | 1 | 1 |
| Carrying Costs Income (Expense) | 2 | (1) |
| Allowance for Equity Funds Used During Construction | 14 | 10 |
| Interest Expense | (131) | (131) |
| Income Before Income Tax Expense and Equity Earnings | 463 | 436 |
| Income Tax Expense | 164 | 157 |
| Equity Earnings of Unconsolidated Subsidiaries | 1 | — |
| Net Income | 300 | 279 |
| Net Income Attributable to Noncontrolling Interests | 1 | 1 |
| Earnings Attributable to AEP Common Shareholders | $299 | $278 |

Summary of KWh Energy Sales for Vertically Integrated Utilities

| | Three Months Ended March 31, 2015 | 2014 |
|---|---|---|
| | (in millions of KWhs) | |
| Retail: | | |
| Residential | 10,379 | 10,905 |
| Commercial | 6,011 | 6,115 |
| Industrial | 8,360 | 8,332 |
| Miscellaneous | 548 | 555 |
| Total Retail | 25,298 | 25,907 |
| | | |
| Wholesale (a) | 8,268 | 10,184 |

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

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in our eastern region have a larger effect on revenues than changes in our western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (in degree days) | |
| Eastern Region | | |
| Actual – Heating (a) | 2,045 | 2,128 |
| Normal – Heating (b) | 1,604 | 1,593 |
| | | |
| Actual – Cooling (c) | — | — |
| Normal – Cooling (b) | 5 | 5 |
| | | |
| Western Region | | |
| Actual – Heating (a) | 1,040 | 1,186 |
| Normal – Heating (b) | 877 | 887 |
| | | |
| Actual – Cooling (c) | 14 | 6 |
| Normal – Cooling (b) | 23 | 24 |

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

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

| | |
|---|---|
| First Quarter of 2014 | $278 |
| | |
| Changes in Gross Margin: | |
| Retail Margins | 101 |
| Off-system Sales | (72) |
| Other Revenues | 1 |
| Total Change in Gross Margin | 30 |
| | |
| Changes in Expenses and Other: | |
| Other Operation and Maintenance | — |
| Depreciation and Amortization | (9) |
| Taxes Other Than Income Taxes | (1) |
| Carrying Costs Income | 3 |
| Allowance for Equity Funds Used During Construction | 4 |
| Total Change in Expenses and Other | (3) |
| | |
| Income Tax Expense | (7) |
| Equity Earnings | 1 |
| | |
| First Quarter of 2015 | $299 |

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 $101 million primarily due to the following:
- The effect of successful rate proceedings in our service territories which include:
- A $46 million increase primarily due to rate increases in West Virginia and Virginia, including an adjustment due to the amended Virginia law affecting Biennial Reviews.
- A $30 million rate increase for I&M.
- An $11 million increase primarily due to revenue increases from SWEPCo rate riders in Louisiana and Texas.
- A $9 million rate increase for PSO.

For the rate increases described above, $45 million relate to riders/trackers which have corresponding increases in expense items below.
- A $31 million decrease in PJM expenses net of recovery or offsets.

These increases were partially offset by:
- A $27 million decrease in weather-normalized load primarily due to lower residential sales in the eastern region.
- Margins from Off-system Sales decreased $72 million primarily due to lower market prices and decreased sales volumes.

17

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

- Other Operation and Maintenance expenses remained unchanged but included:
  - A $23 million decrease in employee-related expenses.
  - A $23 million increase in recoverable expenses, primarily including PJM expenses currently fully recovered in rate recovery riders/trackers.
- Depreciation and Amortization expenses increased $9 million primarily due to amortization related to an advanced metering rider implemented in November 2014 in Oklahoma and overall higher depreciable base.
- Allowance for Equity Funds Used During Construction increased $4 million primarily due to increases in environmental construction and transmission projects.
- Income Tax Expense increased $7 million primarily due to an increase in pretax book income, partially offset by other book/tax differences which are accounted for on a flow-through basis.

TRANSMISSION AND DISTRIBUTION UTILITIES

| | Three Months Ended March 31, | |
|---|---|---|
| Transmission and Distribution Utilities | 2015 | 2014 |
| | (in millions) | |
| Revenues | $1,270 | $1,215 |
| Purchased Electricity | 421 | 403 |
| Amortization of Generation Deferrals | 31 | 31 |
| Gross Margin | 818 | 781 |
| Other Operation and Maintenance | 319 | 293 |
| Depreciation and Amortization | 168 | 161 |
| Taxes Other Than Income Taxes | 122 | 119 |
| Operating Income | 209 | 208 |
| Interest and Investment Income | 2 | 3 |
| Carrying Costs Income | 6 | 7 |
| Allowance for Equity Funds Used During Construction | 4 | 3 |
| Interest Expense | (70) | (70) |
| Income Before Income Tax Expense | 151 | 151 |
| Income Tax Expense | 54 | 54 |
| Net Income | 97 | 97 |
| Net Income Attributable to Noncontrolling Interests | — | — |
| Earnings Attributable to AEP Common Shareholders | $97 | $97 |

Summary of KWh Energy Sales for Transmission and Distribution Utilities

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (in millions of KWhs) | |
| Retail: | | |
| Residential | 7,266 | 7,527 |
| Commercial | 5,915 | 5,902 |
| Industrial | 5,280 | 5,143 |
| Miscellaneous | 161 | 171 |
| Total Retail (a) | 18,622 | 18,743 |
| | | |
| Wholesale (b) | 534 | 700 |

(a) Represents energy delivered to distribution customers.

(b) Ohio's contractually obligated purchases of OVEC power sold into PJM.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in our eastern region have a larger effect on revenues than changes in our western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Transmission and Distribution Utilities

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (in degree days) | |
| Eastern Region | | |
| Actual – Heating (a) | 2,438 | 2,409 |
| Normal – Heating (b) | 1,881 | 1,880 |
| | | |
| Actual – Cooling (c) | — | — |
| Normal – Cooling (b) | 3 | 3 |
| | | |
| Western Region | | |
| Actual – Heating (a) | 320 | 300 |
| Normal – Heating (b) | 188 | 196 |
| | | |
| Actual – Cooling (d) | 41 | 70 |
| Normal – Cooling (b) | 109 | 108 |

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

| | | |
|---|---|---|
| First Quarter of 2014 | $97 | |
| | | |
| Changes in Gross Margin: | | |
| Retail Margins | 31 | |
| Off-System Sales | 1 | |
| Transmission Revenues | 4 | |
| Other Revenues | 1 | |
| Total Change in Gross Margin | 37 | |
| | | |
| Changes in Expenses and Other: | | |
| Other Operation and Maintenance | (26 | ) |
| Depreciation and Amortization | (7 | ) |
| Taxes Other Than Income Taxes | (3 | ) |
| Interest and Investment Income | (1 | ) |
| Carrying Costs Income | (1 | ) |
| Allowance for Equity Funds Used During Construction | 1 | |
| Total Change in Expenses and Other | (37 | ) |
| | | |
| Income Tax Expense | — | |
| | | |
| First Quarter of 2015 | $97 | |

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 $31 million primarily due to the following:
- A $17 million increase in TCC and TNC revenues primarily due to the recovery of ERCOT transmission expenses, which is offset in Other Operation and Maintenance expenses below.
- A $12 million increase in Ohio base rates due to the discontinuance of seasonal rates.
- Transmission Revenues increased $4 million primarily due to increased transmission investment in ERCOT.

Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $26 million primarily due to the following:
- A $23 million increase in recoverable expenses, including ERCOT expenses and PJM expenses, currently fully recovered in rate recovery riders/trackers.
- A $13 million increase due to the amortization of 2012 Ohio deferred storm expenses. This increase was offset by a corresponding increase in Retail Margins above.
- A $6 million increase due to PUCO ordered contributions to the Ohio Growth Fund.

These increases were partially offset by:

- A $10 million decrease in the Ohio Energy Efficiency (EE), Peak Demand Reduction Cost Recovery Rider (PDR) costs and associated deferrals. This decrease was offset by a corresponding decrease in Retail Margins above.
- A $6 million decrease in remitted Ohio Universal Service Fund (USF) surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset by a

corresponding decrease in Retail Margins above.

- Depreciation and Amortization expenses increased $7 million primarily due to the following:
  - A $4 million increase due to an increase in the depreciable base of transmission and distribution assets.
  - A $3 million increase in TCC's securitization transition asset, which is partially offset in Other Revenues.

20

AEP TRANSMISSION HOLDCO

| AEP Transmission Holdco | Three Months Ended March 31, 2015 | 2014 |
|---|---|---|
| | (in millions) | |
| Transmission Revenues | $58 | $28 |
| Gross Margin | 58 | 28 |
| Other Operation and Maintenance | 8 | 5 |
| Depreciation and Amortization | 9 | 5 |
| Taxes Other Than Income Taxes | 16 | 7 |
| Operating Income | 25 | 11 |
| Allowance for Equity Funds Used During Construction | 12 | 9 |
| Interest Expense | (8) | (5) |
| Income Before Income Tax Expense and Equity Earnings | 29 | 15 |
| Income Tax Expense | 14 | 8 |
| Equity Earnings of Unconsolidated Subsidiaries | 22 | 17 |
| Net Income | 37 | 24 |
| Net Income Attributable to Noncontrolling Interests | 1 | — |
| Earnings Attributable to AEP Common Shareholders | $36 | $24 |

Summary of Net Plant in Service and CWIP for Transmission Holdco

| | As of March 31, 2015 | 2014 |
|---|---|---|
| | (in millions) | |
| Net Plant in Service | $1,832 | $1,024 |
| CWIP | 1,120 | 804 |

First Quarter of 2015 Compared to First Quarter of 2014

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

| | | |
|---|---|---|
| First Quarter of 2014 | $24 | |
| | | |
| Changes in Transmission Revenues: | | |
| Transmission Revenues | 30 | |
| Total Change in Transmission Revenues | 30 | |
| | | |
| Changes in Expenses and Other: | | |
| Other Operation and Maintenance | (3 | ) |
| Depreciation and Amortization | (4 | ) |
| Taxes Other Than Income Taxes | (9 | ) |
| Allowance for Equity Funds Used During Construction | 3 | |
| Interest Expense | (3 | ) |
| Total Change in Expenses and Other | (16 | ) |
| | | |
| Income Tax Expense | (6 | ) |
| Equity Earnings | 5 | |
| Net Income Attributable to Noncontrolling Interests | (1 | ) |
| | | |
| First Quarter of 2015 | $36 | |

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 $30 million primarily due to an increase in projects placed in-service by our wholly-owned transmission subsidiaries.

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

- Other Operation and Maintenance expenses increased $3 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $4 million primarily due to higher depreciable base.
- Taxes Other Than Income Taxes increased $9 million primarily due to increased property taxes.
- Allowance for Equity Funds Used During Construction increased $3 million primarily due to increased transmission investment.
- Interest Expense increased $3 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense increased $6 million primarily due to an increase in pretax book income.
- Equity Earnings increased $5 million primarily due to an increase in transmission investment by ETT.

GENERATION & MARKETING

| Generation & Marketing | Three Months Ended March 31, 2015 | 2014 |
|---|---|---|
| | (in millions) | |
| Revenues | $1,170 | $1,251 |
| Fuel, Purchased Electricity and Other | 716 | 805 |
| Gross Margin | 454 | 446 |
| Other Operation and Maintenance | 100 | 116 |
| Depreciation and Amortization | 50 | 57 |
| Taxes Other Than Income Taxes | 9 | 12 |
| Operating Income | 295 | 261 |
| Interest and Investment Income | 1 | 1 |
| Interest Expense | (11) | (12) |
| Income Before Income Tax Expense | 285 | 250 |
| Income Tax Expense | 98 | 87 |
| Net Income | 187 | 163 |
| Net Income Attributable to Noncontrolling Interests | — | — |
| Earnings Attributable to AEP Common Shareholders | $187 | $163 |

Summary of MWhs Generated for Generation & Marketing

| | Three Months Ended March 31, 2015 | 2014 |
|---|---|---|
| | (in millions of MWhs) | |
| Fuel Type: | | |
| Coal | 10 | 12 |
| Natural Gas | 4 | 2 |
| Total MWhs | 14 | 14 |

23

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

| | | |
|---|---|---|
| First Quarter of 2014 | $163 | |
| | | |
| Changes in Gross Margin: | | |
| Generation | (24 | ) |
| Retail, Trading and Marketing | 34 | |
| Other | (2 | ) |
| Total Change in Gross Margin | 8 | |
| | | |
| Changes in Expenses and Other: | | |
| Other Operation and Maintenance | 16 | |
| Depreciation and Amortization | 7 | |
| Taxes Other Than Income Taxes | 3 | |
| Interest Expense | 1 | |
| Total Change in Expenses and Other | 27 | |
| | | |
| Income Tax Expense | (11 | ) |
| | | |
| First Quarter of 2015 | $187 | |

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

- Generation decreased $24 million primarily due to lower capacity revenue.
- Retail, Trading and Marketing increased $34 million primarily due to favorable wholesale trading and marketing performance.

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

- Other Operation and Maintenance expenses decreased $16 million primarily due to a decrease in plant outage and maintenance costs.
- Depreciation and Amortization expenses decreased $7 million primarily due to reduced plant in service.
- Income Tax Expense increased $11 million primarily due to an increase in pretax book income.

AEP RIVER OPERATIONS

First Quarter of 2015 Compared to First Quarter of 2014

Earnings Attributable to AEP Common Shareholders from our AEP River Operations segment increased from income of $3 million in 2014 to income of $11 million in 2015 primarily due to a reduction in operating expenses, including lower fuel prices and reduced consumption, lower barge and boat charter expenses and reduced purchases of towing and port services.

24

CORPORATE AND OTHER

First Quarter of 2015 Compared to First Quarter of 2014

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $5 million in 2014 to a loss of $1 million in 2015 primarily due to other book/tax differences which are accounted for on a flow-through basis.

AEP SYSTEM INCOME TAXES

First Quarter of 2015 Compared to First Quarter of 2014

Income Tax Expense increased $26 million primarily due to an increase in pretax book income, partially offset by other book/tax differences which are accounted for on a flow-through basis.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

| | March 31, 2015 | | | December 31, 2014 | | |
|---|---|---|---|---|---|---|
| | (dollars in millions) | | | | | |
| Long-term Debt, including amounts due within one year | $19,229 | 51.5 | % | $18,684 | 50.7 | % |
| Short-term Debt | 855 | 2.3 | | 1,346 | 3.6 | |
| Total Debt | 20,084 | 53.8 | | 20,030 | 54.3 | |
| AEP Common Equity | 17,241 | 46.2 | | 16,820 | 45.7 | |
| Noncontrolling Interests | 7 | — | | 4 | — | |
| Total Debt and Equity Capitalization | $37,332 | 100.0 | % | $36,854 | 100.0 | % |

Our ratio of debt-to-total capital improved from 54.3% as of December 31, 2014 to 53.8% as of March 31, 2015 primarily due to an increase in our common equity from earnings.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We believe we have adequate liquidity under our existing credit facilities. As of March 31, 2015, we had $3.5 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a receivables securitization agreement. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-and-leaseback or leasing agreements or common stock.

Commercial Paper Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. As of March 31, 2015, our available liquidity was approximately $3.5 billion as illustrated in the table below:

| | | Amount (in millions) | Maturity |
|---|---|---|---|
| Commercial Paper Backup: | | | |
| | Revolving Credit Facility | $1,750 | June 2017 |
| | Revolving Credit Facility | 1,750 | July 2018 |
| Total | | 3,500 | |
| Cash and Cash Equivalents | | 190 | |
| Total Liquidity Sources | | 3,690 | |
| Less: | AEP Commercial Paper Outstanding | 115 | |
| | Letters of Credit Issued | 75 | |
| Net Available Liquidity | | $3,500 | |

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

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during the first three months of 2015 was $788 million. The weighted-average interest rate for our commercial paper during 2015 was 0.46%.

Other Credit Facilities

We issue letters of credit under a $100 million uncommitted facility. As of March 31, 2015, the maximum future payments for letters of credit issued under the uncommitted facility were $100 million with a maturity of July 2015. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

Securitized Accounts Receivable

Our receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. This agreement expires in June 2016.

Debt Covenants and Borrowing Limitations

Our credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually defined in our credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of March 31, 2015, this contractually-defined percentage was 50.8%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of March 31, 2015, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of our non-exchange traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our credit agreements.

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

26

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders and we manage our borrowings to stay within those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.53 per share in April 2015. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income primarily derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends.

We do not believe restrictions related to our various financing arrangements and regulatory requirements will have any significant impact on Parent's ability to access cash to meet the payment of dividends on its common stock.

Credit Ratings

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

CASH FLOW

Managing our cash flows is a major factor in maintaining our liquidity strength.

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (in millions) | |
| Cash and Cash Equivalents at Beginning of Period | $163 | $118 |
| Net Cash Flows from Operating Activities | 1,257 | 1,133 |
| Net Cash Flows Used for Investing Activities | (1,017) | (981) |
| Net Cash Flows from (Used for) Financing Activities | (213) | 22 |
| Net Increase in Cash and Cash Equivalents | 27 | 174 |
| Cash and Cash Equivalents at End of Period | $190 | $292 |

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

Operating Activities

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (in millions) | |
| Net Income | $631 | $561 |
| Depreciation and Amortization | 505 | 491 |
| Other | 121 | 81 |
| Net Cash Flows from Operating Activities | $1,257 | $1,133 |

27

Net Cash Flows from Operating Activities were $1.3 billion in 2015 consisting primarily of Net Income of $631 million and $505 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.

Net Cash Flows from Operating Activities were $1.1 billion in 2014 consisting primarily of Net Income of $561 million and $491 million of noncash Depreciation and Amortization partially offset by $137 million of fuel cost deferrals and $56 million of Ohio capacity deferrals as a result of the PUCO's July 2012 approval of a capacity deferral mechanism. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Deferred Income Taxes increased primarily due to provisions in the Taxpayer Relief Act of 2012 and an increase in tax/book temporary differences from operations. The reduction in Fuel, Material and Supplies balances reflects a decrease in fuel inventory due to the cold winter weather and increased generation.

Investing Activities

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (in millions) | |
| Construction Expenditures | $(1,077) | $(907) |
| Acquisitions of Nuclear Fuel | (52) | (49) |
| Acquisitions of Assets/Businesses | (2) | (43) |
| Other | 114 | 18 |
| Net Cash Flows Used for Investing Activities | $(1,017) | $(981) |

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

Net Cash Flows Used for Investing Activities were $981 million in 2014 primarily due to Construction Expenditures for environmental, distribution and transmission investments. We also purchased transmission assets for $38 million.

Financing Activities

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (in millions) | |
| Issuance of Common Stock, Net | $31 | $15 |
| Issuance/Retirement of Debt, Net | 44 | 281 |
| Dividends Paid on Common Stock | (260) | (245) |
| Other | (28) | (29) |
| Net Cash Flows from (Used for) Financing Activities | $(213) | $22 |

Net Cash Flows Used for Financing Activities in 2015 were $213 million. Our 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. We paid common stock dividends of $260 million. See Note 11 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows from Financing Activities in 2014 were $22 million. Our net debt issuances were $281 million. The net issuances included issuances of $76 million of other debt notes and an increase in short-term borrowing of $575 million offset by retirements of $258 million of senior unsecured and other debt notes and $112 million of securitization bonds. We paid common stock dividends of $245 million. See Note 11 - Financing Activities for a complete discussion of long-term debt issuances and retirements.

In April 2015, APCo issued $86 million of 1.9% Pollution Control Bonds due in 2019.

In April 2015, OPCo retired $86 million of 3.125% Pollution Control Bonds due in 2015.

In April 2015, SWEPCo retired $100 million of 5.375% Senior Unsecured Notes due in 2015.

OFF-BALANCE SHEET ARRANGEMENTS

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

| | March 31, 2015 | December 31, 2014 |
|---|---|---|
| | (in millions) | |
| Rockport Plant, Unit 2 Future Minimum Lease Payments | $1,184 | $1,184 |
| Railcars Maximum Potential Loss from Lease Agreement | 19 | 19 |

For complete information on each of these off-balance sheet arrangements, see the “Off-balance Sheet Arrangements” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2014 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of our contractual obligations is included in our 2014 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the “Cash Flow” section above.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the “Critical Accounting Policies and Estimates” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2014 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During the First Quarter of 2015

The FASB issued ASU 2014-08 “Presentation of Financial Statements and Property, Plant and Equipment” changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity’s operations and financial results when the component meets the criteria to be classified as held-for-sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. We adopted ASU 2014-08 effective January 1, 2015. There were no events requiring application of the new accounting guidance.

Pronouncements Effective in the Future

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

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

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

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

Future Accounting Changes

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

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

Our Transmission and Distribution Utilities segment is exposed to FTR price risk as it relates to RTO congestion during the June 2012 - May 2015 Ohio ESP period. Additional risks include energy procurement risk and interest rate risk.

Our Generation & Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates. In addition, our Generation & Marketing segment is also exposed to certain market risks as a major power producer and through its transactions in wholesale electricity, natural gas and coal trading and marketing contracts.

We employ risk management contracts including physical forward purchase-and-sale contracts and financial forward purchase-and-sale contracts. We engage in risk management of power, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply, and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various daily and quarterly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, and Chief Risk Officer in addition to Energy Supply's President and Vice President. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the respective committee.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2014:
MTM Risk Management Contract Net Assets (Liabilities)
Three Months Ended March 31, 2015

| | Vertically Integrated Utilities | Transmission and Distribution Utilities | Generation & Marketing | Total |
|---|---|---|---|---|
| | (in millions) | | | |
| Total MTM Risk Management Contract Net Assets as of December 31, 2014 | $36 | $46 | $140 | $222 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | (24) | (6) | 1 | (29) |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | — | — | 47 | 47 |
| Changes in Fair Value Due to Market Fluctuations During the Period (b) | — | — | 4 | 4 |
| Changes in Fair Value Allocated to Regulated Jurisdictions (c) | (5) | 4 | — | (1) |
| Total MTM Risk Management Contract Net Assets as of March 31, 2015 | $7 | $44 | $192 | 243 |
| Commodity Cash Flow Hedge Contracts | | | | (8) |
| Interest Rate and Foreign Currency Cash Flow Hedge Contracts | | | | (1) |
| Fair Value Hedge Contracts | | | | (2) |
| Collateral Deposits | | | | 32 |
| | | | | $264 |

Total MTM Derivative Contract Net Assets as of
March 31, 2015

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.

(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

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

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

Credit Risk

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

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of March 31, 2015, our credit exposure net of collateral to sub investment grade counterparties was approximately 7.9%, 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, 2015, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

| Counterparty Credit Quality | Exposure Before Credit Collateral | Credit Collateral | Net Exposure | Number of Counterparties >10% of Net Exposure | Net Exposure of Counterparties >10% |
|---|---|---|---|---|---|
| | (in millions, except number of counterparties) | | | | |
| Investment Grade | $641 | $— | $641 | 2 | $261 |
| Split Rating | 23 | — | 23 | 1 | 23 |
| Noninvestment Grade | 1 | 1 | — | — | — |
| No External Ratings: | | | | | |
| Internal Investment Grade | 106 | — | 106 | 4 | 73 |
| Internal Noninvestment Grade | 84 | 18 | 66 | 2 | 37 |
| Total as of March 31, 2015 | $855 | $19 | $836 | 9 | $394 |
| | | | | | |
| Total as of December 31, 2014 | $817 | $21 | $796 | 8 | $347 |

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

Value at Risk (VaR) Associated with Risk Management Contracts

We use a risk measurement model, which calculates VaR, to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of March 31, 2015, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

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

VaR Model
Trading Portfolio

| Three Months Ended March 31, 2015 | | | | Twelve Months Ended December 31, 2014 | | | |
|---|---|---|---|---|---|---|---|
| End | High | Average | Low | End | High | Average | Low |
| (in millions) | | | | (in millions) | | | |
| $— | $1 | $— | $— | $— | $3 | $1 | $— |

VaR Model
Non-Trading Portfolio

| Three Months Ended March 31, 2015 | | | | Twelve Months Ended December 31, 2014 | | | |
|---|---|---|---|---|---|---|---|
| End | High | Average | Low | End | High | Average | Low |
| (in millions) | | | | (in millions) | | | |
| $1 | $2 | $1 | $— | $2 | $3 | $1 | $— |

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

As our VaR calculation captures recent price movements, we also perform regular stress testing of the trading portfolio to understand our exposure to extreme price movements. We employ a historical-based method whereby the current trading portfolio is subjected to actual, observed price movements from the last several years in order to ascertain which historical price movements translated into the largest potential MTM loss. We then research the underlying positions, price movements and market events that created the most significant exposure and report the findings to the Risk Executive Committee, Regulated Risk Committee, or Competitive Risk Committee as appropriate.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which our interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of March 31, 2015 and December 31, 2014, the estimated EaR on our debt portfolio for the following twelve months was $36 million and $33 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2015 and 2014
(in millions, except per-share and share amounts)
(Unaudited)

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| REVENUES | | |
| Vertically Integrated Utilities | $2,487 | $2,549 |
| Transmission and Distribution Utilities | 1,206 | 1,161 |
| Generation & Marketing | 859 | 821 |
| Other Revenues | 156 | 117 |
| TOTAL REVENUES | 4,708 | 4,648 |
| | | |
| EXPENSES | | |
| Fuel and Other Consumables Used for Electric Generation | 1,071 | 1,168 |
| Purchased Electricity for Resale | 718 | 638 |
| Other Operation | 746 | 780 |
| Maintenance | 294 | 292 |
| Depreciation and Amortization | 505 | 491 |
| Taxes Other Than Income Taxes | 250 | 238 |
| TOTAL EXPENSES | 3,584 | 3,607 |
| | | |
| OPERATING INCOME | 1,124 | 1,041 |
| | | |
| Other Income (Expense): | | |
| Interest and Investment Income | 1 | 1 |
| Carrying Costs Income | 8 | 6 |
| Allowance for Equity Funds Used During Construction | 30 | 22 |
| Interest Expense | (223) | (220) |
| | | |
| INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS | 940 | 850 |
| | | |
| Income Tax Expense | 333 | 307 |
| Equity Earnings of Unconsolidated Subsidiaries | 24 | 18 |
| | | |
| NET INCOME | 631 | 561 |
| | | |
| Net Income Attributable to Noncontrolling Interests | 2 | 1 |
| | | |
| EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS | $629 | $560 |
| | | |
| WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING | 489,597,986 | 487,867,089 |
| | | |
| TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS | $1.29 | $1.15 |

| | | |
|---|---|---|
| WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING | 489,936,726 | 488,271,167 |
| TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS | $1.29 | $1.15 |
| CASH DIVIDENDS DECLARED PER SHARE | $0.53 | $0.50 |

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 40.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2015 and 2014
(in millions)
(Unaudited)

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| Net Income | $631 | $561 |
| | | |
| OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES | | |
| Cash Flow Hedges, Net of Tax of $3 and $3 in 2015 and 2014, Respectively | (6) | 5 |
| Securities Available for Sale, Net of Tax of $0 and $0 in 2015 and 2014, Respectively | 1 | — |
| Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 in 2015 and 2014, Respectively | — | 1 |
| | | |
| TOTAL OTHER COMPREHENSIVE INCOME (LOSS) | (5) | 6 |
| | | |
| TOTAL COMPREHENSIVE INCOME | 626 | 567 |
| | | |
| Total Comprehensive Income Attributable to Noncontrolling Interests | 2 | 1 |
| | | |
| TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS | $624 | $566 |

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 40.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Three Months Ended March 31, 2015 and 2014
(in millions)
(Unaudited)

| | AEP Common Shareholders | | | | | | |
|---|---|---|---|---|---|---|---|
| | Common Stock | | | | | | |
| | Shares | Amount | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Noncontrolling Interests | Total |
| TOTAL EQUITY – DECEMBER 31, 2013 | 508 | $3,303 | $6,131 | $6,766 | $(115) | $1 | $16,086 |
| Issuance of Common Stock | | 2 | 13 | | | | 15 |
| Common Stock Dividends | | | | (244) | | (1) | (245) |
| Other Changes in Equity | | | | (6) | | 2 | (4) |
| Net Income | | | | 560 | | 1 | 561 |
| Other Comprehensive Income | | | | | 6 | | 6 |
| TOTAL EQUITY – MARCH 31, 2014 | 508 | $3,305 | $6,144 | $7,076 | $(109) | $3 | $16,419 |
| TOTAL EQUITY – DECEMBER 31, 2014 | 510 | $3,313 | $6,204 | $7,406 | $(103) | $4 | $16,824 |
| Issuance of Common Stock | | 4 | 27 | | | | 31 |
| Common Stock Dividends | | | | (259) | | (1) | (260) |
| Other Changes in Equity | | | 3 | | | 2 | 5 |
| Deferred State Income Tax Rate Adjustment | | | 17 | | | | 17 |
| Net Income | | | | 629 | | 2 | 631 |
| Other Comprehensive Loss | | | | | (5) | | (5) |
| Pension and OPEB Adjustment Related to Mitchell Plant | | | | | 5 | | 5 |
| TOTAL EQUITY – MARCH 31, 2015 | 510 | $3,317 | $6,251 | $7,776 | $(103) | $7 | $17,248 |

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 40.

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

| | March 31, 2015 | December 31, 2014 |
|---|---|---|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | $190 | $163 |
| Other Temporary Investments (March 31, 2015 and December 31, 2014 Amounts Include $281 and $371, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and EIS) | 293 | 386 |
| Accounts Receivable: | | |
| Customers | 725 | 727 |
| Accrued Unbilled Revenues | 107 | 146 |
| Pledged Accounts Receivable – AEP Credit | 1,005 | 987 |
| Miscellaneous | 78 | 87 |
| Allowance for Uncollectible Accounts | (26) | (21) |
| Total Accounts Receivable | 1,889 | 1,926 |
| Fuel | 452 | 587 |
| Materials and Supplies | 740 | 738 |
| Risk Management Assets | 138 | 178 |
| Regulatory Asset for Under-Recovered Fuel Costs | 137 | 127 |
| Margin Deposits | 129 | 95 |
| Prepayments and Other Current Assets | 148 | 278 |
| TOTAL CURRENT ASSETS | 4,116 | 4,478 |
| | | |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Generation | 25,856 | 25,727 |
| Transmission | 12,531 | 12,433 |
| Distribution | 17,375 | 17,157 |
| Other Property, Plant and Equipment (Including Plant to be Retired, Coal Mining and Nuclear Fuel) | 5,834 | 5,770 |
| Construction Work in Progress | 3,710 | 3,218 |
| Total Property, Plant and Equipment | 65,306 | 64,305 |
| Accumulated Depreciation and Amortization | 20,496 | 20,188 |
| TOTAL PROPERTY, PLANT AND EQUIPMENT – NET | 44,810 | 44,117 |
| | | |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 4,255 | 4,264 |
| Securitized Assets | 2,001 | 2,072 |
| Spent Nuclear Fuel and Decommissioning Trusts | 2,122 | 2,096 |
| Goodwill | 91 | 91 |
| Long-term Risk Management Assets | 365 | 294 |
| Deferred Charges and Other Noncurrent Assets | 2,278 | 2,221 |
| TOTAL OTHER NONCURRENT ASSETS | 11,112 | 11,038 |

| | | |
|---|---|---|
| TOTAL ASSETS | $60,038 | $59,633 |

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 40.

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

| | March 31, 2015 | December 31, 2014 |
|---|---|---|
| CURRENT LIABILITIES | | |
| Accounts Payable | $1,283 | $1,287 |
| Short-term Debt: | | |
| Securitized Debt for Receivables – AEP Credit | 740 | 744 |
| Other Short-term Debt | 115 | 602 |
| Total Short-term Debt | 855 | 1,346 |
| Long-term Debt Due Within One Year (March 31, 2015 and December 31, 2014 Amounts Include $434 and $431, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine) | 2,451 | 2,503 |
| Risk Management Liabilities | 83 | 92 |
| Customer Deposits | 335 | 324 |
| Accrued Taxes | 846 | 871 |
| Accrued Interest | 227 | 239 |
| Regulatory Liability for Over-Recovered Fuel Costs | 48 | 55 |
| Other Current Liabilities | 1,000 | 1,250 |
| TOTAL CURRENT LIABILITIES | 7,128 | 7,967 |
| | | |
| NONCURRENT LIABILITIES | | |
| Long-term Debt (March 31, 2015 and December 31, 2014 Amounts Include $2,084 and $2,260, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy and Sabine) | 16,778 | 16,181 |
| Long-term Risk Management Liabilities | 156 | 131 |
| Deferred Income Taxes | 11,188 | 10,986 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 3,911 | 3,892 |
| Asset Retirement Obligations | 1,969 | 1,951 |
| Employee Benefits and Pension Obligations | 598 | 630 |
| Deferred Credits and Other Noncurrent Liabilities | 1,062 | 1,071 |
| TOTAL NONCURRENT LIABILITIES | 35,662 | 34,842 |
| | | |
| TOTAL LIABILITIES | 42,790 | 42,809 |

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

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

| | 2015 | 2014 |
|---|---|---|
| Shares Authorized | 600,000,000 | 600,000,000 |

| | | | | |
|---|---|---|---|---|
| Shares Issued | 510,266,134 | 509,739,159 | | |
| (20,336,592 Shares were Held in Treasury as of March 31, 2015 and December 31, 2014) | | | 3,317 | 3,313 |
| Paid-in Capital | | | 6,251 | 6,204 |
| Retained Earnings | | | 7,776 | 7,406 |
| Accumulated Other Comprehensive Income (Loss) | | | (103 ) | (103 ) |
| TOTAL AEP COMMON SHAREHOLDERS’ EQUITY | | | 17,241 | 16,820 |
| Noncontrolling Interests | | | 7 | 4 |
| TOTAL EQUITY | | | 17,248 | 16,824 |
| TOTAL LIABILITIES AND EQUITY | | | $60,038 | $59,633 |

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 40.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2015 and 2014
(in millions)
(Unaudited)

| | Three Months Ended March 31, 2015 | 2014 |
|---|---|---|
| OPERATING ACTIVITIES | | |
| Net Income | $631 | $561 |
| Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities: | | |
| Depreciation and Amortization | 505 | 491 |
| Deferred Income Taxes | 243 | 299 |
| Carrying Costs Income | (8) | (6) |
| Allowance for Equity Funds Used During Construction | (30) | (22) |
| Mark-to-Market of Risk Management Contracts | (21) | 6 |
| Amortization of Nuclear Fuel | 38 | 38 |
| Property Taxes | (35) | (54) |
| Fuel Over/Under-Recovery, Net | 3 | (137) |
| Deferral of Ohio Capacity Costs, Net | (7) | (56) |
| Change in Other Noncurrent Assets | 1 | (25) |
| Change in Other Noncurrent Liabilities | (31) | 77 |
| Changes in Certain Components of Working Capital: | | |
| Accounts Receivable, Net | 37 | (83) |
| Fuel, Materials and Supplies | 133 | 209 |
| Accounts Payable | 49 | 33 |
| Accrued Taxes, Net | 35 | (16) |
| Other Current Assets | (17) | (51) |
| Other Current Liabilities | (269) | (131) |
| Net Cash Flows from Operating Activities | 1,257 | 1,133 |
| | | |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (1,077) | (907) |
| Change in Other Temporary Investments, Net | 93 | 44 |
| Purchases of Investment Securities | (246) | (165) |
| Sales of Investment Securities | 228 | 148 |
| Acquisitions of Nuclear Fuel | (52) | (49) |
| Acquisitions of Assets/Businesses | (2) | (43) |
| Other Investing Activities | 39 | (9) |
| Net Cash Flows Used for Investing Activities | (1,017) | (981) |
| | | |
| FINANCING ACTIVITIES | | |
| Issuance of Common Stock, Net | 31 | 15 |
| Issuance of Long-term Debt | 774 | 76 |
| Change in Short-term Debt, Net | (491) | 575 |
| Retirement of Long-term Debt | (239) | (370) |
| Principal Payments for Capital Lease Obligations | (31) | (33) |
| Dividends Paid on Common Stock | (260) | (245) |
| Other Financing Activities | 3 | 4 |
| Net Cash Flows from (Used for) Financing Activities | (213) | 22 |

| | | |
|---|---|---|
| Net Increase in Cash and Cash Equivalents | 27 | 174 |
| Cash and Cash Equivalents at Beginning of Period | 163 | 118 |
| Cash and Cash Equivalents at End of Period | $190 | $292 |
| | | |
| SUPPLEMENTARY INFORMATION | | |
| Cash Paid for Interest, Net of Capitalized Amounts | $223 | $234 |
| Net Cash Paid (Received) for Income Taxes | 2 | (6) |
| Noncash Acquisitions Under Capital Leases | 29 | 20 |
| Construction Expenditures Included in Current Liabilities as of March 31, | 529 | 387 |
| Construction Expenditures Included in Noncurrent Liabilities as of March 31, | 43 | — |

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 40.

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

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

## 1. SIGNIFICANT ACCOUNTING MATTERS

### General

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

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

### Revenue Recognition

#### Electricity Supply and Delivery Activities - Transactions with PJM

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

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

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

Earnings Per Share (EPS)

Basic EPS is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

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

| | Three Months Ended March 31, | | | |
|---|---|---|---|---|
| | 2015 | | 2014 | |
| | (in millions, except per share data) | | | |
| | | $/share | | $/share |
| Earnings Attributable to AEP Common Shareholders | $629 | | $560 | |
| | | | | |
| Weighted Average Number of Basic Shares Outstanding | 489.6 | $1.29 | 487.9 | $1.15 |
| Weighted Average Dilutive Effect of Restricted Stock Units | 0.3 | — | 0.4 | — |
| Weighted Average Number of Diluted Shares Outstanding | 489.9 | $1.29 | 488.3 | $1.15 |

There were no antidilutive shares outstanding as of March 31, 2015 and 2014.

2. NEW ACCOUNTING PRONOUNCEMENTS

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

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

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

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. If applicable, this standard will change the presentation of our financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. We adopted ASU 2014-08 effective January 1, 2015. There were no events requiring the application of this new accounting guidance.

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

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

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

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

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

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

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

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

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

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

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

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three months ended March 31, 2015 and 2014. All amounts in the following tables are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended 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 | $(19) | $8 | $(93) | $(103) |
| Change in Fair Value Recognized in AOCI | 1 | — | 1 | — | 2 |
| Amounts Reclassified from AOCI | (8) | 1 | — | — | (7) |
| Net Current Period Other Comprehensive Income (Loss) | (7) | 1 | 1 | — | (5) |
| Pension and OPEB Adjustment Related to Mitchell Plant | — | — | — | 5 | 5 |
| Balance in AOCI as of March 31, 2015 | $(6) | $(18) | $9 | $(88) | $(103) |

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2014

| | Cash Flow Hedges | | | | |
|---|---|---|---|---|---|
| | Commodity | Interest Rate and Foreign Currency | Securities Available for Sale | Pension and OPEB | Total |
| | (in millions) | | | | |
| Balance in AOCI as of December 31, 2013 | $— | $(23) | $7 | $(99) | $(115) |
| Change in Fair Value Recognized in AOCI | (14) | — | — | — | (14) |
| Amounts Reclassified from AOCI | 18 | 1 | — | 1 | 20 |
| Net Current Period Other Comprehensive Income | 4 | 1 | — | 1 | 6 |
| Balance in AOCI as of March 31, 2014 | $4 | $(22) | $7 | $(98) | $(109) |

Reclassifications from Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the three months ended March 31, 2015 and 2014. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended March 31, 2015 and 2014

| | Amount of (Gain) Loss Reclassified from AOCI Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| Gains and Losses on Cash Flow Hedges | (in millions) | |
| Commodity: | | |
| Generation & Marketing Revenues | $(13) | $— |
| Purchased Electricity for Resale | 1 | 31 |
| Regulatory Assets/(Liabilities), Net (a) | — | (3) |
| Subtotal – Commodity | (12) | 28 |
| | | |
| Interest Rate and Foreign Currency: | | |
| Interest Expense | 1 | 2 |
| Subtotal – Interest Rate and Foreign Currency | 1 | 2 |
| | | |
| Reclassifications from AOCI, before Income Tax (Expense) Credit | (11) | 30 |
| Income Tax (Expense) Credit | (4) | 11 |
| Reclassifications from AOCI, Net of Income Tax (Expense) Credit | (7) | 19 |
| | | |
| Pension and OPEB | | |
| Amortization of Prior Service Cost (Credit) | (5) | (5) |
| Amortization of Actuarial (Gains)/Losses | 5 | 7 |
| Reclassifications from AOCI, before Income Tax (Expense) Credit | — | 2 |
| Income Tax (Expense) Credit | — | 1 |
| Reclassifications from AOCI, Net of Income Tax (Expense) Credit | — | 1 |
| | | |
| Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit | $(7) | $20 |

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

4. RATE MATTERS

As discussed in the 2014 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2014 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2015 and updates the 2014 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

| Noncurrent Regulatory Assets | March 31, 2015 | December 31, 2014 |
|---|---|---|
| | (in millions) | |
| Regulatory Assets Currently Earning a Return | | |
| West Virginia Vegetation Management Program | $26 | $20 |
| Storm Related Costs | 20 | 20 |
| Regulatory Assets Currently Not Earning a Return | | |
| Storm Related Costs | 100 | 100 |
| Asset Retirement Obligation | 17 | 9 |
| Carbon Capture and Storage Product Validation Facility | 13 | 13 |
| IGCC Pre-Construction Costs | 11 | 11 |
| Virginia Demand Response Program Costs | 10 | 9 |
| Ormet Special Rate Recovery Mechanism | 10 | 10 |
| Other Regulatory Assets Pending Final Regulatory Approval | 29 | 34 |
| Total Regulatory Assets Pending Final Regulatory Approval | $236 | $226 |

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

OPCo Rate Matters

Ohio Electric Security Plan Filings

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018.

In August 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover deferred fuel costs in rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. In November 2012, OPCo appealed that PUCO order to the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated 2009 - 2011 ESP order, which granted a weighted average cost of capital (WACC) rate. In November 2012, the IEU filed an appeal of the PUCO decision that included the argument that carrying costs should be reduced due to an accumulated deferred income tax credit which, as of March 31, 2015, could reduce carrying costs by $25 million including $13 million of unrecognized equity carrying costs. Oral arguments at the Supreme Court of Ohio were held in February 2015. OPCo argued for a remand to reinstate the WACC carrying charges initially approved by the PUCO and challenged the IEU argument that the carrying charges should be reduced due to an accumulated deferred income tax credit. A decision from the Supreme Court of Ohio is pending.

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

June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that established base generation rates through May 2015. This ruling was generally upheld in rehearing orders in January and March 2013.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the RPM price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The OPCo RPM price collected from CRES providers, which includes reserve margins, was approximately $34/MW day through May 2014 and is $150/MW day from June 2014 through May 2015. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and is currently collected at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In July 2014, OPCo submitted a separate application to continue the RSR to collect the unrecovered portion of the deferred capacity costs at the rate of $4.00/MWh, until the balance of the capacity deferrals has been collected. In April 2015, the PUCO issued an order approving the application to continue the RSR, with modifications. The order included approval to continue the collection of deferred capacity costs at a rate of $4.00/MWh beginning June 1, 2015 for approximately 32 months, with carrying costs at a long-term cost of debt rate. Additionally, the order stated that an audit will be conducted of the final capacity deferral balance as of May 31, 2015. As of March 31, 2015, OPCo's incurred deferred capacity costs balance of $434 million, including debt carrying costs, was recorded in regulatory assets on the condensed balance sheet.

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

In November 2013, the PUCO issued an order approving OPCo’s CBP with modifications. As ordered, in 2014, OPCo conducted multiple energy-only auctions for a total of 100% of the SSO load with delivery beginning April 2014 through May 2015. For delivery starting in June 2015, OPCo will conduct energy and capacity auctions for its entire SSO load. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit.

In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC. In March 2014, the PUCO approved OPCo’s request to implement riders related to the unbundling of the FAC. In October 2014, the independent auditor, selected by the PUCO, filed its report for the period August 2012 through May 2015 with the PUCO. If the PUCO ultimately concludes that a portion of the fixed fuel costs are also recovered through OPCo's $188.88/MW day capacity charge, the independent auditor recommends a methodology for calculating a refund of a portion of certain fixed fuel costs. The retail share of these fixed fuel costs is approximately $90 million annually. A hearing related to this matter has not been scheduled. Management believes that no over-recovery of costs has occurred and intends to oppose the findings in the audit report.

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

June 2015 - May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments and the continuation and modification of certain existing riders, including the Distribution Investment Rider (DIR), effective June 2015 through May 2018. The proposal included a return on common equity of 10.65% on capital costs for certain riders. The proposal also included a purchased power agreement (PPA) rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based purchase power agreement. The PPA would initially be based upon the OVEC contractual entitlement and could, upon further approval, be expanded to include other contracts involving other Ohio legacy generation assets.

In October 2014, OPCo filed a separate application with the PUCO to propose a new extended PPA for inclusion in the PPA rider, discussed above. The new PPA would include an additional 2,671 MW to be purchased from AGR over the life of the respective generating units.

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 April 2015, the PUCO issued an order that granted applications for rehearing for further consideration filed by OPCo and various intervenors.

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

Significantly Excessive Earnings Test Filings

In January 2011, the PUCO issued an order on the 2009 SEET filing. The order gave consideration for a future commitment to invest $20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend $20 million on this solar project or another project. In September 2013, a proposed second phase of OPCo’s gridSMART® program was filed with the PUCO which included a proposed project to satisfy this PUCO directive. A decision from the PUCO is pending.

Management believes its financial statements adequately address the impact of 2014 SEET requirements.

Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo’s generation assets including the transfer of OPCo’s generation assets and associated generation liabilities at net book value to AGR. In June 2013, the IEU filed an appeal with the Supreme Court of Ohio claiming the PUCO order approving the corporate separation was unlawful. A decision from the Supreme Court of Ohio is pending. In December 2013, corporate separation of OPCo’s generation assets was completed. If any part of the PUCO order is overturned, it could reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

In January 2012, the PUCO issued an order in OPCo’s 2009 FAC that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo’s under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. As a result, OPCo recorded a $30 million net favorable adjustment on the 2012 statement of income. 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 is still pending. If the PUCO ultimately determines that additional amounts should benefit ratepayers as a result of the consultant's review of the coal reserve valuation, it could reduce future net income and cash flows and impact financial condition.

2012 and 2013 Fuel Adjustment Clause Audits

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

Ormet

Ormet, a large aluminum company, had a contract to purchase power from OPCo through 2018. In February 2013, Ormet filed for bankruptcy and subsequently shut down operations in October 2013. In March 2014, the PUCO issued an order in OPCo's Economic Development Rider (EDR) filing allowing OPCo to include $39 million of Ormet-related foregone revenues in the EDR effective April 2014. The order stated that if the stipulation agreement between OPCo and Ormet is subsequently adopted by the PUCO, OPCo could file an application to modify the EDR rate for the remainder of the period requesting recovery of the remaining $10 million of Ormet deferrals which, as of March 31, 2015, is recorded in regulatory assets on the condensed balance sheet. In April 2014, an intervenor filed testimony objecting to $5 million of the remaining foregone revenues. A hearing at the PUCO related to the stipulation agreement was held in May 2014.

In addition, in the 2009 - 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related revenues under a previous interim arrangement (effective from January 2009 through September 2009) and requested that the PUCO prevent OPCo from collecting Ormet-related revenues in the future. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. The PUCO did not take any action on this request. The intervenors raised this issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement.

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

SWEPCo Rate Matters

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In October 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo's recovery of AFUDC in addition to limits on its recovery of cash construction costs. Additionally, the PUCT deferred consideration of the requested increase in depreciation expense related to the change in the 2016 retirement date of the Welsh Plant, Unit 2. As of March 31, 2015, the net book value of Welsh Plant, Unit 2 was $84 million, before cost of removal, including materials and supplies inventory and CWIP.

50

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

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

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and approved by the LPSC. The settlement increased SWEPCo's Louisiana total rates by approximately $2 million annually, effective March 2013, which consisted of an increase in base rates of approximately $85 million annually offset by a decrease in fuel and other rates of approximately $83 million annually. The March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit. The rates are subject to refund based on the staff review of the cost of service and the prudency review of the Turk Plant. The settlement also provided that the LPSC review base rates in 2014 and 2015 and that SWEPCo recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. In December 2014, the LPSC approved a settlement agreement related to the staff review of the cost of service. The settlement agreement reduced the requested revenue increase by $3 million, primarily due to the timing of both the allowed recovery of certain existing regulatory assets and the establishment of a regulatory asset for certain previously expensed costs. If the LPSC orders refunds based upon the pending prudence review of the Turk Plant investment, it could reduce future net income and cash flows and impact financial condition.

2014 Louisiana Formula Rate Filing

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

2015 Louisiana Formula Rate Filing

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

51

Welsh Plant, Units 1 and 3 - Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet mercury and air toxics standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC.  Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC.  As of March 31, 2015, SWEPCo has incurred costs of $211 million and has remaining contractual construction obligations of $84 million related to these projects.  SWEPCo will seek recovery of these project costs from customers through filings at the state commissions and the FERC. As of March 31, 2015, the net book value of Welsh Plant, Units 1 and 3 was $431 million, before cost of removal, including materials and supplies inventory and CWIP.  If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

APCo and WPCo Rate Matters

2014 West Virginia Base Rate Case

In June 2014, APCo filed a request with the WVPSC to increase annual base rates by $181 million, based upon a 10.62% return on common equity, to be effective in the second quarter of 2015. The filing included a request to increase generation depreciation rates primarily due to the increase in plant investment and changes in the expected service lives of various generating units. The filing also requested recovery of $89 million in regulatory assets over five years related to 2012 West Virginia storm costs, IGCC and other deferred costs. In addition to the base rate request, the filing also included a request to implement a rider of approximately $45 million annually to recover vegetation management costs, including a return on capital investment.  In October 2014, the WVPSC approved APCo's motion to revise the procedural schedule which included a request to change the date of implementation of the new rates to May 2015.  In December 2014 and January 2015, intervenors filed testimony which proposed total annual revenue increases ranging from $35 million to $59 million based upon returns on common equity ranging from 9% to 10% and regulatory asset disallowances ranging from $7 million to $9 million.  Additionally, other intervenors proposed that the revenue requirement be based on a return on common equity of 8.7% and that $89 million of regulatory assets be disallowed.  Intervenors also recommended a disallowance of approximately $44 million related to the December 2013 transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo.  Hearings at the WVPSC were held in January 2015.  An order is anticipated in the second quarter of 2015. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2015 Virginia Regulatory Asset Proceeding

In January 2015, the Virginia SCC initiated a separate proceeding to address the proper treatment of APCo’s authorized regulatory assets. As of March 31, 2015, APCo’s authorized regulatory assets under review in this proceeding are estimated to be $14 million. In February and March 2015, briefs related to this proceeding were filed by various parties. If any of these costs, or any additional costs that may be subject to review, are not recoverable, it could reduce future net income and cash flows and impact financial condition.

New Virginia Legislation Affecting Biennial Reviews

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

PSO Rate Matters

2014 Oklahoma Base Rate Case

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

In June 2014, a non-unanimous stipulation agreement between PSO, the OCC staff and certain intervenors was filed with the OCC. The parties to the stipulation recommended no overall change to the transmission rider or to annual revenues, other than additional revenues through a separate rider related to advanced metering costs, and that the terms of the stipulation be effective November 2014. The advanced metering rider would provide $24 million of revenues over 14 months beginning in November 2014 and increase to $27 million in 2016. New depreciation rates are recommended for advanced metering investments and existing meters, also to be effective November 2014. Further, the stipulation recommends a return on common equity of 9.85% to be used only in the formula to calculate AFUDC, factoring of customer receivables and for riders with an equity component. Additionally, the stipulation recommends recovery of regulatory assets for 2013 storms and regulatory case expenses. In July 2014, the Attorney General joined in the stipulation agreement. In October 2014, the Administrative Law Judge recommended approval of the stipulation agreement and interim rates were implemented in November 2014, subject to refund. In April 2015, the OCC issued an order that approved the stipulation agreement.

I&M Rate Matters

Tanners Creek Plant

I&M announced that it would retire Tanners Creek Plant by June 2015 to comply with proposed environmental regulations. I&M is currently recovering depreciation and a return on the net book value of the Tanners Creek Plant in base rates.

In October 2014, I&M filed an application with the IURC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and the Tanners Creek Plant. Upon retirement of the Tanners Creek Plant, I&M proposed that, for purposes of determining its depreciation rates, the net book value of the Tanners Creek Plant be recovered over the remaining life of the Rockport Plant. The new depreciation rates would result in a decrease in I&M's Indiana jurisdictional electric depreciation expense which I&M proposed to reduce customer rates through a credit rider. In February 2015, the OUCC filed testimony that recommended approval of I&M's application. A hearing at the IURC was held in March 2015. A decision from the IURC is pending.

As of March 31, 2015, the net book value of the Tanners Creek Plant was $333 million, before cost of removal, including materials and supplies inventory and CWIP. If I&M is ultimately not permitted to fully recover its net book value of the Tanners Creek Plant and its retirement-related costs, it could reduce future net income and cash flows and impact financial condition.

Transmission, Distribution and Storage System Improvement Charge (TDSIC)

In October 2014, I&M filed petitions with the IURC for approval of a TDSIC Rider and approval of I&M’s seven-year TDSIC Plan, from 2015 through 2021, for eligible transmission, distribution and storage system improvements. The initial estimated cost of the capital improvements and associated operation and maintenance expenses included in the TDSIC Plan of $787 million, excluding AFUDC, will be updated annually. The TDSIC Plan included distribution investments specific to the Indiana jurisdiction. The TDSIC Rider will allow the periodic adjustment of I&M's rates to provide for timely recovery of 80% of approved TDSIC Plan costs. I&M will defer the remaining 20% of approved

TDSIC Plan costs to be recovered in I&M's next general rate case. I&M is not seeking a rate adjustment in this proceeding but is seeking approval of a TDSIC Rider rate adjustment mechanism for subsequent proceedings. In January 2015, intervenors filed testimony that recommended denial of certain portions of the TDSIC Plan including recommended changes to the capital structure, recovery of requested operation and maintenance cost allocations and the rate design within the TDSIC Rider mechanism. A hearing at the IURC was held in February 2015. In April 2015, I&M filed a notice with the IURC to seek approval of the proposed TDSIC Plan excluding $117 million of certain projects that were challenged in this proceeding. A decision from the IURC is pending. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

KPCo Rate Matters

Plant Transfer

In October 2013, the KPSC issued an order that approved a modified settlement agreement which included the approval to transfer to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed.

In December 2013, the Attorney General filed an appeal of the order with the Franklin County Circuit Court. In May 2014, KPCo's motion to dismiss the appeal was denied. In May 2014, KPCo filed motions for reconsideration and clarification with the Franklin County Circuit Court. In June 2014, the motion for reconsideration was denied but the motion to clarify was granted, thereby limiting the appeal to the issues of law presented in the Attorney General's appeal. In April 2015, the Franklin County Circuit Court issued an order that affirmed the KPSC's October 2013 order.

Kentucky Fuel Adjustment Clause Review

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. In January 2015, the KPSC issued an order disallowing certain FAC costs during the period of January 2014 through May 2015 while KPCo owns and operates both Big Sandy Plant, Unit 2 and its one-half interest in the Mitchell Plant. As a result of this order, KPCo recorded a regulatory disallowance of $36 million in December 2014. In February 2015, KPCo filed an appeal of this order with the Franklin County Circuit Court. In April 2015, the Franklin County Circuit Court issued an order approving intervenors request to hold this case in abeyance until the KPSC issues a final order in KPCo’s two-year FAC review case for the period November 1, 2012 through October 31, 2014.

2014 Kentucky Base Rate Case

In December 2014, KPCo filed a request with the KPSC for a net increase in rates of $70 million, which consists of a $75 million increase in rider rates, offset by a $5 million decrease in annual base rates, to be effective July 2015 based upon a 10.62% return on common equity.  The net increase reflects KPCo's ownership interest in the Mitchell Plant, riders to recover the Big Sandy Plant retirement and operational costs and the inclusion of an environmental compliance plan related to the Mitchell Plant FGD.  Additionally, the filing included a request to recover deferred storm costs.  In March 2015, intervenors filed testimony which recommended net increases in rates ranging from $20 million to $26 million.  These increases consist of proposed increases in rider rates ranging from $55 million to $63 million, offset by decreases in annual base rates ranging from $35 million to $37 million and based upon returns on common equity ranging from 8.65% to 8.75%.  Intervenor recommendations include the recovery of deferred storm costs.  Hearings at the KPSC are scheduled for May 2015.  If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

54

## 5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on our financial statements. The Commitments, Guarantees and Contingencies note within our 2014 Annual Report should be read in conjunction with this report.

### GUARANTEES

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

#### Letters of Credit

We enter into standby letters of credit with third parties. As Parent, we issue all of these letters of credit in our ordinary course of business on behalf of our subsidiaries. These letters of credit cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

We have two revolving credit facilities totaling $3.5 billion, under which we may issue up to $1.2 billion as letters of credit. As of March 31, 2015, the maximum future payments for letters of credit issued under the revolving credit facilities were $75 million with maturities ranging from April 2015 to May 2016.

We issue letters of credit under a $100 million uncommitted facility. As of March 31, 2015, the maximum future payments for letters of credit issued under the uncommitted facility were $100 million with a maturity of July 2015. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

We have $477 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $483 million. The letters of credit have maturities ranging from March 2016 to July 2017.

#### Guarantees of Third-Party Obligations

#### SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study completed in 2010, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of $58 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of March 31, 2015, SWEPCo has collected $64 million through a rider for final mine closure and reclamation costs, of which $16 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $48 million is recorded in Asset Retirement Obligations on our condensed balance sheets.

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

Indemnifications and Other Guarantees

Contracts

We enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. As of March 31, 2015, there were no material liabilities recorded for any indemnifications.

Master Lease Agreements

We lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, we are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term, the fair value has been in excess of the unamortized balance. As of March 31, 2015, the maximum potential loss for these lease agreements was $26 million assuming the fair value of the equipment is zero at the end of the lease term.

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignments are accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $11 million and $13 million for I&M and SWEPCo, respectively, for the remaining railcars as of March 31, 2015.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from 83% 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, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss.

ENVIRONMENTAL CONTINGENCIES

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

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

56

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. In 2014, I&M recorded an accrual for remediation at certain additional sites in Michigan. As a result of receiving approval of completed remediation work from the MDEQ in March 2015, I&M's accrual for all of these sites was reduced to approximately $9 million. As the remediation work is completed, I&M's cost may change as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation. We cannot predict the amount of additional cost, if any.

NUCLEAR CONTINGENCIES

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

OPERATIONAL CONTINGENCIES

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court granted our motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs' claims. Several claims remain, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. We will continue to defend against the remaining claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. We settled, received summary judgment or were dismissed from all of these cases. The plaintiffs appealed the Nevada federal district court's dismissal of several cases involving AEP companies to the U.S. Court of Appeals for the Ninth Circuit. In April 2013, the appellate court reversed in part, and affirmed in part, the district court's orders in these cases. The appellate court reversed the district court's holding that the state antitrust claims were preempted by the

Natural Gas Act and the order dismissing AEP from two of the cases on personal jurisdiction grounds and affirmed the decision denying leave to the plaintiffs to amend their complaints in two of the cases. Defendants in these cases, including AEP, filed a petition seeking further review with the U.S. Supreme Court on the preemption issue. AEP also subsequently filed a separate petition with the U.S. Supreme Court seeking review of the personal jurisdiction issue. In July 2014, the U.S. Supreme Court granted the defendants' previously filed petition for further review with the U.S. Supreme Court on the preemption issue. Oral argument occurred in January 2015. In April 2015, the U.S. Supreme Court affirmed the judgment of the U.S. Court of Appeals for the Ninth Circuit on the preemption issue, holding that the plaintiffs' state antitrust claims were not preempted by the Natural Gas Act. AEP's petition for review on the personal jurisdiction issue remains pending. We will continue to defend the cases. We believe the provision we have is adequate. We are unable to determine the amount of potential additional losses that are reasonably possible of occurring.

Wage and Hours Lawsuit

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

In March 2014, the federal court granted plaintiffs’ motion to conditionally certify the action as a class action. Notice was given to all potential class members and an additional 44 individuals opted in to the class, bringing the plaintiff class to 80 current and former employees. We will continue to defend the case. We are unable to determine a range of potential losses that are reasonably possible of occurring.

National Do Not Call Registry Lawsuit

In May 2014, AEP Energy was served with a complaint filed in the U.S. District Court for the Northern District of Illinois, alleging violations of the Telephone Consumer Protection Act (TCPA). The plaintiff alleges that he received telemarketing calls on behalf of AEP Energy despite having registered his telephone number on the National Do Not Call Registry. Plaintiff seeks to represent a class of persons who allegedly received such calls. Plaintiff seeks statutory damages under the TCPA on behalf of himself and the alleged class as well as injunctive relief. As a result of a mediation held in October 2014, the parties reached an agreement in principle, subject to final documentation and preliminary and final court approval. In April 2015, we filed a motion with the court for preliminary approval of the settlement. We will continue to defend the case. We believe the provision we have is adequate. We are unable to determine the amount of potential additional losses that are reasonably possible of occurring.

Gavin Landfill Litigation

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

6. BENEFIT PLANS

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

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost (credit) for the plans for the three months ended March 31, 2015 and 2014:

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---|---|---|---|---|
| | Three Months Ended March 31, | | Three Months Ended March 31, | |
| | 2015 | 2014 | 2015 | 2014 |
| | (in millions) | | | |
| Service Cost | $23 | $18 | $3 | $4 |
| Interest Cost | 51 | 55 | 14 | 17 |
| Expected Return on Plan Assets | (69) | (66) | (28) | (28) |
| Amortization of Prior Service Cost (Credit) | 1 | 1 | (17) | (17) |
| Amortization of Net Actuarial Loss | 27 | 31 | 5 | 5 |
| Net Periodic Benefit Cost (Credit) | $33 | $39 | $(23) | $(19) |

7. BUSINESS SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. Within our Vertically Integrated Utilities segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

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

AEP Transmission Holdco

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

Generation & Marketing

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

AEP River Operations

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

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

The tables below present our reportable segment income statement information for the three months ended March 31, 2015 and 2014 and reportable segment balance sheet information as of March 31, 2015 and December 31, 2014. These amounts include certain estimates and allocations where necessary.

| | Vertically Integrated Utilities | Transmission and Distribution Utilities | AEP Transmission Holdco | Generation & Marketing | AEP River Operations | Corporate and Other (a) | Reconciling Adjustments | Consolidated |
|---|---|---|---|---|---|---|---|---|
| | (in millions) | | | | | | | |
| Three Months Ended March 31, 2015 | | | | | | | | |
| Revenues from: | | | | | | | | |
| External Customers | $ 2,487 | $ 1,206 | $ 22 | $ 859 | $ 128 | $ 6 | $ — | $ 4,708 |
| Other Operating Segments | 18 | 64 | 36 | 311 | 11 | 20 | (460 ) | — |
| Total Revenues | $ 2,505 | $ 1,270 | $ 58 | $ 1,170 | $ 139 | $ 26 | $ (460 ) | $ 4,708 |
| Net Income (Loss) | $ 300 | $ 97 | $ 37 | $ 187 | $ 11 | $ (1 ) | $ — | $ 631 |

| | Vertically Integrated Utilities | Transmission and Distribution Utilities | AEP Transmission Holdco | Generation & Marketing | AEP River Operations | Corporate and Other (a) | Reconciling Adjustments | Consolidated |
|---|---|---|---|---|---|---|---|---|
| | (in millions) | | | | | | | |
| Three Months Ended March 31, 2014 | | | | | | | | |
| Revenues from: | | | | | | | | |
| External Customers | $ 2,549 (b) | $ 1,161 | $ 12 | $ 821 (b) | $ 146 | $ 10 | $ (51 ) (c) | $ 4,648 |
| Other Operating Segments | 37 (b) | 54 | 16 | 430 (b) | 19 | 16 | (572 ) | — |
| Total Revenues | $ 2,586 | $ 1,215 | $ 28 | $ 1,251 | $ 165 | $ 26 | $ (623 ) | $ 4,648 |
| Net Income (Loss) | $ 279 | $ 97 | $ 24 | $ 163 | $ 3 | $ (5 ) | $ — | $ 561 |

61

| | Vertically Integrated Utilities | Transmission and Distribution Utilities | AEP Transmission Holdco | Generation & Marketing | AEP River Operations | Corporate and Other (a) | Reconciling Adjustments | | Consolidated |
|---|---|---|---|---|---|---|---|---|---|
| | (in millions) | | | | | | | | |
| March 31, 2015 | | | | | | | | | |
| Total Property, Plant and Equipment | $40,890 | $ 13,251 | $ 2,980 | $7,414 | $701 | $350 | $(280 | ) (d) | $ 65,306 |
| Accumulated Depreciation and Amortization | 13,335 | 3,520 | 28 | 3,309 | 223 | 183 | (102 | ) (d) | 20,496 |
| Total Property Plant and Equipment - Net | $27,555 | $ 9,731 | $ 2,952 | $4,105 | $478 | $167 | $(178 | ) (d) | $ 44,810 |
| Total Assets | $35,075 | $ 14,403 | $ 3,736 | $5,706 | $743 | $21,402 | $(21,027 | ) (d) (e) | $ 60,038 |
| Long-term Debt Due Within One Year: | | | | | | | | | |
| Affiliated | $111 | $ — | $ — | $86 | $— | $— | $(197 | ) | $ — |
| Non-Affiliated | 1,291 | 414 | — | 740 | 3 | 3 | — | | 2,451 |
| Long-term Debt: | | | | | | | | | |
| Affiliated | 20 | — | — | 32 | — | — | (52 | ) | — |
| Non-Affiliated | 9,393 | 5,105 | 1,207 | 148 | 80 | 845 | — | | 16,778 |
| Total Long-term Debt | $10,815 | $ 5,519 | $ 1,207 | $1,006 | $83 | $848 | $(249 | ) | $ 19,229 |

| | Vertically Integrated Utilities | Transmission and Distribution Utilities | AEP Transmission Holdco | Generation & Marketing | AEP River Operations | Corporate and Other (a) | Reconciling Adjustments | | Consolidated |
|---|---|---|---|---|---|---|---|---|---|
| | (in millions) | | | | | | | | |
| December 31, 2014 | | | | | | | | | |
| Total Property, Plant and Equipment | $39,402 | $ 13,024 | $ 2,714 | $8,394 | $700 | $343 | $(272 | ) (d) | $ 64,305 |
| | 12,773 | 3,481 | 25 | 3,603 | 217 | 188 | (99 | ) (d) | 20,188 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Accumulated Depreciation and Amortization | | | | | | | | | |
| Total Property Plant and Equipment - Net | $26,629 | $ 9,543 | $ 2,689 | $4,791 | $483 | $155 | $(173 | ) (d) | $ 44,117 |
| Total Assets | $33,750 | $ 14,495 | $ 3,575 | $6,329 | $749 | $21,081 | $(20,346 | ) (d) (e) | $ 59,633 |
| Long-term Debt Due Within One Year: | | | | | | | | | |
| Affiliated | $111 | $ — | $ — | $86 | $— | $— | $(197 | ) | $ — |
| Non-Affiliated | 1,352 | 405 | — | 740 | 3 | 3 | — | | 2,503 |
| Long-term Debt: | | | | | | | | | |
| Affiliated | 20 | — | — | 32 | — | — | (52 | ) | — |
| Non-Affiliated | 8,634 | 5,256 | 1,153 | 217 | 80 | 841 | — | | 16,181 |
| Total Long-term Debt | $10,117 | $ 5,661 | $ 1,153 | $1,075 | $83 | $844 | $(249 | ) | $ 18,684 |

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
(b) Includes the impact of corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013, as well as the impact of the termination of the Interconnection Agreement effective January 1, 2014.
(c) Reconciling Adjustments for External Customers primarily include eliminations as a result of corporate separation in Ohio.
(d) Includes eliminations due to an intercompany capital lease.
(e) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

## 8. DERIVATIVES AND HEDGING

### OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

We are exposed to certain market risks as a major power producer and marketer of wholesale electricity, natural gas, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates. We manage these risks using derivative instruments.

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

#### Risk Management Strategies

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

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

The following table represents the gross notional volume of our outstanding derivative contracts as of March 31, 2015 and December 31, 2014:

Notional Volume of Derivative Instruments

| Primary Risk Exposure | Volume<br>March 31,<br>2015<br>(in millions) | December 31,<br>2014 | Unit of<br>Measure |
|---|---|---|---|
| Commodity: | | | |
| Power | 271 | 334 | MWhs |
| Coal | 2 | 3 | Tons |
| Natural Gas | 75 | 106 | MMBtus |
| Heating Oil and Gasoline | 4 | 6 | Gallons |
| Interest Rate | $140 | $152 | USD |
| | | | |
| Interest Rate and Foreign Currency | $814 | $815 | USD |

63

Fair Value Hedging Strategies

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

Cash Flow Hedging Strategies

We enter into and designate as cash flow hedges certain derivative transactions for the purchase and sale of power and natural gas (“Commodity”) in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect profit margins for a portion of future electricity sales and energy purchases. We do not hedge all commodity price risk.

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. We discontinued cash flow hedge accounting for these derivative contracts effective March 31, 2014. In March 2014, these contracts were grouped as "Commodity" with other risk management activities. We do not hedge all fuel price risk.

We enter into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. Our forecasted fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. We do not hedge all interest rate exposure.

At times, we are exposed to foreign currency exchange rate risks primarily when we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency’s appreciation against the dollar. We do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR FINANCIAL STATEMENTS

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

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

According to the accounting guidance for "Derivatives and Hedging," we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2015 and December 31, 2014 condensed balance sheets, we netted $4 million and $4 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $37 million and $35 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of our derivative activity on our condensed balance sheets as of March 31, 2015 and December 31, 2014:

Fair Value of Derivative Instruments
March 31, 2015

| | Risk Management Contracts | Hedging Contracts | | Gross Amounts of Risk Management Assets/ Liabilities Recognized | Gross Amounts Offset in the Statement of Financial Position (b) | Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c) |
|---|---|---|---|---|---|---|
| Balance Sheet Location | Commodity (a) | Commodity (a) | Interest Rate and Foreign Currency (a) | | | |
| | (in millions) | | | | | |
| Current Risk Management Assets | $342 | $10 | $3 | $355 | $(217) | $ 138 |
| Long-term Risk Management Assets | 453 | 4 | — | 457 | (92) | 365 |
| Total Assets | 795 | 14 | 3 | 812 | (309) | 503 |
| | | | | | | |
| Current Risk Management Liabilities | 302 | 12 | 1 | 315 | (232) | 83 |
| Long-term Risk Management Liabilities | 250 | 10 | 5 | 265 | (109) | 156 |
| Total Liabilities | 552 | 22 | 6 | 580 | (341) | 239 |
| | | | | | | |
| Total MTM Derivative Contract Net Assets (Liabilities) | $243 | $(8) | $(3) | $232 | $32 | $ 264 |

Fair Value of Derivative Instruments
December 31, 2014

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

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

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

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

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

The table below presents our activity of derivative risk management contracts for the three months ended March 31, 2015 and 2014:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2015 and 2014

| Location of Gain (Loss) | 2015 | 2014 |
|---|---|---|
| | (in millions) | |
| Vertically Integrated Utilities Revenues | $5 | $18 |
| Generation & Marketing Revenues | 49 | 32 |
| Other Operation Expense | (1) | — |
| Maintenance Expense | (1) | — |
| Purchased Electricity for Resale | 3 | — |
| Regulatory Assets (a) | (4) | — |
| Regulatory Liabilities (a) | 4 | 89 |
| Total Gain on Risk Management Contracts | $55 | $139 |

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the condensed statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the condensed statements of income as that of the associated risk. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for “Regulated Operations.”

Accounting for Fair Value Hedging Strategies

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

We record realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on our condensed statements of income. The following table shows the results of our hedging gains (losses) during the three months ended March 31, 2015 and 2014:

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (in millions) | |
| Gain on Fair Value Hedging Instruments | $5 | $2 |
| Loss on Fair Value Portion of Long-term Debt | (5) | (2) |

During the three months ended March 31, 2015 and 2014, hedge ineffectiveness was immaterial.

Accounting for Cash Flow Hedging Strategies

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

Realized gains and losses on derivative contracts for the purchase and sale of power and natural gas designated as cash flow hedges are included in Revenues or Purchased Electricity for Resale on our condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on our condensed balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2015 and 2014, we designated power and natural gas derivatives as cash flow hedges.

We reclassify gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on our condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our condensed statements of income. The impact of cash flow hedge accounting for these derivative contracts was immaterial and was discontinued effective March 31, 2014.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) on our condensed balance sheets into Interest Expense on our condensed statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2015 and 2014, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our condensed balance sheets into Depreciation and Amortization expense on our condensed statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three months ended March 31, 2015 and 2014, we did not designate any foreign currency derivatives as cash flow hedges.

During the three months ended March 31, 2015 and 2014, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our condensed balance sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2015 and 2014, see Note 3.

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

| | Commodity | Interest Rate and Foreign Currency | Total |
|---|---|---|---|
| | (in millions) | | |
| Hedging Assets (a) | $4 | $— | $4 |
| Hedging Liabilities (a) | 12 | 1 | 13 |
| AOCI Gain (Loss) Net of Tax | (6) | (18) | (24) |
| Portion Expected to be Reclassified to Net Income During the Next Twelve Months | (6) | (2) | (8) |

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

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

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

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.  As of March 31, 2015, the maximum length of time that we are hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") our exposure to variability in future cash flows related to forecasted transactions was 69 months.

Credit Risk

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

When we use standardized master agreements, these agreements may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds our established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with our credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

68

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs), a limited number of derivative and non-derivative contracts primarily related to our competitive retail auction loads, and guaranties for contractual obligations, we are obligated to post an additional amount of collateral if our credit ratings decline below a specified rating threshold. The amount of collateral required fluctuates based on market prices and our total exposure. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. AEP and its subsidiaries have not experienced a downgrade below a specified rating threshold that would require the posting of additional collateral. The following table represents our exposure if our credit ratings were to decline below a specified rating threshold as of March 31, 2015 and December 31, 2014:

| | March 31, 2015 | December 31, 2014 |
|---|---|---|
| | (in millions) | |
| Fair Value of Contracts with Credit Downgrade Triggers | $— | $— |
| Amount of Collateral AEP Subsidiaries Would Have been Required to Post for Derivative Contracts as well as Derivative and Non-Derivative Contracts Subject to the Same Master Netting Arrangement | — | — |
| Amount of Collateral AEP Subsidiaries Would Have Been Required to Post Attributable to RTOs and ISOs | 29 | 36 |
| Amount of Collateral Attributable to Other Contracts (a) | 300 | 281 |

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

In addition, a majority of our non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million.  On an ongoing basis, our risk management organization assesses the appropriateness of these cross-default provisions in our contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral we have posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering our contractual netting arrangements as of March 31, 2015 and December 31, 2014:

| | March 31, 2015 | December 31, 2014 |
|---|---|---|
| | (in millions) | |
| Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements | $271 | $235 |
| Amount of Cash Collateral Posted | 8 | 9 |
| Additional Settlement Liability if Cross Default Provision is Triggered | 203 | 178 |

69

## 9. FAIR VALUE MEASUREMENTS

### Fair Value Hierarchy and Valuation Techniques

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

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

We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in the nuclear trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

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

Fair Value Measurements of Long-term Debt

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

The book values and fair values of Long-term Debt as of March 31, 2015 and December 31, 2014 are summarized in the following table:

| | March 31, 2015 | | December 31, 2014 | |
|---|---|---|---|---|
| | Book Value | Fair Value | Book Value | Fair Value |
| | (in millions) | | | |
| Long-term Debt | $19,229 | $22,015 | $18,684 | $21,075 |

Fair Value Measurements of Other Temporary Investments

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

The following is a summary of Other Temporary Investments:

| | March 31, 2015 | | | |
|---|---|---|---|---|
| Other Temporary Investments | Cost | Gross Unrealized Gains | Gross Unrealized Losses | Estimated Fair Value |
| | (in millions) | | | |
| Restricted Cash (a) | $186 | $— | $— | $186 |
| Fixed Income Securities – Mutual Funds | 81 | — | — | 81 |
| Equity Securities – Mutual Funds | 13 | 13 | — | 26 |
| Total Other Temporary Investments | $280 | $13 | $— | $293 |

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

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

The following table provides the activity for our fixed income and equity securities within Other Temporary Investments for the three months ended March 31, 2015 and 2014:

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (in millions) | |
| Proceeds from Investment Sales | $— | $— |
| Purchases of Investments | — | 1 |
| Gross Realized Gains on Investment Sales | — | — |
| Gross Realized Losses on Investment Sales | — | — |

As of March 31, 2015 and December 31, 2014, we had no Other Temporary Investments with an unrealized loss position. As of March 31, 2015, fixed income securities were primarily debt based mutual funds with short and intermediate maturities. Mutual funds may be sold and do not contain maturity dates.

For details of the reasons for changes in Securities Available for Sale included in Accumulated Other Comprehensive Income (Loss) for the three months ended March 31, 2015 and 2014, see Note 3.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

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

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

We maintain trust records for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both fixed income and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and fixed income investments held in these trusts and generally intends to sell fixed income securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains and other-than-temporary impairments from securities in the trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. The trust assets are recorded by jurisdiction and may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds.

72

The following is a summary of nuclear trust fund investments as of March 31, 2015 and December 31, 2014: