SCHEDULE 14A
(Rule 14a-101)
INFORMATION REQUIRED IN PROXY STATEMENT
SCHEDULE 14A INFORMATION
Proxy Statement Pursuant to Section 14(a) of the Securities Exchange Act of 1934
(Amendment No.)

Filed by the Registrant ☒

Filed by a Party other than the Registrant ☐

Check the appropriate box:

☐ Preliminary Proxy Statement

☐ **Confidential, for Use of the Commission Only (as permitted by Rule 14a-6(e)(2))**

☒ Definitive Proxy Statement

☐ Definitive Additional Materials

☐ Soliciting Material Pursuant to Rule 14a-12.

American Electric Power Company, Inc.

(Name of Registrant as Specified in its Charter)

(Name of Person(s) Filing Proxy Statement, if other than the Registrant)

Payment of Filing Fee (Check the appropriate box):

☒ No fee required.

☐ Fee computed on table below per Exchange Act Rules 14a-6(i)(1) and 0-11.

(1) Title of each class of securities to which transaction applies:

(2) Aggregate number of securities to which transaction applies:

(3) Per unit price or other underlying value of transaction computed pursuant to Exchange Act Rule 0-11 (Set forth the amount on which the filing fee is calculated and state how it was determined):

(4) Proposed maximum aggregate value of transaction:

(5) Total fee paid:

☐ Fee paid previously with preliminary materials.

☐ Check box if any part of the fee is offset as provided by Exchange Act Rule 0-11(a)(2) and identify the filing for which the offsetting fee was paid previously. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

(1) Amount Previously Paid:

(2) Form, Schedule or Registration Statement No.:

(3) Filing Party:

(4) Date Filed:

Notice of 2014 Annual Meeting • Proxy Statement

American Electric Power
1 Riverside Plaza
Columbus, OH 43215

Nicholas K. Akins
Chairman of the Board and
Chief Executive Officer

March 12, 2014

Dear Shareholders:

This year's annual meeting of shareholders will be held at Grand Wayne Convention Center,120 W. Jefferson Boulevard, Fort Wayne, Indiana, on Tuesday, April 22, 2014, at 9:00 a.m. Eastern Time.

Your Board of Directors and I cordially invite you to attend. Registration will begin at 8:00 a.m. Only shareholders who owned shares on the record date, February 24, 2014, are entitled to vote and attend the meeting. To attend the meeting, you will need to present an admission ticket or the notice you received. If your shares are registered in your name, and you received your proxy materials by mail, your admission ticket is attached to your proxy card. A map and directions are printed on the admission ticket. If your shares are registered in your name and you received your proxy materials electronically via the Internet, you will need to print an admission ticket after you vote by clicking on the "Options" button. If you hold shares through an account with a bank or broker, you will need to contact them and request a legal proxy, or bring a copy of your statement to the meeting that shows that you owned the shares on the record date. Each ticket will admit a shareholder and one guest.

We are mailing to many of our shareholders a notice instead of a paper copy of this proxy statement and our 2013 Annual Report. The notice contains instructions on how to access those documents over the Internet. The notice also contains instructions on how shareholders can receive a paper copy of our proxy materials, including this proxy statement, our 2013 Annual Report and a form of proxy card or voting instruction card.

During the course of the meeting there will be the usual time for discussion of the items on the agenda and for questions regarding AEP's affairs. Directors and officers will be available to talk individually with shareholders before and after the meeting.

Your vote is very important. Shareholders of record can vote in any one of the following three ways:

- **By Internet, at www.envisionreports.com/AEP**
- **By toll-free telephone at 800-652-8683**
- **By completing and mailing your proxy card if you receive paper copies of the proxy materials**

If your shares are held in the name of a bank, broker or other holder of record, you will receive instructions from the holder of record that you must follow in order for you to vote your shares.

If you have any questions about the meeting, please contact Investor Relations, American Electric Power Company, 1 Riverside Plaza, Columbus, Ohio 43215. The telephone number is 800-237-2667.

Sincerely,

/s/ Nicholas K. Akins

NOTICE OF 2014 ANNUAL MEETING

American Electric Power Company, Inc.
1 Riverside Plaza
Columbus, Ohio 43215

TIME	9:00 a.m. Eastern Time on Tuesday, April 22, 2014
PLACE	Grand Wayne Convention Center 120 W. Jefferson Boulevard Fort Wayne, Indiana
ITEMS OF BUSINESS	(1) To elect the 12 directors named herein to hold office until the next annual meeting and until their successors are duly elected. (2) To ratify the appointment of Deloitte & Touche LLP as the independent registered public accounting firm for the year 2014. (3) To hold an advisory vote on executive compensation. (4) To consider and act on such other matters as may properly come before the meeting.
RECORD DATE	Only shareholders of record at the close of business on February 24, 2014 are entitled to notice of and to vote at the meeting or any adjournment thereof.
ANNUAL REPORT	Appendix A to this proxy statement has AEP's audited financial statements, management's discussion and analysis of results of operations and financial condition and the report of the independent registered public accounting firm.
PROXY VOTING	It is important that your shares be represented and voted at the meeting. Please vote in one of these ways: **(1) MARK, SIGN, DATE AND PROMPTLY RETURN** your proxy card if you receive paper copies of the proxy materials. **(2) CALL TOLL-FREE** by telephone at 800-652-8683. **(3) VISIT THE WEB SITE** shown on the notice of Internet availability of proxy materials to vote via the Internet. If your shares are held in the name of a bank, broker or other holder of record, please follow the instructions from the holder of record in order to vote your shares. Any proxy may be revoked at any time before your shares are voted at the meeting.

March 12, 2014

David M. Feinberg
Secretary

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Proxy Statement

March 12, 2014

Proxy and Voting Information

A notice of Internet availability of proxy materials or paper copy of the proxy statement and form of proxy is to be mailed to shareholders on or about March 12, 2014, in connection with the solicitation of proxies by the Board of Directors of American Electric Power Company, Inc., 1 Riverside Plaza, Columbus, Ohio 43215, for the annual meeting of shareholders to be held on April 22, 2014 in Fort Wayne, Indiana.

We use the terms "AEP," the "Company," "we," "our" and "us" in this proxy statement to refer to American Electric Power Company, Inc. and, where applicable, its subsidiaries. All references to "years," unless otherwise noted, refer to our fiscal year, which ends on December 31.

Who Can Vote. Only the holders of shares of AEP Common Stock at the close of business on the record date, February 24, 2014, are entitled to vote at the meeting. Each such holder has one vote for each share held on all matters to come before the meeting. On that date, there were 487,820,462 shares of AEP Common Stock, $6.50 par value, outstanding.

How You Can Vote. Shareholders of record can give proxies by (i) mailing their signed proxy cards; (ii) calling a toll-free telephone number; or (iii) using the Internet. The telephone and Internet voting procedures are designed to authenticate shareholders' identities, to allow shareholders to give their voting instructions and to confirm that shareholders' instructions have been properly recorded. Instructions for shareholders of record who wish to use the telephone or Internet voting procedures are set forth on the proxy card or the website shown on the notice of internet availability of proxy materials.

If your shares are held in the name of a bank, broker or other holder of record, you will receive instructions from the holder of record that you must follow in order for you to vote your shares.

When proxies are returned, the shares represented thereby will be voted by the persons named on the proxy card or by their substitutes in accordance with shareholders' directions. If a proxy card is signed and returned without choices marked, it will be voted for the nominees for directors listed on the card and as recommended by the Board of Directors with respect to other matters. The proxies of shareholders who are participants in the Dividend Reinvestment and Stock Purchase Plan include both the shares registered in their names and the whole shares held in their Plan accounts on February 24, 2014.

Revocation of Proxies. A shareholder giving a proxy may revoke it at any time before it is voted at the meeting by simply voting again after the date of the proxy being revoked or by attending the meeting and voting in person.

How Votes are Counted. The presence of the holders of a majority of the outstanding shares of common stock entitled to vote at the Annual Meeting, present in person or represented by proxy, is necessary to constitute a quorum. Abstentions and "broker non-votes" are counted as present and entitled to vote for purposes of determining a quorum. A "broker non-vote" occurs when a broker holding shares for a beneficial owner does not vote on a particular proposal because the broker does not have discretionary voting power for that particular item and has not received instructions from the beneficial owner.

Under New York Stock Exchange (NYSE) rules, the proposal to ratify the appointment of Deloitte & Touche LLP as our independent registered public accounting firm is considered a “discretionary” item. This means that brokerage firms may vote in their discretion on this matter on behalf of their clients who have not furnished voting instructions. The proposals to elect directors and the advisory vote on executive compensation are “non-discretionary” matters. That means that brokerage firms may not use their discretion to vote on such matters without express voting instructions from their clients.

The Company has implemented a majority voting standard for the election of directors in uncontested elections of directors. The election of directors at the Annual Meeting is an uncontested election, so for a nominee to be elected to the Board, the number of votes cast “for” the nominee’s election must exceed the number of votes cast “against” his or her election. Abstentions and broker non-votes will not be considered votes cast “for” or “against” a nominee and will therefore have no effect on the outcome. If a nominee is not elected because he or she did not receive a greater number of votes “for” his or her election than “against” such election, he or she will be required to tender his or her resignation for the Board’s consideration of whether to accept such resignation in accordance with our Bylaws. No shareholder has the right to cumulate his or her voting power in the election of directors at the Annual Meeting.

Shareholder approval of each of the other proposals (Item 2: Proposal to Ratify Appointment of Independent Registered Public Accounting Firm and Item 3: Advisory Vote on Executive Compensation) requires an affirmative vote of a majority of votes cast at a meeting of shareholders. This means that the votes cast “for” the proposal must exceed the votes cast “against” the proposal. Abstentions and broker non-votes are not counted as votes “for” or “against” Item 3 (Advisory Vote on Executive Compensation) and therefore will have no effect on the outcome of the votes with respect to such proposal.

Abstentions are not counted as votes “for” or “against” Item 2 (Proposal to Ratify the Appointment of Independent Registered Public Accounting Firm) and therefore will have no effect on the outcome of the vote with respect to such proposal.

Your Vote is Confidential. It is AEP’s policy that shareholders be provided privacy in voting. All proxies, voting instructions and ballots, which identify shareholders, are held on a confidential basis, except as may be necessary to meet any applicable legal requirements. We direct proxies to an independent third-party tabulator, who receives, inspects, and tabulates them. Voted proxies and ballots are not seen by nor reported to AEP except (i) in aggregate number or to determine if (rather than how) a shareholder has voted, (ii) in cases where shareholders write comments on their proxy cards or (iii) in a contested proxy solicitation.

Multiple Copies of Annual Report, Proxy Statement or Notice of Internet Availability of Proxy Materials to Shareholders. Securities and Exchange Commission (SEC) rules provide that more than one annual report, proxy statement or notice of Internet availability of proxy materials need not be sent to the same address. This practice is commonly called “householding” and is intended to eliminate duplicate mailings of shareholder documents. Mailing of your annual report, proxy statement or notice of Internet availability of proxy materials is being householded indefinitely unless you instruct us otherwise. We will deliver promptly upon written or oral request a separate copy of the annual report, proxy statement or notice of Internet availability of proxy materials to a shareholder at a shared address. To receive a separate copy of the annual report, proxy statement or notice of Internet availability of proxy materials, write to AEP, attention: Investor Relations, at 1 Riverside Plaza, Columbus, OH 43215 or call 1-800-237-2667. If more than one annual report, proxy statement or notice of Internet availability of proxy materials is being sent to your address, at your request, mailing of the duplicate copy can be discontinued by contacting our transfer agent, Computershare Trust Company, N.A. (Computershare), at 800-328-6955 or writing to them at P.O Box 43078, Providence, RI 02940-3078. If you wish to resume receiving separate annual reports, proxy statements or notice of Internet availability of proxy materials at the same address in the future, you may call Computershare at 800-328-6955 or write to them at P.O Box 43078, Providence, RI 02940-3078. The change will be effective 30 days after receipt.

Additional Information. Our website address is *www.aep.com*. We make available free of charge on the Investor Relations section of our website (*www.aep.com/investors*) our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (Exchange Act). We also make available through our website other reports filed with or furnished to the SEC under the Exchange Act, including our proxy statements and reports filed by officers and directors under Section 16(a) of the Exchange Act. You may request any of these materials and information in print by contacting Investor Relations at: AEP, attention: Investor Relations, 1 Riverside Plaza, Columbus, OH 43215. We do not intend for information contained on our website to be part of this proxy statement. In addition, this proxy statement and the Annual Report on Form 10-K for the fiscal year ended December 31, 2013 are available at *www.edocumentview.com/aep.*

Item 1. Election of Directors

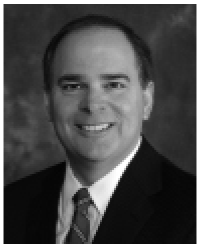
Currently, AEP's Board of Directors consists of 15 members. Mr. Morris, Dr. Sandor and Mr. Turner will end their service as members of the Board effective as of the date of the annual meeting; therefore, the Board of Directors has authorized a reduction in the size of the Board to 12 members, effective as of April 22, 2014, as permitted by the Bylaws.

Twelve directors are to be elected to hold office until the next annual meeting and until their successors have been elected. AEP's Bylaws provide that the number of directors of AEP shall be such number, not less than 9 nor more than 17, as shall be determined from time to time by resolution of the Board.

The 12 nominees named on pages 4 to 7 were nominated by the Board on the recommendation of the Committee on Directors and Corporate Governance of the Board, following individual evaluation of each incumbent nominee's qualifications and 2013 performance. The proxies named on the proxy card or their substitutes will vote for the Board's nominees, unless instructed otherwise. All of the Board's nominees were elected by the shareholders at the 2013 annual meeting, except for Mr. Beasley, who was appointed as a director in February 2014. Mr. Beasley was recommended to the Board by a director search firm, which was paid a fee to identify and evaluate potential Board members. Messrs. Hoaglin, Morris and Akins interviewed Mr. Beasley and recommended him to the Committee on Directors and Corporate Governance. That Committee reviewed his qualifications and recommended him to the full Board. We do not expect any of the nominees will be unable to stand for election or be unable to serve if elected. If a vacancy in the slate of nominees occurs before the meeting, the proxies may be voted for another person nominated by the Board or the number of directors may be reduced accordingly.

Biographical Information. The following brief biographies of the nominees include their principal occupations, ages on the date of this proxy statement, accounts of their business experience and names of certain companies of which they are directors. Data with respect to the number of shares of AEP's Common Stock and stock-based units beneficially owned by each of them appear on page 71.

Nominees For Director



Nicholas K. Akins
Dublin, Ohio
Age 53
Director since 2011

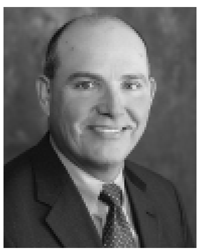
Elected chief executive officer of AEP in November 2011; elected chairman of the board in January 2014; and chairman and chief executive officer of all of its major subsidiaries in November 2011. President of AEP from January 2011 to October 2011 and executive vice president of AEP from 2006 to 2011. A director of Fifth Third Bancorp.

Mr. Akins' qualifications to serve on the Board include his extensive senior executive experience in the utility industry and his deep knowledge of the Company as our chief executive officer.

David J. Anderson
Morristown, New Jersey
Age 64
Director since 2011

Senior vice president and chief financial officer of Honeywell International, a diversified technology and manufacturing company, since 2003.

Mr. Anderson's qualifications to serve on the Board include his corporate finance expertise as the chief financial officer of a Fortune 100 company.



J. Barnie Beasley, Jr.
Sylvania, Georgia
Age 62
Director since 2014

Mr. Beasley has served as an independent nuclear safety and operations expert to the board of directors of the Tennessee Valley Authority, a large electric utility in the southeastern United States, since 2011. Retired chairman, president and chief executive officer of Southern Nuclear Operating Company, the nuclear operating company subsidiary of an electric utility (2005-2008). Mr. Beasley was formerly a director of EnergySolutions, Inc. (2008-2013).

Mr. Beasley's qualifications to serve on the Board include his nuclear expertise as the chief executive officer of the nuclear operating company subsidiary of Southern Company and his experience in the utility industry and as a public company director.

Ralph D. Crosby, Jr.
McLean, Virginia
Age 66
Director since 2006

Retired chairman of EADS North America, Inc., an aerospace company (2002-2011). Retired chief executive officer of EADS North America, Inc. (2002-2009). A director of Serco Group PLC and Airbus Group N.V. Mr. Crosby was formerly a director of Ducommun Incorporated (2000-2013).

Mr. Crosby's qualifications to serve on the Board include his extensive senior executive experience in the aerospace industry and his experience as a public company director.

Nominees for Director — continued

Linda A. Goodspeed
Crestview, Florida
Age 52
Director since 2005

Managing partner of Wealthstrategies Financial Advisors, LLC since 2008. Retired senior vice president and chief information officer of The ServiceMaster Company, a residential and commercial service company (2011-2013). From 2008 to 2011, vice president of information systems of Nissan North America, Inc., an automobile manufacturer. A director of Columbus McKinnon Corp and AutoZone, Inc.

Ms. Goodspeed's qualifications to serve on the Board include her information technology expertise as the chief information officer of a service company and her experience as a public company director.

Thomas E. Hoaglin
Columbus, Ohio
Age 64
Director since 2008

Retired chairman and chief executive officer of Huntington Bancshares Incorporated, a bank holding company (2001-2009). A director of The Gorman-Rupp Company.

Mr. Hoaglin's qualifications to serve on the Board include his extensive senior executive experience in the banking industry and his experience as a public company director.

Sandra Beach Lin
Flower Mound, Texas
Age 56
Director since 2012

Retired chief executive officer of Calisolar, Inc., a solar silicon company, a position she held from August 2010 until December 2011. Corporate executive vice president (February 2009 to July 2010) and executive vice president (July 2007 to February 2009) of Celanese Corporation, a global hybrid chemical company. A director of WESCO International and PolyOne Corporation.

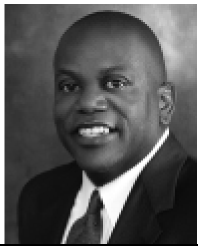
Ms. Lin's qualifications to serve on the Board include her senior executive experience managing global businesses in multiple industries and her experience as a public company director.

Richard C. Notebaert
Chicago, Illinois
Age 67
Director since 2011

Retired chief executive officer of Qwest Communications International Inc., a telecommunications systems company (2002-2007). A director of Aon Corporation and Cardinal Health, Inc.

Mr. Notebaert's qualifications to serve on the Board include his extensive senior executive experience in the regulated telecommunications industry and his experience as a public company director.

Nominees for Director — continued



Lionel L. Nowell III
Cos Cob, Connecticut
Age 59
Director since 2004

Retired senior vice president and treasurer of PepsiCo, Inc., a food and beverage company (2001-2009). A director of Reynolds American Inc. and Bank of America Corporation.

Mr. Nowell's qualifications to serve on the Board include his capital markets, accounting, financial reporting, and risk management skills and experience at a Fortune 100 company, and his experience as a public company director.

Stephen S. Rasmussen
Columbus, Ohio
Age 61
Director since 2012

Chief executive officer of Nationwide Mutual Insurance Company (Nationwide) since 2009. President and chief operating officer of Nationwide (2003 – 2009).

Mr. Rasmussen's qualifications to serve on the Board include his extensive senior executive experience in the regulated insurance industry.

Oliver G. Richard, III
Lake Charles, Louisiana
Age 61
Director since 2013

Chairman of privately held CleanfuelUSA, an alternative vehicular fuel company since 2006. Owner and president of Empire of the Seed LLC, a private consulting firm in the energy and management industries, as well as the private investments industry since 2005. Mr. Richard served as chairman, president and chief executive officer of Columbia Energy Group ("Columbia Energy") from April 1995 until Columbia Energy was acquired by NiSource Inc. in November 2000. Mr. Richard served as a commissioner of the Federal Energy Regulatory Commission from 1982 to 1985. A director of Buckeye Partners, L.P. and Cheniere Energy Partners, GP, LLC.

Mr. Richard's qualifications to serve on the Board include his extensive knowledge of the utility industry as a former commissioner of the Federal Energy Regulatory Commission, his senior executive experience at a utility company and his experience as a public company director.

Nominees for Director — continued

Sara Martinez Tucker
San Francisco, California
Age 58
Director since 2009

Chief executive officer of the National Math and Science Initiative since March 1, 2013. From 2009 to February 2013, independent consultant. Former Under Secretary of Education in the U.S. Department of Education (2006-2008). Chief executive officer and president of the Hispanic Scholarship Fund from 1997 to 2006. Retired executive of AT&T. A director of Xerox Corporation and Sprint Corporation.

Ms. Tucker's qualifications to serve on the Board include her experience in governmental affairs as the Under Secretary of Education, her experience in human resources and customer service operations in the regulated telecommunications industry and her experience as a public company director.

AEP's Board of Directors and Committees

Under New York law, AEP is managed under the direction of the Board of Directors. The Board establishes broad corporate policies and authorizes various types of transactions, but it is not involved in day-to-day operational details. During 2013, the Board held seven regular meetings and one telephonic meeting. AEP encourages but does not require members of the Board to attend the annual shareholders' meeting. Last year, all directors attended the annual meeting.

Each year, the Policy Committee provides training and educational programs to the Company's directors. During 2013, the Policy Committee had a presentation from an outside lawyer on best practices for directors. In 2013, two of our directors, Ms. Lin and Mr. Nowell, were recognized by The National Association of Corporate Directors as one of the top 100 most influential people in the boardroom community.

Board Meetings and Committees. The Board expects that its members will rigorously prepare for, attend and participate in all Board and applicable committee meetings. Directors are also expected to become familiar with AEP's management team and operations as a basis for discharging their oversight responsibilities.

The Board has seven standing committees. The table below shows the number of meetings conducted in 2013 by each committee and the directors who currently serve on these committees. Each director attended 75 percent or more of the meetings of the Board and Board committees on which he or she served during 2013, and the average director attendance in 2013 was 98 percent.

	BOARD COMMITTEES						
DIRECTOR	**Audit**	**Directors and Corporate Governance**	**Policy**	**Executive**	**Finance**	**Human Resources**	**Nuclear Oversight**
Mr. Akins			X	X (Chair)			
Mr. Anderson	X		X		X		
Mr. Beasley	X		X				X
Mr. Crosby			X	X		X (Chair)	X
Ms. Goodspeed	X		X (Chair)				X
Mr. Hoaglin		X (Chair)	X	X		X	
Ms. Lin	X	X	X				
Mr. Morris			X	X	X		X (Chair)
Mr. Notebaert		X	X			X	
Mr. Nowell	X (Chair)	X	X	X	X		
Mr. Rasmussen		X	X		X		
Mr. Richard			X			X	X
Dr. Sandor			X	X	X (Chair)		
Ms. Tucker	X	X	X				
Mr. Turner	X		X				X
2013 Meetings	7	7	3	0	5	8	4

The functions of the committees are described below.

The ***Committee on Directors and Corporate Governance*** has the responsibilities set forth in its charter, including:

1. Recommending the size of the Board within the limits imposed by the Bylaws.
2. Recommending selection criteria for nominees for election or appointment to the Board.
3. Conducting independent searches for qualified nominees and screening the qualifications of candidates recommended by others.
4. Recommending to the Board nominees for appointment to fill vacancies on the Board as they occur and the slate of nominees for election at the annual meeting.
5. Reviewing and making recommendations to the Board with respect to compensation of directors and corporate governance.
6. Recommending members to serve on committees and chairs of the committees of the Board.
7. Reviewing the independence and possible conflicts of interest of directors and executive officers.
8. Overseeing the AEP Corporate Compliance Program.
9. Overseeing the annual evaluation of the Board of Directors.
10. Overseeing the annual evaluation of individual directors.
11. Overseeing the implementation of AEP's Related Person Transaction Approval Policy.
12. Overseeing AEP's Sustainability Report, including the material about political contributions.

13. Overseeing elements of the Company's risks that are within the scope of the Committee's responsibility as assigned to it by the Board of Directors.

A copy of the charter can be found on our website at *www.aep.com/investors/corporateleadersandgovernance*. Consistent with the rules of the NYSE and our Director Independence Standards, all members of the Committee on Directors and Corporate Governance are independent.

The ***Human Resources Committee*** (the HR Committee) annually reviews and approves AEP's executive compensation in the context of the performance of management and the Company. None of the members of the HR Committee is or has been an officer or employee of any AEP System company. In addition, each of the current members of the HR Committee has been determined to be independent by the Board in accordance with NYSE rules and our Director Independence Standards. In addition, each member is a "non-employee director" as defined in SEC Rule 16b-3 under the Exchange Act and is an "outside director" as defined in Section 162 (m) of the Internal Revenue Code.

The HR Committee also reviews the Compensation, Discussion and Analysis section of this proxy statement and recommends that it be included in the Company's Annual Report on Form 10-K.

The HR Committee has the responsibilities set forth in its charter, a copy of which can be found on our website at *www.aep.com/investors/corporateleadersandgovernance.*

For a more complete description of the HR Committee's responsibilities, see the Human Resources Committee Report on page 44.

The ***Audit Committee*** is responsible for, among other things, the appointment of the independent registered public accounting firm (independent auditor) for the Company; reviewing with the independent auditor the plan and scope of the audit and approving audit fees; monitoring the adequacy of financial reporting and internal control over financial reporting and meeting periodically with the internal auditor and the independent auditor. A more detailed discussion of the purposes, duties and responsibilities of the Audit Committee is found in the Audit Committee charter, a copy of which can be found on our website at *www.aep.com/investors/corporateleadersandgovernance*. Consistent with the rules of the NYSE and our Director Independence Standards, all members of the Audit Committee are independent. Each Audit Committee member has sufficient knowledge in financial and auditing matters to serve on the Audit Committee. In addition, the Board has determined that at least one member, Mr. Nowell, is an "audit committee financial expert" as defined by SEC rules.

The ***Finance Committee*** monitors and reports to the Board with respect to the capital requirements and financing plans and programs of AEP and its subsidiaries, including reviewing and making recommendations concerning the short and long-term financing plans and programs of AEP and its subsidiaries. The Finance Committee also provides recommendations to the Board on dividend policy, including the declaration and payment of dividends. The Finance Committee also reviews and approves the treasury policies of the Company.

The ***Nuclear Oversight Committee*** is responsible for overseeing and reporting to the Board with respect to the management and operation of AEP's nuclear generation.

The ***Policy Committee*** is responsible for examining AEP's policies on major public issues affecting the AEP System, including environmental, technology, fuel supply, industry change and other matters.

The ***Executive Committee*** is empowered to exercise all the authority of the Board, subject to certain limitations prescribed in the Bylaws, during the intervals between meetings of the Board.

The Board's role in AEP's risk oversight process

The Board has the overall responsibility for overseeing the Company's management of risks. Management is responsible for identifying and managing the Company's risks. The Board reviews the Company's processes for identifying and managing risks and communicating with the Board about those risks to help ensure that the processes are effective.

Like other companies, we have very diverse risks. These include financial and accounting risks, capital deployment risks, operational risks, compensation risks, liquidity risks, litigation risks, strategic risks, regulatory risks, reputation risks, natural-disaster risks and technology risks. Some critical risks having enterprise-wide significance, such as corporate strategy and capital budget, require the full Board's active oversight, but our Board committees also play a key role because they can devote more time to reviewing specific risks. For example, our Nuclear Oversight Committee focuses on the specific risks of operating a nuclear plant. Other committees oversee both specific and broad types of risks. Some of the committees have oversight responsibility for specific risks that are inherent in carrying out their responsibilities set forth in their charters. For example, the Audit Committee is responsible for overseeing financial reporting risks.

The Board is responsible for ensuring that these types of risks are properly delegated to the appropriate committee, and that the risk oversight activities are properly coordinated and communicated among the Board and the various committees that oversee the risks. Management prepared and categorized a list of the Company's major types of risks. The Audit Committee and the Directors and Corporate Governance Committee reviewed that list and proposed an assignment of risks either to the full Board or to specific committees. The Board reviewed the recommendations and adopted the proposed allocation of responsibilities.

Under the NYSE's listing standards, our Audit Committee must discuss AEP's policies for risk assessment and risk management. The Audit Committee oversees the process of identifying major enterprise risks and communicates those risks to the Board for assignment of oversight among the Board and the various committees. Our Chief Financial Officer, Chief Risk Officer, Chief Accounting Officer and General Counsel attend the Audit Committee meetings. The Audit Committee oversees the Company's maintenance of financial and disclosure controls and procedures and also specifically reviews our litigation and regulatory risks as part of their review of the Company's disclosures.

Our Finance Committee broadly oversees our financial risks, which include energy trading risks, liquidity risks and interest rate risks. The Finance Committee reviews and approves the Company's risk policies relating to our power marketing and hedging activities and also oversees the performance of the assets in our pension plans. Our Chief Financial Officer and General Counsel attend the Finance Committee meetings.

Our HR Committee reviews the Company's incentive compensation practices to ensure they do not encourage excessive risk-taking and are consistent with the Company's risk tolerance. The HR Committee also oversees our succession planning and executive leadership development. Our Chief Administrative Officer attends the HR Committee meetings.

The Directors and Corporate Governance Committee focuses on corporate governance risks and oversees the Company's Corporate Compliance Program, which includes the Company's whistleblower program. Our General Counsel attends the Directors and Corporate Governance Committee meetings.

Compensation Risk

As specified in its charter, the HR Committee (with the assistance of its independent compensation consultant and Company management) reviewed the Company's compensation policies and practices for all employees, including executive officers, and determined that the compensation programs are appropriate and are not reasonably likely to have a material adverse effect on the Company.

The Company has designed its executive compensation process, with oversight from the HR Committee, to identify and manage risk and to ensure that its executive compensation programs do not encourage excessive risk taking. The Company provides annual and long-term incentive compensation in amounts that represented approximately 16 percent and 71 percent of our CEO's total compensation opportunity for 2013, respectively. The HR Committee believes this appropriately allocated the CEO's compensation among base salary, annual incentive compensation and long-term incentive compensation opportunities in such a way as to not encourage excessive risk-taking. The Company's incentive compensation also has the following characteristics:

- It is part of a market competitive compensation package that enables the Company to attract, retain and motivate executives with the skills and experience needed to successfully manage the Company, which reduces risk by better ensuring both strong management competence and continuity;
- Incentive award opportunities for all employees are capped, generally at 200 percent of their target. Capping the potential payout limits the extent that employees could potentially profit by taking on excessive risk;
- The HR Committee provides the large majority of incentive compensation to executive officers as long-term stock-based incentive compensation to ensure that short-term performance is not encouraged or rewarded at the expense of long-term performance. This is important primarily because of the large amount of capital investments required in our business;
- Annual incentive compensation funding for nearly all employees, including all executive officers, is based substantially on AEP's operating earnings per share, which helps ensure that incentive awards are commensurate with the Company's earnings;
- Annual incentive compensation funding includes safety measures which helps ensure that no employees are encouraged to achieve earnings objectives at the expense of workplace safety;
- The primary metrics used in the Company's long-term incentive compensation are cumulative operating earnings per share and total shareholder return, which are both robust measures of shareholder value that reduce the risk that employees might be encouraged to pursue other objectives that increase risk or reduce financial performance;
- Annual and long-term incentive compensation programs are reviewed by AEP's internal audit staff;
- Incentive compensation performance scores are subject to an internal audit and incentive award payouts to 25 senior officers are subject to the review and approval of the HR Committee; or in the case of the CEO, the independent members of the Board; and these groups may discretionarily reduce or eliminate any payouts;
- Annual and long-term incentive payments and deferrals are subject to the Company's recoupment of incentive compensation policy ("clawback policy") as described in the Compensation Discussion and Analysis section on page 40;
- AEP granted seventy percent of its long-term incentive awards in the form of performance units with a three-year performance and vesting period, and granted the remaining thirty percent of its long-term incentive awards in the form of restricted stock units that vest over a forty month period which aligns the interests of employees to the long-term interests of shareholders and serves as a retention tool; and
- AEP maintains stock ownership requirements for 52 officers (as of January 31, 2014) as described in Compensation Discussion and Analysis on page 39.

Corporate Governance

AEP maintains a corporate governance page on its website that includes key information about corporate governance initiatives, including AEP's Principles of Corporate Governance, AEP's Principles of Business Conduct, Code of Business Conduct and Ethics for Members of the Board of Directors, Director Independence Standards, and charters for the Audit, Directors and Corporate Governance and HR Committees of the Board. The corporate governance page can be found at *www.aep.com/investors/corporateleadersandgovernance*. Printed copies of all of these materials also are available upon written request to Investor Relations at: AEP, attention: Investor Relations, 1 Riverside Plaza, Columbus, Ohio 43215.

AEP's policies and practices reflect corporate governance initiatives that are designed to comply with SEC rules, the listing requirements of the NYSE and the corporate governance requirements of the Sarbanes-Oxley Act of 2002, including:

- The Board of Directors has adopted corporate governance policies;
- All but two of its Board members (the CEO and the former CEO, who is retiring from the Board) are independent under the NYSE rules and our Director Independence Standards;
- All members of the Audit Committee, HR Committee and the Committee on Directors and Corporate Governance are independent;
- The independent members of the Board meet regularly without the presence of management;
- AEP has a code of business conduct that applies to its principal executive officer, principal financial officer and principal accounting officer and will promptly disclose waivers of the code for these officers;
- The charters of the Board committees clearly establish their respective roles and responsibilities; and
- The Board, the Committee on Directors and Corporate Governance, the Audit Committee and the HR Committee conduct annual self-assessments. The Committee on Directors and Corporate Governance also oversees the annual evaluation of the individual directors.

Directors

The Committee on Directors and Corporate Governance is responsible for recruiting new directors and uses a variety of methods for identifying and evaluating nominees for director. The Committee on Directors and Corporate Governance regularly assesses the appropriate size and composition of the Board, the needs of the Board and the respective committees of the Board and the qualifications of candidates in light of these needs. Candidates may come to the attention of the Committee on Directors and Corporate Governance through shareholders, management, current members of the Board or search firms. Shareholders who wish to recommend director candidates to the Committee on Directors and Corporate Governance may do so by following the procedures described in Shareholder Proposals and Nominations on page 72.

Director qualifications. The Company's Principles of Corporate Governance (Principles) are available on its website at *www.aep.com/investors/corporateleadersandgovernance.* With respect to director qualifications and attributes, the Principles provide that in nominating a slate of Directors, it is the Board's objective, with the assistance of the Committee on Directors and Corporate Governance, to select individuals with skills and experience to effectively oversee management's operation of the Company's business.

In addition, the Principles provide that directors should possess the highest personal and professional ethics, integrity and values, and be committed to representing the long-term interests of the shareholders, and that directors must also have an inquisitive and objective perspective, practical wisdom and mature judgment.

These requirements are expanded in the Criteria for Evaluating Directors (Criteria), which was initially adopted by the Committee on Directors and Corporate Governance in 2005 and has been subsequently reviewed and refined several times. The Criteria are available on the Company's website at *www.aep.com/investors/corporateleadersandgovernance.*

As indicated in the Principles and the Criteria, directors should have personal attributes such as high integrity, intelligence, wisdom and judgment. In addition, they should have skills and experience that mesh effectively with the skills and experience of other Board members, so that the talents of all members blend together to be as effective as possible in overseeing a large electric utility business.

Board Diversity

Our Criteria for Evaluating Directors also includes the Company's statement regarding how the Board considers diversity in identifying nominees for our Board. The Criteria provide:

> Two central objectives in selecting board members and continued board service are that the skills, experiences and perspectives of the Board as a whole should be broad and diverse, and that the talents of all members of the Board should blend together to be as effective as possible. In particular, the Board should be balanced by having complementary knowledge, expertise and skill in areas such as business, finance, accounting, marketing, public policy, manufacturing and operations, government, technology, environmental and other areas that the Board has decided are desirable and helpful to fulfilling its role. Diversity in gender, race, age, tenure of board service, geography and background of directors, consistent with the Board's requirements for knowledge and experience, are desirable in the mix of the Board.

Our Directors and Corporate Governance Committee considers these criteria each year as it determines the slate of director nominees to recommend to the Board for election at our annual meeting. It also considers these criteria each time a new director is recommended for election to the Board. The Board believes that its implementation of this policy is effective in considering the diversity of the members of the Board.

Director Independence

In accordance with the NYSE standards, a majority of the members of the Board of Directors must qualify as independent directors. Under the NYSE standards, no member of the Board is independent unless the Board affirmatively determines that such member does not have a direct or indirect material relationship with the Company. The Board has adopted categorical standards to assist it in making this determination of director independence (Director Independence Standards). These standards can be found on our web site at *www.aep.com/investors/corporateleadersandgovernance.*

Each year, our directors complete a questionnaire that elicits information to assist the Committee on Directors and Corporate Governance in assessing whether the director meets the Company's Director Independence Standards. Each director lists all the companies and charitable organizations that he or she, or an immediate family member, has a relationship with as a partner, trustee, director or officer, and indicates whether that entity made or received payments from AEP. The Company reviews its financial records to determine the amounts paid to or received from those entities. A list of the entities and the amounts AEP paid to or received from those entities is provided to the Committee on Directors and Corporate Governance. Utilizing this information, the

Committee on Directors and Corporate Governance evaluates, with regard to each director, whether the director has any material relationship with AEP or any of its subsidiaries and also confirms that none of these relationships is advisory in nature. The Committee on Directors and Corporate Governance determines whether the amount of any payments between those entities and AEP could interfere with a director's ability to exercise independent judgment. The Committee on Directors and Corporate Governance also reviews any other relevant facts and circumstances regarding the nature of these relationships, to determine whether other factors, regardless of the categorical standards the Board has adopted, might impede a director's independence.

We are a large electric utility company that operates in parts of eleven different states. Any organization that does business in our service territory is served by one of our subsidiaries. Many of our directors live in our service territory or are executives, directors or trustees of organizations that do business in our service area. Most of those organizations purchase electric service from us. However, there are no unique negotiated rates with any of those organizations. Therefore, the Committee on Directors and Corporate Governance determined that none of those relationships impedes a director's independence.

We make numerous charitable contributions to nonprofit and community organizations and universities in the states where we do business. Again, because many of our directors live in our service territory and are highly accomplished individuals in their communities, our directors are frequently affiliated with many of the same educational institutions, museums, charities and other community organizations. The Committee on Directors and Corporate Governance reviews all charitable contributions made by AEP to organizations with which our directors or their immediate family members are affiliated. The Committee on Directors and Corporate Governance also reviewed contributions made from The American Electric Power Foundation, which was created to support and play an active, positive role in the communities in which we operate by contributing funds to organizations in those communities. The Committee on Directors and Corporate Governance determined that the Company's contributions were not materially influenced by the director's relationship with the organization, and therefore none of these relationships conflicts with the interests of the Company or would impair the director's independence or judgment.

The Board's independence determinations specifically included reviewing the following transactions:

- Mr. Rasmussen is an executive officer of Nationwide Insurance. Nationwide purchases electricity from our subsidiaries (substantially less than one percent of the Company's gross revenues). In addition, the Company paid an insignificant amount to Nationwide for standard insurance premiums, rent for office space and interest payments on ordinary course debt issued by the Company and its subsidiaries, which was sold through underwriters or brokers (which totaled substantially less than one percent of Nationwide's gross revenues). The transactions between Nationwide and the Company were in the ordinary course and entered into on an arm's length basis, and payments were for services that were transactional in nature and did not involve any consulting or advisory work. Therefore, the Board determined that these transactions did not impair the independence of Mr. Rasmussen.
- Mr. Anderson is an executive officer of Honeywell International. Although Honeywell purchases electricity from our subsidiaries (substantially less than one percent of the Company's gross revenues), and the Company purchased an insignificant amount of goods from Honeywell (substantially less than one percent of Honeywell's gross revenue), the Board determined that those transactions did not impair the independence of Mr. Anderson.
- Mr. Turner is a director of Peabody Energy Corporation, another company that transacted business with AEP. Mr. Turner is not an employee or executive officer of that company, and Mr. Turner is retiring from the AEP Board. AEP purchases a significant amount of coal from Peabody Energy Corporation, but AEP entered into these coal buying relationships

with Peabody in the ordinary course of business. AEP's purchases from Peabody are typically awarded through a competitive process. In addition, all of AEP's public utility subsidiaries' coal purchase contracts, including those with Peabody, are subject to review by the applicable state public service commissions. Therefore, the Board determined that those transactions did not impair the independence of Mr. Turner.

As a result of this review, the Board has determined that, other than Messrs. Akins and Morris, each of the directors and director nominees standing for election, including Messrs. Anderson, Beasley, Crosby, Hoaglin, Notebaert, Nowell, Rasmussen, Richard and Turner, Dr. Sandor, Ms. Goodspeed, Ms. Lin and Ms. Tucker, has no material relationship with the Company (either directly or as a partner, stockholder or officer of an organization that has a relationship with the Company) and is independent under the NYSE rules and the Company's Director Independence Standards.

Involvement by Mr. Hoaglin in Certain Legal Proceedings

On June 2, 2005, Huntington Bancshares Incorporated (Huntington) announced that the SEC approved a settlement of its previously announced formal investigation into certain financial accounting matters relating to fiscal years 2002 and earlier and certain related disclosure matters. As part of the settlement, the SEC instituted a cease and desist administrative proceeding and entered a cease and desist order and also filed a civil action in federal district court pursuant to which, without admitting or denying the allegations in the complaint, Huntington and Mr. Hoaglin consented to pay civil money penalties. Without admitting or denying the charges in the administrative proceeding, Mr. Hoaglin agreed to cease and desist from committing and/or causing the violations charged as well as any future violations of these provisions. Additionally, Mr. Hoaglin agreed to pay disgorgement, pre-judgment interest and penalties in the amount of $667,609.

Shareholder Nominees for Directors

The Committee on Directors and Corporate Governance will consider shareholder recommendations of candidates to be nominated as directors of the Company. All such recommendations must be in writing and submitted in accordance with the procedures described under Shareholder Proposals and Nominations on page 72 and must include information required in AEP's Policy on Consideration of Candidates for Director Recommended by Shareholders. A copy of this policy is on our website at *www.aep.com/investors/corporateleadersandgovernance.* Shareholders' nominees who comply with these procedures will receive the same consideration that all other nominees receive.

Board Leadership

We believe the Company and its shareholders are best served by a Board that has the flexibility to establish a leadership structure that fits the needs of the Company at a particular point in time. Under the Company's Principles of Corporate Governance, the Board has the authority to combine or separate the positions of Chairman and CEO, as well as to determine whether, if the positions are separated, the Chairman should be an employee, non-employee, or an independent director.

The Board's judgment is that the functioning of the Board is currently best served by maintaining a structure of having one individual serve as both Chairman and CEO. The Board believes that having a single person acting in those capacities promotes unified leadership and direction for both the Board and management and also provides a single, clear focus to execute the Company's strategy especially during this time of significant change in the utility business. However, in certain circumstances, such as the transition from one chief executive officer to another, the Board believes it may be appropriate for the role of Chairman and CEO to be split. In November 2011, in order to promote an orderly CEO transition from Mr. Morris to Mr. Akins, the Board made the determination that it was in the best interest of the Company and its shareholders that the two offices be separated. Now that Mr. Akins has served for over two years in his role as CEO, the Board's judgment is that Mr. Akins should now serve as Chairman and CEO.

Under the Company's Principles of Corporate Governance, in circumstances where the Chairman of the Board is not independent or where the positions of Chairman and Chief Executive Officer are filled by the same person, the Board considers it useful and appropriate to designate a Lead Director. The Company already has policies and practices in place to provide independent oversight of management and the Company's strategy. The Board currently includes 13 independent directors among its 15 members. The Board routinely holds executive sessions at which only independent directors are present, and, each year, the independent directors select a Lead Director responsible for facilitating and chairing the independent directors sessions.

Mr. Hoaglin has been the Lead Director of the Board since April 2012. The purpose of the Lead Director is to promote the independence of the Board in order to represent the interests of the shareholders. The Lead Director is selected by the independent directors.

The Lead Director is responsible for working closely with the CEO to finalize information flow to the Board, set meeting agendas and arrange meeting schedules. He also chairs meetings of the independent directors and serves as principal liaison between the independent directors and management. In addition, Mr. Hoaglin has the ability to call special meetings of the Board, as needed. He has the authority to retain outside legal counsel or other advisors as needed by the Board. He provides a channel of communications between the directors and management, assures that directors receive timely and necessary information in advance of meetings, and receives communications from shareholders on behalf of non-management directors.

Communicating with the Board

Anyone who would like to communicate directly with our Board, our independent directors as a group, or our Lead Director, may submit a written communication to American Electric Power Company, Inc., P.O. Box 163609, Attention: AEP Independent Directors, Columbus, Ohio 43216. The Company's Corporate Secretary reviews such inquiries or communications, and communications other than advertising or promotions of a product or service are forwarded to our Board, our independent directors as a group or our Lead Director, as appropriate.

Transactions with Related Persons

The American Electric Power Company, Inc. Related Person Transaction Approval Policy (Policy) was adopted by the Board in December 2006. The written Policy is administered by the Committee on Directors and Corporate Governance. A copy of the Policy is available on our website at *www.aep.com/investors/corporateleadersandgovernance.*

The Policy defines a "Transaction with a Related Person" as any transaction or series of transactions in which (i) the Company or a subsidiary is a participant, (ii) the aggregate amount involved exceeds $120,000 and (iii) any "Related Person" has a direct or indirect material interest. A "Related Person" is any director or executive officer of the Company, any nominee for director, any shareholder owning in excess of five percent of the total equity of the Company and any immediate family member of any such person.

The Directors and Corporate Governance Committee considers all of the relevant facts and circumstances in determining whether or not to approve a Transaction with a Related Person and approves only those transactions that are in the best interests of the Company. The Directors and

Corporate Governance Committee considers various factors, including, among other things: the nature of the Related Person's interest in the transaction; whether the transaction involves arm's-length bids or market prices and terms; the materiality of the transaction to each party; the availability of the product or services through other sources; whether the transaction would impair the judgment of a director or executive officer to act in the best interest of the Company; the acceptability of the transaction to the Company's regulators; and in the case of a non-management director, whether the transaction would impair his or her independence or status as an "outside" or "non-management" director.

If Company management determines it is impractical or undesirable to wait until a meeting of the Directors and Corporate Governance Committee to consummate a Transaction with a Related Person, the Chair of the Directors and Corporate Governance Committee may review and approve the Transaction with a Related Person. Any such approval is reported to the Directors and Corporate Governance Committee at or before its next regularly scheduled meeting.

No approval or ratification of a Transaction with a Related Person supersedes the requirements of the Company's Code of Business Conduct and Ethics for Members of the Board of Directors or AEP's Principles of Business Conduct applicable to any executive officer. To the extent applicable, any Transaction with a Related Person is also considered in light of the requirements set forth in those documents.

Since January 1, 2013, there have been no transactions and there are no currently proposed transactions, involving an amount exceeding $120,000 in which AEP was or is expected to be a participant and in which any Related Person had a direct or indirect material interest.

Director Compensation

Directors who are employees of the Company receive no additional compensation for service as a director other than accidental insurance coverage. The table below shows the elements and amount of compensation that we paid to our non-management directors for 2013.

Compensation Element	Until October 1, 2013	On and After October 1, 2013
Annual Retainer (1)	$ 92,000	$ 97,000
Annual Stock Unit Awards (2)	138,000	145,000
Committee Chair Annual Retainers (1):		
Audit Committee	20,000	20,000
HR Committee	20,000	20,000
Audit Committee Member Annual Retainers (1)	15,000	15,000
HR Committee Member Annual Retainers (1)	10,000	10,000
Lead Director		
Annual Retainer (1)	30,000	30,000
Non-Executive Chairman (3)		
Annual Retainer (1)	330,000	330,000

(1) Retainer amounts are paid in cash in quarterly installments.

(2) In 2013, pursuant to the Stock Unit Accumulation Plan for Non-Management Directors, each non-management director was awarded $139,750 in AEP stock units. These AEP stock units are credited to directors quarterly, based on the closing price of AEP Common Stock on the payment date. Amounts equivalent to cash dividends on the AEP stock units accrue as additional AEP stock units. AEP stock units are paid to each non-management director in cash shortly after termination of service unless the director has elected to further defer payment.

(3) Following his January 1, 2012 appointment as Non-Executive Chairman, Mr. Morris provided support on strategic and public policy issues to the Company. As compensation for his service as Non-Executive Chairman of the Board of Directors, Mr. Morris received an additional annual retainer of $330,000. The additional Non-Executive Chairman compensation was eliminated as of January 1, 2014 when Mr. Akins was elected Chairman of the Board.

The Board has determined that Board compensation should consist of a mix of cash and AEP stock units. In September 2013, upon the recommendation of the Committee on Directors and Corporate Governance and taking into account comparative data from Meridian Compensation Partners, LLC, an outside independent consultant ("Meridian"), the Board determined that effective October 1, 2013, (i) the amount of AEP stock units awarded to non-employee directors pursuant to the Stock Unit Accumulation Plan should increase from $138,000 annually to $145,000 annually and (ii) the amount of the annual cash retainer paid to non-employee directors should increase from $92,000 annually to $97,000 annually. The Committee on Directors and Corporate Governance assessed the independence of Meridian pursuant to SEC rules and concluded that Meridian's work for the Committee on Directors and Corporate Governance does not raise any conflict of interest.

The Board believes that the director compensation set forth above compensates directors appropriately for all general services that are rendered as a director, committee member, committee chair or as Lead Director, including education and training appropriate to the director's responsibilities. The Company believes, however, that special compensation can be appropriate when individual directors are asked to undertake special assignments requiring a significant amount of additional time, effort and responsibility. The Board's Special Compensation Policy provides for directors to be compensated at a daily rate when called upon to undertake special additional services beyond those contemplated by the Annual Retainer. Under the Special Compensation Policy, the Committee on Directors and Corporate Governance determines (a) the amount of any special compensation in light of the actual or anticipated time, effort and responsibility required of the director and (b) the form of special compensation, which may include a per diem fee, an hourly fee, a flat fee or any other reasonable payment or payments. No special compensation was paid for services provided in 2013.

Expenses. Directors are reimbursed for expenses incurred in attending Board, committee and shareholder meetings. Directors are also reimbursed for reasonable expenses associated with other business activities that benefit the Company, including participation in director education programs.

Spouses may occasionally join directors on Company aircraft when a director is traveling to or from Board meetings or other business activities. The Company generally provides for, or reimburses the expenses of, the directors and their spouses for attendance at such meetings. The Board eliminated tax gross-ups on any director perquisites.

Retainer Deferral Plan. The Retainer Deferral Plan for Non-Employee Directors is a non-qualified deferred compensation plan that permits non-employee directors to choose to defer up to 100 percent of their annual cash retainer and fees into a variety of investment fund options, all with market-based returns, including an AEP stock fund. The Plan permits the non-employee directors to defer receipt until termination of service or for a period that results in payment commencing not later than five years after termination of service.

Insurance. AEP maintains a group 24-hour accident insurance policy to provide a $1,000,000 accidental death benefit for each director, $100,000 for each spouse of a director and $50,000 for all dependent children. The current policy, effective September 1, 2012 to September 1, 2015, has a premium of $28,905.

Stock Ownership. Non-management directors are required by our Corporate Governance Principles to own AEP common stock or AEP stock units worth five times their annual equity award, which is met within the first five years of a non-management director's term by requiring the director to hold the AEP stock units awarded under the Stock Unit Accumulation Plan. Each non-management director is required to hold these stock units until termination of service. After five years of service on the Board, non-management directors receive contributions to an AEP stock fund under the Stock Unit Accumulation Plan. During open trading windows they may subsequently transfer those amounts into other investment fund options, similar to those in the Retainer Deferral Plan.

Matching Gifts Program. Directors may participate in our Matching Gifts Program on the same terms as AEP employees. Under the program, AEP will match between $250 and $1,000 per higher education institution each year in charitable contributions from a director.

Charitable Award Program. AEP is continuing a memorial gift program for former Central and South West Corporation directors and executive officers who had been previously participating in this program. The program currently has 26 participants, including Dr. Sandor. Under this program, AEP makes donations in a director's name to up to three charitable organizations in an aggregate amount of up to $500,000, payable by AEP upon such person's death. AEP maintains corporate-owned life insurance policies to support portions of the program. AEP paid an annual premium of $103,569 on those policies for 2013.

2013 Director Compensation Table

The following table presents the compensation provided by the Company in 2013 to our non-management directors.

Name	Fees Earned Or Paid in Cash ($)	Stock Awards ($) (2)(3)	All Other Compensation ($) (4)	Total ($)
David. J. Anderson	108,250	139,750	642	248,642
James F. Cordes (1)	31,952	43,229	642	75,823
Ralph D. Crosby, Jr.	123,250	139,750	642	263,642
Linda A. Goodspeed	108,250	139,750	642	248,642
Thomas E. Hoaglin	133,250	139,750	642	273,642
Sandra Beach Lin	108,250	139,750	642	248,642
Michael G. Morris	423,250	139,750	642	563,642
Richard C. Notebaert	103,250	139,750	642	243,642
Lionel L. Nowell III	128,250	139,750	642	268,642
Stephen S. Rasmussen	93,250	139,750	642	233,642
Oliver G. Richard III	103,250	139,750	642	243,642
Richard L. Sandor	93,250	139,750	4,625	237,625
Sara M. Tucker	108,250	139,750	5,642	253,642
John F. Turner	108,250	139,750	642	248,642

(1) Mr. Cordes' term as a director ended effective as of April 23, 2013, the date of our 2013 Annual Meeting.

(2) The dollar amounts reported represent the grant date fair value calculated in accordance with FASB ASC Topic 718 of AEP stock units granted under the Stock Unit Accumulation Plan for Non-Employee Directors, without taking into account estimated forfeitures. AEP Stock Units are credited to directors quarterly, based on the closing price of AEP common stock on the payment date.

(3) Each non-employee director who served the full year received 3,051.287 AEP stock units in 2013. Due to his service for less than a full year, Mr. Cordes received 881.803 AEP stock units.

The current directors had the following aggregate number of AEP stock units at 2013 year-end: Mr. Anderson (9,353), Mr. Crosby (29,436), Ms. Goodspeed (30,210), Mr. Hoaglin (23,667), Ms. Lin (4,736), Mr. Morris (6,539), Mr. Notebaert (9,353), Mr. Nowell (33,961), Mr. Rasmussen (4,208), Mr. Richard (3,101), Dr. Sandor (43,046), Ms. Tucker (19,559) and Mr. Turner (21,754).

(4) The amounts reported in all other compensation consists of (a) a premium of $642 for accidental death insurance policy, (b) a matching gift contribution of $5,000 for Ms. Tucker and (c) an amount of $3,983 for Dr. Sandor's participation in the Central and South West Corporation Memorial Gift Program.

Insurance

AEP and the AEP System Companies and their directors and officers are insured, subject to certain exclusions and deductibles, against losses resulting from any claim or claims made against them while acting in their capacities as directors and officers. Such insurance, effective March 15, 2013 to March 15, 2014, is provided by: Associated Electric & Gas Insurance Services Ltd., Energy Insurance Mutual Ltd., Zurich American Insurance Company, AXIS Insurance Company, U.S. Specialty Insurance Company, Arch Insurance Company, Travelers Casualty and Surety Co. of America, Westchester Fire Insurance Company (ACE), Berkley Insurance Co., RSUI Insurance Company, Alterra America Insurance Company, Scottsdale Indemnity Company (Freedom Specialty), Arch Reinsurance, Ltd., Illinois National Fire Insurance Company (AIG), Allied World Assurance Company Ltd. (AWAC), Liberty Mutual Insurance Company, Travelers Casualty & Surety Company (Travelers), Endurance Risk Solutions Assurance Co., Catlin Specialty Insurance Company (Catlin, Inc.) and ACE Bermuda LTD. The total cost of this insurance is $3,298,391.

Fiduciary liability insurance provides coverage for AEP System companies and their affiliated trusts, their directors and officers, and any employee deemed to be a fiduciary or trustee, for breach of fiduciary responsibility, obligation, or duties as imposed under the Employee Retirement Income Security Act of 1974. Such insurance, effective March 15, 2013 to March 15, 2014, is provided by U.S. Specialty Insurance Company, AXIS Specialty Insurance Company, Energy Insurance Mutual Ltd., and Scottsdale Indemnity Company (Freedom Specialty). The total cost of this insurance is $561,320.

Item 2. Proposal to Ratify Appointment of Independent Registered Public Accounting Firm

The Audit Committee has appointed the firm of Deloitte & Touche LLP as the Company's independent registered public accounting firm for 2014. Although action by the shareholders in this matter is not required, the Audit Committee believes that it is appropriate to seek shareholder ratification of this appointment in light of the critical role played by the independent registered public accounting firm in maintaining the integrity of Company financial controls and reporting, and will seriously consider shareholder input on this issue. Whether or not the appointment of Deloitte & Touche LLP is ratified by the shareholders, the Audit Committee may, in its discretion, change the appointment at any time during the year if it determines that such change would be in the best interests of the Company and its shareholders.

One or more representatives of Deloitte & Touche LLP will be in attendance at the annual meeting on April 22, 2014. The representatives will have the opportunity to make a statement, if desired, and will be available to respond to appropriate questions from shareholders.

Vote Required.

Approval of this proposal requires the affirmative vote of holders of a majority of the votes cast at the meeting.

Your Board of Directors recommends a vote **FOR** this Item 2.

Audit and Non-Audit Fees

The following table presents fees for professional audit services rendered by Deloitte & Touche LLP for the audit of the Company's annual financial statements for the years ended December 31, 2013 and December 31, 2012, and fees billed for other services rendered by Deloitte & Touche LLP during those periods.

	2013	2012
Audit Fees(1)	$12,344,000	$10,757,000
Audit-Related Fees(2)	$ 706,000	$ 1,361,000
Tax Fees(3)	$ 587,000	$ 147,000
TOTAL	$13,637,000	$12,265,000

(1) Audit fees in 2012 and 2013 consisted primarily of fees related to the audit of the Company's annual consolidated financial statements, including each registrant subsidiary. Audit fees also included auditing procedures performed in accordance with Sarbanes-Oxley Act Section 404 and the related Public Company Accounting Oversight Board Auditing Standard Number 5 regarding the Company's internal control over financial reporting. This category also includes work generally only the independent registered public accounting firm can reasonably be expected to provide.

(2) Audit-related fees consisted principally of regulatory, statutory and employee benefit plan audits. A rate filing in 2012 required external audit assurance.

(3) Tax fees consisted principally of advisory services. Tax services are rendered based upon facts already in existence, transactions that have already occurred, as well as tax consequences of proposed transactions. Evaluation of the tax aspects of proposed transactions in 2013 accounted for the increase.

The Audit Committee has considered whether the provision of services other than audit services by Deloitte & Touche LLP and its domestic and global affiliates is compatible with maintaining independence, and the Audit Committee believes that this provision of services is compatible with maintaining Deloitte & Touche LLP's independence.

Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of the Independent Registered Public Accounting Firm

The Audit Committee's policy is to pre-approve all services provided by the independent registered public accounting firm. These services may include audit services, audit-related services, tax services and other services. Pre-approval is provided for up to one year and any pre-approval is detailed as to the particular service or category of services and is subject to a specific limitation. The independent registered public accounting firm and management are required to report to the Audit Committee at each regular meeting regarding the extent of services provided by the independent registered public accounting firm in accordance with this pre-approval policy, and the fees for the services performed to date. The Audit Committee Chairman may also pre-approve particular services on a case-by-case basis. In 2013, all Deloitte & Touche LLP services were pre-approved by the Audit Committee in accordance with this policy.

Audit Committee Report

The Audit Committee reviews AEP's financial reporting process as well as the internal control over financial reporting on behalf of the Board. Management has the primary responsibility for the financial statements and the reporting process, including the system of internal control over financial reporting.

The Audit Committee met seven times during the year and held discussions, some of which were in private, with management, the internal auditor, and the independent registered public accounting firm. Management represented to the Audit Committee that AEP's consolidated financial statements were prepared in accordance with generally accepted accounting principles. Management has also concluded that the Company's internal control over financial reporting was effective as of December 31, 2013. The Audit Committee has reviewed and discussed the audited consolidated financial statements and internal control over financial reporting with management, the internal auditor and the independent registered public accounting firm. The Audit Committee discussed with the independent registered public accounting firm the matters required to be discussed by the Public Company Accounting Oversight Board (PCAOB).

In addition, the Audit Committee had discussions with and received written communications from the independent registered public accounting firm regarding its independence as required by the PCAOB. The Audit Committee has also received written communication regarding the results of the independent registered public accounting firm's internal quality control reviews and procedures and other matters, as required by the New York Stock Exchange listing standards.

In reliance on the reviews, communications and discussions referred to above, the Audit Committee recommended to the Board, and the Board has approved, that the audited financial statements be included in AEP's Annual Report on Form 10-K for the year ended December 31, 2013, for filing with the SEC.

Audit Committee Members
Lionel L. Nowell, III, Chair
David J. Anderson
J. Barnie Beasley, Jr.
Linda A. Goodspeed
Sandra Beach Lin
Sara Martinez Tucker
John F. Turner

Item 3. Advisory Vote on Executive Compensation

In accordance with the requirements of Section 14A of the Securities Exchange Act, we are including in these proxy materials a separate resolution for shareholders to vote upon, on an advisory (non-binding) basis, the compensation paid to our named executive officers as disclosed in this proxy statement in accordance with the SEC's rules.

As described in detail under the heading "Compensation Discussion and Analysis," our executive compensation programs are designed to attract, motivate, and retain our named executive officers who are critical to our success. Under these programs, our named executive officers are rewarded for the achievement of annual and long-term goals. Please read the "Compensation Discussion and Analysis" beginning on page 24 for additional details about the 2013 compensation of our named executive officers.

The HR Committee continually reviews the compensation programs for our named executive officers to ensure they achieve the desired goals of aligning our executive compensation structure with our shareholders' interests and current market practices. As a result of its review process, the HR Committee maintains the following executive compensation practices:

- Emphasizing long-term incentive compensation to promote the longer-term interests of the Company and encourage management to make decisions that are aligned with shareholders' interests;
- Tying the value of a substantial portion (70 percent) of this long-term compensation to two robust measures of shareholder value:
  - Three-year total shareholder return compared to the S&P 500 Electric Utilities Industry Index, and
  - Three year cumulative earnings per share compared to a board approved objective;
- Maintaining a clawback policy that allows the Board to recoup any excess incentive compensation paid to our named executive officers and other key members of our executive team if the financial results on which the awards were based are materially restated due to misconduct of the executive.

We are asking our shareholders to indicate their support for our named executive officer compensation as described in this proxy statement. This proposal, commonly known as a "say-on-pay" proposal, gives our shareholders the opportunity to express their views on our named executive officers' compensation. This advisory vote is not intended to address any specific item of compensation, but rather the overall compensation of our named executive officers and the philosophy, policies and practices described in this proxy statement. Accordingly, we will ask our shareholders to vote "FOR" the following resolution at the Annual Meeting:

"RESOLVED, that the compensation paid to the Company's named executive officers, as disclosed in the Company's Proxy Statement for the 2014 Annual Meeting of Shareholders pursuant to rules of the SEC, including the Compensation Discussion and Analysis, compensation tables and related narrative disclosure is hereby APPROVED."

While the Board intends to consider carefully the results of this vote, the say-on-pay vote is advisory only, and therefore will not be binding on the Company or our Board of Directors.

Vote Required.

Approval of this proposal requires the affirmative vote of holders of a majority of the votes cast at the meeting.

Your Board of Directors recommends a vote **FOR** this Item 3.

Other Business

The Board of Directors does not intend to present to the meeting any business other than the election of directors, the ratification of the appointment of the independent registered public accounting firm and the advisory vote on the compensation of the named executive officers as disclosed in this proxy statement.

If any other business not described herein should properly come before the meeting for action by the shareholders, the persons named as proxies on the proxy card or their substitutes will vote the shares represented by them in accordance with their best judgment. At the time this proxy statement was printed, the Board of Directors was not aware of any other matters that might be presented.

Compensation Discussion and Analysis

This section explains AEP's compensation philosophy, summarizes its compensation programs and reviews compensation decisions for the following named executive officers:

Name	Title
Mr. Akins	Chairman, Chief Executive Officer and President
Mr. Tierney	Executive Vice President and Chief Financial Officer
Mr. Powers	Executive Vice President and Chief Operating Officer
Mr. Feinberg	Executive Vice President and General Counsel
Ms. Hillebrand	Senior Vice President and Chief Administrative Officer

Executive Summary

2013 Business Performance Highlights. AEP's shareholders received a 14.2 percent total shareholder return including dividends for the year, which was well above the total shareholder return for the S&P 500 Electric Utilities Index of 7.8 percent. The Company's 2013 operating earnings were $3.23 per share, which was above the mid-point of our earnings guidance for the year. During 2013, the Company successfully accomplished several strategic and operating initiatives. AEP Ohio completed the corporate separation of its generation assets on December 31, 2013, as planned. Throughout 2013 the Company also focused on ways to work differently through a continuous improvement culture to create sustainable O&M savings and increase revenues. As part of this program, the Company reached approximately $242 million in sustainable O&M savings and revenue enhancements. And, for the second year in a row, the Company did not experience a fatal employee accident.

At the beginning of the year, the HR Committee established threshold (0 percent of target payout), target and maximum (200 percent of target payout) operating earnings per share measures for 2013 annual incentive compensation at $3.00, $3.15 and $3.30 per share, respectively. In setting the $3.15 per share target, the HR Committee considered the slow economic recovery in our service territory, the level of customer switching at AEP Ohio and continued low natural gas prices that impact our off system sales. Despite these anticipated challenges, the HR Committee slightly increased the target for annual incentive compensation by $0.03 per share from AEP's 2012 target. In 2013 AEP produced operating earnings per share of $3.23, which was above the target of $3.15. As a result, earnings of $3.23 were included in the calculation of annual incentive funding. Throughout this CD&A, we refer to operating earnings, which is a non-GAAP financial measure. Exhibit A to this proxy statement contains a reconciliation of GAAP earnings per share to operating earnings per share for 2013.

The Company's operating earnings per share, together with the Company's performance on the strategic and operating measures for corporate separation, continuous improvement and safety discussed above, produced an initial score of 152.4 percent of target. The HR Committee established two extra credit goals for 2013: 7.5 percent for zero fatalities and up to 5 percent for cultural improvement. The Company did not experience a fatal employee accident, which resulted in a 7.5 percent addition to the score. The HR Committee subjectively considered the Company's achievement of predetermined culture improvement activity milestones, as well as the opportunity for further improvement in AEP's culture, and awarded 3 of 5 possible percentage points for this goal. As a result, the overall annual incentive funding for AEP's executive officers was 162.9 percent of target for 2013.

The cumulative operating earnings per share score for the 2011-2013 performance units was 97.5 percent of target. The relative total shareholder return (TSR) measure at the end of the performance period was at the 62nd percentile of the comparator group, which produced a score of 140 percent of target. The operating earnings per share and TSR scores combined to produce an overall score of 118.8 percent of target for the 2011-2013 performance period. As a result, 118.8 percent of the 2011-2013 performance units outstanding at year-end were earned.

2013 Executive Compensation Highlights. The HR Committee undertook a project in 2012 to assess the competitiveness of realizable executive compensation looking backwards over one, three and five year periods for senior executive positions relative to utility industry peers. This analysis showed that, on a percentile basis, the realizable compensation of AEP executives over these periods was consistently below AEP's total shareholder return performance. As a result, the HR Committee directed management to develop a multi-year plan to address the root causes of this gap between realizable compensation and performance. This plan was adopted by the HR Committee in 2013 and included both structural changes to AEP's compensation program and compensation changes for some executives, where their target compensation was significantly below market. The HR Committee also decided to establish salaries for newly promoted and hired executives closer to the market competitive target going forward.

The HR Committee continues to target market median compensation for all of the named executive officers, but now also considers other market pay levels, such as the 25th, 60th and 75th percentiles, in addition to the market median to provide a more complete picture of market comparisons.

The basis for funding for the annual incentive program was modified for 2013 from 100 percent operating earnings per share to 75 percent operating earnings per share and 25 percent strategic, safety and operating goals. The HR Committee added these additional funding measures to create a balanced scorecard for incentive funding. The strategic, operating and safety goals only provide funding if the operating earnings per share threshold is met and are capped at an aggregate 150 percent of target score.

The HR Committee also changed the plus or minus 10 percent fatality adjustment to a plus 7.5 percent extra credit if the Company had zero fatalities for the year. Safety remained a focus of the plan with a safety measure with a 10 percent weight, as well as the zero fatality goal with a 7.5 percent extra credit potential.

In addition, the HR Committee approved the inclusion of a culture measure with a potential 5 percent extra credit. Achievement of this extra credit was based on meeting specific, predetermined culture improvement activity milestones.

For 2013, the HR Committee also changed the award mix for long-term incentive awards to increase the percentage granted in the form of performance units from 60 percent to 70 percent, and to reduce the percentage granted in the form of restricted stock units from 40 percent to 30 percent. The HR Committee made this change to increase the amount of long-term incentive compensation that is performance-based. This long-term incentive award mix is similar to the median mix of performance based and non-performance based long-term awards among the companies in AEP's Compensation Peer Group. AEP's three-year performance unit awards accounted for approximately 50 percent of the total compensation opportunity for Mr. Akins. These performance units are tied to AEP's three year cumulative operating earnings per share and three year total shareholder return relative to the S&P 500 Electric Utilities Industry Index. An additional 21 percent of the total compensation opportunity for Mr. Akins was tied to the value of AEP common stock as restricted stock units that vest over a 40-month period.

Effective January 1, 2014, the HR Committee replaced all of the Company's change in control agreements to eliminate the provisions that provided a tax gross-up for excise taxes to certain participants. Prior to this change, some of the named executive officers had change in control agreements that provided for a payment that offset the effect of an excise tax with a "gross-up" payment that would have reimbursed those executives for any excise tax on an after tax basis.

The HR Committee also changed the stock ownership targets for executives from a fixed number of shares to a multiple of base salary. The CEO's target is five times his base salary, and the target for each of the other named executive officers is three times their base salary. This is more consistent with the way most companies establish stock ownership targets.

As part of the HR Committee's independent compensation consultant's comprehensive review of the Company's executive compensation in September 2013, the consultant noted that the Company's practice of using a mix of electric utility and general industry peers differed from the majority practice in the utility industry. Therefore, the HR Committee approved changing the Company's peer group. It retained all of the existing utility peer companies and added three utility peer companies, but removed all of the general industry companies. The HR Committee made these changes because the HR Committee assessed that an all utility peer group provides more meaningful compensation comparisons and because other similar utility companies are the primary competitors for the Company's executive talent. In addition, recent consolidations and mergers in the utility industry increased the size of a number of the utility peer companies. This change in peer group is discussed in detail on page 30.

Corporate Governance Highlights. For many years, the Company has:

- Had significant stock ownership requirements for its executive officers;
- Tied a substantial portion of the compensation for its executives to annual and long-term performance;
- Had a policy that allows the Company to claw back incentive compensation in certain circumstances; and
- Had an insider trading policy that prohibits our executives and directors from hedging their AEP stock holdings or holding them in margin accounts without Company approval.

In addition, the HR Committee has made several changes to the Company's executive compensation program in the last several years to align with best practices, including:

- Granting long-term incentive awards with change in control provisions that include a double trigger that results in vesting of these awards only if there is a change in control and a separation from service;
- Eliminating company paid country club memberships for executive officers;
- Generally eliminating personal use of Company provided aircraft, to the extent that such use has an incremental cost to the Company;
- Generally eliminating tax gross-ups, other than for relocation;

- Amending the Company's Insider Trading Policy to prohibit directors and executive officers from pledging Company stock; and
- Eliminating the reimbursement and tax gross-up for excise taxes triggered under change in control agreements.

Results of 2013 Advisory Vote to Approve Executive Compensation

At the Company's annual meeting of shareholders held in April 2013, approximately 95 percent of the votes cast on the Company's say-on-pay proposal voted in favor of the proposal. In accordance with this vote, the HR Committee continued to apply the same principles and philosophy it has used in previous years in determining executive compensation. The HR Committee will continue to consider the outcome of the Company's say-on-pay vote and other sources of stakeholder feedback when establishing compensation programs and making compensation decisions for the named executive officers.

The Board decided that AEP will hold an advisory vote on the compensation of named executive officers at each annual meeting of shareholders until the next required shareholder vote to determine the frequency of the advisory votes on executive compensation. Because the Dodd-Frank Act requires that such frequency votes be held at least once every six years, we currently expect the next shareholder vote on frequency to occur at the Company's 2017 annual meeting of shareholders.

Overview

The HR Committee oversees and determines AEP's executive compensation (other than that of the CEO). The HR Committee makes recommendations to the independent members of the board of directors about the compensation of the Chief Executive Officer, and those independent board members determine the CEO's compensation.

AEP's executive compensation programs are designed to:

- Attract, retain, motivate and reward an outstanding leadership team with market competitive compensation and benefits to achieve both excellent team and individual performance;
- Reflect AEP's financial and operational size and the complexity of its multi-state operations;
- Provide a substantial portion of executive officers' total compensation opportunity in the form of performance based incentive compensation;
- Align the interests of the Company's executive officers with those of AEP's shareholders by providing a majority of the total compensation opportunity for executive officers in the form of stock-based compensation with a value that is linked to the total return on AEP's common stock and by maintaining significant stock ownership requirements for executives;
- Support the implementation of the Company's business strategy by tying annual incentive awards to an operating earnings per share target and to the achievement of specific operating and strategic objectives; and
- Promote the stability of the management team by creating strong retention incentives with multi-year vesting schedules for long-term incentive compensation.

Overall, AEP's executive compensation program is intended to create a total compensation opportunity (base salary, annual incentive opportunity and long-term incentive opportunity) that, on average, is equal to the median of AEP's Compensation Peer Group, as described under Compensation Peer Group on page 29. The HR Committee's independent compensation consultant, Meridian Compensation Partners, LLC (Meridian), participates in HR Committee meetings, assists the HR Committee in developing the compensation program and has an opportunity to meet with the HR Committee in executive session without management present. See the Human Resources Committee Report on page 44 for additional information about Meridian's independence.

Compensation Program Design

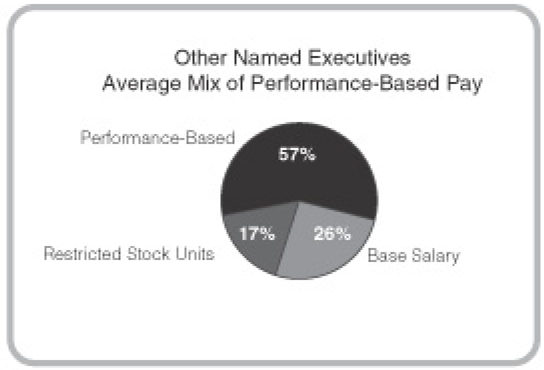
The compensation program for executive officers includes base salary, annual incentive compensation, long-term incentive compensation, a comprehensive benefits program and limited perquisites. The Company provides a balance of annual and long-term incentive compensation that is consistent with the compensation mix provided by AEP's Compensation Peer Group. For AEP's annual incentive compensation, the HR Committee balances meeting AEP's operating earnings per share target with other objectives, such as safety, strategic goals and culture.

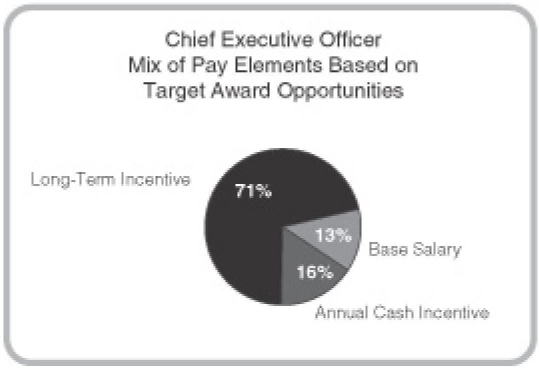
For 2013, operating earnings per share constituted 75 percent of the funding measure for annual incentive compensation. The HR Committee chose this measure because it largely reflects management's performance in operating the Company. It is also strongly correlated with shareholder returns and is the primary measure by which the Company communicates its actual and expected future financial performance to the investment community and employees. The operating earnings per share measure is also well understood by both our shareholders and employees. Management and the HR Committee believe that operating earnings per share growth is the primary means for the Company to create long-term shareholder value. For 2013, the remaining 25 percent of the funding for annual incentive compensation was tied to strategic and safety goals. In addition, the HR Committee established two extra credit goals for 2013: zero fatalities and culture, which could add an additional 7.5 percent and up to 5 percent to the score, respectively.

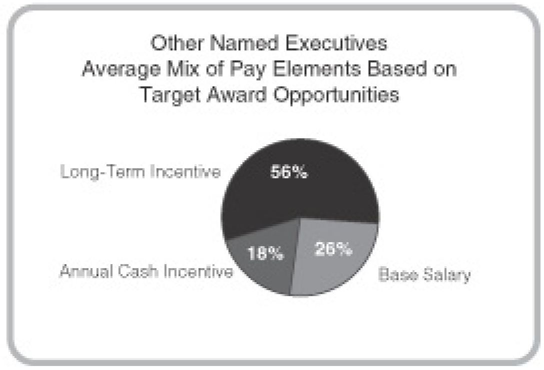
In 2013, the majority of AEP's long-term incentive compensation (70 percent) for executive officers was tied to longer-term shareholder return objectives to maintain an appropriate focus on creating sustainable long-term shareholder value. The HR Committee awarded performance units to executive officers with three-year performance measures tied to AEP's total shareholder return relative to all of the companies in the S&P 500 Electric Utilities Industry Index, and cumulative operating earnings per share relative to a board approved target. A cumulative measure of operating earnings was chosen to ensure that earnings for all three years contribute equally to the award calculation. The HR Committee also chose a total shareholder return measure for these awards to provide an external performance comparison that reflects the effectiveness of management's strategic decisions and actions over the three-year period relative to other large companies in our industry.

The HR Committee also uses long-term incentives as a retention tool to foster management continuity. Performance unit awards are subject to a three-year vesting period, and restricted stock units (RSUs) vest over 40 months in three approximately equal components on the May 1st following the first, second and third anniversaries of the grant date. Effective January 1, 2013, the HR Committee altered the mix of long-term incentive awards to increase the percentage granted in the form of performance units from 60 percent to 70 percent, and to reduce the percentage granted in the form of RSUs from 40 percent to 30 percent. The HR Committee made this change to increase the amount of long-term incentive compensation that is performance based.

The HR Committee annually reviews the mix of the three elements of total direct compensation: base salary, annual incentive compensation and long-term incentive compensation. As illustrated in the charts below, in 2013, 66 percent of the target total direct compensation for the CEO and 57 percent on average for the other named executive officers was performance-based (target annual incentive compensation and grant date value of performance units). An additional 21 percent of the CEO's target total direct compensation and an additional 17 percent on average for the other named executive officers was provided in the form of RSUs (grant date value) which are tied to AEP's stock price.







For 2013, the HR Committee targeted the median total compensation of the Compensation Peer Group for each of the named executive officers. Plus or minus 15 percent of the target is the range of compensation that is generally considered to be market competitive by the HR Committee's independent compensation consultant. The HR Committee generally chooses the median as a target because the Company is by design near the median of the Compensation Peer Group based on revenues. To the extent that the total compensation opportunity for an executive in a job that is well matched in the Compensation Peer Group is above or below the +/- 15 percent target range around the peer group median, the HR Committee adjusts elements of pay over time to bring the executive's total compensation opportunity into the target range. The HR Committee's independent compensation consultant completes an annual executive compensation study. In October 2012, this study found that (in aggregate, for the named executive officers) each of base salary, total cash compensation and total direct compensation was within the +/- 15 percent market competitive range.

Compensation Peer Group

The HR Committee, supported by its independent compensation consultant, annually reviews AEP's executive compensation relative to a peer group of companies that represent the talent markets with which AEP must compete to attract and retain executives. The companies included in the Compensation Peer Group were chosen from utilities and industrial companies that were comparable in size to AEP. At the end of 2012, the HR Committee used the Compensation Peer Group consisting of the 14 utility industry companies and the 12 general industry companies shown in the table below in setting the compensation for our named executive officers for 2013.

The HR Committee's independent compensation consultant annually provides the HR Committee with an executive compensation study covering all executive officer positions and many other executive positions based on survey information for the Compensation Peer Group. The methodology and job matches used in this study are generally determined by the HR Committee's independent compensation consultant based on descriptions of each executive's responsibilities and are reviewed with the HR Committee. The standard benchmark is the median value of compensation paid by the Compensation Peer Group. The HR Committee considers percentiles other than the median and may select any percentile as a benchmark if, in their judgment, such other benchmarks provide a better comparison based on the specific scope of the job being matched. Broader energy and general industry data is used when sufficient data is not available in the Compensation Peer Group to provide a comparison, but this was not the case in 2013 with respect to any of the named executive officers.

AEP's 2013 Compensation Peer Group

Energy (14 Companies)	***General Industry (12 Companies)***
Centerpoint Energy, Inc.	3M Company
Dominion Resources, Inc.	Bristol-Myers Squibb Company
Duke Energy Corporation	Caterpillar Inc.
Edison International	CSX Corporation
Entergy Corporation	Goodyear Tire & Rubber Company
Exelon Corporation	Northrop Grumman Corporation
FirstEnergy Corp.	PPG Industries, Inc.
NextEra Energy, Inc.	Schlumberger N.V.
PPL Corporation	Sunoco, Inc.
PG&E Corporation	Textron Inc.
Public Service Enterprise Group Inc.	Union Pacific Corporation
Sempra Energy	Weyerhaeuser Company
Southern Company (The)	
Xcel Energy Inc.	

The table below shows that, at the time the Compensation Peer Group data was collected in July 2012, AEP's revenue was slightly above the 50th percentile of the combined peer group.

2013 Compensation Peer Group

	Revenue ($ million)
Compensation Peer Group	
25th Percentile	$11,275
50th Percentile	$14,956
75th Percentile	$21,244
Utility Industry Median	$14,236
General Industry Median	$22,006
AEP	**$15,116**

As part of the HR Committee's independent compensation consultant's comprehensive review of the Company's executive compensation in September 2013, the consultant noted that the Company's practice of using a mix of electric utility and general industry peers differed from the majority practice in the utility industry. Therefore, the HR Committee approved changing the composition of the Company's peer group. It retained all of the existing utility peer companies, added three utility peer companies, and removed all of the general industry companies, thereby creating a compensation peer group consisting entirely of utility companies. The HR Committee made these changes because it determined that an all utility peer group provides more meaningful compensation comparisons and because other similar utility companies are the primary competitors for the company's executive talent. Recent consolidations and mergers in the utility industry increased the size of a number of the utility peer companies. This provided for a sufficiently sized peer group of companies with revenues in a suitable range as compared to the Company's. The peer group set forth below serves as our peer group for 2014.

AEP's 2014 Compensation Peer Group

AES Corporation
Centerpoint Energy, Inc.
Consolidated Edison Inc.
Dominion Resources, Inc.
DTE Energy Company
Duke Energy Corporation
Edison International
Entergy Corporation
Exelon Corporation
FirstEnergy Corp.
NextEra Energy, Inc.
PPL Corporation
PG&E Corporation
Public Service Enterprise Group Inc.
Sempra Energy
Southern Company
Xcel Energy Inc.

The table below shows that, at the time the Compensation Peer Group data was collected in July 2013, AEP's revenue was above the 50th percentile of the combined peer group.

2014 Compensation Peer Group

	Revenue ($ million)
Compensation Peer Group	
25th Percentile	$11,128
50th Percentile	$13,418
75th Percentile	$15,320
AEP	**$14,945**

Executive Compensation Program Detail

Executive Compensation Components Summary. The following table summarizes the major components of the Company's executive compensation program.

Component	Purpose	Key Attributes
Base Salary	• To provide a market-competitive and consistent minimum level of compensation.	• A 3 percent executive merit budget was approved by the HR Committee for 2013. • Merit and other salary increases for executives are awarded by the HR Committee based on a variety of factors, which are described under Base Salary on page 33.

Annual Incentive Compensation	• To focus executive officers on achieving annual earnings objectives and other performance objectives that are critical to AEP's success, which for 2013 included:
	  • Safety
	  • Operations
	  • Strategic Initiatives
	  • Zero Fatalities
	  • Culture
	• To communicate and align executive and employee efforts to the Company's earnings, operational performance and strategic objectives.
		• Annual incentive targets are established by the HR Committee based on competitive compensation information provided by the HR Committee's independent compensation consultant.
		  • Actual awards generally may vary within a range of 0 percent to 200 percent of each executive's annual incentive target.
		• Operating earnings per share was chosen as the funding measure for 2013.
		  • An operating earnings per share threshold of $3.00 per share was established that provided annual incentive funding only if the threshold was exceeded.
		• Individual awards are then approved by the HR Committee based on:
		  • Each executive's calculated annual incentive payout opportunity, and
		  • The CEO's subjective evaluation of each named executive officer's individual performance for the year.

Component	Purpose	Key Attributes

Long-Term Incentive Compensation	• To motivate AEP management to maximize shareholder value by linking a substantial portion of their potential executive compensation directly to shareholder returns.
	• To help ensure that Company management remains focused on longer-term results, which the HR Committee considers to be essential given the large long-term investments in physical assets required in our business.
	• To reduce executive turnover and maintain management consistency.
		• For 2013, the HR Committee provided long-term incentive awards in the form of three-year performance units, which were 70 percent of the grant value, and restricted stock units (RSUs), which were 30 percent of the grant value.
		• For the 2013-2015 performance unit awards, the HR Committee established the following equally weighted performance measures:
		  • Three-year cumulative operating earnings per share relative to a board approved target, and
		  • Three-year total shareholder return relative to the S&P 500 Electric Utilities Industry Index.
		• Individual long-term incentive awards are based on:
		  • Award guidelines for each salary grade and market competitive compensation information provided by the HR Committee's independent compensation consultant, and
		  • A subjective evaluation of the individual's potential contribution to shareholder value during the performance period.

Base Salary. Merit and other salary increases for executives are awarded by the HR Committee based on:

- The Company's merit budget,
- Sustained individual performance as assessed by each executive's direct manager,
- The market competitiveness of the executive's salary,
- Internal comparisons,
- The responsibilities, experience and future potential of each executive,
- Reporting relationships, and
- The impact that any change in base salary may have on other pay elements and the market competitiveness of the executive's total compensation.

The HR Committee approved a 3 percent merit budget for 2013 for executives and also approved several other salary adjustments to bring executive pay closer to market competitive levels. Effective January 1, 2013, the HR Committee increased the base salaries for Mr. Akins and Mr. Feinberg by $300,000 and $100,000, which brought their base salaries to $1,200,000 and

$550,000, respectively. Mr. Akins' and Mr. Feinberg's salary increases each included a market adjustment to bring their compensation closer to the market median level for similar positions in the Company's Compensation Peer Group. In addition, Mr. Feinberg's salary increase reflected his promotion to executive vice president. The HR Committee approved a 3.0 percent merit budget for 2014 for executives.

Annual Incentive Compensation.

Annual Incentive Targets. Annual incentive compensation focuses executive officers on achieving annual earnings objectives and other performance objectives that are critical to AEP's success. The HR Committee, in consultation with its independent compensation consultant and Company management, establishes the annual incentive targets for each executive officer position primarily based on compensation benchmark studies. For 2013, the HR Committee established the following annual incentive targets for each of the positions held by the named executive officers:

- 125 percent of base earnings for the CEO position (Mr. Akins);
- 80 percent of base earnings for the CFO position (Mr. Tierney);
- 80 percent of base earnings for the EVP and Chief Operating Officer position (Mr. Powers);
- 65 percent of base earnings for the EVP, General Counsel and Secretary position (Mr. Feinberg); and
- 60 percent of base earnings for the SVP and Chief Administrative Officer position (Ms. Hillebrand).

The HR Committee increased the target for the CEO from 110 percent to 125 percent to bring target annual incentive compensation and target total cash compensation in line with the Company's Compensation Peer Group median.

Funding For Annual Incentive Plan. In 2013, AEP produced operating earnings per share of $3.23, which was above the target of $3.15. This earnings result, together with the Company's performance on the strategic measures discussed below (safety, operations and strategic initiatives), produced a result of 152.4 percent of the target award opportunity for executive officers. Because the Company did not experience a fatal employee accident, 7.5 percent was added to the annual incentive funding. In addition, the HR Committee approved a 3 percent addition for achieving culture initiative milestones. These positive adjustments increased the incentive funding to 162.9 percent of target for 2013.

For 2013, GAAP earnings per share reported in AEP's financial statements was $0.19 per share lower than operating earnings, primarily because of generation plant impairments. Exhibit A to this proxy statement contains a reconciliation of GAAP earnings per share to operating earnings per share.

Annual Performance Objectives. For 2013, the HR Committee developed a balanced scorecard to tie annual incentive awards for AEP's executive team to the Company's performance objectives for the year in three areas of performance: safety, operations and strategic initiatives. The HR Committee uses this balanced scorecard because it mitigates the risk that executives will focus on one or a few overriding objectives, such as short term financial performance, to the detriment of other objectives. The weightings of those targets are determined by the HR Committee. The threshold, target and maximum payout levels are determined by the HR Committee and are set forth with

2013 actual results and scores in the table below. We more fully explain the measures and the reasons we chose the measures in the text following the table.

	Weight	Threshold	Target	Maximum	Actual Performance Result	Actual Award Score (as a percent of target opportunity)	Weighted Score
Operating Earnings Per Share (75%)	75%	$3.00	$3.15	$3.30	$3.234	156%	1.170
Safety (10%)							
Recordable Case Rate (the number of Occupational Safety and Health Administration recordable incidents per 200,000 work hours)	4%	1.07	0.94	0.82	0.83	191.7%	0.077
Severity Rate (the number of lost and restricted duty days due to Occupational Safety and Health Administration recordable incidents per 200,000 work hours)	5%	21.07	18.64	16.21	23.04	0%	0.000
Contractor Recordable Case Rate (the number of Occupational Safety and Health Administration recordable incidents per 200,000 work hours for major AEP contractors)	1%	1.84	1.60	1.36	1.38	191.7%	0.019
Operations (10%)							
Repositioning Implementation Savings – O&M savings/revenue enhancements for 2013 and projected savings/revenues for future years	10%	$150 million	$200 million	$225 million	$242 million	200%	0.200
Strategic Initiatives (5%)							
Corporate Separation and Development of Competitive Unregulated Energy Business – The score is determined subjectively by the HR Committee based on progress made during 2013	5%	This is a subjective measure that was scored at 116.7% because we completed corporate separation of AEP Ohio's generation assets, terminated the generation pool sharing agreement for our eastern subsidiaries and developed the competitive business, including trading and retail energy sales.			Not Applicable	116.7%	0.058
Additional Credit Measures							
Fatality Adjustment	NA	+7.5% of composite score for year without a fatal work related employee incident			No employee fatality	+7.5% of composite score	0.075
Culture Adjustment	NA	+5% of composite score for culture measure. This is a subjective measure that was scored at +3%.			Not Applicable	+3% of composite score	0.030
Total Score							**1.629**

Safety. With safety as an AEP core value, maintaining the safety of AEP employees and the general public is always our primary consideration. Accordingly, safety measures comprised 10 percent of the 2013 scorecard. We measure this using employee and contractor recordable case rate in accordance with the methodology prescribed by the Occupational Safety and Health Administration (OSHA) for recordable incidents. We also measure the incident severity rate portion by the number of lost and restricted duty work days per 200,000 work hours. In addition to these safety measures, the HR Committee also established a fatality credit adjustment for 2013, which is discussed below.

Operations. In 2013, the Company implemented a Repositioning Study and developed an Engage to Gain Program to encourage employees to develop ways to create sustainable O&M savings and revenue improvements. Therefore, the HR Committee tied 10 percent of the scorecard to reaching a sustainable O&M savings and revenue improvement goal.

Strategic Initiatives. The remaining 5 percent of the executive council scorecard was tied to strategic initiatives for 2013. These initiatives included the corporate separation of AEP Ohio and the development of a competitive unregulated energy business.

Fatality and Culture Adjustment Credits. The HR Committee established a fatality adjustment credit for 2013 that would add 7.5 percent to the Overall Performance Score in the event of a fatality free year. The HR Committee also established a culture adjustment credit for 2013 that would add up to 5 percent if specific, predetermined culture improvement activity milestones were met.

2013 Individual Award Calculations. The calculation of the 2013 annual incentive opportunity is shown in the chart below for each named executive officer. This is the starting point for determining actual annual incentive awards. The HR Committee then subjectively evaluates the individual performance of each named executive officer to determine the actual awards, which are also shown in the table below for 2013.

Name	2013 Base Earnings*		Annual Incentive Target %		Final Performance Score		Calculated Annual Incentive Opportunity	2013 Actual Awards
Mr. Akins	$1,193,077	x	125%	x	162.9%	=	$2,429,403	$2,430,000
Mr. Tierney	$ 671,981	x	80%	x	162.9%	=	$ 875,725	$ 875,500
Mr. Powers	$ 671,981	x	80%	x	162.9%	=	$ 875,725	$ 875,500
Mr. Feinberg	$ 547,692	x	65%	x	162.9%	=	$ 579,924	$ 585,000
Ms. Hillebrand	$ 470,000	x	60%	x	162.9%	=	$ 459,378	$ 480,000

* Based on earnings paid in 2013, which is slightly different than the salary earned for 2013 shown in the Summary Compensation Table on page 48.

The HR Committee believes that annual incentive compensation should not be based purely on a formulaic calculation, such as that shown in the Calculated Annual Incentive Opportunity column above, but should instead be adjusted from this starting point to reflect each executive's individual performance and contribution. Based on recommendations from the CEO focusing on the individual performance and contribution of the other named executive officers, the HR Committee approved the annual incentive awards shown in the 2013 Actual Awards column. The annual incentive award for the CEO was approved by the independent members of the Board.

AEP provides annual incentive compensation to executive officers through the Senior Officer Incentive Plan, which was approved by shareholders at the 2012 annual meeting. This plan establishes the maximum annual incentive award opportunity for each executive officer that is potentially tax deductible by the Company under section 162(m) of the Internal Revenue Code.

Long-Term Incentive Compensation. The HR Committee grants long-term incentive compensation to executive officers on an annual award cycle. Long-term incentive compensation consists of stock awards in the form of (i) performance units with three-year performance measures tied to AEP's total shareholder return and cumulative operating earnings per share and (ii) restricted stock units (RSUs) which vest over a forty month period. AEP annually reviews the mix of long-term incentive compensation provided to its executives. For the 2013 award cycle, the HR Committee increased the percentage of long-term incentive awards granted as performance units from 60 percent to 70 percent of the aggregate grant date fair value and made a corresponding decrease in the percentage granted as RSUs from 40 percent to 30 percent. For 2014, the HR Committee retained this mix of long-term incentive awards.

Both the 2013 performance units and RSUs were granted with change in control provisions that include a double trigger, which means that awards would vest only if both a change in control and a separation from service occur under defined circumstances.

In 2013 the HR Committee established a practice of granting long-term incentive compensation to executives and other management employees promoted to positions with larger long-term incentive opportunities. If an executive is promoted, the HR Committee will provide a promotional award to step-up his or her long-term incentive award, adjusted on a pro rata basis, to reflect the portion of the vesting period remaining for outstanding long-term incentive awards at the time of the participant's promotion into the new role. As part of this program, in connection with Mr. Feinberg's promotion to Executive Vice President, Mr. Feinberg received a prorated long-term incentive award with a grant date fair value of $104,000 in February 2013.

The HR Committee establishes award guidelines for each named executive officer position based primarily on market competitive long-term and total compensation for similar positions in AEP's Compensation Peer Group. Long-term incentive awards are approved by the HR Committee, or, for the CEO, by the independent members of the Board. These determinations are made based on:

- Award guidelines for each named executive officer position and each salary grade level that are established by the HR Committee, which creates an overall award pool that AEP management and the HR Committee use in determining awards;
- Individual performance assessments. However, any positive discretionary adjustments based on individual performance must generally be offset by negative adjustments for other participants to avoid exceeding the award pool;
- The individual executive's total direct compensation relative to market median compensation for his or her position as shown in the annual executive compensation study conducted by the HR Committee's independent compensation consultant;
- The executive officer's future potential for advancement, and
- A subjective evaluation of the individual's potential contribution to shareholder value during the performance period.

The HR Committee also regularly reviews tally sheets for the Chief Executive Officer that show the potential future payout of outstanding equity awards. These tally sheets show the extent to which the value of the potential payout from all outstanding equity awards is linked to changes in AEP's stock price and the value likely to be paid from all outstanding equity awards taking Company performance into consideration. The tally sheets also show whether the value that the Chief Executive Officer has already received from equity awards is so large as to cause the HR Committee to reassess the need for or effectiveness of any future equity awards.

Performance Units. The HR Committee granted performance unit awards for a 2013 – 2015 performance period to each named executive officer shown in the 2013 Long-Term Incentive Awards table below. Dividends are reinvested in additional performance units, but those additional performance units are subject to the same performance measures and vesting requirements as the underlying performance units. The total number of performance units held at the end of the performance period is multiplied by the weighted score for the two performance measures shown below to determine the award payout; however, the maximum score for each performance measure is 200 percent. For further information on these awards, see the description under 2013 Stock Award Grants beginning on page 51. The cumulative earnings per share target was set at $9.833, which consisted of $3.15 for 2013, which was the midpoint of the Company's earnings guidance, and an assumed four percent growth rate for 2014 and 2015.

Performance Measures for 2013 – 2015 Performance Units

Performance Measure	Weight	Threshold Performance	Target Performance	Maximum Payout Performance
3-Year Cumulative Earnings Per Share	50%	$8.85 (30% payout)	$9.833 (100% payout)	$10.816 (200% payout)
3-Year Total Shareholder Return vs. S&P 500 Electric Utilities Industry Index	50%	20th Percentile (0% payout)	50th Percentile (100% payout)	80th Percentile (200% payout)

Performance units that were granted for the 2011 – 2013 performance period vested on December 31, 2013. The combined score for the 2011-2013 performance period was 118.8 percent of target. The final score calculation for these performance measures is shown in the chart below. For more information on the number of performance units earned by each named executive officer for the 2011-2013 performance period, see the Option Exercises and Stock Vested for 2013 Table on page 55.

2011 – 2013 Performance Units

Performance Measures	Threshold Performance	Target Performance	Maximum Payout Performance	Actual Performance	Score	Weight	Weighted Score
3-Year Cumulative Earnings Per Share	$8.73 (0% payout)	$9.70 (100% Payout)	$10.67 (200% Payout)	$9.67	97.5%	50%	48.8%
3-Year Total Shareholder Return vs. S&P Electric Utilities	20th Percentile (0% Payout)	50th Percentile (100% Payout)	80th Percentile (200% Payout)	62nd Percentile	140%	50%	70%
Composite Result							**118.8%**

Restricted Stock Units.

The HR Committee also granted 30 percent of the aggregate grant date value of the Company's 2013 long-term incentive awards as RSUs. These RSUs vest over a forty month period, subject to the executive's continued employment, in three approximately equal installments on May 1, 2014, May 1, 2015 and May 1, 2016, respectively. Dividends are reinvested in additional RSUs, but those additional RSUs vest at the same time as the underlying RSUs vest. Upon vesting, the RSUs granted in 2013 payout in cash to executive officers. The HR Committee granted RSU awards that payout in cash to executive officers because these executives have other means of meeting their stock ownership requirements and might otherwise be prevented from utilizing this compensation for extended periods of time due to restrictions on insider trading. For further information on these awards, see the description under 2013 Stock Award Grants beginning on page 51.

2013 Long-Term Incentive Awards

Name	Number of Performance Units Granted	Number of Restricted Stock Units Granted	Total Units Granted	Total Grant Date Fair Value
Mr. Akins	101,535	43,515	145,050	$6,720,167
Mr. Tierney	28,602	12,258	40,860	$1,893,044
Mr. Powers	28,602	12,258	40,860	$1,893,044
Mr. Feinberg	15,591	7,079	22,670	$1,050,301
Ms. Hillebrand	12,635	12,106	24,741	$1,146,251

These performance units and RSUs provide total direct compensation opportunities to executives that are on average within the market competitive range. Differences between the awards for individual executives primarily reflect differences in the long-term incentive targets for their respective positions as of January 2013.

Mr. Feinberg received 1,290 of his performance units and 950 of his restricted stock units in connection with his promotion to Executive Vice President under the promotional award program described above under the Long-Term Incentive Compensation.

Ms. Hillebrand received 6,691 of her restricted stock units that offset the loss of a similar value of stock units that she forfeited when she left her prior employer. These RSUs vest over a forty month period, subject to the executive's continued employment, in three approximately equal installments on May 1, 2014, May 1, 2015 and May 1, 2016.

Stock Ownership Requirements. The HR Committee believes that linking a significant portion of an executive's financial rewards to the Company's success, as reflected by the value of AEP stock, gives the executive a stake similar to that of the Company's shareholders and encourages long-term management strategies that benefit shareholders. Therefore, the HR Committee requires certain officers (52 individuals as of December 31, 2013) to accumulate and hold a specific amount of AEP common stock or stock equivalents. The HR Committee annually reviews the minimum stock ownership level for each officer salary grade and periodically adjusts these levels. Each named executive officer has met his or her stock ownership requirement or is on pace to meet the requirement within five years of the date it was assigned.

In 2013, the HR Committee changed the stock ownership targets for executive officers from a fixed number of shares to a multiple of base salary. The CEO's target is five times his base salary, and the other named executive officers' targets are three times their respective base salaries. This is more consistent with the way most companies establish stock ownership targets.

Performance units are mandatorily deferred into AEP Career Shares to the extent necessary for each executive to meet his or her minimum stock ownership requirement. AEP Career Shares are stock units that are paid out in cash in an amount equal to the market value of AEP common stock. In addition, in the event that an executive has not met his or her minimum stock ownership requirement within five years of the date it was assigned, the executive is subject to mandatory deferral into AEP Career Shares of up to 50 percent of his or her annual incentive compensation award. AEP Career Shares are not paid to participants until after their AEP employment ends.

Benefits. AEP generally provides the same health and welfare benefits to named executive officers as it provides to other employees. AEP also provides the named executive officers with either four or five weeks of paid vacation.

AEP's named executive officers participate in the same pension and savings plans as other eligible employees. These include tax-qualified defined contribution and defined benefit plans. AEP's named executive officers also participate in the Company's non-qualified retirement benefit plans, which are largely designed to provide "supplemental benefits" that would otherwise be offered through the tax-qualified plans except for the limits imposed by the Internal Revenue Code on those tax-qualified plans. As a result, the non-qualified plans allow eligible employees to accumulate higher levels of replacement income upon retirement than would be allowed under the tax-qualified plans alone.

The HR Committee recognizes that the non-qualified plans result in the deferral of the Company's income tax deduction until such benefits are paid, but the HR Committee believes that executives generally should be entitled to the same retirement benefits, as a percentage of their eligible pay, as other employees; that these benefits are prevalent among similar companies; and that these benefits are a part of a market competitive total rewards package.

The Company can also provide contractual benefits under the non-qualified plans. For example, in 1997, Mr. Powers negotiated additional years of credited service under AEP's non-qualified pension plan as part of his initial employment arrangement with AEP to offset pension benefits that he would have been able to earn from his prior employer due to his length of service to that company.

The HR Committee limits both the amount and types of compensation that are included in the qualified and non-qualified retirement plans because they believe that compensation over certain limits and certain types of compensation should not be further enhanced by including it in retirement benefit calculations. Therefore:

- Long-term incentive compensation is not included in the calculations that determine retirement and other benefits under AEP's benefit plans,
- The cash balance formula of the AEP Supplemental Benefit Plan limits eligible compensation to the greater of $1 million or twice the participant's base salary, and
- Eligible compensation is also limited to $2 million under the non-qualified Supplemental Retirement Savings Plan.

AEP provides group term life insurance benefits to all employees, including the named executive officers, in the amount of two times their base salary.

For executives who relocate, it is AEP's practice to offer relocation assistance to offset their moving expenses. This policy enables AEP to obtain high quality new hires and relocate internal candidates as needed.

Perquisites. The HR Committee annually reviews the perquisites provided by the Company to ensure that they are efficient and effective uses of AEP's resources. The HR Committee also periodically reviews the value of perquisites provided to each named executive officer. In 2013, AEP only provided executives with independent financial counseling and tax preparation services to assist executives with financial planning and tax filings. Income is imputed to executives and taxes are withheld for these services. AEP does not provide a gross-up for these taxes.

While corporate aircraft provides enhanced security, travel flexibility and reduced travel time, which benefits the Company, the HR Committee is sensitive to concerns regarding the expense of corporate aircraft and the public perception regarding personal use of such aircraft. Accordingly, effective October 2009, the HR Committee generally prohibited personal use of corporate aircraft that has an incremental cost to the Company. The Company allows spouses to accompany executives on business trips using corporate aircraft if there is no incremental cost to the Company. Taxes are withheld on the value of executive spouse travel on corporate aircraft in accordance with IRS standards, and AEP does not provide a gross-up for these taxes.

Other Compensation Information

Recoupment of Incentive Compensation.

The Board believes that incentive compensation should be reimbursed to the Company if, in the Board's determination:

- Such incentive compensation was predicated upon the achievement of financial or other results that were subsequently materially restated or corrected,
- The executive from whom such reimbursement is sought engaged in misconduct that caused or partially caused the need for the restatement or correction, and

- A lower payment would have been made to the executive based upon the restated or corrected financial results.

The Board adopted this clawback policy in February 2007, and the HR Committee has directed the Company to design and administer all of the Company's incentive compensation programs in a manner that provides for the Company's ability to obtain such reimbursement. The Company will seek reimbursement, if and to the extent that, in the Board's view, such reimbursement is warranted by the facts and circumstances of the particular case or if the applicable legal requirements impose more stringent requirements on AEP to obtain reimbursement of such compensation. AEP may also retain any deferred compensation previously credited to the executive if, when, and to the extent that it otherwise would become payable. This right to reimbursement is in addition to, and not in substitution for, any and all other rights AEP might have to pursue reimbursement or such other remedies against an executive for misconduct in the course of employment by AEP or otherwise based on applicable legal considerations.

Role of the CEO and Compensation Consultant with Respect to Determining Executive Compensation. The HR Committee invites the CEO and all directors to attend HR Committee meetings. The HR Committee regularly holds executive sessions without the CEO or other management present to provide a confidential forum for any concerns to be expressed. The Chairman of the Board and the HR Committee Chairman have the authority to call meetings of the HR Committee.

The CEO has assigned AEP's Senior Vice President & Chief Administrative Officer and Director – Compensation and Executive Benefits to support the HR Committee. These individuals work closely with the HR Committee Chairman, the CEO and the Committee's independent compensation consultant (Meridian Compensation Consultants, LLC, "Meridian") to research and develop requested information, prepare meeting materials, implement the HR Committee's actions and administer the Company's executive compensation and benefit programs in keeping with the objectives established by the HR Committee. Members of management supporting the HR Committee also meet with the CEO, the HR Committee Chairman and Meridian prior to meetings to review and finalize the meeting agenda and meeting materials.

The CEO regularly discusses his strategic vision and direction for the Company during HR Committee meetings with Meridian in attendance. Likewise, Meridian regularly discusses compensation strategy alternatives, in light of the CEO's strategic vision and direction, during HR Committee meetings with the CEO in attendance. The HR Committee believes that this open dialogue and exchange of ideas is important to the development and implementation of a successful executive compensation strategy.

The CEO discusses the individual performance of all the named executive officers with the HR Committee and recommends their compensation to the HR Committee. The CEO also has substantial input into the development of employment offers for outside candidates for executive positions, although all employment offers for executive officer positions require the approval of the HR Committee.

Change In Control Agreements. The HR Committee provides change in control agreements to all the named executive officers to help align the interests of these executives with those of AEP's shareholders by mitigating the financial impact that would occur to them if their employment was terminated as a result of a change in control. The HR Committee also considers change in control agreements as an important tool in recruiting external candidates for certain executive positions. The HR Committee limits participation to those executives whose full support and sustained contributions in the course of a lengthy and complex possible corporate transaction would be critical to the successful completion of a change in control. As of December 31, 2013, there were 22 officers who have change in control agreements.

While the HR Committee believes these agreements are consistent with the practices of its peer companies, the most important reason for these agreements is to protect the Company and the interests of shareholders in the event of an anticipated or actual change in control. During such transitions, retaining and continuing to motivate the Company's key executives would be critical to protecting shareholder value. In a change of control situation, outside competitors are more likely to try to recruit top performers away from the Company, and our executive officers may consider other opportunities when faced with uncertainty about retaining their positions. Therefore, the HR Committee uses these agreements to provide security and protection to our officers in such circumstances for the long-term benefit of the Company and its shareholders.

The Board has adopted a policy that requires shareholder approval of future executive severance agreements that provide benefits generally exceeding 2.99 times the sum of the named executive officer's salary plus annual incentive compensation. In consultation with its independent compensation consultant, the HR Committee periodically reviews change in control agreement practices of similar companies, including the companies in our Compensation Peer Group. The HR Committee has found that change in control agreements are common among these companies, and that 2.99 or 3 multiples are the most common for named executive officers. Therefore, the HR Committee approved change in control multiples of 2.99 times base salary and bonus for all of the named executive officers other than Ms. Hillebrand, who has a 2.0 multiple. Most of the other executives covered by change in control agreements also have the lesser multiple of 2.0 times their base salary and target annual incentive award. All of the change in control agreements have a "double trigger," which means the severance payments and benefits would be provided only upon a change in control accompanied by an involuntary termination or constructive termination within two years.

Effective January 1, 2014, the HR Committee replaced all of the Company's change in control agreements to eliminate the provision that provided a tax gross-up for excise taxes. Prior to this date, some of the named executive officers had change in control agreements that provided for a payment that offset the effect of an excise tax with a "gross-up" payment that would have reimbursed those executives for any excise tax on an after tax basis.

Long-term incentive compensation may also vest in the event of a change in control. In the event an executive's employment is terminated within one year after a change in control under qualifying conditions, such as by the Company without cause or by the executive for good reason, then a pro rata portion of the executive's outstanding performance units will vest and be paid at the target performance score. All outstanding restricted stock unit awards granted before December 2010 also fully vest in the event of a change in control. A double trigger was added to restricted stock unit awards granted on or after this date. This double trigger requires that an executive's employment be terminated under defined circumstances within one year after a change in control in order for all of the executive's outstanding restricted stock units to vest.

Other compensation and benefits provided to executive officers in the event their employment is terminated as a result of a change in control are consistent with that provided in the event an executive's employment is terminated due to a consolidation, restructuring or downsizing as described below.

Other Employment Separations. AEP maintains a severance plan that provides two weeks of base pay per year of service to all employees, including executive officers, if their employment is terminated due to a consolidation, restructuring or downsizing, subject to the employee's agreement to waive claims against AEP. In addition, our severance benefits for all employees include outplacement services and access to health benefits at active employee rates for up to 18 months (or until age 65 for employees who are at least age 50 with 10 years of service at the time of their severance).

Named executive officers and other employees remain eligible for an annual incentive award based on their eligible pay for the year, which reflects the portion of the year that they worked, if they separate from service prior to year-end due to their retirement or death. A prorated portion of outstanding performance units vest if a participant retires, which is defined as a termination, other than for cause, after the executive reaches age 55 with five years of service or if a participant is severed. A prorated portion of outstanding performance units would also vest to a participant's heirs in the event of their death. The pro-rated performance units will not become payable until the end of the performance period and remain subject to all performance objectives.

In 2013, executive officers were also entitled to one year of continued financial counseling service in the event they are severed from service as the result of a restructuring, consolidation or downsizing. In the event of their death, their spouse or the executor of their estate would be eligible for this benefit.

Effective January 1, 2014, the HR Committee adopted an Executive Severance Plan (the "Executive Severance Plan") that provides severance benefits to selected officers of the Company, including the named executive officers, subject to the executive's agreement with the provisions of the plan. Executives remain eligible for benefits under the general severance plan described above; however, any benefits provided under the Executive Severance Plan will be reduced by any amounts provided under the general severance plan. The HR Committee adopted this plan because the majority of utility peer companies have a written executive severance plan. Benefits under the Executive Severance Plan would be triggered by a good reason resignation or an involuntary termination. If benefits under the Executive Severance Plan are triggered, our named executive officers would receive pay continuation of two times their base salary and target annual incentive payable over two years. In addition, a pro-rated portion of their outstanding performance units and restricted stock units would vest. The pro-rated performance units will not become payable until the end of the performance period and remain subject to all performance objectives. Any severance benefits payable under the Executive Severance Plan are subject to execution of an agreement by the executive officer releasing claims against the Company and containing a non-competition obligation. Participants are also obligated to comply with the confidentiality, non-solicitation and non-disparagement provisions under the Executive Severance Plan.

Insider Trading, Hedging and Pledging. The Company maintains an insider trading policy that prohibits directors and executive officers from hedging their AEP stock holdings through short sales and the use of options, warrants, puts and calls or similar instruments. The policy also prohibits directors and executive officers from placing AEP stock in margin accounts without the approval of the Company and from pledging AEP stock as collateral for any loan.

Tax Considerations. Section 162(m) of the Internal Revenue Code (Section 162 (m)) limits the Company's ability to deduct compensation in excess of $1,000,000 paid in any year to the Company's CEO or any of the next three highest paid named executive officers, other than the Chief Financial Officer. The HR Committee considers the limits imposed by Section 162(m) when designing compensation and benefit programs for the Company and its executive officers. Because the annual incentive compensation awarded in 2013 was performance-based and awarded by a committee of independent outside directors pursuant to the Senior Officer Incentive Plan (the SOIP), which was approved by shareholders, its deductibility is not subject to the Section 162(m) limit. The HR Committee established 0.75 percent of income before discontinued operations, extraordinary items and the cumulative effect of accounting changes (Adjusted Income) as the performance measure for the 2013 SOIP and further allocated a specific percentage of Adjusted Income to each executive officer. In this way, the HR Committee retains the flexibility to make awards that are based on individual performance in a way that is consistent with the requirements for tax deductibility by the Company under Section 162(m). In no case did the annual incentive awards paid for 2013 exceed the maximum award provided under the SOIP.

Amounts paid to the named executive officers for vested performance units, which were granted under the shareholder approved Long-Term Incentive Plan, also are not subject to the deductibility limit because they are performance-based. For the 2013-2015 performance period, the HR Committee established cumulative three-year income before discontinued operations, extraordinary items and the cumulative effect of accounting changes (Adjusted Income) as the performance measure with a threshold (0 percent) payout at $1 billion and a maximum (200 percent) payout at $2.5 billion. Because these awards are based on an objective definition of earnings that was approved by shareholders as part of the long-term incentive plan, they are consistent with the requirements for tax deductibility by the Company under Section 162(m). However, the HR Committee retains the discretion to reduce the payout.

AEP's restricted stock units are not considered to be performance-based under Section 162(m). Therefore, any amounts attributable to those restricted stock units are not tax deductible if and to the extent that such units cause the compensation of the covered named executive officer to exceed $1,000,000 for the year.

By meeting the requirements for performance based compensation under Section 162(m) for annual incentive compensation and performance units, these payments are potentially tax deductible for the Company. The HR Committee intends to continue to utilize shareholder approved plans and performance based awards to allow the Company to deduct most annual and long-term incentive compensation paid to named executive officers. However, the HR Committee may exercise discretion to pay nondeductible compensation if following the requirements of Section 162(m) would not be in the interests of shareholders.

Finally, Section 409A of the Internal Revenue Code imposes additional taxes on named executive officers whose deferred compensation fails to comply with Section 409A. The Company has reviewed its compensation arrangements to help ensure they comply with applicable Section 409A requirements.

Human Resources Committee Report

Membership and Independence. The HR Committee had four members during the majority of 2013. The Board has determined that each member of the HR Committee is an independent director, as defined by the NYSE listing standards. Each member of the HR Committee is also a "non-employee director" for purposes of SEC Rule 16b-3 and an "outside director" for purposes of Section 162(m). Each member of the HR Committee attends professional development training that addresses topics of specific relevance to public company compensation committees.

Purpose. The primary purpose of the HR Committee is to provide independent oversight of the compensation and human resources policies and practices of the Company. The primary objective of the HR Committee with respect to executive compensation is to ensure that executive officers and other key employees are compensated in a manner that is consistent with the Company's business strategy, risk tolerance, competitive practices, internal equity considerations, and Company and Board policies.

Functions and Process. The HR Committee operates under a written charter reviewed, modified and adopted annually by the Board. This charter is available on AEP's website at *www.aep.com/investors/corporateleadersandgovernance*.

The HR Committee annually reviews AEP's executive compensation in the context of the performance of management and the Company. The HR Committee reviews and approves the compensation for all executive officers, other than the CEO, and other senior officers. With respect to the compensation of the CEO, the HR Committee is responsible for making compensation recommendations to the independent members of the Board, who review and approve the CEO's compensation.

In carrying out its responsibilities, the HR Committee addressed many aspects of AEP's human resource and executive compensation programs and practices in 2013, including:

- Establishing annual and long-term performance objectives for senior executives;
- Assessing the performance of the CEO, other senior executives and the Company relative to those established performance objectives;
- Conducting an evaluation of Mr. Akins based on written comments from board members, senior AEP management, and the audit firm partner overseeing AEP's external audit;
- Determining the mix of base salary, annual incentive compensation and long-term equity based compensation to be provided to executives;
- Assessing the competitiveness of 2013 and proposed 2014 target compensation for all executive officers relative to AEP's Compensation Peer Group;
- Directing the creation of a multi-year plan to address the root causes of the gap between realizable compensation and performance, which includes:
    - Taking steps to bring base pay and incentive compensation targets to market competitive levels over 2-3 years;
    - Taking steps to establish base pay at more competitive levels for promoted employees going forward;
    - Redesigning aspects of the Company's short-term incentive program to more closely tie payouts to performance; and
    - Granting a promotional award to step-up the current year's long-term incentive award, adjusted on a pro rata basis, to reflect the portion of the vesting period remaining at the time of the participant's promotion into the new role.
- Changing the mix of performance units and restricted stock units in the long-term incentive program from 60/40 to 70/30;
- Reviewing and approving the base salaries, annual incentive awards and long-term incentive award opportunities for 39 officers for 2013 and 25 positions for 2014;
- Undertaking a comprehensive review of the Company's executive rewards program with assistance of Meridian that included a thorough analysis of the Company's executive total reward program;
- Assessing compensation risk;
- Reviewing, adjusting and approving the major terms of employment, change in control agreements and executive severance agreements with senior executives;
- Reviewing the Company's workforce safety efforts and results;
- Reviewing the senior management succession and development plans;
- Reviewing and approving reports to shareholders regarding executive compensation; and
- Selecting and engaging an independent compensation consultant to provide objective and independent advice to the HR Committee.

In establishing performance objectives, the HR Committee considers the interests of other major AEP stakeholders, such as AEP's customers, employees, and the communities in which AEP operates, in addition to those of AEP's shareholders. For example, the HR Committee tied 2013 annual incentive compensation for all executive officers to measures that included employee safety, while also tying funding for annual incentive compensation to AEP's operating earnings per share.

In determining executive compensation, the HR Committee considers all relevant factors, including:

- Company performance;
- The CEO's individual performance, based, in part, on a leadership assessment that specifically covers integrity and ethics, communication, willingness to confront tough issues, business acumen, strategic planning, teamwork, and fostering a high performance culture;
- Individual performance and compensation recommendations for other executive officers as assessed by the CEO and their direct manager;
- Market competitive compensation survey information from the executive compensation study conducted by the HR Committee's independent compensation consultant;
- Succession planning;
- Executive retention;
- The responsibilities and experience of each executive officer;
- Compensation history;
- The impact salary changes may have on other elements of total rewards;
- The impact of compensation on risk taking;
- The expense implications of any changes; and
- Tally sheets, showing multiple views of the CEO's total compensation.

The HR Committee's Independent Compensation Consultant. In April 2013, the HR Committee engaged Meridian Compensation Partners, LLC (Meridian), to provide recommendations to the HR Committee regarding AEP's executive compensation and benefit programs and practices. Meridian is a nationally recognized executive compensation consultant. The HR Committee is authorized to retain and terminate consultants and advisors without management approval and has the sole authority to approve their fees. Among other assignments, the HR Committee's independent compensation consultant provides an annual executive compensation study and a report on current executive compensation and benefits trends within the electric utility industry. In 2013, the Company paid $269,391 for executive compensation consulting services provided to the HR Committee by Meridian. The Company also paid $43,896 for executive compensation consulting services provided to the HR Committee in 2013 by the HR Committee's previous compensation consultant.

The HR Committee annually assesses and discusses the independence of its executive compensation consultant. The Committee's prior compensation consultant did not provide any services to AEP, other than the work it performed for the HR Committee. Meridian did not provide any services to AEP, other than the work it performed for the HR Committee, and the work it performed for the Directors and Corporate Governance Committee on director compensation. The HR Committee concluded that Meridian and its prior compensation consultant were independent and that there were no conflicts of interest.

The Committee also annually assesses the performance and objectivity of its executive compensation consultant and has found that the advice provided by Meridian and the Committee's prior compensation consultant was of a high quality, objective and appropriate for the Company. Meridian also assists the Directors and Corporate Governance Committee in reviewing and recommending director compensation. The HR Committee regularly holds executive sessions with Meridian to help ensure that they receive full and independent advice and that Meridian is not unduly influenced by AEP management.

In fulfilling its oversight responsibilities, the HR Committee reviewed and discussed with management the Compensation Discussion and Analysis set forth in this proxy statement. Based on its review and these discussions, the HR Committee recommended to the Board that the Compensation Discussion and Analysis be included in this proxy statement and incorporated by reference into the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2013.

Human Resources Committee Members

Ralph D. Crosby, Jr., Chair
Thomas E. Hoaglin
Richard C. Notebaert
Oliver G. Richard III

Executive Compensation

Summary Compensation Table

The following table provides summary information concerning compensation paid to or accrued by us on behalf of our Chief Executive Officer, our Chief Financial Officer and the three other most highly compensated executive officers, to whom we refer collectively as the named executive officers.

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)	Stock Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)(3)	Change in Pension Value and Non-qualified Deferred Compensation Earnings ($)(4)	All Other Compensation ($)(5)	Total ($)
Nicholas K. Akins—	2013	1,204,615	—	6,720,167	2,430,000	155,741	102,065	10,612,588
Chairman of the Board and	2012	903,461	—	4,600,008	1,500,000	176,312	106,709	7,286,490
Chief Executive Officer	2011	770,192	—	1,123,168	750,000	112,879	51,563	2,807,802
Brian X. Tierney—	2013	675,086	—	1,893,044	875,500	0	77,689	3,521,319
Executive Vice President and	2012	652,500	—	1,896,860	800,000	228,760	49,467	3,627,587
Chief Financial Officer	2011	601,660	—	1,200,030	450,000	131,605	46,533	2,429,828
Robert P. Powers—	2013	675,086	—	1,893,044	875,500	0	78,184	3,521,814
Executive Vice President and Chief Operating Officer	2012	652,500	—	1,896,860	800,000	586,359	60,809	3,996,528
	2011	606,731	—	1,123,168	450,000	392,240	57,639	2,629,778
David M. Feinberg(6)—	2013	552,115	—	1,050,302	585,000	36,057	55,309	2,278,783
Executive Vice President and General Counsel	2012	451,731	—	857,807	450,000	30,361	37,044	1,826,943
Lana L. Hillebrand(7)—	2013	471,808	—	1,146,251	480,000	8,193	64,386	2,170,638
Senior Vice President and Chief Administrative Officer	2012	19,884	464,000	—	—	8,002	—	483,884

(1) Amounts in the salary column are composed of executive salaries paid for the year shown, which include 261 days of pay for 2013, which is one day more than the standard 260 calendar work days and holidays in a year.

(2) The amounts reported in this column reflect the total grant date fair value, calculated in accordance with FASB ASC Topic 718, of performance units and restricted stock units granted under our Long-Term Incentive Plan. See Note 15 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2013 for a discussion of the relevant assumptions used in calculating these amounts. With respect to the performance units, the estimates of the grant date fair values determined in accordance with FASB ASC Topic 718 assumes the vesting of 100% of the performance units awarded. The value realized for the performance units, if any, will depend on the Company's performance during a three-year performance and vesting period. The potential payout can range from 0 percent to 200 percent of the target number of performance units, plus any dividend equivalents. Therefore, the maximum amount payable for the 2013 performance units is equal to $9,807,454 for Mr. Akins, $2,807,952 for Messrs. Power and Tierney, $1,352,936 for Mr. Feinberg and $1,220,475 for Ms. Hillebrand; and the maximum amount payable for the 2012 performance units is equal to $6,809,551 for Mr. Akins, $2,762,708 for Messrs. Power and Tierney and $1,381,354 for Mr. Feinberg. The 2011 performance units vested on December 31, 2013 and are shown in the Option Exercises and Stock Vested Table for 2013.The restricted stock units vest over a forty month period. For further information on these awards, see the Grants of Plan-Based Awards Table on page 50 and the Outstanding Equity Awards at Fiscal Year-End Table on page 53.

(3) The amounts shown in this column are annual incentive compensation paid under the Senior Officer Incentive Plan for the year shown. At the outset of each year, the HR Committee sets annual incentive targets and performance criteria that are used after year-end to determine if and the extent to which executive officers may receive annual incentive award payments under this plan.

(4) The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and non-qualified defined benefit plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. See the Pension Benefits Table on page 56, and related footnotes for additional information. See Note 8 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2013 for a discussion of the relevant assumptions. No named executive officer received preferential or above-market earnings on deferred compensation. The actual change in pension value in 2013 for Mr. Tierney was ($163,271) and for Mr. Powers was ($236,687).

(5) Amounts shown in the All Other Compensation column for 2013 include: (a) Company contributions to the Company's Retirement Savings Plan, (b) Company contributions to the Company's Supplemental Retirement Savings Plan, (c) temporary living and relocation, (d) tax reimbursement and (e) perquisites. The amounts are listed in the following table:

Type	Nicholas K. Akins	Brian X. Tierney	Robert P. Powers	David M. Feinberg	Lana L. Hillebrand
Retirement Savings Plan Match	$ 11,448	$11,475	$11,475	$11,475	$ 6,486
Supplemental Retirement Savings Plan Match	$ 78,525	$54,764	$54,764	$33,421	$ 9,675
Temporary Living and Relocation	$ 0	$ 0	$ 0	$ 0	$ 21,498
Tax Reimbursement(8)	$ 0	$ 0	$ 0	$ 0	$ 16,554
Perquisites	$ 12,092	$11,450	$11,945	$10,413	$ 10,173
Total	$102,065	$77,689	$78,184	$55,309	$ 64,386

Perquisites provided in 2013 included: financial counseling and tax preparation, and, for Mr. Akins, director's accidental death insurance premium. Executive officers may also have the occasional personal use of event tickets when such tickets are not being used for business purposes, however, there is no associated incremental cost. From time to time executive officers may receive token gifts from third parties that sponsor sporting events (subject to our policies on conflicts of interest). None of the individual perquisites had a value exceeding $25,000 for a named executive officer.

(6) Mr. Feinberg was not considered an executive officer prior to 2012.

(7) Ms. Hillebrand was not considered an executive officer prior to 2012. Ms. Hillebrand has an agreement with the Company pursuant to which we paid her $464,000 in 2012 to offset the loss of near-term compensation payments that she forfeited by coming to work at the Company. In addition, she was granted an additional $310,000 in restricted stock units on February 26, 2013 to offset the loss of stock units that she forfeited when she left her prior employer.

(8) We paid a tax reimbursement to Ms. Hillebrand for imputed income with respect to relocation and temporary living expenses.

Grants of Plan-Based Awards for 2013

The following table provides information on plan-based awards granted in 2013 to each of our named executive officers.

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards(1) Threshold ($)	Target ($)	Maximum ($)(2)	Estimated Future Payouts Under Equity Incentive Plan Awards(3) Threshold (#)(4)	Target (#)	Maximum (#)(5)	All Other Stock Awards: Number of Shares of Stock or Units (#)(6)	Grant Date Fair Value of Stock and Option Awards ($)(7)
Nicholas K. Akins									
2013 Senior Officer Incentive Plan		—	1,491,346	2,982,692					
2013 – 2015 Performance Units	2/26/2013				15,230	101,535	203,070		4,704,117
Restricted Stock Units	2/26/2013							43,515	2,016,050
Brian X. Tierney									
2013 Senior Officer Incentive Plan		—	537,585	1,075,170					
2013 – 2015 Performance Units	2/26/2013				4,290	28,602	57,204		1,325,131
Restricted Stock Units	2/26/2013							12,258	567,913
Robert P. Powers									
2013 Senior Officer Incentive Plan		—	537,585	1,075,170					
2013 – 2015 Performance Units	2/26/2013				4,290	28,602	57,204		1,325,131
Restricted Stock Units	2/26/2013							12,258	567,913
David M. Feinberg(8)									
2013 Senior Officer Incentive Plan		—	356,000	712,000					
2013 – 2015 Performance Units	2/26/2013				2,145	14,301	28,602		662,565
2012 – 2014 Performance Units	2/26/2013				129	860	1,720		39,844
2011 – 2013 Performance Units	2/26/2013				65	430	860		19,922
Restricted Stock Units	2/26/2013							7,079	327,970
Lana L. Hillebrand									
2013 Senior Officer Incentive Plan		—	282,000	564,000					
2013 – 2015 Performance Units	2/26/2013				1,895	12,635	25,270		585,380
Restricted Stock Units**(9)**	2/26/2013							12,106	560,871

(1) Represents potential payouts under the Senior Officer Incentive Plan (SOIP), which are based on base earnings paid during the year.

(2) The amounts shown in this column represent 200 percent of the target award for each of the named executive officers, which is generally the maximum annual incentive award for all AEP executive officers and other employees.

(3) Represents performance units awarded under our Long-Term Incentive Plan for the three-year performance period shown. These awards generally vest at the end of the three year performance period based on attainment of specified performance measures. The 2011-2013 performance units granted to Mr. Feinberg vested on December 31, 2013. For further information on these awards, see the description under 2013 Stock Award Grants below. The number of performance units does not include additional units that may be allocated as a result of the reinvestment of phantom dividend equivalents.

(4) The amounts shown in the Threshold column represent 15% of the target award for each of the named executive officers because the Operating Earnings Per Share measure has a 30% payout for threshold performance, the Total Shareholder Return measure has a 0% payout for threshold performance and these measures are equally weighted. However, the Operating Earnings Per Share threshold does not guarantee a minimum payout because the score would be 0% of target if threshold performance is not achieved.

(5) The amounts shown in this column represent 200 percent of the target award for each of the named executive officers, which is generally the maximum performance unit award score for all AEP executive officers and other participants.

(6) Represents restricted stock units awarded under the Long-Term Incentive Plan. These awards generally vest in three equal installments on May 1, 2014, May 1, 2015 and May 1, 2016. The number of restricted stock units does not include additional units that may be allocated as a result of the reinvestment of phantom dividend equivalents. The restricted stock units granted to Mr. Feinberg included 950 units that were granted under a promotional award program described below in footnote 8.

(7) Amount represents the grant date fair value of performance units and restricted stock units measured in accordance with the guidance in FASB ASC Topic 718, utilizing the assumptions discussed in Note 15 to our consolidated financial statements for the fiscal year ended December 31, 2013, without taking into account estimated forfeitures. With respect to performance units, the grant date fair value assumes the vesting of the target number of performance units

granted. The actual number of performance units earned will depend on AEP's performance over the 2013 through 2015 period and could vary from 0 percent to 200 percent of the target award plus reinvested dividends. The value of performance units earned will be equal to AEP's average closing share price for the last 20 trading days of the performance period multiplied by the number of performance units earned.

(8) Mr. Feinberg received the 2011-2013 performance units and the 2012-2014 performance units under a promotional award program that granted a pro rata portion of outstanding long-term incentive awards to promoted employees to bring their long-term compensation to the target level on a going forward basis, rather than waiting to layer such awards in over three or more years. Under this policy, Mr. Feinberg also received 350 restricted stock units (half of which vested on May 1, 2013 and half of which will vest on May 1, 2014) and 600 restricted stock units (one-third of which vested on May 1, 2013, one-third of which will vest on May 1, 2014, and another one-third will vest on May 1, 2015).

(9) Ms. Hillebrand received 6,691 of these restricted stock units pursuant to a letter agreement when she joined the Company. These units offset the loss of a similar value of stock units that she forfeited when she left her prior employer.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

2013 Stock Award Grants. On February 26, 2013, the named executive officers were granted long-term incentive awards as part of AEP's regular annual grant cycle. These awards were granted with double trigger change in control provisions that provide early vesting of awards only in the event of a change in control and a covered separation from service. Of these awards, 70 percent were granted in the form of performance units for the 2013-2015 three-year performance period that generally vest, subject to the participant's continued AEP employment, at the end of the performance period. Performance units are generally equivalent in value to shares of AEP common stock. Dividend equivalents are reinvested in additional performance units with the same vesting conditions as the underlying performance units.

The 2013-2015 performance units, including the dividend equivalents, are subject to two equally weighted performance measures for the three-year performance period, which are:

- Three-year total shareholder return relative to the S&P 500 Electric Utilities Industry Index, and
- Three-year cumulative operating earnings per share relative to a performance objective established by the HR Committee.

These performance measures are described in detail in Compensation Discussion and Analysis-Performance Units beginning on page 37. The scores for these performance measures determine the percentage of the performance units earned at the end of the performance period and can range from zero percent to 200 percent of the target. Recipients must remain employed by AEP through the end of the vesting period to receive a payout unless they retire; are severed by the Company as part of a consolidation, restructuring or downsizing (or, effective January 1, 2014, are involuntarily terminated or resign for good reason as described in the AEP Executive Severance Plan); or are terminated in conjunction with a change in control. In the event of a participant's retirement or severance by the Company, a prorated portion of their performance units will vest based on the number of months that the participant actively worked. Each performance unit that is vested and earned is paid out or deferred with a value equal to the average closing price of AEP common stock for the last twenty trading days of the performance period. If a participant's employment is terminated in conjunction with a change in control, then all of the performance units will vest and be paid out immediately at the target performance.

The remaining 30 percent of AEP's long-term incentive awards were granted in the form of restricted stock units (RSUs) that generally vest, subject to the executive officer's continued employment, in three equal installments on May 1, 2014, May 1, 2015 and May 1, 2016. Recipients must remain employed by AEP through the vesting date to receive a payout for the RSUs that vest on such date unless they retire pursuant to AEP's mandatory officer retirement policy at age 65; are severed by the Company as part of a consolidation, restructuring or downsizing (or, effective January 1, 2014, are involuntarily terminated or resign for good reason as described in the AEP Executive Severance Plan); or are terminated in conjunction with a change in control. In the event of a participant's retirement pursuant to AEP's mandatory retirement policy or severance by the Company, a prorated portion of their RSUs will vest based on the number of months that the participant actively worked. RSUs that vest pursuant to the mandatory retirement policy, less shares withheld for taxes, are subject to a two year post-retirement holding period. If a participant's employment is terminated in conjunction with a change in control, all of the RSUs vest. Upon vesting, the RSUs pay out in cash to executive officers.

Employment Agreements.

Mr. Powers has an agreement with the Company, which credits him with 17 additional years of service under AEP's Supplemental Benefit Plan. In 1997, the Company granted additional years of credited service to Mr. Powers when he joined AEP to offset pension benefits that he would have been able to earn from his prior employer due to his length of service at that company. For further information on this, see note (2) under the Pension Benefits on page 56.

Ms. Hillebrand has an agreement with the Company pursuant to which the Company paid her $464,000 in 2012 to offset the loss of near-term compensation payments that she forfeited by coming to work at the Company. In addition, she was granted an additional $310,000 in restricted stock units on February 26, 2013 to offset the loss of stock units that she forfeited when she left her prior employer. These restricted stock units vest in equal thirds on May 1, 2014, May 1, 2015 and May 1, 2016. Ms. Hillebrand's agreement also provides her a payment of one times her annual salary plus her target annual incentive opportunity if she terminates her employment for good reason. For further information, see Potential Payments Upon Termination of Employment or Change in Control beginning on page 60.

Outstanding Equity Awards at Fiscal Year-End for 2013

The following table provides information with respect to holdings of restricted stock units and performance units by the named executive officers at December 31, 2013. The named executive officers do not have any outstanding stock options.

	Stock Awards			
Name	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(1)
Nicholas K. Akins				
2012 – 2014 Performance Units(2)			72,845	6,809,551
2013 – 2015 Performance Units(2)			104,915	9,807,454
Restricted Stock Units(3)	32,427	1,515,638		
2011 Restricted Stock Units(4)	4,851	226,736		
2012 Restricted Stock Units(5)	32,375	1,513,208		
2013 Restricted Stock Units(6)	44,964	2,101,617		
Brian X. Tierney				
2012 – 2014 Performance Units(2)			30,038	2,807,952
2013 – 2015 Performance Units(2)			29,554	2,762,708
Restricted Stock Units(3)	32,427	1,515,638		
2011 Restricted Stock Units(4)	5,184	242,300		
2012 Restricted Stock Units(5)	13,350	623,979		
2013 Restricted Stock Units(6)	12,666	592,009		
Robert P. Powers				
2012 – 2014 Performance Units(2)			30,038	2,807,952
2013 – 2015 Performance Units(2)			29,554	2,762,708
Restricted Stock Units(3)	32,427	1,515,638		
2011 Restricted Stock Units(4)	4,851	226,736		
2012 Restricted Stock Units(5)	13,350	623,979		
2013 Restricted Stock Units(6)	12,666	592,009		
David M. Feinberg				
2012 – 2014 Performance Units(2)			14,473	1,352,936
2013 – 2015 Performance Units(2)			14,777	1,381,354
2011 Restricted Stock Units(4)	1,832	85,628		
2012 Restricted Stock Units(5)	6,450	301,473		
2013 Restricted Stock Units(6)	6,333	296,004		
Lana L. Hillebrand				
2013 – 2015 Performance Units(2)			13,056	1,220,475
2013 Restricted Stock Units(6)	12,509	584,671		

(1) The market value of the performance units reported in this column was computed by multiplying the closing price of AEP's common stock on December 31, 2013 ($46.74) by the maximum number of performance units issuable (200% of the target amount set forth in the preceding column) because the payout for the 2011-2013 performance units was above target. However, the actual number of performance units credited upon vesting will be based on AEP's performance over the applicable three year period.

(2) AEP currently grants performance units at the beginning of each year with a three-year performance and vesting period. This results in awards for overlapping successive three-year performance periods. These awards generally vest at the end of the three year performance period. The performance units awarded for the 2011 – 2013 performance period vested at December 31, 2013 and are shown in the Options Exercises and Stock Vested for 2013 table below. The awards shown for the 2012 – 2014 and 2013 – 2015 performance periods include performance units resulting from reinvested dividends. Mr. Feinberg also was granted 860 performance units for the 2012-2014 performance period pursuant to the promotional award program that were approved by the HR Committee on February 26, 2013.

(3) These restricted stock units were granted on August 3, 2010 in connection with a CEO transition plan and include restricted stock units resulting from reinvested dividends. These units will vest, subject to the executive officer's continued employment, in two equal installments, on August 3, 2014 and August 3, 2015.

(4) The numbers set forth include restricted stock units resulting from reinvested dividends. They will vest, subject to the executive officer's continued employment, on May 1, 2014. For all named executive officers other than Mr. Feinberg, these restricted stock units were approved by the HR Committee on December 7, 2010, effective January 1, 2011. For Mr. Feinberg, the restricted stock units were approved by the HR Committee on May 23, 2011. Mr. Feinberg also was granted 350 restricted stock units pursuant to the promotional award program that were approved by the HR Committee on February 26, 2013.

(5) The numbers set forth include restricted stock units resulting from reinvested dividends. They will vest, subject to the executive officer's continued employment, in two equal installments, on May 1, 2014 and May 1, 2015. These restricted stock units were granted on January 25, 2012. Mr. Feinberg also was granted 600 restricted stock units pursuant to the promotional award program that were approved by the HR Committee on February 26, 2013.

(6) These restricted stock units were granted on February 26, 2013 and include restricted stock units resulting from reinvested dividends. They will vest, subject to the executive officer's continued employment, in three equal installments, on May 1, 2014, May 1, 2015 and May 1, 2016.

Option Exercises and Stock Vested for 2013

The following table provides information with respect to the vesting of restricted stock units and performance units granted to our named executive officers. The named executive officers did not exercise any stock options in 2013.

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting (#)(1)	Value Realized on Vesting ($) (2)
Nicholas K. Akins	—	—	62,152	2,990,855
Brian X. Tierney	—	—	55,040	2,618,542
Robert P. Powers	—	—	52,946	2,519,232
David M. Feinberg	—	—	14,251	688,066
Lana L. Hillebrand	—	—	—	—

(1) This column includes the following performance units for the 2011 – 2013 performance period that vested on December 31, 2013: 25,933 for Mr. Akins; 27,707 for Mr. Tierney; 25,933 for Mr. Powers; and 9,357 for Mr. Feinberg. This column also includes the following restricted stock units that vested on May 1, 2013: 20,361 for Mr. Akins; 11,476 for Mr. Tierney; 11,155 for Mr. Powers; and 4,895 for Mr. Feinberg. This column also includes 15,858 restricted stock units that vested on August 5, 2013 for Messrs. Akins, Powers and Tierney.

(2) As is required, the value included in this column for performance units is computed by multiplying the number of units by the market value of these units on the vesting date of December 31, 2013 ($46.74). However, the actual value realized from these units was based on the previous 20-day average closing market price of AEP common stock as of the vesting date ($46.42). For a more detailed discussion of vesting of the performance units, see the Long-Term Incentive Compensation section of the Compensation Discussion and Analysis beginning on page 38. This column also includes the value of restricted stock units that vested on May 1, 2013 and August 5, 2013, which had a market value of $51.23 per share and $46.39 per share, respectively.

Pension Benefits for 2013

The following table provides information regarding the pension benefits for our named executive officers under AEP's pension plans. The material terms of the plans are described following the table.

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit($)(1)	Payments During Last Fiscal Year($)
Nicholas K Akins	AEP Retirement Plan	31.6	444,540	—
	CSW Executive Retirement Plan	31.6	616,465	—
Brian X. Tierney	AEP Retirement Plan	15.7	222,643	—
	AEP Supplemental Benefit Plan	15.7	737,230	—
Robert P. Powers	AEP Retirement Plan	15.5	481,199	—
	AEP Supplemental Benefit Plan	32.5 (2)	3,643,278	—
David M. Feinberg	AEP Retirement Plan	2.7	30,986	—
	AEP Supplemental Benefit Plan	2.7	48,185	—
Lana L. Hillebrand	AEP Retirement Plan	18.6 (3)	259,359	—
	AEP Supplemental Benefit Plan	18.6	17,768	—

(1) The Present Value of Accumulated Benefits is based on the benefit accrued under the applicable plan through December 31, 2013, and the following assumptions (which are consistent with those used in AEP's financial statements):

- The named executive officer retires at age 65 (or, for Mr. Tierney and Mr. Powers, retires at age 62), and commences the payment of benefits (the "accrued benefit").
- The value of the annuity benefit at the named executive officer's assumed retirement age is determined based upon the accrued benefit, an assumed interest rate of 4.70 percent, 4.55 percent and 4.55 percent for the benefits accrued under the AEP Retirement Plan, AEP Supplemental Benefit Plan and the CSW Executive Retirement Plan, respectively, and assumed mortality based upon the IRS 2014 sex-distinct mortality tables. The value of the lump sum benefit at that assumed retirement age is determined based upon the accrued benefit, an assumed interest rate of 5.90 percent and assumed mortality based on the 2014 IRS Applicable Mortality table. The present value of both the annuity benefit and the lump sum benefit at each executive's current age is based upon an assumed interest rate of 4.70 percent, 4.55 percent and 4.55 percent for the benefits accrued under the AEP Retirement Plan, AEP Supplemental Benefit Plan and CSW Executive Retirement Plan, respectively.
- The present value of the accrued benefit is weighted based on 75 percent lump sum and 25 percent annuity (or 40 percent lump sum and 60 percent annuity for Mr. Powers due to his eligibility for early retirement under the final average pay benefit formula), based on the assumption that participants elect those benefit options in that proportion.

(2) Mr. Powers has a letter agreement with AEP that credits him with years of service in addition to his actual years of service with AEP. The Company granted 17 additional years of credited service to Mr. Powers when he joined AEP in 1997 to offset pension benefits that he would have been able to earn from his prior employer due to his length of service at that company. The additional years of service credit have augmented the present value of his accumulated benefits under the AEP Supplemental Benefit Plan by $2,155,983.

(3) The benefit available to Ms. Hillebrand from the AEP Retirement Plan consists of two pieces: one under the Central and South West Corporation Cash Balance Retirement Plan (the "CSW Retirement Plan") attributable to her prior period of service between December 15, 1982 and June 30, 2000 (her "CSW Retirement Plan Benefit") and one under the cash balance formula

since her return on December 17, 2012. Her CSW Retirement Plan Benefit will be paid to her either as a lump sum or in one of the annuity options offered by the plan. The amount available to her as a lump sum would be the greater of (i) her CSW Retirement Plan cash balance account ($195,349 as of December 31, 2013), or (ii) the lump sum value of her CSW Retirement Plan protected minimum normal retirement annuity (which had accrued during the 14.5 year period until her traditional pension formula benefit became frozen effective July 1, 1997), calculated using a factor based on then applicable interest and mortality assumptions as well as an assumed future cost of living adjustment rate of 3.00%. The payment available to her as an annuity would be based on the greater of (i) her CSW Retirement Plan protected minimum normal retirement annuity ($3,279 per month) or (ii) the life annuity equivalent of her then CSW Retirement Plan cash balance account, calculated using a factor based on then applicable interest and mortality assumptions.

Overview. AEP maintains tax-qualified and nonqualified defined benefit pension plans for eligible employees. The nonqualified plans provide (i) benefits that cannot be paid under the tax-qualified plan because of maximum limitations imposed on such plans by the Internal Revenue Code and (ii) benefits pursuant to individual agreements with certain of the named executive officers. The plans are designed to provide a source of income upon retirement to executives and their spouses, as well as a market competitive benefit opportunity as part of a market competitive total rewards package.

AEP Retirement Plan. The AEP Retirement Plan is a tax-qualified defined benefit pension plan under which benefits are generally determined by reference to a cash balance formula. The AEP Retirement Plan also encompasses the Central and South West Corporation Cash Balance Retirement Plan (the "CSW Retirement Plan"), which was merged into the AEP Retirement Plan effective December 31, 2008. As of December 31, 2013, each of the named executive officers other than Mr. Feinberg was vested. Mr. Feinberg's benefits will become fully vested if his employment terminates upon his death or disability or once he has been credited with at least three years of service.

In addition, employees who have continuously participated in the AEP Retirement Plan (but not the CSW Retirement Plan) since December 31, 2000 ("Grandfathered AEP Participants," which includes Mr. Tierney and Mr. Powers) remain eligible for an alternate pension benefit calculated by reference to a final average pay formula. The benefits under this final average pay formula were frozen as of December 31, 2010.

Cash Balance Formula. Under the cash balance formula, each participant has an account established to which dollar credits are allocated each year.

1. *Company Credits.* Each year, participants' accounts are credited with an amount equal to a percentage of their salary for that year and annual incentive award for the prior year. The applicable percentage is based on the participant's age and years of service. The following table shows the applicable percentage:

Sum of Age Plus Years of Service	Applicable Percentage
Less than 30	3.0%
30-39	3.5%
40-49	4.5%
50-59	5.5%
60-69	7.0%
70 or more	8.5%

Each year, the IRS calculates a limit on the amount of eligible pay that can be used to calculate pension benefits in a qualified plan. For 2013, the limit was $255,000.

2. *Interest Credits.* All amounts in the cash balance accounts earn interest at the average interest rate on 30-year Treasury securities for the month of November of the prior year, with a floor of 4 percent. For 2013, the interest rate was 4 percent.

Final Average Pay Formula. Grandfathered AEP Participants receive their benefits under the cash balance formula or the final average pay formula, whichever provides the higher benefit. On December 31, 2010, the final average pay benefit payable at the Grandfathered AEP Participant's normal retirement age was frozen, meaning that their final average pay formula benefit is not affected by the participant's service or compensation subsequent to this date. This frozen final average pay normal retirement benefit is based on the following calculation as of December 31, 2010: the participant's then years of service times the sum of (i) 1.1 percent of the participant's then high 36 consecutive months of base pay ("High 36"); plus (ii) 0.5 percent of the amount by which the participant's then High 36 exceeded the participant's applicable average Social Security covered compensation.

Grandfathered AEP Participants may become entitled to a subsidized benefit under the final average pay formula if they would retire early (that is, once they have remained employed past age 55 with at least three years of service). The benefit payable under the final average pay formula would be unreduced if it commences at age 62 or later and is reduced by 3 percent for each year prior to age 62 that his benefits are commenced. Mr. Powers is eligible for such early retirement benefits.

AEP Supplemental Benefit Plan. The AEP Supplemental Benefit Plan is a nonqualified defined benefit pension plan. It generally provides eligible participants with benefits that are in excess of those provided under the AEP Retirement Plan (without regard to the provisions now included as the result of the merger of the CSW Retirement Plan into the AEP Retirement Plan) as determined upon the participant's termination of employment. These excess benefits are calculated under the terms of the AEP Retirement Plan described above with the following modifications: (i) additional years of service or benefit credits are taken into account; (ii) annual incentive pay was taken into account for purposes of the frozen final average pay formula; and (iii) the limitations imposed by the Internal Revenue Code on annual compensation and annual benefits are disregarded. However, eligible pay taken into account under the cash balance formula is limited to the greater of $1 million or two times the participant's year-end base pay.

AEP granted Mr. Powers with 17 additional years of credited service under the AEP Supplemental Benefit Plan when he joined the Company in 1997. The Company granted additional years of credited service to Mr. Powers to offset pension benefits that he would have been able to earn from his prior employer due to his length of service at that company.

Participants do not become vested in their AEP Supplemental Plan benefit until they become vested in their AEP Retirement Plan benefit or upon a change in control. As of December 31, 2013, each of the named executive officers, other than Mr. Feinberg, was fully vested in their AEP Supplemental Benefit Plan benefit. Mr. Feinberg's benefits will become fully vested once he has completed three years of service, upon a change in control of AEP or if his employment terminates either upon his death or due to his disability.

CSW Executive Retirement Plan. The CSW Executive Retirement Plan is a nonqualified defined benefit pension plan. It generally provides eligible participants with benefits that are in excess of those provided under the terms of the former CSW Retirement Plan (which was merged into the AEP Retirement Plan) as determined upon the participant's termination of employment. The excess benefits are calculated without regard to the limitations imposed by the Internal Revenue Code on annual compensation and annual benefits.

Nonqualified Deferred Compensation for 2013

The following table provides information regarding contributions, earnings and balances for our named executive officers under AEP's three non-qualified deferred compensation plans which are each further described below.

Name	Plan Name(1)	Executive Contributions in Last FY(2) ($)	Registrant Contributions in Last FY(3) ($)	Aggregate Earnings in Last FY(4) ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last FYE(5) ($)
Nicholas K. Akins	SRSP	104,700	78,525	93,660	—	914,543
	ICDP	—	—	69,572	—	272,103
	SORP	1,248,267	—	362,065	—	3,283,008
Brian X. Tierney	SRSP	94,746	54,764	240,816	—	2,126,997
	SORP	5,297	—	86,775	—	786,726
Robert P. Powers	SRSP	73,019	54,764	316,399	—	2,614,031
	ICDP	—	—	204,493	—	860,415
	SORP	4,980	—	244,041	—	2,212,609
David M. Feinberg	SRSP	44,562	33,421	2,333	—	118,971
	SORP	—	—	—	—	0
Lana L. Hillebrand	SRSP	12,900	9,675	140	—	22,715
	SORP	—	—	—	—	0

(1) "SRSP" is the American Electric Power System Supplemental Retirement Savings Plan. "ICDP" is the American Electric Power System Incentive Compensation Deferral Plan. "SORP" is the American Electric Power System Stock Ownership Requirement Plan.

(2) The amounts set forth under "Executive Contributions in Last FY" for the SRSP are reported in the Summary Compensation Table as either (i) Salary for 2013 or (ii) the Non-Equity Incentive Plan Compensation for 2012.

(3) The amounts set forth under "Registrant Contributions in Last FY" for the SRSP are reported in the Other Compensation column of the Summary Compensation Table.

(4) No amounts set forth under "Aggregate Earnings in Last FY" have been reported in the Summary Compensation Table as there were no above market or preferential earnings credited to any named executive officer's account in any of the plans.

(5) The amounts set forth in the "Aggregate Balance at Last FYE" column for the SRSP include the SRSP amounts reported in the "Executive Contributions in Last FY" and "Registrant Contributions in Last FY" columns. In addition, the "Aggregate Balance at Last FYE" for the SRSP includes the following amounts previously reported in the Summary Compensation Table for prior years: $265,531 for Mr. Akins, $475,774 for Mr. Tierney, $534,486 for Mr. Powers and $38,164 for Mr. Feinberg. The amounts set forth in the "Aggregate Balance at Last FYE" for the SORP include the SORP amounts reported in the "Executive Contributions in Last FY". In addition, the "Aggregate Balance at Last FYE" for the SORP includes $300,652 for Mr. Akins previously reported in the Summary Compensation Table for prior years.

Overview. AEP maintains non-qualified deferred compensation plans that allow eligible employees, including the named executive officers, to defer receipt of a portion of their base salary, annual incentive compensation and performance unit awards. The plans are unfunded. Participants have an unsecured contractual commitment from the Company to pay the amounts due under the plans from the general assets of the Company. AEP maintains the following non-qualified deferred compensation plans:

- The American Electric Power System Supplemental Retirement Savings Plan;
- The American Electric Power System Incentive Compensation Deferral Plan; and
- The American Electric Power System Stock Ownership Requirement Plan.

Supplemental Retirement Savings Plan. This plan allows eligible participants to save on a pre-tax basis and to continue to receive Company matching contributions beyond the limits imposed by the Internal Revenue Code on qualified plans of this type.

- Participants can defer up to 50 percent of their base pay and annual incentive pay in excess of the IRS' eligible compensation limit for qualified plans, which was $255,000 for 2013, up to $2,000,000.
- The Company matches 100 percent of the participant's contributions up to 1 percent of eligible compensation and 70 percent of the participant's contributions from the next 5 percent of eligible compensation (for a total Company match of 4.5%).
- Participants may not withdraw any amount credited to their account until their termination of employment with AEP. Participants may elect a distribution of their account as a lump-sum or annual installment payments over a period of up to 10 years. Participants may delay the commencement of distributions for up to five years from the date of their termination of employment.
- Participants may direct the investment of their plan account among the investment options that are available to all employees in AEP's qualified Retirement Savings Plan and one additional option that provides interest at a rate set each December at 120 percent of the applicable federal long-term rate with monthly compounding. There were no above-market or preferential earnings with respect to the Supplemental Retirement Savings Plan.

Incentive Compensation Deferral Plan. This plan allows eligible employees to defer payment of up to 80 percent of earned performance units.

- AEP does not offer any matching contributions.
- Participants may direct the investment of their plan accounts among the investment options that are available to all employees in AEP's qualified Retirement Savings Plan. There were no above-market or preferential earnings with respect to the Incentive Compensation Deferral Plan.
- Generally, participants may not withdraw any amount credited to their account until their termination of employment with AEP. However, participants may make one withdrawal of amounts attributable to their pre-2005 contributions prior to termination of employment. The withdrawal amount would be subject to a 10 percent withdrawal penalty. Participants may elect to take distributions from their account in the same manner as described above for the Supplemental Retirement Savings Plan.

Stock Ownership Requirement Plan. This plan assists executives in achieving their minimum stock ownership requirements. It does this primarily by tracking the executive's AEP Career Shares. AEP Career Shares are a form of deferred compensation, which are unfunded and unsecured general obligations of AEP. The rate of return on AEP Career Shares is equivalent to the total return on AEP stock with dividends reinvested. Participants may not withdraw any amount credited to their account until their termination of employment with AEP. AEP Career Shares are paid in cash. Participants may elect to take distribution of their AEP Career Shares in the same manner as described above for the Supplemental Retirement Savings Plan.

Potential Payments Upon Termination of Employment or Change in Control

The Company has entered into agreements and maintains plans that will require the Company to provide compensation to the named executive officers in the event of a termination of their employment or a change in control of the Company. Actual payments will depend on the circumstances and timing of any termination of employment or change of control. In addition, in connection with any actual termination or change of control transaction, we may enter into agreements or establish arrangements that provide additional or alternative benefits or amounts from those described below. The agreements and plans summarized below are complex legal documents with terms and conditions having precise meanings, which are designed to address many possible but currently hypothetical situations. It is not possible to reduce them to simple explanations without some loss of precision.

Severance. AEP currently provides full-time employees, including the named executive officers, with severance benefits if their employment is terminated as the direct result of a restructuring or downsizing ("Severance-Eligible Employees") and the employee releases AEP from any and all claims. These severance benefits include:

- A lump sum severance payment equal to two weeks of base pay for each year of Company service, with a minimum of 8 weeks for employees with at least one year of AEP service;
- Continued eligibility for medical and dental benefits at the active employee rates for eighteen months or until the participant becomes eligible for coverage from another employer, whichever occurs first;
- For employees who are at least age 50 with 10 years of AEP service and who do not qualify for AEP's retiree medical benefits or to be bridged to such retiree benefit eligibility (described below), AEP also provides medical and dental benefit eligibility at rates equivalent to those provided to retirees until age 65 or until the participant becomes eligible for coverage from another employer, whichever occurs first; and
- Outplacement services, the incremental cost of which may be up to $28,000 for executive officers.

Severance-Eligible Employees who have enough weeks of severance (up to one year) and vacation to cover a period that would allow them to become eligible for retiree medical benefits, which is available to those employees who are at least age 55 with at least 10 years of service ("Retirement-Eligible Employees") are retained as employees on a paid leave of absence until they become retirement eligible. This benefit applies in lieu of severance and unused vacation payments that these employees would otherwise receive. The Company pays any remaining severance and vacation pay at the time of their retirement. This delay of an employee's termination date does not apply to the plans providing nonqualified deferred compensation, which define a participant's termination date by reference to Code Section 409A.

A Severance-Eligible executive's termination entitles that executive to a pro-rata portion of any outstanding performance units that the executive has held for at least six months and to the payment of a pro-rata portion of any restricted stock units to the extent not already vested and paid. The pro-rated performance units will not become payable until the end of the performance period and remain subject to all performance objectives.

Severance-Eligible executives may continue financial counseling and tax preparation services for one year following their termination up to a maximum annual incremental cost to the Company for 2014 of $11,905 plus related incidental expenses of the advisor.

In addition, Ms. Hillebrand has an agreement that entitles her to a payment of one times her annual salary plus her target annual incentive opportunity if she terminates her employment because her duties are changed without her consent, provided that her termination is not a Qualifying Termination (as defined in the Company's long-term incentive awards). See Change in Control below. Payment is conditioned upon her releasing AEP from all claims, including claims for any other severance benefits.

Effective January 1, 2014, the HR Committee adopted the American Electric Power Executive Severance Plan that is described further on page 43 under Compensation Discussion & Analysis—Other Employment Separations.

Change In Control. AEP defines "change in control" under its change in control agreements and Long-Term Incentive Plan as:

- The acquisition by any person of the beneficial ownership of securities representing more than one-third of AEP's voting stock;

- A merger or consolidation of AEP with another corporation unless AEP's voting securities outstanding immediately before such merger or consolidation continue to represent at least two-thirds of the total voting power of the surviving entity outstanding immediately after such merger or consolidation; or
- Approval by the shareholders of the liquidation of AEP or the disposition of all or substantially all of the assets of AEP.

AEP has a change in control agreement with each of the named executive officers that is triggered if there is a Qualifying Termination of the named executive officer's employment. A "Qualifying Termination" for this purpose generally occurs when the executive's employment is terminated in connection with that change in control (i) by AEP without "cause" or (ii) by the named executive officer for "good reason." Such termination must be no later than two years after the change in control. These agreements provide for:

- A lump sum payment equal to 2.99 or 2.0, as applicable, times the named executive officers' annual base salary plus target annual incentive under the annual incentive program; and
- Outplacement services.

In December 2013, the HR Committee decided to amend all of the Company's change in control agreements to eliminate the provision that provided a tax gross-up for excise taxes. Up until December 31, 2013, some of the named executive officers had change in control agreements that provided for a payment that offset the effect of an excise tax with a "gross-up" payment that would have reimbursed those executives for any excise tax on an after tax basis.

The term "cause" with respect to AEP's change in control agreements means:

(i) The willful and continued failure of the executive to perform the executive's duties after a written demand for performance is delivered to the executive by the Board; or

(ii) The willful conduct or omission by the executive, which the Board determines to be illegal; gross misconduct that is injurious to the Company; or a breach of the executive's fiduciary duty to the Company.

The term "good reason" with respect to AEP's change in control agreements means:

(i) An adverse change in the executive's status, duties or responsibilities from that in effect immediately prior to the change in control;

(ii) The Company's failure to pay in a timely fashion the salary or benefits to which the executive is entitled under any employment agreement in effect on the date of the change in control;

(iii) The reduction of the executive's salary as in effect on the date of the change in control;

(iv) Any action taken by the Company that would substantially diminish the aggregate projected value of the executive's awards or benefits under the Company's benefit plans or policies;

(v) A failure by the Company to obtain from any successor the assent to the change in control agreement; or

(vi) The relocation, without the executive's prior approval, of the office at which the executive is to perform services to a location that is more than fifty (50) miles from its location immediately prior to the change in control.

The Company must be given notice and an opportunity to cure any of these circumstances before they would be considered to be "good reason."

Awards under the Long-Term Incentive Plan will vest upon a "Qualifying Termination" upon or within one year after a change in control. The term "Qualifying Termination" with respect to long-term incentive awards generally is the same as that described for the change in control agreements, except that an executive's mandatory retirement at age 65 is explicitly excluded, and "Cause" is defined more broadly to encompass:

(i) Failure or refusal to perform assigned duties and responsibilities in a competent or satisfactory manner;

(ii) Commission of an act of dishonesty, including, but not limited to, misappropriation of funds or any property of AEP;

(iii) Engagement in activities or conduct injurious to the best interest or reputation of AEP;

(iv) Insubordination;

(v) A violation of any material term or condition of any written agreement with AEP;

(vi) Violation of any of AEP's rules of conduct of behavior;

(vii) Commission of a felony, a misdemeanor involving an act of moral turpitude, or a misdemeanor committed in connection with employment at AEP which is injurious to the best interest or reputation of AEP; or

(viii) Disclosure, dissemination, or misappropriation of confidential, proprietary, and/or trade secret information.

In addition, performance units would be deemed to have been fully earned at 100 percent of the target score upon a "Qualifying Termination" following a change in control. The value of each vested performance unit following a "Qualifying Termination" would be (1) the closing price of a share of AEP common stock on the date of the Qualifying Termination or (2) if the date of the Qualifying Termination is coincident with the change in control and if the change in control is the result of a tender offer, merger, or sale of all or substantially all of the assets of AEP, the price paid per share of common stock in that transaction.

The AEP Supplemental Benefit Plan also provides that all accrued supplemental retirement benefits become fully vested upon a change in control.

Termination Scenarios

The following tables show the incremental compensation and benefits that would have been paid to each named executive officer who was employed by AEP on December 31, 2013 under the hypothetical circumstances cited in each column and calculated in accordance with the methodology required by the SEC. In addition, in connection with any actual termination or change of control transaction, the Company may enter into agreements or establish arrangements that provide additional benefits or amounts, or may alter the terms of benefits described below.

With respect to annual incentive compensation for the completed year, the initial calculated annual incentive opportunity is shown, (before any discretionary adjustment), which varies from the actual value paid and reported in the Summary Compensation Table on page 48.

The values shown in the severance column show the compensation and benefits that would be provided if the severance had occurred on December 31, 2013. The amounts shown do not include the compensation and benefits that would be provided under the Executive Severance Plan that was adopted by the HR Committee effective January 1, 2014 and was accepted by each of the named executive officers in February 2014. That plan is described further on page 43 under Compensation Discussion & Analysis—Other Employment Separations.

The values shown in the change in control column are triggered only if the named executive officer's employment is terminated under the circumstances (described above under Change In Control) that trigger the payment or provision of each of the types of compensation and benefits shown. As of December 31, 2013, Mr. Tierney and Mr. Powers had change in control agreements that provided for a payment that offset the effect of an excise tax with a "gross-up" payment that would have reimbursed those executives for any excise tax on an after tax basis. However, the tax gross-ups were eliminated from all of AEP's change in control agreements effective January 1, 2014. In the hypothetical circumstance that Mr. Tierney's and Mr. Powers' employment was terminated on December 31, 2013 when the tax gross-up provision was still in effect, the value of the tax gross-up would have been \$5,020,221 and \$4,735,439, respectively.

No information is provided for terminations due to disability because it is not AEP's practice to terminate the employment of any employee so long as they remain eligible for AEP's long-term disability benefits. AEP successively provides sick pay and then long-term disability benefits for up to two years to employees with a disability that prevents them from returning to their job. Such disability benefits continue (generally until the employee reaches age 65) for employees that cannot perform any occupation for which they are reasonably qualified. Because disabled participants remain employed by the Company, they continue to vest in long-term incentive awards while they are disabled. AEP treats a participant's disability as a termination to the extent required by the regulations issued under Code Section 409A, but such terminations only trigger the payment of benefits that had previously vested. In addition, restricted stock unit awards granted effective on or after January 1, 2011 allow participants terminated due to disability to continue to vest as if their employment had continued.

**Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2013
For Nicholas K. Akins**

Executive Benefits and Payments Upon Termination	Resignation or Retirement	Severance	Involuntary Termination for Cause	Change-In-Control	Death
Compensation:					
Base Salary ($1,200,000)	$ 0	$1,476,923	$ 0	$ 3,588,000	$ 0
Annual Incentive for Completed Year(1)	$2,429,403	$2,429,403	$ 0	$ 2,429,403	$ 2,429,403
Other Payment for Annual Incentives(2)	$ 0	$ 0	$ 0	$ 4,485,000	$ 0
Long-Term Incentives:(3)					
2012-2014 Performance Units(4)	$ 0	$2,269,850	$ 0	$ 3,404,775	$ 2,269,850
2013-2015 Performance Units(4)	$ 0	$1,634,576	$ 0	$ 4,903,727	$ 1,634,576
Restricted Stock Units	$ 0	$ 252,606	$ 0	$ 1,515,638	$ 1,515,638
2011 Restricted Stock Units	$ 0	$ 158,715	$ 0	$ 226,736	$ 226,736
2012 Restricted Stock Units	$ 0	$ 605,283	$ 0	$ 1,513,208	$ 1,513,208
2013 Restricted Stock Units	$ 0	$ 630,485	$ 0	$ 2,101,617	$ 2,101,617
Benefits:					
Financial Counseling	$ 0	$ 11,905	$ 0	$ 11,905	$ 11,905
Outplacement Services(5)	$ 0	$ 28,000	$ 0	$ 28,000	$ 0
Total Incremental Compensation and Benefits	$2,429,403	$9,497,746	$ 0	$24,208,009	$11,702,933

Notes for the Potential Incremental Termination Scenario tables are provided collectively following the last such table.

Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2013
For Brian X. Tierney

Executive Benefits and Payments Upon Termination	Resignation or Retirement	Severance	Involuntary Termination for Cause	Change-In-Control	Death
Compensation:					
Base Salary ($672,500)	$ 0	$ 413,846	$ 0	$ 2,010,775	$ 0
Annual Incentive for Completed Year(1)	$ 875,725	$ 875,725	$ 0	$ 875,725	$ 875,725
Other Payment for Annual Incentives(2)	$ 0	$ 0	$ 0	$ 1,608,620	$ 0
Long-Term Incentives:(3)					
2012-2014 Performance Units(4)	$ 0	$ 935,984	$ 0	$ 1,403,976	$ 935,984
2013-2015 Performance Units(4)	$ 0	$ 460,451	$ 0	$ 1,381,354	$ 460,451
Restricted Stock Units	$ 0	$ 252,606	$ 0	$ 1,515,638	$1,515,638
2011 Restricted Stock Units	$ 0	$ 169,610	$ 0	$ 242,300	$ 242,300
2012 Restricted Stock Units	$ 0	$ 249,592	$ 0	$ 623,979	$ 623,979
2013 Restricted Stock Units	$ 0	$ 177,603	$ 0	$ 592,009	$ 592,009
Benefits:					
Financial Counseling	$ 0	$ 11,905	$ 0	$ 11,905	$ 11,905
Outplacement Services(5)	$ 0	$ 28,000	$ 0	$ 28,000	$ 0
Total Incremental Compensation and Benefits	$ 875,725	$3,575,322	$ 0	$10,294,281	$5,257,991

Notes for the Potential Incremental Termination Scenario tables are provided collectively following the last such table.

Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2013
For Robert P. Powers

Executive Benefits and Payments Upon Termination	Resignation or Retirement	Severance	Involuntary Termination for Cause	Change-In-Control	Death
Compensation:					
Base Salary ($672,500)	$ 0	$ 413,846	$ 0	$ 2,010,775	$ 0
Annual Incentive for Completed Year(1)	$ 875,725	$ 875,725	$ 0	$ 875,725	$ 875,725
Other Payment for Annual Incentives(2)	$ 0	$ 0	$ 0	$ 1,608,620	$ 0
Long-Term Incentives:(3)					
2012-2014 Performance Units(4)	$	$ 935,984	$ 0	$ 1,403,976	$ 935,984
2013-2015 Performance Units(4)	$	$ 460,451	$ 0	$ 1,381,354	$ 460,451
Restricted Stock Units	$ 0	$ 252,606	$ 0	$ 1,515,638	$1,515,638
2011 Restricted Stock Units	$ 0	$ 158,715	$ 0	$ 226,736	$ 226,736
2012 Restricted Stock Units	$ 0	$ 249,592	$ 0	$ 623,979	$ 623,979
2013 Restricted Stock Units	$ 0	$ 177,603	$ 0	$ 592,009	$ 592,009
Benefits:					
Financial Counseling	$	$ 11,905	$ 0	$ 11,905	$ 11,905
Outplacement Services(5)	$ 0	$ 28,000	$ 0	$ 28,000	$ 0
Total Incremental Compensation and Benefits	$ 875,725	$3,564,427	$ 0	$10,278,717	$5,242,427

Notes for the Potential Incremental Termination Scenario tables are provided collectively following the last such table.

Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2013
For David M. Feinberg

Executive Benefits and Payments Upon Termination	Resignation or Retirement	Severance	Involuntary Termination for Cause	Change-In-Control	Death
Compensation:					
Base Salary ($550,000)	$ 0	$ 84,615	$ 0	$1,644,500	$ 0
Annual Incentive for Completed Year (1)	$ 579,924	$ 579,924	$ 0	$ 579,924	$ 579,924
Other Payment for Annual Incentives (2)	$ 0	$ 0	$ 0	$1,068,925	$ 0
Long-Term Incentives:(3)					
2012-2014 Performance Units(4)	$ 0	$ 450,978	$ 0	$ 676,468	$ 450,978
2013-2015 Performance Units(4)	$	$ 230,226	$ 0	$ 690,677	$ 230,226
2011 Restricted Stock Units	$ 0	$ 54,940	$ 0	$ 85,628	$ 85,628
2012 Restricted Stock Units	$ 0	$ 115,626	$ 0	$ 301,473	$ 301,473
2013 Restricted Stock Units	$ 0	$ 88,801	$ 0	$ 296,004	$ 296,004
Benefits:					
Pension(6)	$ 0	$ 0	$ 0	$ 87,883	$ 87,883
Financial Counseling	$ 0	$ 11,905	$ 0	$ 11,905	$ 11,905
Outplacement Services(5)	$ 0	$ 28,000	$ 0	$ 28,000	$ 0
Total Incremental Compensation and Benefits	$ 579,924	$1,645,015	$ 0	$5,471,387	$2,044,021

Notes for the Potential Incremental Termination Scenario tables are provided collectively following the last such table.

Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2013
For Lana L. Hillebrand

Executive Benefits and Payments Upon Termination	Resignation or Retirement	Severance	Involuntary Termination for Cause	Change-In-Control	Death
Compensation:					
Base Salary ($470,000)	$ 0	$ 470,000(7)	$ 0	$ 940,000	$ 0
Annual Incentive for Completed Year (1)	$ 459,378	$ 459,378	$ 0	$ 459,378	$ 459,378
Other Payment for Annual Incentives (2)	$ 0	$ 282,000	$ 0	$ 564,000	$ 0
Long-Term Incentives:(3)					
2013-2015 Performance Units(4)	$	$ 203,412	$ 0	$ 610,237	$ 203,412
2013 Restricted Stock Units	$ 0	$ 175,401	$ 0	$ 584,671	$ 584,671
Benefits:					
Financial Counseling	$	$ 11,905	$ 0	$ 11,905	$ 11,905
Outplacement Services(5)	$ 0	$ 28,000	$ 0	$ 28,000	$ 0
Total Incremental Compensation and Benefits	$ 459,378	$1,630,096	$ 0	$3,198,191	$1,259,366

(1) Executive officers and all other employees are eligible for an annual incentive award based on their earnings for the year if they remain employed with AEP through year-end, if they die or if they incur a retirement-eligible termination. The amount shown is the calculated annual incentive opportunity, as shown on page 36, but all annual incentives for executive officers are awarded at the discretion of the HR Committee or independent members of the board pursuant to the award determination process described in the Compensation Discussion and Analysis.

(2) Represents a payment of 2.99 times the applicable target annual incentive opportunity for each of the named executive officers, other than Ms. Hillebrand, in the event of a change in control. Represents a payment to Ms. Hillebrand of her target annual incentive opportunity in the event of a severance under the terms of her agreement with the Company, and 2.0 times this amount in the event of a change in control.

(3) The long-term incentive values shown represent the values that would be paid under such circumstances shown in each column, which are different from the values calculated in accordance with FASB ASC Topic 718.

(4) The target value of performance unit awards are shown. The actual value paid in the event of voluntary termination, retirement, severance or death, if any, will depend on the actual performance score for the full performance period. Any payments for awards under those circumstances are not paid until the end of the three year performance period. In the event of a qualifying termination in connection with a change in control, awards would be paid at a target performance score as soon as administratively practical after the change in control.

(5) Represents the maximum cost of Company paid outplacement services, which the Company provides through an unaffiliated third party vendor.

(6) Represents the total lump sum benefit payable from the AEP Retirement Plan and the AEP Supplemental Benefit Plan. AEP's pension benefits fully vest upon death or a change in control.

(7) Represents a payment to Ms. Hillebrand of her annual salary in the event of a severance under the terms of her agreement with the Company.

The following table shows the value of previously earned and vested compensation and benefits as of December 31, 2013, that would have been provided to each named executive officer following a termination of his or her employment on December 31, 2013. In all cases, these amounts were generally earned or vested over multiple years of service to the Company, other than the amounts shown for Ms. Hillebrand who was rehired in December 2012, and only a portion is attributable to compensation for 2013.

Non-Incremental Post-Termination Compensation and Benefits on December 31, 2013

	Long-Term Incentives		Benefits		
Name	**Vested Performance Units (1)**	**AEP Career Shares (2)**	**Vacation Payout (3)**	**Post Retirement Benefits (4)**	**Deferred Compensation (5)**
Nicholas K. Akins	$1,212,108	$3,305,640	$182,308	$ 1,112,204	$ 1,186,646
Brian X. Tierney	$1,295,025	$ 792,150	$ 30,392	$ 758,039	$ 2,126,997
Robert P. Powers	$1,212,108	$2,227,862	$ 47,851	$ 3,429,938	$ 3,474,446
David M. Feinberg	$ 437,346	$ 0	$ 60,553	$ 0	$ 118,971
Lana L. Hillebrand	$ 0	$ 0	$ 12,654	$ 248,647	$ 22,715

(1) Represents the value of performance units that vested on December 31, 2013 calculated using the market value of these shares on December 31, 2013. However, the actual value realized or deferred to AEP Career Shares from these performance units in February 2014 was based on the previous 20-day average closing market price of AEP common stock as of the vesting date.

(2) Represents the value of AEP share equivalents deferred mandatorily into AEP's Stock Ownership Requirement Plan calculated using the market value of these shares on December 31, 2013. However, the actual value that would have been realized from these AEP share equivalents would have been determined using the previous 20-day average closing market price of AEP common stock as of the date of termination.

(3) Represents accumulated but unused vacation.

(4) Represents the lump sum benefit calculated for the named executive officer pursuant to the terms of the AEP Retirement Plan, AEP Supplemental Benefit Plan and CSW Executive Retirement Plan, as applicable.

(5) Includes balances from the Supplemental Retirement Savings Plan and Incentive Compensation Deferral Plans, but does not include AEP Career Share balances, which are listed separately in column (2).

Share Ownership of Directors and Executive Officers

The following table sets forth the beneficial ownership of AEP Common Stock and stock-based units as of February 26, 2014 for all Directors, director nominees, each of the persons named in the Summary Compensation Table and all Directors and executive officers as a group.

Unless otherwise noted, each person had sole voting and investment power over the number of shares of AEP Common Stock set forth across from his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	Shares(a)	Stock Units(b)	Total(c)
N. K. Akins	21,438	94,885	116,323
D. J. Anderson	0	9,353	9,353
J. B. Beasley, Jr(d)	0	0	0
R. D. Crosby, Jr.	0	29,436	29,436
D. M. Feinberg	4,293	8,625	12,918
L. A. Goodspeed	0	30,210	30,210
L. L. Hillebrand	0	0	0
T. Hoaglin	1,000	23,677	24,677
S. B. Lin	1,000	4,736	5,736
M. G. Morris	270,410	6,539	276,949
R. C. Notebaert	0	9,353	9,353
L. L. Nowell III	0	33,961	33,961
R. P. Powers	967	70,129	71,096
R. S. Rasmussen	0	4,208	4,208
O. G. Richard III	2,195	3,101	5,296
R. L. Sandor	1,092	46,891	47,983
B. X. Tierney	8,921	58,100	67,021
S. Martinez Tucker	1,532(e)	19,559	21,091
J. F. Turner	0	21,754	21,754
All directors, nominees and executive officers as a group (22 persons)	331,862(f)	532,714	864,576

(a) None of the shares is pledged. This column also includes share equivalents held in the AEP Retirement Savings Plan.
(b) This column includes amounts deferred in stock units and held under the Stock Unit Accumulation Plan for Non-Employee Directors and amounts deferred in share equivalents in the Retainer Deferral Plan for Non-Employee Directors. This column also includes amounts deferred in share equivalents held under AEP's Supplemental Retirement Savings Plan, AEP's Incentive Compensation Deferral Plan and the following numbers of AEP Career Shares: Mr. Akins, 94,885; Mr. Feinberg, 8,625; Mr. Powers, 47,665; Mr. Tierney, 16,948; and all directors and executive officers as a group, 220,608.
(c) This column does not include restricted stock units that will not vest within 60 days.
(d) Mr. Beasley was appointed as a director on February 25, 2014.
(e) Includes 32 shares held by family members of Ms. Tucker over which she disclaims beneficial ownership.
(f) As of February 26, 2014, the directors and executive officers as a group beneficially owned less than one percent of the outstanding shares of the Company's common stock.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires AEP's executive officers, directors and persons who beneficially own more than 10 percent of AEP's Common stock to file initial reports of ownership and reports of changes in ownership of AEP Common Stock with the SEC. Executive officers and directors are required by SEC regulations to furnish AEP with copies of all reports they file. Based solely on a review of the copies of such reports furnished to AEP and written representations from AEP's executive officers and directors during the fiscal year ended December 31, 2013, AEP believes that all of its directors and executive officers timely met all of their respective Section 16(a) filing requirements during 2013.

Share Ownership of Certain Beneficial Owners

Set forth below are the only persons or groups known to AEP as of February 15, 2014, with beneficial ownership of five percent or more of AEP Common Stock.

	AEP Shares	
Name and Address of Beneficial Owner	**Amount of Beneficial Ownership**	**Percent of Class**
BlackRock, Inc. 40 East 52nd Street New York, NY 10022	35,152,661(a)	7.2%
The Vanguard Group 100 Vanguard Boulevard Malvern, PA 19355	24,429,063(b)	5.0%

(a) Based on the Schedule 13G filed with the SEC, BlackRock, Inc. reported that it has sole power to vote 29,986,129 shares and sole dispositive power for 35,152,661 shares.

(b) Based on the Schedule 13G filed with the SEC, The Vanguard Group reported that it has sole voting power to vote 1,002,477 shares and sole dispositive power for 23,688,101 shares.

Shareholder Proposals and Nominations

To be included in AEP's proxy statement and form of proxy for the 2015 annual meeting of shareholders, any proposal which a shareholder intends to present at such meeting must be received by AEP, attention: Thomas G. Berkemeyer, Assistant Secretary, at AEP's office at 1 Riverside Plaza, Columbus, OH 43215 by November 12, 2014.

Notice to nominate a director must include your name, address, and number of shares you own; the name, age, business address, residence address and principal occupation of the nominee and the number of shares beneficially owned by the nominee. It must also include all the information required in AEP's Policy on Consideration of Candidates for Director Recommended by Shareholders. A copy of this Policy is posted on our website at *www.aep.com/investors/corporateleadersandgovernance*. All such notices must be received by AEP, attention: Thomas G. Berkemeyer, Assistant Secretary, at AEP's office at 1 Riverside Plaza, Columbus, OH 43215 by November 12, 2014. The Assistant Secretary will forward the recommendations to the Committee on Directors and Corporate Governance for consideration.

For any proposal intended to be presented by a shareholder without inclusion in AEP's proxy statement and form of proxy for the 2015 annual meeting, the proxies named in AEP's form of proxy for that meeting will be entitled to exercise discretionary authority on that proposal unless AEP receives notice of the matter by January 26, 2015. However, even if notice is timely received, the proxies may nevertheless be entitled to exercise discretionary authority on the matter to the extent permitted by SEC regulations.

Solicitation Expenses

These proxies are being solicited by our Board of Directors. The costs of this proxy solicitation will be paid by AEP. Proxies will be solicited principally by mail and the Internet, but some telephone or personal solicitations of holders of AEP Common Stock may be made. Any officers or employees of the AEP System who make or assist in such solicitations will receive no compensation, other than their regular salaries, for doing so. AEP will request brokers, banks and other custodians or fiduciaries holding shares in their names or in the names of nominees to forward copies of the proxy-soliciting materials to the beneficial owners of the shares held by them, and AEP will reimburse them for their expenses incurred in doing so at rates prescribed by the New York Stock Exchange. We have engaged Morrow & Co., LLC, 470 West Ave., Stamford, Connecticut 06902, to assist us with the solicitation of proxies for an estimated fee of $13,000, plus reasonable out-of-pocket expenses.

Exhibit A

Reconciliation of GAAP and Non-GAAP Financial Measures.

The Company reports its financial results in accordance with generally accepted accounting principles ("GAAP"). However, AEP's management believes that the Company's operating earnings provide users with additional meaningful financial information about the Company's performance. Management also uses these non-GAAP financial measures when communicating with stock analysts and investors regarding its earnings outlook and results. Non-GAAP financial measures should be viewed in addition to, and not as an alternative for, the Company's reported results prepared in accordance with GAAP.

For additional details regarding the reconciliation of GAAP and non-GAAP financial measures below, see the Company's Current Report on Form 8-K filed with the SEC on January 27, 2014.

	EPS
Operating Earnings	$ 3.23
Special Items	
Restructuring Program	(0.01)
Reversal of Storm Damage Deferral-Virginia	(0.04)
Muskingum River Plant Impairment	(0.20)
Big Sandy FGC Impairment	(0.04)
Adjustment to Impairments	(0.01)
Amos 3 Unit Regulatory Disallowance	(0.05)
UK Windfall Tax	0.16
GAAP Reported Earnings	$ 3.04

AMERICAN ELECTRIC POWER

1 Riverside Plaza
Columbus, OH 43215-2378

AMERICAN ELECTRIC POWER

IMPORTANT ANNUAL MEETING INFORMATION

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ENDORSEMENT_LINE______________ SACKPACK_____________

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DESIGNATION (IF ANY)
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Admission Ticket

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Electronic Voting Instructions

Available 24 hours a day, 7 days a week!

Instead of mailing your proxy, you may choose one of the voting methods outlined below to vote your proxy.

VALIDATION DETAILS ARE LOCATED BELOW IN THE TITLE BAR.

Proxies submitted by the Internet or telephone must be received by 1:00 a.m., Eastern Time, on April 22, 2014.

Vote by Internet

- Go to **www.envisionreports.com/AEP**
- Or scan the QR code with your smartphone
- Follow the steps outlined on the secure website

Vote by telephone

- Call toll free 1-800-652-VOTE (8683) within the USA, US territories & Canada on a touch tone telephone
- Follow the instructions provided by the recorded message

Using a **black ink** pen, mark your votes with an **X** as shown in this example.
Please do not write outside the designated areas.

☒

Annual Meeting Proxy Card

1234 5678 9012 345

▼ **IF YOU HAVE NOT VOTED VIA THE INTERNET OR TELEPHONE, FOLD ALONG THE PERFORATION, DETACH AND RETURN THE BOTTOM PORTION IN THE ENCLOSED ENVELOPE.** ▼

A Proposals — The Board of Directors recommends a vote FOR all the nominees listed and FOR Proposals 2 and 3.

1. Election of Directors:

Nominee	For	Against	Abstain	Nominee	For	Against	Abstain	Nominee	For	Against	Abstain
01 - Nicholas K. Akins	☐	☐	☐	02 - David J. Anderson	☐	☐	☐	03 - J. Barnie Beasley, Jr.	☐	☐	☐
04 - Ralph D. Crosby, Jr.	☐	☐	☐	05 - Linda A. Goodspeed	☐	☐	☐	06 - Thomas E. Hoaglin	☐	☐	☐
07 - Sandra Beach Lin	☐	☐	☐	08 - Richard C. Notebaert	☐	☐	☐	09 - Lionel L. Nowell III	☐	☐	☐
10 - Stephen S. Rasmussen	☐	☐	☐	11 - Oliver G. Richard III	☐	☐	☐	12 - Sara Martinez Tucker	☐	☐	☐

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Proposal	For	Against	Abstain
2. Ratification of the appointment of Deloitte & Touche LLP as the Company's independent registered public accounting firm for the fiscal year ending December 31, 2014.	☐	☐	☐
3. Advisory approval of the Company's executive compensation.	☐	☐	☐

B **Authorized Signatures — This section must be completed for your vote to be counted. — Date and Sign Below**

Please sign exactly as name(s) appears hereon. Joint owners should each sign. When signing as attorney, executor, administrator, corporate officer, trustee, guardian, or custodian, please give full title.

Date (mm/dd/yyyy) — Please print date below.	Signature 1 — Please keep signature within the box.	Signature 2 — Please keep signature within the box.
/ /		

IF VOTING BY MAIL, YOU MUST COMPLETE SECTIONS A AND B.

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MR A SAMPLE (THIS AREA IS SET UP TO ACCOMMODATE 140 CHARACTERS) MR A SAMPLE AND MR A SAMPLE AND MR A SAMPLE AND MR A SAMPLE AND MR A SAMPLE AND MR A SAMPLE AND MR A SAMPLE AND MR A SAMPLE AND

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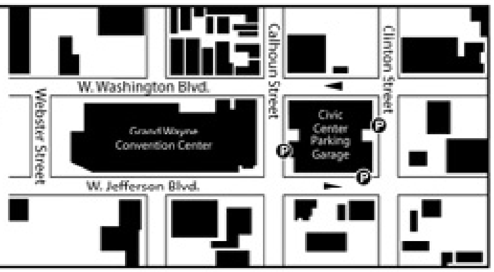
American Electric Power Company, Inc.
2014 Annual Meeting of Shareholders and Admission Ticket
Tuesday April 22, 2014, at 9:00 a.m. Eastern Time
Grand Wayne Convention Center
120 W. Jefferson Boulevard
Fort Wayne, Indiana

If you wish to attend and vote at the meeting, please bring this admission ticket and identification with you.

AGENDA

- **Introduction and Welcome**
- **Election of Directors**
- **Ratification of Auditors**
- **Advisory approval of the Company's executive compensation**
- **Chief Executive Officer's Report**
- **Comments and Questions from Shareholders**

Grand Wayne Convention Center is at 120 W. Jefferson Boulevard. Shareholders should park in the Civic Center Parking Garage, which is connected to the convention center and the adjacent Hilton Hotel. The garage can be accessed from Jefferson Boulevard, Clinton Street or Calhoun Street. The skywalk bridge to the convention center and hotel is on the third floor of the garage. You must pick up a parking stub to enter the garage. Exchanging the parking stub for a voucher at the registration desk outside the meeting room will allow you to exit the garage at no cost to you.



▼ IF YOU HAVE NOT VOTED VIA THE INTERNET OR TELEPHONE, FOLD ALONG THE PERFORATION, DETACH AND RETURN THE BOTTOM PORTION IN THE ENCLOSED ENVELOPE. ▼

AEP AMERICAN® ELECTRIC POWER

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Proxy — American Electric Power Company, Inc.

Proxy Solicited on behalf of the Board of Directors for the Annual Meeting to be held April 22, 2014

The shareholder signing on the reverse of this proxy card appoints Nicholas K. Akins and Brian X. Tierney, and each of them, acting by a majority if more than one be present, attorneys and proxies to the undersigned, with power of substitution, to represent the undersigned at the annual meeting of shareholders of American Electric Power Company, Inc. to be held on April 22, 2014, and at any adjournment thereof, and to vote all shares of Common Stock of the Company which the undersigned is entitled to vote on all matters coming before said meeting. If no direction is given, such shares will be voted in accordance with the recommendations of the Board of Directors and at the discretion of the proxy holders as to any other matters coming before the meeting.

Trustee's Authorization. The undersigned authorizes JP Morgan Chase Bank, National Association to vote all shares of Common Stock of the Company credited to the undersigned's account under the American Electric Power System retirement savings plan at the annual meeting in accordance with instructions on the reverse side.

You are encouraged to specify your choices by marking the appropriate boxes (SEE REVERSE SIDE), but you need not mark any boxes if you wish to vote in accordance with the Board of Directors' recommendations.

Nominees for:

01 - Nicholas K. Akins	02 - David J. Anderson	03 - J. Barnie Beasley, Jr.	04 - Ralph D. Crosby, Jr.	05 - Linda A. Goodspeed	06 - Thomas E. Hoaglin
07 - Sandra Beach Lin	08 - Richard C. Notebaert	09 - Lionel L. Nowell III	10 - Stephen S. Rasmussen	11 - Oliver G. Richard III	12 - Sara Martinez Tucker

C Non-Voting Items

Change of Address — Please print new address below.

Comments — Please print your comments below.

IF VOTING BY MAIL, YOU MUST COMPLETE SECTIONS A AND B ON THE OTHER SIDE OF THIS CARD.

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Appendix A to the
Proxy Statement

American Electric Power

2013 Annual Report

Audited Consolidated Financial Statements and
Management's Discussion and Analysis of Financial Condition and Results of Operations

AEP: America's Energy Partner®

CONTENTS	**AMERICAN ELECTRIC POWER** **1 Riverside Plaza** **Columbus, Ohio 43215-2373**

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEP West Companies	PSO, SWEPCo, TCC and TNC.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a nonregulated AEP subsidiary that acquired the generation assets and liabilities of OPCo.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
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.
BlueStar	BlueStar Energy Holdings, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
BOA	Bank of America Corporation.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.

Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
CWIP	Construction Work in Progress.

Term	Meaning
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC, DCC Fuel V LLC and DCC Fuel VI LLC, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
E&R	Environmental compliance and transmission and distribution system reliability.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ENEC	Expanded Net Energy Charge.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP and MidAmerican Energy Holdings Company Texas Transco, LLC 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.
kV	Kilovolt.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate transactions among members of the Interconnection Agreement.
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.

Term	Meaning
NSR	New Source Review.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PCA	Power Coordination Agreement among APCo, I&M and KPCo.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
POLR	Provider of Last Resort revenues.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, I&M, OPCo, PSO and SWEPCo.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
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, 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 enacted in 1999 to restructure the electric utility industry in Texas.

Legislation	
TNC	AEP Texas North Company, an AEP electric utility subsidiary.

Term	Meaning
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 law.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
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," 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 reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate, growth or contraction within and changes in market demand and demographic patterns in our service territory.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of retail competition, particularly in Ohio.
- Weather conditions, including storms and drought conditions, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- 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 (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- 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 or alternative sources of generation.
- Our ability to recover through rates or market prices any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas.

- Changes in utility regulation and the allocation of costs within regional transmission organizations, including PJM and SPP.
- The transition to market generation in Ohio, including the implementation of ESPs.
- Our ability to successfully and profitably manage our Ohio generation assets in a startup, nonregulated merchant business.
- 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 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.

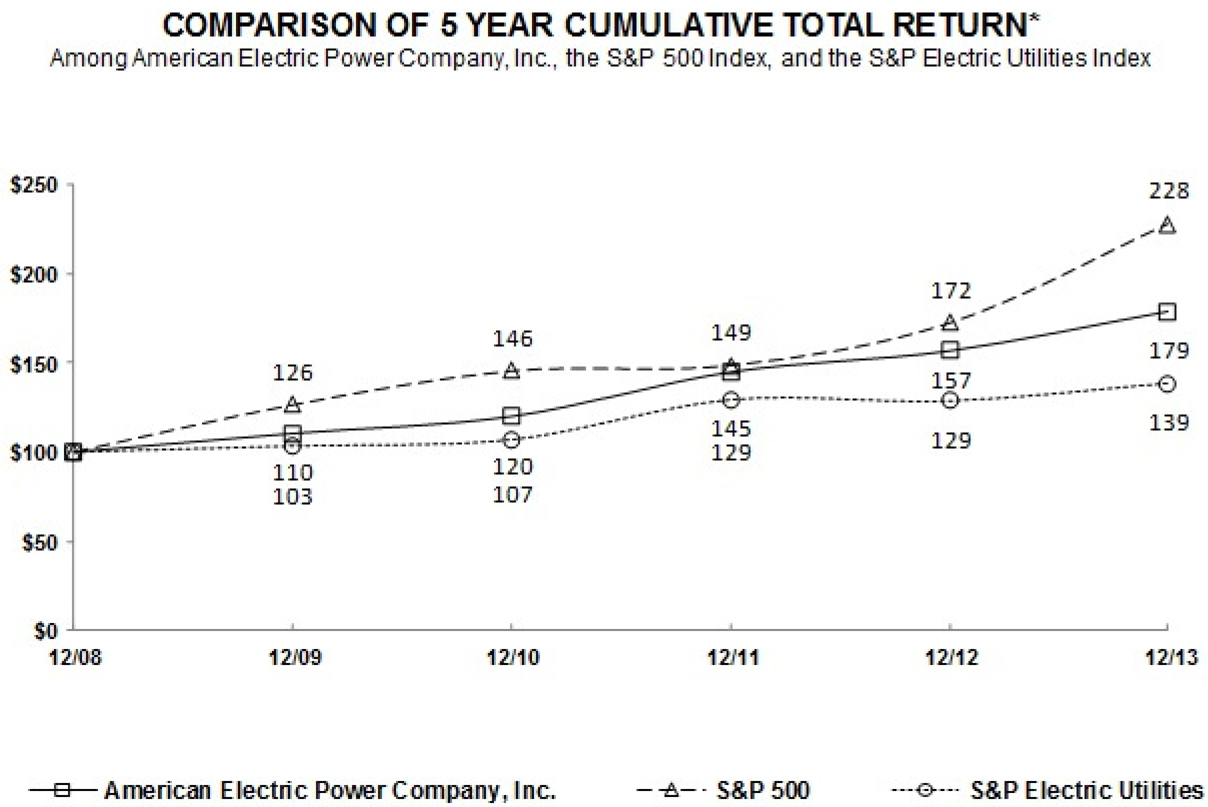
The forward looking statements of AEP and its Registrant Subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors,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

AEP COMMON STOCK AND DIVIDEND INFORMATION

The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Quarter-End Closing Price	Dividend
December 31, 2013	$ 48.40	$ 43.01	$ 46.74	$ 0.50
September 30, 2013	47.59	41.83	43.35	0.49
June 30, 2013	51.60	42.83	44.78	0.49
March 31, 2013	48.68	42.92	48.63	0.47
December 31, 2012	$ 45.41	$ 40.56	$ 42.68	$ 0.47
September 30, 2012	44.84	39.62	43.94	0.47
June 30, 2012	40.46	36.97	39.90	0.47
March 31, 2012	41.98	37.46	38.58	0.47

AEP common stock is traded principally on the New York Stock Exchange. As of December 31, 2013, AEP had approximately 78,000 registered shareholders.



*$100 invested on 12/31/08 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2013	2012	2011	2010	2009
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$ 15,357	$ 14,945	$ 15,116	$ 14,427	$ 13,489
Operating Income	$ 2,855	$ 2,656	$ 2,782	$ 2,663	$ 2,771
Income Before Extraordinary Items	$ 1,484	$ 1,262	$ 1,576	$ 1,218	$ 1,370
Extraordinary Items, Net of Tax	-	-	373	-	(5)
Net Income	1,484	1,262	1,949	1,218	1,365
Net Income Attributable to Noncontrolling Interests	4	3	3	4	5
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,480	1,259	1,946	1,214	1,360
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	-	5	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,480	$ 1,259	$ 1,941	$ 1,211	$ 1,357
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$ 60,285	$ 57,454	$ 55,670	$ 53,740	$ 51,684
Accumulated Depreciation and Amortization	19,288	18,691	18,699	18,066	17,340
Total Property, Plant and Equipment – Net	$ 40,997	$ 38,763	$ 36,971	$ 35,674	$ 34,344
Total Assets	$ 56,414	$ 54,367	$ 52,223	$ 50,455	$ 48,348
Total AEP Common Shareholders' Equity	$ 16,085	$ 15,237	$ 14,664	$ 13,622	$ 13,140
Noncontrolling Interests	$ 1	$ -	$ 1	$ -	$ -
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ -	$ -	$ -	$ 60	$ 61
Long-term Debt (a)	$ 18,377	$ 17,757	$ 16,516	$ 16,811	$ 17,498
Obligations Under Capital Leases (a)	$ 538	$ 449	$ 458	$ 474 (b)	$ 317
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					

Income Before Extraordinary Items	$ 3.04	$ 2.60	$ 3.25	$ 2.53	$ 2.97
Extraordinary Items, Net of Tax	-	-	0.77	-	(0.01)
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 3.04	$ 2.60	$ 4.02	$ 2.53	$ 2.96
Weighted Average Number of Basic Shares Outstanding (in millions)	487	485	482	479	459
Market Price Range:					
High	$ 51.60	$ 45.41	$ 41.71	$ 37.94	$ 36.51
Low	$ 41.83	$ 36.97	$ 33.09	$ 28.17	$ 24.00
Year-end Market Price	$ 46.74	$ 42.68	$ 41.31	$ 35.98	$ 34.79
Cash Dividends Declared per AEP Common Share	$ 1.95	$ 1.88	$ 1.85	$ 1.71	$ 1.64
Dividend Payout Ratio	64.14%	72.31%	46.02%	67.59%	55.41%
Book Value per AEP Common Share	$ 32.98	$ 31.35	$ 30.36	$ 28.32	$ 27.49

(a) Includes portion due within one year.

(b) Obligations Under Capital Leases increased primarily due to capital leases under new master lease agreements for property that was previously leased under operating leases.

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

EXECUTIVE OVERVIEW

Company Overview

American Electric Power Company, Inc. (AEP) is one of the largest investor-owned electric public utility holding companies in the United States. Our electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

Our subsidiaries operate an extensive portfolio of assets including:

- Approximately 37,600 megawatts of generating capacity, one of the largest complements of generation in the United States.
- More than 40,000 miles of transmission lines, including 2,110 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern United States.
- Approximately 222,000 miles of distribution lines that deliver electricity to 5.3 million customers.
- Substantial commodity transportation assets (more than 5,700 railcars, approximately 3,000 barges, 60 towboats, 25 harbor boats and a coal handling terminal with approximately 18 million tons of annual capacity). Our commercial barging operations annually transport approximately 37 million tons of coal and dry bulk commodities. Approximately 39% of the barging is for transportation of agricultural products, 26% for coal, 20% for steel and 15% for other commodities.

Corporate Separation

Background

On December 31, 2013, based on FERC and PUCO orders which approved corporate separation of generation assets and associated liabilities, OPCo transferred its generation assets and related generation liabilities at net book value to AGR. In accordance with Ohio law, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. Effective January 1, 2014, OPCo will purchase power from both affiliated and nonaffiliated entities, subject to PUCO approval, to meet the energy and capacity needs of customers.

On December 31, 2013, subsequent to the transfer of OPCo's generation assets and associated liabilities to AGR, AGR transferred at net book value its ownership (867 MW) in Amos Plant, Unit 3 to APCo. The transfer of these generation assets and associated liabilities was approved by the FERC, the Virginia SCC and the WVPSC.

On December 31, 2013, subsequent to the transfer of OPCo's generation assets and associated liabilities to AGR, AGR transferred at net book value a one-half interest (780 MW) in the Mitchell Plant to KPCo. The transfer of these generation assets and associated liabilities was approved by the FERC and the KPSC.

Other Impacts of Corporate Separation

In accordance with our December 2010 announcement and our October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

Effective January 1, 2014, the FERC approved the following:

- Power Coordination Agreement among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources.
- Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent to address open commitments related to the termination of the Interconnection Agreement and responsibilities to PJM.
- Power Supply Agreement between AGR and OPCo for AGR to supply capacity for OPCo's switched and non-switched retail load for the period January 1, 2014 through May 31, 2015 and to supply the energy needs of OPCo's non-switched retail load that is not acquired through auctions from January 1, 2014 through December 31, 2014.

For a further discussion of corporate separation, see the "Corporate Separation" section of Note 1 and the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters in Note 4.

Ohio Electric Security Plan Filings

2009 – 2011 ESP

In August 2012, the PUCO issued an order in a separate proceeding which implemented a Phase-In Recovery Rider (PIRR) to recover OPCo's deferred fuel costs in rates beginning September 2012. As of December 31, 2013, OPCo's net deferred fuel balance was $445 million, excluding unrecognized equity carrying costs. Decisions from the Supreme Court of Ohio are pending related to various appeals which, if ordered, could reduce OPCo's net deferred fuel costs balance.

June 2012 – May 2015 Ohio ESP Including Capacity Charge

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

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (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 RPM price is approximately $33/MW day through May 2014 and $148/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 Retail Stability Rider (RSR), effective September 2012. The RSR is being collected from customers at $3.50/MWh through May 2014 and will be collected at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In April and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order, including the RSR. As of December 31, 2013, OPCo's incurred deferred capacity costs balance was $288 million, including debt carrying costs.

In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. The modifications include the delay of the energy auctions that were originally ordered in the ESP order. OPCo must conduct an energy-only auction for 10% of the SSO load with delivery beginning April 2014 through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning November 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit. In December 2013, the PUCO granted applications for rehearing for further consideration filed by OPCo and intervenors. 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.

Proposed June 2015 – May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that includes proposed rate adjustments and the continuation and modification of certain existing riders effective June 2015 through May 2018. This filing is consistent with the PUCO's objective for a full transition from FAC and base generation rates to market. The proposal includes a recommended auction schedule, a return on common equity of 10.65% on capital costs for certain riders and estimates an average decrease in rates of 9% over the three-year term of the plan for customers who receive their RPM and energy auction-based generation through OPCo. Additionally, the application identifies OPCo's intention to submit a separate application to continue the RSR established in the June 2012 – May 2015 ESP in which the unrecovered portion of the deferred capacity costs will continue to be collected at the rate of $4.00/MWh until the balance of the capacity deferrals has been collected. Management intends to file this application in the first quarter of 2014.

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

Ohio Customer Choice

In our Ohio service territory, various CRES providers are targeting retail customers by offering alternative generation service. The reduction in gross margin as a result of customer switching in Ohio is partially offset by (a) collection of capacity revenues from CRES providers, (b) off-system sales, (c) deferral of unrecovered capacity costs, (d) RSR collections and (e) revenues from AEP Energy. AEP Energy is our CRES provider and part of our Generation & Marketing segment which targets retail customers, both within and outside of our retail service territory.

Customer Demand

In comparison to 2012, our weather-normalized retail sales decreased 1.6% for the year ended December 31, 2013. Our industrial sales declined 4.5% partially due to lower production levels at Ormet, a large aluminum company. Ormet had a contract to purchase power from OPCo through 2018. In October 2013, Ormet announced that it was unable to emerge from bankruptcy and shut down its operations effective immediately. The loss of Ormet's load will not have a material impact on future gross margin. Power previously sold to Ormet will be available to be sold into wholesale markets.

In 2014, we anticipate weather-normalized retail sales will decline by 1.1%. Excluding Ormet, total weather-normalized retail sales are projected to increase by 0.1% in 2014. The largest decline is projected to occur in the industrial class, principally due to Ormet's decision to shut down. Excluding Ormet, the industrial class is projected to grow by 1.2% in 2014, primarily related to a number of new oil and natural gas expansions, especially around the major shale gas areas within AEP's footprint. Weather-normalized residential sales are projected to decline by 0.9% in 2014, continuing the recent trend of declining use per customer related to higher saturations of energy efficient appliances and the promotion of utility sponsored energy efficiency programs. The commercial class energy sales are projected to remain flat compared to 2013.

PJM Capacity Auction

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

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

We formed a coalition with other utility companies to address mutual concerns related to the PJM capacity auction process, including: (a) import limits for power without firm transmission, (b) placing bidding caps on available demand response resources in comparison to base generation capacity, (c) modification and enforcement of the timing of demand response requirements to better reflect real-time capacity requirements and (d) tightened rules for incremental auctions in which speculative bidders sell resources in the base auction and buy back that capacity in an incremental auction, resulting in no additional capacity and lower market prices. PJM has made three FERC filings related to the first three issues. We anticipate that another filing will be made by PJM later in the first quarter of

2014 to address the fourth issue. In January 2014, FERC accepted without modification PJM's filed recommendations on placing bidding caps on certain demand response products that are available only during the summer period. We expect to receive FERC decisions on the other filings prior to the next RPM auction in May 2014.

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. As of December 31, 2013, SWEPCo's share of incurred construction expenditures for the Turk Plant was approximately $1.758 billion. As of December 31, 2013, a pretax provision of $59 million has been recorded for costs incurred in excess of a Texas cost cap, resulting in total net capitalized expenditures of $1.699 billion.

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. 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 Turk Plant output that is currently not subject to cost-based rate recovery and is being sold into the wholesale market. If SWEPCo cannot ultimately recover its investment and expenses related to the Turk Plant or transmission lines, it could reduce future net income and cash flows and impact financial condition. See the "Turk Plant" section of Note 4.

2012 Texas Base Rate Case

In December 2013, the PUCT issued an order granting rehearing and reversed its decision on consolidated tax savings increasing SWEPCo's annual revenues by $5 million. In January 2014, the PUCT determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result of these rulings, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. These rulings also increased SWEPCo's previously approved annual base rates by a total of $13 million. The resulting annual base rate increase is approximately $52 million. See the "Turk Plant" and the "2012 Texas Base Rate Case" sections of Note 4.

2012 Louisiana Formula Rate Filing

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

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 December 31, 2013, SWEPCo has incurred $32 million in costs related to these projects. SWEPCo will seek recovery of costs it incurs from these projects from its state commissions and FERC customers.

2011 Indiana Base Rate Case

In 2013, the IURC issued an order that granted a $92 million annual increase in base rates based upon a return on common equity of 10.2%. In March 2013, the Indiana Office of Utility Consumer Counselor (OUCC) filed an appeal of the orders with the Indiana Court of Appeals. In September 2013, the OUCC filed a brief on appeal that included objections to certain aspects of the rate case. If any part of the IURC order is overturned by the Indiana Court of Appeals, it could reduce future net income and cash flows. See the "2011 Indiana Base Rate Case" section of Note 4.

2014 Oklahoma Base Rate Case

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

Rockport Plant Clean Coal Technology Project (CCT Project)

In April 2013, I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit both units of the Rockport Plant with a dry sorbent injection system. The estimated cost in the application was $285 million, excluding AFUDC to be shared equally between I&M and AEGCo. In November 2013, the IURC approved a settlement agreement that included the approval of the CPCN with an updated estimated CCT Project cost of $258 million, excluding AFUDC, and the recovery of the Indiana jurisdictional share of I&M's ownership share. As of December 31, 2013, we have incurred costs of $109 million related to the CCT Project, including AFUDC. See the "Rockport Plant Clean Coal Technology Project (CCT Project)" section of Note 4.

Cook Plant Life Cycle Management Project (LCM Project)

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the LCM Project, which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life (2034 for Unit 1 and 2037 for Unit 2). The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. As of December 31, 2013, I&M has incurred costs of $380 million related to the LCM Project, including AFUDC.

In July 2013, the IURC approved I&M's proposed project with the exception of an estimated $23 million related to certain items which the IURC stated I&M could seek recovery of in a subsequent base rate case. I&M will recover approved costs through an LCM rider which will be determined in semi-annual proceedings. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in rates. In October 2013, I&M filed an application with the IURC for LCM rider rates effective January 2014. In December 2013, the IURC issued an interim order authorizing the implementation of LCM rider rates effective January 2014, subject to reconciliation upon the issuance of a final order by the IURC.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project and authorized deferral accounting for costs incurred related to the approved projects effective January 2013 until these costs are included in rates. In February 2013, intervenors filed appeals with the Michigan Court of Appeals objecting to the issuance of the CON.

If I&M is not ultimately permitted to recover its LCM Project costs, it could reduce future net income and cash flows and impact financial condition. See “Cook Plant Life Cycle Management Project (LCM Project)” section of Note 4.

Repositioning Efforts

In April 2012, we initiated a process to identify strategic repositioning opportunities and efficiencies that resulted in sustainable cost savings. This process included evaluations of our employee and retiree benefit programs as well as evaluations of the functional effectiveness and staffing levels of our finance and accounting, information technology, generation and supply chain and procurement organizations. While we have completed certain aspects of this program, our continuous improvement initiatives in generation, distribution, transmission, supply chain, procurement and the corporate center continues to yield cost savings for many of our subsidiaries, allowing us to direct many of these savings into infrastructure and other areas of our business.

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 and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

Rockport Plant Litigation

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

ENVIRONMENTAL ISSUES

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

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.

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 December 31, 2013, the AEP System had a total generating capacity of nearly 37,600 MWs, of which over 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 coal-fired generating facilities. Based upon our estimates, investment to meet these proposed requirements ranges from approximately $3 billion to $3.5 billion between 2013 and 2020. These amounts include investments to convert some of our coal generation to natural gas. If natural gas conversion is not completed, these units could be retired sooner than planned.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. The cost estimates will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans or federal implementation plans 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 nonregulated plants.

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

Company	Plant Name and Unit	Generating Capacity (in MWs)
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/AGR	Sporn Plant, Units 1-4	600
I&M	Tanners Creek Plant, Units 1-4	995
KPCo	Big Sandy Plant, Unit 2	800
AGR	Kammer Plant	630
AGR	Muskingum River Plant, Units 1-5	1,440
AGR	Picway Plant	100
PSO	Northeastern Station, Unit 4	470
SWEPCo	Welsh Plant, Unit 2	528
Total		6,533

As of December 31, 2013, 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 other plants in the table above was $1 billion. See Note 5 for further discussion.

In 2013, we re-evaluated potential courses of action with respect to the planned operation of Muskingum River Plant, Unit 5 and concluded that completion of a refueling project which would extend the unit's useful life is remote. As a result, in 2013, we completed an impairment analysis and recorded a $154 million pretax ($99 million, net of tax) impairment charge for AGR's net book value of Muskingum River Plant, Unit 5. We expect to retire the plant no later than 2015. See "Muskingum River Plant, Unit 5" section of Note 7.

In addition, we are in the process of obtaining permits and other necessary regulatory approvals for either the conversion of some of our coal units to natural gas or installing emission control equipment on certain units. The following table lists the plants or units that are either awaiting regulatory approval or are still being evaluated by management based on changes in emission requirements and demand for power:

Company	Plant Name and Unit	Generating Capacity (in MWs)
KPCo	Big Sandy Plant, Unit 1	278
PSO	Northeastern Station, Unit 3	470
Total		748

As of December 31, 2013, the net book value before cost of removal, including related material and supplies inventory and CWIP balances, of the plants in the table above was $295 million.

Volatility in natural gas prices, pending environmental rules and other market factors could also have an adverse impact on the accounting evaluation of the recoverability of the net book values of coal-fired units. For regulated plants that 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.

Modification of the NSR Litigation Consent Decree

In 2007, the U.S. District Court for the Southern District of Ohio approved a consent decree between the AEP subsidiaries in the eastern area of the AEP System and the Department of Justice, the Federal EPA, eight northeastern states and other interested parties to settle claims that the AEP subsidiaries violated the NSR provisions of the CAA when it undertook various equipment repair and replacement projects over a period of nearly 20 years. The consent decree's terms include installation of environmental control equipment on certain generating units, a declining cap on SO_2 and NO_x emissions from the AEP System and various mitigation projects.

The original consent decree required certain types of control equipment to be installed at Muskingum River Plant, Unit 5, Big Sandy Plant, Unit 2 and the two units of the Rockport Plant in 2015, 2017 and 2019, respectively. In January 2013, an agreement to modify the consent decree was reached and filed with the court. The terms of the agreement include more options for the affected units (including alternative control technologies, re-fueling and/or retirement), more stringent SO_2 emission caps for the AEP System and additional mitigation measures. The modified consent decree was approved by the court in May 2013. For the units of the Rockport Plant, the modified decree requires installation of dry sorbent injection technology for SO_2 control on both units in 2015. In addition, the consent decree imposes a declining plant-wide cap on SO_2 emissions beginning in 2016.

Oklahoma Environmental Compliance Plan

In September 2012, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES), Unit 4 in 2016 and additional environmental controls on NES, Unit 3 to continue operations through 2026. As of December 31, 2013, the net book values of NES, Units 3 and 4 were $208 million and $106 million, respectively, before cost of removal, including materials and supplies inventory and CWIP. In August 2013, the OCC dismissed PSO's environmental compliance plan case without prejudice but will permit PSO to seek recovery in a future proceeding. PSO will address the environmental compliance plan issues in future regulatory proceedings when it seeks cost recovery of the plan. If PSO is ultimately not permitted to fully recover its net book value of NES, Units 3 and 4 and other environmental compliance costs, it could 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. In 2008, the District of Columbia Circuit Court of Appeals issued a decision remanding CAIR to the Federal EPA. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) (discussed in detail below) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. The U.S. Court of Appeals for the District of Columbia Circuit issued an order in December 2011 staying the effective date of the rule pending judicial review. In 2012, a panel of the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. That decision has been appealed to the U.S. Supreme Court. Nearly all of the states in which our power plants are located are covered by CAIR.

The Federal EPA issued the final maximum achievable control technology (MACT) standards for coal and oil-fired power plants (discussed in detail below) in 2012.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual state implementation plans (SIPs) or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas. The Arkansas SIP was disapproved and the state is developing a revised submittal. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the U.S. Court of Appeals for the District of Columbia Circuit and its fate is uncertain given developments in the CSAPR litigation.

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

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

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

Cross-State Air Pollution Rule (CSAPR)

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

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. Several of the petitioners filed motions to stay the implementation of the rule pending judicial review. In 2011, the court granted the motions for stay. In 2012, the panel issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the Clean Air Interstate Rule until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to "overcontrol" emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. The Federal EPA and other respondents filed petitions for rehearing but in January 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied all petitions for rehearing. The petition for further review filed by the Federal EPA and other parties in the U.S. Supreme Court was granted in June 2013. Separate appeals of the supplemental rule, the Error Corrections Rule and the further revisions have been filed, but are being held in abeyance.

The time frames and stringency of the required emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and our electric utility customers. We cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metal) and hydrogen chloride (as a surrogate for acid gases) for units burning coal on a site-wide 30-day rolling average basis. In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. The effective date of the final rule was April 16, 2012 and compliance is required within three years. We are participating through various organizations in the petitions for administrative reconsideration and judicial review that have been filed. In 2012, the Federal EPA published a notice announcing that it would accept comments on its reconsideration of certain issues related to the new source standards, including clarification of the requirements that apply during periods of start-up and shut down, measurement issues and the application of variability factors that may have an impact on the level of the standards. The Federal EPA issued revisions to the new source standards consistent with the proposed rule, except the start-up and shut down provisions in March 2013. The Federal EPA is still considering additional changes to the start-up and shut down provisions.

The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and allows operators to exclude periods of start-up and shut down from the emissions averaging periods. The compliance time frame remains a serious concern. A one-year administrative extension may be available if the extension is necessary for 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 are concerned about the availability of compliance extensions and the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines. We are participating in petitions for review filed in the U.S. Court of Appeals for the District of Columbia Circuit by several organizations of which we are members. Certain issues related to the standards for new coal-fired units have been severed from the main case and are being held in abeyance pending completion of the Federal EPA's reconsideration proceeding. The case is briefed and argued, and remains pending before the court.

Regional Haze

In 2011, the Federal EPA proposed to approve in part and disapprove in part the regional haze SIP submitted by the State of Oklahoma through the Department of Environmental Quality. The Federal EPA proposed to approve all of the NO_x control measures in the SIP and disapprove the SO_2 control measures for six electric generating units, including two units owned by PSO. The Federal EPA finalized a FIP that would require these units to install technology capable of reducing SO_2 emissions to 0.06 pounds per million British thermal units within five years of the effective date of the FIP. PSO filed a petition for review of the FIP in the Tenth Circuit Court of Appeals and engaged in settlement discussions with the Federal EPA, the State of Oklahoma and other parties. In November 2012, we notified the court that the parties had reached agreement on a settlement that would provide for submission of a revised Regional Haze SIP requiring the retirement of one coal-fired unit of PSO's Northeastern Station no later than 2016, installation of emission controls on the second coal-fired Northeastern unit in 2016 and retirement of the second unit no later than 2026. The Tenth Circuit Court of Appeals is holding the appeal in abeyance pending implementation of the settlement. A revised regional haze SIP was adopted by the State of Oklahoma and the Federal EPA approved the revised SIP in February 2014. Upon publication of the final approval and withdrawal of the FIP, the Tenth Circuit proceeding will be dismissed.

CO_2 Regulation

In March 2012, the Federal EPA issued a proposal to regulate CO_2 emissions from new fossil fuel-fired electricity generating units. The proposed rule establishes a new source performance standard of 1,000 pounds of CO_2 per megawatt hour of electricity generated, a rate that most natural gas combined cycle units can meet, but that is substantially below the emission rate of a new pulverized coal generator or an integrated gas combined cycle unit that uses coal for fuel. As proposed, the rule does not apply to new gas-fired stationary combustion turbines used as peaking units, does not apply to existing, modified or reconstructed sources and does not apply to units whose CO_2 emission rate increases as a result of the addition of pollution control equipment to control criteria pollutant emissions or HAPs. The rule is not anticipated to have a significant immediate impact on the AEP System since it does not apply to existing units or units that have already commenced construction. New source performance standards affect units that have not yet received permits. The proposed standards were challenged in the U.S. Court of Appeals for the District of Columbia Circuit. That case was dismissed because the court determined that no final agency action had yet been taken.

In June 2013, 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 in September 2013. The new proposal was issued in September 2013 and requires new large natural gas units to meet 1,000 pounds of CO_2 per MWh of electricity generated and small natural gas units to meet 1,100 pounds of CO_2 per MWh. New coal-fired units are required to meet the 1,100 pounds of CO_2 per MWh limit, with the option to meet the tighter limits if they choose to average emissions over multiple years. This proposal was published in the Federal Register in January 2014 and the March 2012 proposal has been withdrawn.

The Federal EPA was also directed to develop and issue a separate proposal regulating carbon emissions from existing, modified and reconstructed electric generating units before June 2014, to finalize those standards by June 2015 and to require states to submit revisions to their implementation plans including such standards no later than June 2016. The President directed the Federal EPA, in developing this proposal, to directly engage states, leaders in the power sector, labor leaders and other stakeholders, to tailor the regulations to reduce costs, to develop market-based instruments and allow regulatory flexibilities and "assure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power." 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 June 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. A petition for rehearing was filed which the court denied in December 2012. The U.S. Supreme Court granted several petitions for review and will determine whether the Federal EPA made a reasonable determination that adoption of the motor vehicle standards trigger PSD and Title V permitting obligations for stationary sources. A decision is expected by June 2014.

The Federal EPA also finalized a rule in June 2012 that retains the current thresholds for permitting stationary sources under the PSD and Title V operating permit programs at 100,000 tons per year for new sources and 75,000 tons per year for modified sources. The Federal EPA also confirmed that it will re-evaluate these thresholds during its five-year review in 2016. Our generating units are large sources of CO_2 emissions and we will continue to evaluate the permitting obligations in light of these thresholds.

Coal Combustion Residual Rule

In 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at coal-fired electric generating units. The rule contains two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the 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 would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule. In 2011, the Federal EPA issued a notice of data availability requesting comments on a number of technical reports and other data received during the comment period for the original proposal and requesting comments on potential modeling analyses to update its risk assessment. In 2013, the Federal EPA also issued a notice of data availability requesting comments on a narrow set of items.

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

In February 2014, the Federal EPA completed an evaluation of the beneficial uses of coal fly ash in concrete and wallboard and concluded that the Federal EPA supports these beneficial uses. Currently, approximately 40% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, we currently use surface impoundments and landfills to manage these materials at our generating facilities and will incur significant costs to upgrade or close and replace these existing facilities under the proposed solid waste management alternative. Regulation of these materials as hazardous wastes would significantly increase these costs. As the rule is not final, we are unable to determine a range of potential costs that are reasonably possible of occurring but expect the costs to be significant.

Clean Water Act Regulations

In 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The proposed standards affect all plants withdrawing more than two million gallons of cooling water per day and establish specific intake design and intake velocity standards meant to allow fish to avoid or escape impingement. Compliance with this standard is required within eight years of the effective date of the final rule. The proposed standard for entrainment for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. The proposed entrainment standard for new units at existing facilities requires either intake flows commensurate with closed cycle cooling or achieving entrainment reductions equivalent to 90% or greater of the reductions that could be achieved with closed cycle cooling. Plants withdrawing more than 125 million gallons of cooling water per day must submit a detailed technology study to be reviewed by the state permitting authority. We are evaluating the proposal and engaged in the collection of additional information regarding the feasibility of implementing this proposal at our facilities. In June 2012, the Federal EPA issued additional Notices of Data Availability and requested public comments. We submitted comments in July 2012. Issuance of a final rule is expected in 2014. We are preparing to begin activities to implement the rule following its issuance and an analysis of the final requirements.

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 2014. 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.

Climate Change

National public policy makers and regulators in the 11 states we serve have diverse views on climate change. We are currently focused on responding to these emerging views with prudent actions, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies and evaluating our assets across a range of plausible scenarios and outcomes. We are also active participants in a variety of public policy discussions at state and federal levels to assure that proposed new requirements are feasible and the economies of the states we serve are not placed at a competitive disadvantage.

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

Several states have adopted programs that directly regulate CO_2 emissions from power plants. The majority of the states where we have generating facilities have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. We are taking steps to comply with these requirements. In order to meet these requirements and as a key part of our corporate sustainability effort, we pledged to increase our wind power.

We have taken measurable, voluntary actions to reduce and offset our CO_2 emissions. We estimate that our 2013 emissions were approximately 115 million metric tons. This represents a reduction of 21% compared to our 2005 CO_2 emissions of approximately 145 million metric tons.

Future 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. Public perception may ultimately have a significant impact on future legislation and regulation that could adversely affect our ability to recover our investments in coal-fired plants.

Climate change and its resultant impact on weather patterns could modify our customers' power usage. Our customers' energy needs currently vary with weather conditions and the economy. Increased or decreased energy usage could require the acquisition or construction of more generation and transmission assets or cause early retirement of such assets. The timing and duration of extreme weather conditions may require more system backup and contribute to increased system stresses, including service interruptions and increased storm restoration costs. Extreme weather conditions that create high energy demand could raise electricity prices, which could increase the cost of energy we provide to our customers and could provide opportunity for increased wholesale sales and higher margins.

To the extent climate change affects a region's economic health, it could also affect our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods, has an impact on the economic health of our communities. The cost of additional regulatory requirements would normally be borne by consumers through higher prices for energy and purchased goods.

RESULTS OF OPERATIONS

SEGMENTS

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

During the fourth quarter of 2013, we realigned our business segments as a result of corporate separation and plant transfers. We retrospectively adjusted 2012 and 2011 segment information to reflect our new business segments. See the “Corporate Separation” section of Executive Overview.

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
- OPCo purchases energy and capacity to serve remaining generation service customers.

Generation & Marketing

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

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.

AEP River Operations

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

The table below presents Income Before Extraordinary Item by segment for the years ended December 31, 2013, 2012 and 2011.

	Years Ended December 31, 2013	2012	2011
		(in millions)	
Vertically Integrated Utilities	$ 681	$ 803	$ 710

Transmission and Distribution Utilities	358	389	404
Generation & Marketing	228	100	439
AEP Transmission Holdco	80	43	30
AEP River Operations	12	15	45
Corporate and Other (a)	125	(88)	(52)
Income Before Extraordinary Item	$ 1,484	$ 1,262	$ 1,576

(a) While not considered a reportable segment, Corporate and Other primarily includes management and professional services to AEP provided at cost to AEP subsidiaries and 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

2013 Compared to 2012

Income Before Extraordinary Item increased from $1,262 million in 2012 to $1,484 million in 2013 primarily due to:

- Successful rate proceedings in our various jurisdictions.
- 2012 impairments of certain Ohio generation plants.
- A decrease in Ohio depreciation expense due to impairments of certain Ohio generation plants.
- A favorable U.K. Windfall Tax decision by the U.S. Supreme Court in 2013.

These increases were partially offset by:

- Impairments during 2013 for the following:
  - Muskingum River Plant, Unit 5.
  - A write-off from a disallowance of a portion of Amos Plant, Unit 3 pursuant to a Virginia SCC order.
  - A decision from the KPSC disallowing scrubber costs on KPCo's Big Sandy Plant.
- The loss of retail generation customers in Ohio to various CRES providers.
- 2012 reversal of a 2011 recorded obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of OPCo's modified stipulation.

2012 Compared to 2011

Income Before Extraordinary Item decreased from $1,576 million in 2011 to $1,262 million in 2012 primarily due to:

- A decrease in carrying costs income due to the recognition in 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- 2012 impairments of certain Ohio generation plants.
- The loss of retail generation customers in Ohio to various CRES providers.
- A decrease in weather-related usage.
- The elimination of POLR charges, effective June 2011, partially offset by the 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.
- Expenses associated with the early retirement of Parent debt in 2012.
- Expenses related to the 2012 sustainable cost reductions.
- The 2012 adjustment of a U.K. Windfall Tax provision as a result of a related Supreme Court case.

These decreases were partially offset by:

- Successful rate proceedings in our various jurisdictions.
- Lower spending in 2012 as a result of our cost containment efforts.
- A 2011 recording and subsequent 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of OPCo's modified stipulation.

- The 2011 plant impairments for Sporn Plant, Unit 5 and for the FGD project at Muskingum River Plant, Unit 5.
- The 2011 write-off related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision.
- A loss incurred in 2011 related to a settlement of litigation with BOA and Enron.

Our results of operations are discussed below by operating segment.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Years Ended December 31, 2013	2012	2011
	(in millions)		
Revenues	$ 9,992	$ 9,418	$ 9,702
Fuel and Purchased Electricity	4,770	4,408	4,870
Gross Margin	5,222	5,010	4,832
Other Operation and Maintenance	2,276	2,219	2,237
Asset Impairments and Other Related Charges	72	13	49
Depreciation and Amortization	941	873	785
Taxes Other Than Income Taxes	372	344	339
Operating Income	1,561	1,561	1,422
Interest and Investment Income	7	5	13
Carrying Costs Income	14	28	17
Allowance for Equity Funds Used During Construction	35	72	82
Interest Expense	(540)	(520)	(514)
Income Before Income Tax Expense and Equity Earnings	1,077	1,146	1,020
Income Tax Expense	398	345	312
Equity Earnings of Unconsolidated Subsidiaries	2	2	2
Income Before Extraordinary Item	$ 681	$ 803	$ 710

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Years Ended December 31, 2013	2012	2011
	(in millions of KWhs)		
Retail:			
Residential	33,851	33,199	35,135
Commercial	25,037	25,278	25,651
Industrial	34,216	34,692	34,333
Miscellaneous	2,284	2,356	2,349
Total Retail	95,388	95,525	97,468
Wholesale	31,919	28,671	28,290
Total KWhs	127,307	124,196	125,758

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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Years Ended December 31,		
	2013	**2012**	**2011**
		(in degree days)	
Eastern Region			
Actual - Heating (a)	2,949	2,216	2,566
Normal - Heating (b)	2,734	2,774	2,772
Actual - Cooling (c)	1,040	1,253	1,280
Normal - Cooling (b)	1,080	1,079	1,066
Western Region			
Actual - Heating (a)	1,772	1,070	1,582
Normal - Heating (b)	1,501	1,537	1,534
Actual - Cooling (c)	2,163	2,635	2,830
Normal - Cooling (b)	2,202	2,186	2,165

(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.

2013 Compared to 2012

Reconciliation of Year Ended December 31, 2012 to Year Ended December 31, 2013
Income from Vertically Integrated Utilities Before Extraordinary Item
(in millions)

Year Ended December 31, 2012	$	803
Changes in Gross Margin:		
Retail Margins		196
Off-system Sales		(26)
Transmission Revenues		41
Other Revenues		1
Total Change in Gross Margin		212
Changes in Expenses and Other:		
Other Operation and Maintenance		(57)
Asset Impairments and Other Related Charges		(59)
Depreciation and Amortization		(68)
Taxes Other Than Income Taxes		(28)
Interest and Investment Income		2
Carrying Costs Income		(14)
Allowance for Equity Funds Used During Construction		(37)
Interest Expense		(20)
Total Change in Expenses and Other		(281)
Income Tax Expense		(53)
Year Ended December 31, 2013	$	681

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 $196 million primarily due to the following:
  - Successful rate proceedings in our service territories, which include:
    - A $153 million rate increase for SWEPCo.
    - A $112 million rate increase for I&M.
    - A $9 million rate increase for APCo.

      For the rate increases described above, $42 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $29 million increase in weather-related usage in our eastern and western regions primarily due to increases of 33% and 66%, respectively, in heating degree days partially offset by decreases in our eastern and western regions of 17% and 18%, respectively, in cooling degree days.

  These increases were partially offset by:
  - A $15 million decrease in SWEPCo's municipal and cooperative revenues primarily due to lower realizations from changes in sales volume mix.
  - A $23 million decrease due to lower weather normalized retail sales.
  - A $12 million increase in other variable electric generation expenses.

- A $9 million deferral of APCo's additional wind purchase costs in 2012 as a result of the June 2012 Virginia SCC fuel factor order.
- A $9 million decrease due to adjustments for previously disallowed environmental costs by the November 2011 Virginia SCC order subsequently determined in 2012 to be appropriate for recovery by the Supreme Court of Virginia.

- **Margins from Off-system Sales** decreased $26 million primarily due to lower PJM capacity revenue, reduced trading and marketing margins, partially offset by higher prices and volumes.
- **Transmission Revenues** increased $41 million primarily due to increased investment in the PJM and SPP regions. These increased revenues are offset-in-part in Other Operation and Maintenance expenses below.

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

- **Other Operation and Maintenance** expenses increased $57 million primarily due to the following:
  - A $33 million increase in recoverable PJM and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers.
  - A $30 million write-off in 2013 of previously deferred 2012 Virginia storm costs resulting from the 2013 enactment of a Virginia law.
  - A $22 million increase in storm-related expenses primarily in APCo's service territory.
  - A $21 million increase in plant outage expenses.

  These increases were partially offset by:
  - A $26 million decrease due to expenses related to the 2012 sustainable cost reductions.
  - A $25 million decrease due to an agreement reached to settle an insurance claim in 2013.
- **Asset Impairments and Other Related Charges** increased $59 million primarily due to the following:
  - A $39 million increase due to APCo's 2013 write-off from a regulatory disallowance of a portion of Amos Plant, Unit 3 pursuant to a Virginia SCC order approving the transfer of Amos Plant, Unit 3.
  - A $33 million increase due to KPCo's 2013 write-off of scrubber costs on the Big Sandy Plant and other generation costs in accordance with a KPSC's October 2013 order.

  These increases were partially offset by:
  - A 2012 write-off of an additional $13 million related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap.
- **Depreciation and Amortization** expenses increased $68 million primarily due to the following:
  - A $40 million increase due to the Turk Plant being placed in service in December 2012.
  - A $26 million increase due to higher depreciable base and higher depreciation rates reflecting a change in Tanners Creek Plant's estimated life approved by the MPSC effective April 2012 and by the IURC effective March 2013. The majority of the increase in depreciation for Tanners Creek Plant's life is offset within Gross Margin.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - A $13 million decrease in amortization as a result of the cessation of the Virginia Environmental and Reliability surcharge and the Virginia Environmental Rate Adjustment Clause in January 2013 and March 2013, respectively.
- **Taxes Other Than Income Taxes** increased $28 million primarily due to increased property taxes as a result of increased capital investments.
- **Carrying Costs Income** decreased $14 million primarily due to an increased recovery of Virginia environmental costs in new base rates as approved by the Virginia SCC in late January 2012 and decreased carrying charges related to the Dresden Plant.
- **Allowance for Equity Funds Used During Construction** decreased $37 million primarily due to completed construction of the Turk Plant in December 2012.
- **Interest Expense** increased $20 million primarily due to a decrease in the debt component of AFUDC due to completed construction of the Turk Plant in December 2012 partially offset by lower average outstanding long-term debt balances and an increase in the debt component of AFUDC related to projects at the Cook Plant.
- **Income Tax Expense** increased $53 million primarily due to the recording of federal and state income tax adjustments and other book/tax differences which are accounted for on a flow-through basis, offset-in-part by a decrease in pretax book income.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Income from Vertically Integrated Utilities Before Extraordinary Item
(in millions)

Year Ended December 31, 2011	$ 710
Changes in Gross Margin:	
Retail Margins	181
Off-system Sales	(13)
Transmission Revenues	19
Other Revenues	(9)
Total Change in Gross Margin	178
Changes in Expenses and Other:	
Other Operation and Maintenance	18
Asset Impairments and Other Related Charges	36
Depreciation and Amortization	(88)
Taxes Other Than Income Taxes	(5)
Interest and Investment Income	(8)
Carrying Costs Income	11
Allowance for Equity Funds Used During Construction	(10)
Interest Expense	(6)
Total Change in Expenses and Other	(52)
Income Tax Expense	(33)
Year Ended December 31, 2012	$ 803

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 $181 million primarily due to the following:
  - A $130 million increase due to lower capacity settlement expenses under the Interconnection Agreement, net of recovery in West Virginia and environmental deferrals in Virginia. This increase was primarily a result of a mild winter in 2012 and its impact on APCo's winter peak, APCo's completion of the Dresden Plant in January 2012 and the removal of Sport Plant, Unit 5 from the Interconnection Agreement in September 2011.
  - Successful rate proceedings in our service territories which include:
    - An $87 million rate increase for APCo.
    - A $17 million rate increase for I&M.
    - A $13 million rate increase for PSO.
    - An $11 million rate increase for WPCo.

      For the rate increases described above, $99 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $24 million write-off in 2011 related to APCo's disallowance of certain Virginia environmental costs

incurred in 2009 and 2010 as a result of a November 2011 Virginia SCC order.

- A $9 million deferral of APCo's additional wind purchase costs in 2012 as a result of a June 2012 Virginia SCC fuel factor order.
- A $9 million increase due to adjustments for previously disallowed environmental costs by the November 2011 Virginia SCC order subsequently determined in 2012 to be appropriate for recovery by the Supreme Court of Virginia.

These increases were partially offset by:

- A $71 million decrease in weather-related usage in our eastern and western regions primarily due to decreases of 14% and 32%, respectively, in heating degree days and a 7% decrease in cooling degree days in our western region.

- **Margins from Off-system Sales** decreased $13 million primarily due to lower PJM capacity revenue, reduced trading and marketing margins and lower power prices.
- **Transmission Revenues** increased $19 million primarily due to increased investment in the PJM region. These increased revenues are offset-in-part in Other Operation and Maintenance expenses below.
- **Other Revenues** decreased $9 million primarily due to a decrease in miscellaneous sales partially offset by a 2011 unfavorable provision for refund of outage insurance proceeds.

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

- **Other Operation and Maintenance** expenses decreased $18 million primarily due to the following:
  - A $46 million decrease in plant outage and other plant operating and maintenance expenses.
  - A $41 million decrease due to the 2011 write-off of a portion of the West Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC.
  - A $13 million decrease due to APCo's deferral of transmission costs for the Virginia Transmission Rate Adjustment Clause as allowed by the Virginia SCC recovered dollar-for-dollar within Gross Margin.

  These decreases were partially offset by:
  - A $33 million increase due to the 2011 deferral of 2009 storm costs and the 2010 cost reduction initiatives as allowed by the WVPSC.
  - A $27 million increase due to the favorable 2011 asset retirement obligation adjustment for APCo related to the early closure and previous write-off of the Mountaineer Carbon Capture and Storage Product Validation Facility.
  - A $26 million increase due to expenses related to the 2012 sustainable cost reductions.
- **Asset Impairments and Other Related Charges** decreased $36 million due to the 2011 write-off of $49 million related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of a November 2011 Texas Court of Appeals decision. This was partially offset by the 2012 write-off of an additional $13 million related to SWEPCo's Texas capital cost cap.
- **Depreciation and Amortization** expenses increased $88 million primarily due to the following:
  - A $48 million combined increase in depreciation for APCo and I&M primarily due to increases in depreciation rates effective February 2012 (Virginia) and April 2012 (Michigan), respectively. The majority of this increase in depreciation is offset within Gross Margin.
  - An $18 million increase in amortization primarily as a result of the Virginia Environmental Rate Adjustment Clause and the Virginia E&R surcharge, both effective February 2012. This increase in amortization is offset within Gross Margin.
  - Overall higher depreciable property balances.
- **Carrying Costs Income** increased $11 million due to adjustments for disallowed environmental costs as approved in a November 2011 Virginia SCC order and 2012 adjustments for certain costs subsequently determined by the Supreme Court of Virginia to be appropriate for recovery.
- **Allowance for Equity Funds Used During Construction** decreased $10 million primarily due to the completion of APCo's Dresden Plant in January 2012 and I&M's nuclear fuel preparation for usage, partially offset by increases related to SWEPCo's construction of the Turk Plant.
- **Income Tax Expense** increased $33 million primarily due to an increase in pretax book income offset-in-part by the recording of federal and state income tax adjustments.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Years Ended December 31, 2013	2012	2011
	(in millions)		
Revenues	$ 4,478	$ 4,819	$ 5,156
Purchased Electricity	1,627	2,072	2,711
Gross Margin	2,851	2,747	2,445
Other Operation and Maintenance	1,003	911	954
Depreciation and Amortization	591	561	549
Taxes Other Than Income Taxes	435	428	417
Operating Income	822	847	525
Interest and Investment Income	2	4	7
Carrying Costs Income	16	24	375
Allowance for Equity Funds Used During Construction	8	6	9
Interest Expense	(292)	(291)	(293)
Income Before Income Tax Expense	556	590	623
Income Tax Expense	198	201	219
Income Before Extraordinary Item	$ 358	$ 389	$ 404

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Years Ended December 31, 2013	2012	2011
	(in millions of KWhs)		
Retail:			
Residential	25,531	25,581	26,520
Commercial	24,631	24,746	25,116
Industrial	22,668	24,902	25,334
Miscellaneous	710	716	751
Total Retail (a)	73,540	75,945	77,721
Wholesale	8	8	8
Total KWhs	73,548	75,953	77,729

(a) Represents energy delivered to distribution customers.

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

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

	Years Ended December 31,		
	2013	**2012**	**2011**
		(in degree days)	
Eastern Region			
Actual - Heating (a)	3,383	2,610	3,107
Normal - Heating (b)	3,229	3,276	3,266
Actual - Cooling (c)	1,029	1,248	1,112
Normal - Cooling (b)	954	948	936
Western Region			
Actual - Heating (a)	368	177	394
Normal - Heating (b)	337	352	351
Actual - Cooling (d)	2,737	3,100	3,242
Normal - Cooling (b)	2,608	2,584	2,557

(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.

2013 Compared to 2012

Reconciliation of Year Ended December 31, 2012 to Year Ended December 31, 2013
Income from Transmission and Distribution Utilities Before Extraordinary Item
(in millions)

Year Ended December 31, 2012	$	389
Changes in Gross Margin:		
Retail Margins		55
Off-System Sales		1
Transmission Revenues		46
Other Revenues		2
Total Change in Gross Margin		104
Changes in Expenses and Other:		
Other Operation and Maintenance		(92)
Depreciation and Amortization		(30)
Taxes Other Than Income Taxes		(7)
Interest and Investment Income		(2)
Carrying Costs Income		(8)
Allowance for Equity Funds Used During Construction		2
Interest Expense		(1)
Total Change in Expenses and Other		(138)
Income Tax Expense		3
Year Ended December 31, 2013	$	358

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

- **Retail Margins** increased $55 million primarily due to the following:
  - A $123 million increase in revenues associated with OPCo's Universal Service Fund (USF) surcharge and Distribution Investment Recovery Rider. A portion of these increases have corresponding increases in other expense items below.
  - A $17 million increase related to favorable regulatory proceedings for OPCo.

  These increases were partially offset by:
  - A $40 million decrease related to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
  - A $35 million decrease due to OPCo's partial reversal in 2012 of a 2011 fuel provision related to CRES providers.
- **Transmission Revenues** increased $46 million primarily due to increased transmission revenues from Ohio customers who switched to alternative CRES providers.

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

Other Operation and Maintenance expenses increased $92 million primarily due to the following:

-

  - An $86 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in retail margins above.
  - A $30 million net increase related to the reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of the Ohio modified stipulation and the PUCO's August 2012 approval of the June 2012-May 2015 ESP.

These increases were partially offset by:

- A $14 million decrease in expenses related to the 2012 sustainable cost reductions.
- A $13 million decrease in Ohio's *gridSMART*® expenses primarily due to a reduction in the operation

and maintenance component of the *gridSMART®* rider for prior years' over collections. This decrease was partially offset by a corresponding increase in Depreciation and Amortization.

- **Depreciation and Amortization** expenses increased $30 million primarily due to the following:
  - An $8 million increase due to OPCo's and TCC's issuance of securitization bonds in August 2013 and March 2012, respectively. This increase in OPCo's and TCC's securitization related amortizations are offset within Gross Margin.
  - A $7 million increase due to increased investment in distribution and transmission plant.
  - A $4 million increase in Ohio's *gridSMART®* expenses primarily due to an increase in the depreciation component of the *gridSMART®* rider to recover prior years' under collections. This increase was offset by a corresponding decrease in operation and maintenance expense above.
- **Taxes Other Than Income Taxes** increased $7 million primarily due to increased property taxes.
- **Carrying Costs Income** decreased $8 million primarily due to the first quarter 2012 recording of debt carrying costs prior to TCC's issuance of securitization bonds in March 2012.
- **Income Tax Expense** decreased $3 million primarily due to a decrease in pretax book income offset-in-part by the recording of state income tax adjustments.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Income from Transmission and Distribution Utilities Before Extraordinary Item
(in millions)

Year Ended December 31, 2011	$	404
Changes in Gross Margin:		
Retail Margins		192
Transmission Revenues		59
Other Revenues		51
Total Change in Gross Margin		302
Changes in Expenses and Other:		
Other Operation and Maintenance		43
Depreciation and Amortization		(12)
Taxes Other Than Income Taxes		(11)
Interest and Investment Income		(3)
Carrying Costs Income		(351)
Allowance for Equity Funds Used During Construction		(3)
Interest Expense		2
Total Change in Expenses and Other		(335)
Income Tax Expense		18
Year Ended December 31, 2012	$	389

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

- **Retail Margins** increased $192 million primarily due to the following:
  - A $156 million increase in revenues primarily associated with OPCo's Retail Stability Rider, Deferred Asset Recovery Rider and Distribution Investment Recovery Rider. A portion of these increases have corresponding increases in other expense items below.
  - A $35 million increase due to OPCo's partial reversal in 2012 of a 2011 fuel provision related to CRES providers.

  These increases were partially offset by:
  - A $46 million decrease related to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
- **Transmission Revenues** increased $59 million primarily due to increased transmission revenues from Ohio customers who switched to alternative CRES providers.
- **Other Revenues** increased $51 million primarily due to an increase in revenues related to TCC's issuance of securitization bonds in March 2012. This increase in revenues from securitization bonds is partially offset by an increase in Depreciation and Amortization expense.

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

- **Other Operation and Maintenance** expenses decreased $43 million primarily due to the following:
  - A $70 million decrease related to the 2011 recording and subsequent 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of the Ohio modified stipulation.

  These decreases were partially offset by:
  - A $13 million increase in storm-related expenses primarily in Ohio.
  - A $13 million increase due to expenses related to the 2012 sustainable cost reductions.
- **Depreciation and Amortization** expenses increased $12 million primarily due to the following :
  - A $51 million increase due to TCC's issuance of securitization bonds in March 2012. The increase in TCC's securitization related amortization is offset within Gross Margin.

- An $11 million increase in amortization of Deferred Asset Recovery Rider assets as approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012. This increase in amortization is offset within Gross Margin.
- A $9 million increase due to higher depreciable property balances primarily related to the Texas Automated Meter Infrastructure project.

These increases were partially offset by:

- A $39 million decrease due to amortization adjustment approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012.
- A $23 million decrease due to amortization of carrying costs on deferred fuel as a result of the October 2011 PUCO remand order which allowed the POLR refund to be applied against any deferred fuel balances. The equity amortization was offset by amounts recognized in Carrying Costs Income.

- **Taxes Other Than Income Taxes** increased $11 million primarily due to increased property taxes.
- **Carrying Costs Income** decreased $351 million primarily due to the recognition in 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- **Income Tax Expense** decreased $18 million primarily due to a decrease in pretax book income and by the recording of state income tax adjustments.

GENERATION & MARKETING

Generation & Marketing	Years Ended December 31, 2013	2012	2011
	(in millions)		
Revenues	$ 3,665	$ 3,467	$ 3,894
Fuel, Purchased Electricity and Other	2,305	2,065	2,215
Gross Margin	1,360	1,402	1,679
Other Operation and Maintenance	523	507	537
Asset Impairments and Other Related Charges	154	287	90
Depreciation and Amortization	236	349	304
Taxes Other Than Income Taxes	54	62	60
Operating Income	393	197	688
Interest and Investment Income	2	1	4
Interest Expense	(55)	(83)	(87)
Income Before Income Tax Expense	340	115	605
Income Tax Expense	112	15	166
Income Before Extraordinary Item	$ 228	$ 100	$ 439

Summary of MWhs Generated for Generation & Marketing

	Years Ended December 31, 2013	2012	2011
	(in millions of MWhs)		
Fuel Type:			
Coal	38	37	45
Natural Gas	6	11	7
Wind	1	1	1
Total MWhs	45	49	53

2013 Compared to 2012

Reconciliation of Year Ended December 31, 2012 to Year Ended December 31, 2013
Income from Generation & Marketing Before Extraordinary Item
(in millions)

Year Ended December 31, 2012	$ 100
Changes in Gross Margin:	
Generation	(44)
Retail, Trading and Marketing	4
Other	(2)
Total Change in Gross Margin	(42)
Changes in Expenses and Other:	
Other Operation and Maintenance	(16)
Asset Impairments and Other Related Charges	133
Depreciation and Amortization	113
Taxes Other Than Income Taxes	8
Interest and Investment Income	1
Interest Expense	28
Total Change in Expenses and Other	267
Income Tax Expense	(97)
Year Ended December 31, 2013	$ 228

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

- **Generation** decreased $44 million primarily due to the following:
  - A $336 million decrease in affiliated sales to OPCo primarily due to customers switching to alternative CRES providers as well as a reduction in industrial usage.

  This decrease was partially offset by the following:
  - A $221 million net increase in sales to AEP affiliates under the Interconnection Agreement.
  - A $63 million decrease in fuel expenses due to a reduction in generation at the Lawrenceburg Plant.

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

- **Other Operation and Maintenance** expenses increased $16 million primarily due to a 2013 adjustment of $14 million to impaired plant investment as a result of changes to asset retirement obligations for asbestos removal and retirement of ash disposal facilities at impaired plants.
- **Asset Impairments and Other Related Charges** decreased $133 million due to the following:
  - A 2012 impairment of $287 million for certain Ohio generation plants, which includes $13 million of related materials and supplies inventory.

  This decrease was partially offset by:
  - A 2013 impairment of $154 million for Muskingum River Plant, Unit 5.

- **Depreciation and Amortization** expenses decreased $113 million primarily due to depreciation ceasing on certain Ohio generation plants that were impaired in November 2012 and June 2013.
- **Interest Expense** decreased $28 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- **Income Tax Expense** increased $97 million primarily due to an increase in pretax book income and by the recording of state income tax adjustments.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Income from Generation & Marketing Before Extraordinary Item
(in millions)

Year Ended December 31, 2011	$ 439
Changes in Gross Margin:	
Generation	(363)
Retail, Trading and Marketing	86
Total Change in Gross Margin	(277)
Changes in Expenses and Other:	
Other Operation and Maintenance	30
Asset Impairments and Other Related Charges	(197)
Depreciation and Amortization	(45)
Taxes Other Than Income Taxes	(2)
Interest and Investment Income	(3)
Interest Expense	4
Total Change in Expenses and Other	(213)
Income Tax Expense	151
Year Ended December 31, 2012	$ 100

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

- **Generation** decreased $363 million primarily due to the following:
  - A $396 million decrease in affiliated sales to OPCo primarily due to customer switching to alternative CRES providers.

  This decrease was partially offset by:
  - A $29 million increase in non-affiliated sales due to increased sales to Buckeye Power, Inc. for back-up energy under the Cardinal Station Agreement.
- **Retail, Trading and Marketing** increased $86 million primarily due to the March 2012 acquisition of BlueStar.

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

- **Other Operation and Maintenance** expenses decreased $30 million primarily due to the following:
  - A $78 million decrease in plant outage and other plant operating and maintenance expenses.

  This decrease was partially offset by:
  - A $47 million increase in AEP Energy labor and sales expenses due to the acquisition of BlueStar in March 2012.
- **Asset Impairments and Other Related Charges** increased $197 million due to the following:

- A 2012 impairment of $287 million for certain Ohio generation plants, which includes $13 million of related materials and supplies inventory.

  This increase was partially offset by:

  - A 2011 plant impairment of $48 million for Sporn Plant, Unit 5.
  - A 2011 plant impairment of $42 million for FGD project at Muskingum River Plant, Unit 5.

- **Depreciation and Amortization** expenses increased $45 million primarily due to the following:
  - A $58 million increase due to shortened depreciable lives for certain AGR generation plants effective December 2011. The book value of these plants was fully impaired in November 2012.
  - Overall higher depreciable property balances.

  These increases were partially offset by:

  - A $13 million decrease in depreciation due to the 2011 plant impairment of Sporn Plant, Unit 5.

- **Income Tax Expense** decreased $151 million primarily due to a decrease in pretax book income.

AEP TRANSMISSION HOLDCO

2013 Compared to 2012

Income Before Extraordinary Item from our AEP Transmission Holdco segment increased from $43 million in 2012 to $80 million in 2013 primarily due to an increase in investments by our wholly-owned transmission subsidiaries and ETT.

2012 Compared to 2011

Income Before Extraordinary Item from our AEP Transmission Holdco segment increased from $30 million in 2011 to $43 million in 2012 primarily due to an increase in investments by ETT and our wholly-owned transmission subsidiaries.

AEP RIVER OPERATIONS

2013 Compared to 2012

Income Before Extraordinary Item from our AEP River Operations segment decreased from $15 million in 2012 to $12 million in 2013 primarily due to significant reductions in export grain and coal demand. In addition, low water levels in the first and fourth quarters of 2013 limited barge loads and tow sizes.

2012 Compared to 2011

Income Before Extraordinary Item from our AEP River Operations segment decreased from $45 million in 2011 to $15 million in 2012 primarily due to the 2012 drought, which had significant impacts on river conditions and crop yields, resulting in reduced grain exports.

CORPORATE AND OTHER

2013 Compared to 2012

Income Before Extraordinary Item from Corporate and Other increased from a loss of $88 million in 2012 to income of $125 million in 2013 primarily due to a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in 2013 as well as a reduction in interest expense associated with the early retirement of debt in 2012.

2012 Compared to 2011

Income Before Extraordinary Item from Corporate and Other decreased from a loss of $52 million in 2011 to a loss of $88 million in 2012 primarily due to costs associated with the early retirement of debt in 2012 and the 2012 adjustment of a U.K. Windfall Tax provision as a result of a related Supreme Court case, partially offset by a loss incurred in 2011 related to the settlement of litigation with BOA and Enron.

AEP SYSTEM INCOME TAXES

2013 Compared to 2012

Income Tax Expense increased $80 million primarily due to an increase in pretax book income and the recording of state income tax adjustments partially offset by a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in the second quarter of 2013.

2012 Compared to 2011

Income Tax Expense decreased $214 million primarily due to a decrease in pretax book income and the unrealized capital loss valuation allowance related to a deferred tax asset associated with the settlement of litigation with BOA and Enron recorded in 2011, partially offset by the recording of federal and state income tax adjustments.

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

	December 31,			
	2013		2012	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 18,377	52.2 %	$ 17,757	52.3 %
Short-term Debt	757	2.1	981	2.9
Total Debt	19,134	54.3	18,738	55.2
AEP Common Equity	16,085	45.7	15,237	44.8
Noncontrolling Interests	1	-	-	-
Total Debt and Equity Capitalization	$ 35,220	100.0 %	$ 33,975	100.0 %

Our ratio of debt-to-total capital decreased from 55.2% as of December 31, 2012 to 54.3% as of December 31, 2013 primarily due to an increase in common equity, partially offset by a net increase in debt issuances, including the issuance of $647 million of securitization bonds.

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 December 31, 2013, 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-leaseback or leasing agreements or common stock.

Commercial Paper Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. As of December 31, 2013, our available liquidity was approximately $3.4 billion as illustrated in the table below:

	Amount	Maturity
	(in millions)	
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,750	June 2016
Revolving Credit Facility	1,750	July 2017
Total	3,500	
Cash and Cash Equivalents	118	
Total Liquidity Sources	3,618	
Less: AEP Commercial Paper Outstanding	57	

Letters of Credit Issued	170
Net Available Liquidity	$ 3,391

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 2013 was $904 million. The weighted-average interest rate for our commercial paper during 2013 was 0.32%.

Other Credit Facilities

In July 2013, AGR, APCo, KPCo and OPCo entered into a $1 billion term credit facility due in May 2015 to fund certain OPCo maturities on an interim basis and to facilitate OPCo's corporate separation of generation assets from transmission and distribution. As of December 31, 2013, the $1 billion term credit facility was entirely drawn. Repayments prior to maturity are permitted. However, any amount that is repaid may not be re-borrowed and is a permanent reduction of the term credit facility.

In January 2014, we issued letters of credit utilizing the entire amount available under an $85 million uncommitted facility signed in October 2013. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

Financing Plan

As of December 31, 2013, we have $1.5 billion of long-term debt due within one year which includes $879 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that requires the debt be classified as current. Also included in our long-term debt due within one year is $413 million of securitization bonds and DCC Fuel notes payable which will be repaid. We plan to refinance the majority of our other maturities due within one year.

Securitized Accounts Receivables

In 2013, we amended our receivables securitization agreement to extend through June 2014. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. A commitment of $385 million expires in June 2014 and the remaining commitment of $315 million expires in June 2015. We intend to extend or replace the agreement expiring in June 2014 on or before its maturity.

West Virginia Securitization of Regulatory Assets

In September 2013, the WVPSC approved a settlement agreement filed by APCo, WPCo and intervenors which authorized APCo to securitize $376 million, plus upfront financing costs, related primarily to the December 2011 under-recovered Expanded Net Energy Charge (ENEC) deferral balance. In November 2013, APCo issued $380 million of Securitization Bonds to securitize the under-recovered ENEC deferral balance, including $4 million of upfront financing costs, with a final maturity date of August 2031. APCo implemented a new securitization rider which was offset by an equal reduction in ENEC revenues, with no overall change in total revenues.

Ohio Securitization of Regulatory Assets

In March 2013, the PUCO approved OPCo's request to securitize the Deferred Asset Recovery Rider (DARR) balance. In August 2013, OPCo issued $267 million of Securitization Bonds, with a final maturity date of July 2020, to securitize the DARR balance. As a result of the securitization, recovery through the DARR has ceased and has been replaced by the Deferred Asset Phase-in Rider which will recover the securitized assets.

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 credit agreements excludes securitization bonds and debt of AEP Credit. As of December 31, 2013, this contractually-defined percentage was 50.4%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of

December 31, 2013, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of our non-exchange traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our credit agreements.

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

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. As of December 31, 2013, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.50 per share in January 2014. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income 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. However, we do not believe these restrictions 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.

	Years Ended December 31,		
	2013	**2012**	**2011**
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 279	$ 221	$ 294
Net Cash Flows from Operating Activities	4,106	3,804	3,788
Net Cash Flows Used for Investing Activities	(3,818)	(3,391)	(2,890)
Net Cash Flows Used for Financing Activities	(449)	(355)	(971)
Net Increase (Decrease) in Cash and Cash Equivalents	(161)	58	(73)
Cash and Cash Equivalents at End of Period	$ 118	$ 279	$ 221

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

Operating Activities

	Years Ended December 31,		
	2013	2012	2011
		(in millions)	
Net Income	$ 1,484	$ 1,262	$ 1,949
Depreciation and Amortization	1,743	1,782	1,655
Other	879	760	184
Net Cash Flows from Operating Activities	$ 4,106	$ 3,804	$ 3,788

Net Cash Flows from Operating Activities were $4.1 billion in 2013 consisting primarily of Net Income of $1.5 billion, $1.7 billion of noncash Depreciation and Amortization and $226 million of Asset Impairments related to Muskingum River Plant, Unit 5, Big Sandy and Amos Plants, partially offset by $214 million of Ohio capacity deferrals as a result of a 2012 PUCO order. 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 versus book temporary differences from operations. Significant changes in other items include the favorable impact of a decrease in fuel inventory and net cash flows for Accrued Taxes as a result of the recognition of the tax benefit related to the U.K. Windfall Tax.

Net Cash Flows from Operating Activities were $3.8 billion in 2012 consisting primarily of Net Income of $1.3 billion, $1.8 billion of noncash Depreciation and Amortization and $287 million in Asset Impairments related to certain Ohio generation assets. 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. A significant change in other items includes the unfavorable impact of an increase in fuel inventory due to the mild winter weather. Deferred Income Taxes increased primarily due to provisions in the Small Business Jobs Act and the Tax Relief, Unemployment Insurance Reauthorization and Jobs Creation Act and an increase in tax versus book temporary differences from operations. During 2012, we also contributed $200 million to our qualified pension trust.

Net Cash Flows from Operating Activities were $3.8 billion in 2011 consisting primarily of Net Income of $1.9 billion and $1.7 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Following a Supreme Court of Texas reversal of the PUCT's capacity auction true-up disallowance and the PUCT's approval of a stipulation agreement, we recorded an Extraordinary Item, Net of Tax of $373 million for the 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts and the reversal of tax related regulatory credits. We also recorded $393 million in Carrying Costs Income primarily related to the Texas restructuring appeals. A significant change in other items includes the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to bonus depreciation provisions in the Small Business Jobs Act and the Tax Relief, Unemployment Insurance Reauthorization and Jobs Creation Act, the settlement with BOA and Enron and an increase in tax versus book temporary differences from operations. In February 2011, we paid $425 million to BOA of which $211 million was used to settle litigation with BOA and Enron. The remaining $214 million was used to acquire cushion gas as discussed in Investing Activities below. During 2011, we also contributed $450 million to our qualified pension trust.

Investing Activities

	Years Ended December 31,		
	2013	2012	2011
		(in millions)	
Construction Expenditures	$ (3,624)	$ (3,025)	$ (2,669)
Acquisitions of Nuclear Fuel	(154)	(107)	(106)
Acquisitions of Assets/Businesses	(32)	(94)	(19)
Acquisitions of Cushion Gas from BOA	-	-	(214)
Proceeds from Sales of Assets	21	18	123
Other	(29)	(183)	(5)
Net Cash Flows Used for Investing Activities	$ (3,818)	$ (3,391)	$ (2,890)

Net Cash Flows Used for Investing Activities were $3.8 billion in 2013 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Net Cash Flows Used for Investing Activities were $3.4 billion in 2012 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. Acquisitions of Assets/Businesses include our March 2012 purchase of BlueStar for $70 million.

Net Cash Flows Used for Investing Activities were $2.9 billion in 2011 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. We paid $214 million to BOA for cushion gas as part of a litigation settlement.

Financing Activities

	Years Ended December 31,		
	2013	**2012**	**2011**
		(in millions)	
Issuance of Common Stock, Net	$ 84	$ 83	$ 92
Issuance/Retirement of Debt, Net	385	544	(33)
Proceeds from Nuclear Fuel Sale/Leaseback	110	-	-
Retirement of Cumulative Preferred Stock	-	-	(64)
Dividends Paid on Common Stock	(954)	(916)	(898)
Other	(74)	(66)	(68)
Net Cash Flows Used for Financing Activities	$ (449)	$ (355)	$ (971)

Net Cash Flows Used for Financing Activities in 2013 were $449 million. Our net debt issuances were $385 million. The net issuances included issuances of $745 million of senior unsecured notes, $1 billion draws on a $1 billion term credit facility, $647 million of securitization bonds, $328 million of notes payable and other debt and $305 million of pollution control bonds offset by retirements of $1.8 billion of senior unsecured and other debt notes, $331 million of pollution control bonds, $243 million of securitization bonds and a decrease in short-term borrowing of $224 million. We paid common stock dividends of $954 million. See Note 14 – Financing Activities.

Net Cash Flows Used for Financing Activities in 2012 were $355 million. Our net debt issuances were $544 million. The net issuances included issuances of $1.7 billion of senior unsecured notes, $800 million of securitization bonds, $287 million of notes payable and other debt and $65 million of pollution control bonds offset by retirements of $902 million of senior unsecured and other debt notes, $315 million of junior subordinate debentures, $220 million of pollution control bonds, $206 million of securitization bonds and a decrease in short-term borrowing of $669 million. We paid common stock dividends of $916 million.

Net Cash Flows Used for Financing Activities in 2011 were $971 million. Our net debt retirements were $33 million. The net retirements included retirements of $727 million of senior unsecured and other debt notes, $778 million of pollution control bonds and $159 million of securitization bonds offset by issuances of $710 million of notes, $627 million of pollution control bonds and an increase in short-term borrowing of $304 million. We paid common stock dividends of $898 million and $64 million to retire all of our subsidiaries' preferred stocks.

The following financing activities occurred during 2013:

AEP Common Stock:

- During 2013, we issued 2.1 million shares of common stock under our incentive compensation, employee savings and dividend reinvestment plans and received net proceeds of $84 million.

Debt:

- During 2013, we issued approximately $3 billion of long-term debt, including $1 billion drawn on a term credit facility, $745 million of senior notes at interest rates ranging from 2.73% to 5.32% and $647 million of securitization bonds at interest rates ranging from 0.96% to 3.77%. We also issued $190 million of pollution control revenue bonds at interest rates ranging from 3.25% to 4%, $115 million of pollution control revenue bonds at variable interest rates and $328 million of other debt at variable interest rates. The proceeds from these issuances were used to fund long-term debt maturities and our construction programs.
- During 2013, we entered no interest rate derivatives and settled $379 million of such transactions. The settlements resulted in net cash payments of $26 million. As of December 31, 2013, we had in place $820 million of notional interest rate derivatives designated as cash flow and fair value hedges.

In 2014:

- In January 2014, TCC retired $112 million of Securitization Bonds.
- In January and February 2014, I&M retired $24 million of Notes Payable related to DCC Fuel.
- In January 2014, OPCo retired $225 million of 4.85% Senior Unsecured Notes due in 2014.

BUDGETED CONSTRUCTION EXPENDITURES

We forecast approximately $3.8 billion of construction expenditures excluding equity AFUDC for 2014. For 2015 and 2016, we forecast construction expenditures of $3.8 billion each year. The expenditures are generally for transmission, distribution and required environmental investment to comply with Federal EPA rules. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. We expect to fund these construction expenditures through cash flows from operations and financing activities. Generally, the subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. The 2014 estimated construction expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2014 Budgeted Construction Expenditures					
Segment	**Environmental**	**Generation**	**Transmission**	**Distribution**	**Other**	**Total**
			(in millions)			
Vertically Integrated Utilities	$ 467	$ 410	$ 465	$ 564	$ 67	$ 1,973
Transmission and Distribution Utilities	7	5	340	494	36	882
Generation & Marketing	114	63	-	-	14	191

AEP Transmission Holdco	-	-	786	-	1	787
AEP River Operations	-	-	-	-	9	9
Corporate and Other	-	-	-	-	3	3
Total	$ 588	$ 478	$ 1,591	$ 1,058	$ 130	$ 3,845

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.

Rockport Plant, Unit 2

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for AEGCo and I&M are $665 million and $665 million, respectively, as of December 31, 2013.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. Our subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 13. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. We, as well as our subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

Railcars

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. We intend to maintain the lease for the full lease term of twenty years via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $28 million for the remaining railcars as of December 31, 2013. Under a return-and-sale option, the lessor is guaranteed that the sale proceeds will equal at least a specified lessee obligation amount which declines with each five-year renewal. As of December 31, 2013, the maximum potential loss was approximately $19 million 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. We have other railcar lease arrangements that do not utilize this type of financing structure.

CONTRACTUAL OBLIGATION INFORMATION

Our contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations as of December 31, 2013:

Payments Due by Period

Contractual Cash Obligations	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Short-term Debt (a)	$ 757	$ -	$ -	$ -	$ 757
Interest on Fixed Rate Portion of Long-term Debt (b)	784	1,442	1,250	6,283	9,759
Fixed Rate Portion of Long-term Debt (c)	988	2,284	2,853	10,328	16,453
Variable Rate Portion of Long-term Debt (d)	561	1,382	6	-	1,949
Capital Lease Obligations (e)	135	208	123	215	681
Noncancelable Operating Leases (e)	288	514	445	862	2,109
Fuel Purchase Contracts (f)	2,362	3,391	2,235	2,649	10,637
Energy and Capacity Purchase Contracts	195	410	457	2,634	3,696
Construction Contracts for Capital Assets (g)	807	1,123	931	1,797	4,658
Total	$ 6,877	$ 10,754	$ 8,300	$ 24,768	$ 50,699

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 14. Represents principal only excluding interest.
(d) See "Long-term Debt" section of Note 14. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.02% and 1.91% as of December 31, 2013.
(e) See Note 13.
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents only capital assets for which we have signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

Our $51 million liability related to uncertainty in Income Taxes is not included above because we cannot reasonably estimate the cash flows by period.

Our pension funding requirements are not included in the above table. As of December 31, 2013, we expect to make contributions to our pension plans totaling $80 million in 2014. Estimated contributions of $78 million in 2015 and $84 million in 2016 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the accumulated benefit obligation and fair value of assets available to pay pension benefits, our pension plans were 99.9% funded as of December 31, 2013.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. As of December 31, 2013, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

Other Commercial Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Standby Letters of Credit (a)	$ 170	$ -	$ -	$ -	$ 170
Guarantees of the Performance of Outside Parties (b)	-	-	-	115	115
Guarantees of Our Performance (c)	592	-	10	58	660
Total Commercial Commitments	$ 762	$ -	$ 10	$ 173	$ 945

(a) We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. AEP, on behalf of our subsidiaries, and/or the subsidiaries issued all of these LOCs in the ordinary course of business. There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any LOC is drawn, there is no recourse to third parties. The maximum future payments of these LOCs are $170 million with maturities ranging from February 2014 to April 2015. See "Letters of Credit" section of Note 6.
(b) See "Guarantees of Third-Party Obligations" section of Note 6.
(c) We issued performance guarantees and indemnifications for energy trading and various sale agreements.

SIGNIFICANT TAX LEGISLATION

The Small Business Jobs Act extended the time for claiming bonus depreciation and increased the deduction to 100% for 2011 and decreased the deduction to 50% for 2012. The American Taxpayer Relief Act of 2012 provided for the extension of several business and energy industry tax deductions and credits, including the one-year extension of the 50% bonus depreciation to 2013. The enacted provisions had no material impact on net income or financial condition but did have a favorable impact on cash flows in 2013.

CYBER SECURITY

Cyber security presents a heightened risk for electric utility systems because a cyber-attack could affect critical energy infrastructure. Breaches to the cyber security of the grid or to our system are potentially disruptive to people, property and commerce and create risk for our business, investors and customers. In February 2013, President Obama signed an executive order that addresses how government agencies will operate and support the functions in cyber security as well as redefine how the government interfaces with critical infrastructure, such as the electric grid. We already operate under regulatory cyber security standards to protect critical infrastructure. The cyber security framework that is being developed through this executive order will be reviewed by the FERC and the U.S. Department of Energy. We are participating in the process by submitting feedback through our industry trade group and sharing best practices already in place. We protect our critical cyber assets, such as our data centers, power plants, transmission operations centers and business network, using multiple layers of cyber security and authentication. We constantly scan the system for risks or threats.

Cyber hackers have been able to breach a number of very secure facilities, from federal agencies, banks and retailers to social media sites. As these events become known and develop, we continually assess our own cyber security tools and processes to determine where we might need to strengthen our defenses.

In recent years, we have taken additional steps to enhance our capabilities for identifying risks or threats and have shared those threats with our utility peers, industry and federal agencies. We operate our own Cyber Security Operations Center. Funding for this included a grant from the American Recovery and Reinvestment Act – U.S. Department of Energy Smart Grid Demonstration Program. This facility was initially designed as a pilot cyber threat and information-sharing center specifically for the electric sector and today is fully operational.

In 2013, as part of our industry's continuing program to advance threat sharing and coordination, we participated in the North American Electric Reliability Corporation (NERC) GridEx II exercise. This effort, led by NERC, tested and developed the coordination and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid.

In 2012, we signed a cooperative research and development agreement with the Department of Homeland Security's Office of Cyber Security and Communications, further enhancing our ability to directly exchange information about cyber threats. In addition, we continue to partner with a number of federal and industry groups to advance the national capabilities of cyber security. We are working with the U.S. Department of Energy on several projects covering advanced cyber security and assessment tools.

We have partnered with a major defense contractor who has significant cyber security experience and technical capabilities developed through their work with the U.S. Department of Defense. We work with a consortium of other utilities across the country, learning how best to share information about potential threats and collaborating with each other. We continue to work with a nonaffiliated entity to conduct several seminars each year about recognizing and investigating cyber vulnerabilities. Through these types of efforts, we are working to protect ourselves while helping our industry advance its cyber security capabilities.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. We consider an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on net income or financial condition.

We discuss the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosures relating to them.

We believe that the current assumptions and other considerations used to estimate amounts reflected in our financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about our critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

Our financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of expense and income recognition with regulated revenues. We also record liabilities for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, we record them as regulatory assets on the balance sheet. We review the probability of recovery at each balance sheet date and whenever new events occur. Similarly, we record regulatory liabilities when a determination is made that a refund is probable or when ordered by a commission. Examples of new events that affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs as well as the return of revenues, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets or establishment of a regulatory liability may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on our net income. Refer to Note 5 for further detail related to regulatory assets and regulatory liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

We record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which we perform on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. In accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

The changes in unbilled electric utility revenues for our Vertically Integrated Utilities segment were $(9) million, $13 million and $(57) million for the years ended December 31, 2013, 2012 and 2011, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rate increases. Accrued unbilled revenues for the Vertically Integrated Utilities segment were $283 million and $292 million as of December 31, 2013 and 2012, respectively.

The changes in unbilled electric utility revenues for our Transmission and Distribution Utilities segment were $(22) million, $(12) million and $(24) million for the years ended December 31, 2013, 2012 and 2011, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rate increases. Accrued unbilled revenues for the Transmission and Distribution Utilities segment were $165 million and $187 million as of December 31, 2013 and 2012, respectively.

In March 2012, our Generation & Marketing segment acquired an independent retail electric supplier. The change in unbilled electric utility revenues for our Generation & Marketing segment was $10 million and $34 million for the years ended December 31, 2013 and 2012, respectively. Accrued unbilled revenues for the Generation & Marketing segment were $41 million and $31 million as of December 31, 2013 and 2012, respectively.

Assumptions and Approach Used

For each operating company, we compute the monthly estimate for unbilled revenues as net generation (generation plus purchases less sales) less the current month's billed KWh plus the prior month's unbilled KWh. However, due to meter reading issues, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWh to the current month and previous month, on a cycle-by-cycle basis, and by dividing the current month aggregated result by the billed KWh. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

For certain contracts, we calculate unbilled revenues by contract using the most recent historic daily activity adjusted for significant known changes in usage.

Effect if Different Assumptions Used

Significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the accrued unbilled revenues.

Accounting for Derivative Instruments

Nature of Estimates Required

We consider fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

We measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based primarily on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. We calculate liquidity adjustments by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. We calculate credit adjustments on our risk management contracts using estimated default probabilities and recovery rates relative to our counterparties or counterparties with similar credit profiles and contractual netting agreements.

With respect to hedge accounting, we assess hedge effectiveness and evaluate a forecasted transaction's probability of occurrence within the specified time period as provided in the original hedge documentation.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Notes 10 and 11. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of “Property, Plant and Equipment” accounting guidance, we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable including planned abandonments and a probable disallowance for rate-making on a plant under construction or the assets meet the held-for-sale criteria. We utilize a group composite method of depreciation to estimate the useful lives of long-lived assets. The evaluations of long-lived, held-and-used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, we record an impairment to the extent that the fair value of the asset is less than its book value. Performing an impairment evaluation involves a significant degree of estimation and judgment in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets and developing the undiscounted and discounted future cash flows (used to estimate fair value in the absence of market-based value, in some instances) associated with the asset. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, the earnings impact of an impairment charge could be offset by the establishment of a regulatory asset if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. Cash flow estimates are based on relevant information available at the time the estimates are made. Estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. Also, when measuring fair value, management evaluates the characteristics of the asset or liability to determine if market participants would take those characteristics into account when pricing the asset or liability at the measurement date. Such characteristics include, for example, the condition and location of the asset or restrictions of the use of the asset. We perform depreciation studies that include a review of any external factors that may affect the useful life to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions for cost-based regulated assets. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of an asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. The estimate for depreciation rates takes into account the history of interim capital replacements and the amount of salvage expected. In cases of impairment, we made our best estimate of fair value using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and our analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

We maintain a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law for participants in the Qualified Plan (collectively the Pension Plans). Additionally, we entered into individual employment contracts with certain current and retired executives that provide additional retirement benefits as a part of the Nonqualified Plans. We also sponsor other postretirement benefit plans to provide health and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively referred to as the Plans.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see “Investments Held in Trust for Future Liabilities” and “Fair Value Measurements of Assets and Liabilities” sections of Note 1. See Note 8 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost (credit) of the Plans:

Net Periodic Benefit Cost (Credit)	Years Ended December 31, 2013	2012	2011
		(in millions)	
Pension Plans	$ 180	$ 134	$ 118
Postretirement Plans	(17)	89	73

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2014, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. We also considered historical returns of the investment markets and changes in tax rates which affect a portion of the Postretirement Plans' assets. We anticipate that the investment managers we employ for the Plans will invest the assets to generate future returns averaging 6% for the Qualified Plan and 6.75% for the Postretirement Plans.

The expected long-term rate of return on the Plans' assets is based on our targeted asset allocation and our expected investment returns for each investment category. Our assumptions are summarized in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
	2014 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return	2014 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return
Equity	30 %	8.00 %	66 %	7.80 %
Fixed Income	55 %	4.60 %	33 %	4.40 %
Other Investments	15 %	7.00 %	- %	- %
Cash and Cash Equivalents	- %	- %	1 %	3.00 %
Total	100 %		100 %	

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 6% and 6.75% are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 8.1% and 13.8% for the years ended December 31, 2013 and 2012, respectively. The Postretirement Plans' assets had an actual gain of 14.3% and 15.4% for the years ended December 31, 2013 and 2012, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

We base our determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2013, we had cumulative gains of approximately $207 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial gains may result in decreases in the future pension costs depending on several factors, including whether such gains at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that we utilize for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate as of December 31, 2013 under this method was 4.7% for the Qualified Plan, 4.55% for the Nonqualified Plans and 4.7% for the Postretirement Plans. Due to the effect of the unrecognized actuarial gains and based on an expected rate of return on the Pension Plans' assets of 6%, discount rates of 4.7% and 4.55% and various other assumptions, we estimate that the pension costs for the Pension Plans will approximate $161 million,

$113 million and $109 million in 2014, 2015 and 2016, respectively. Based on an expected rate of return on the Postretirement Plans' assets of 6.75%, a discount rate of 4.7% and various other assumptions, we estimate credits will approximate $77 million, $82 million and $82 million in 2014, 2015 and 2016, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

In November 2012, we announced changes to our retiree medical coverage. Effective for retirements after December 2012, our contribution to retiree medical costs was capped reducing our future exposure to medical cost inflation. Effective for employees hired after December 2013, we will not provide retiree medical coverage. This change reduced costs of the plan beginning in 2013 as shown by the estimated credits for Postretirement Plans in the previous paragraph.

The value of the Pension Plans' assets remained unchanged at $4.7 billion as of December 31, 2013 and December 31, 2012 primarily due to investment returns offsetting benefit payments. During 2013, the Qualified Plan paid $324 million and the Nonqualified Plans paid $7 million in benefits to plan participants. The value of the Postretirement Plans' assets increased to $1.7 billion as of December 31, 2013 from $1.6 billion as of December 31, 2012 primarily due to investment returns and contributions by the company and the participants in excess of benefit payments. The Postretirement Plans paid $140 million in benefits to plan participants during 2013.

Nature of Estimates Required

We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under "Compensation" and "Plan Accounting" accounting guidance. The measurement of our pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Compensation increase rate
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
	(in millions)			
Effect on December 31, 2013 Benefit Obligations				
Discount Rate	$ (233)	$ 254	$ (71)	$ 78
Compensation Increase Rate	13	(12)	NA	NA
Cash Balance Crediting Rate	43	(39)	NA	NA
Health Care Cost Trend Rate	NA	NA	25	(28)
Effect on 2013 Periodic Cost				
Discount Rate	(12)	13	(4)	4
Compensation Increase Rate	4	(4)	NA	NA
Cash Balance Crediting Rate	11	(11)	NA	NA
Health Care Cost Trend Rate	NA	NA	4	(4)
Expected Return on Plan Assets	(21)	21	(8)	8

NA Not applicable.

ACCOUNTING PRONOUNCEMENTS

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 revenue recognition, financial instruments, leases, insurance, hedge accounting and consolidation policy. The ultimate pronouncements resulting from these and future projects could have an impact on our future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

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

Our Transmission and Distribution Utilities segment is exposed to FTR price risk as it relates to congestion during the June 2012 – May 2015 Ohio ESP period. Additional risk includes interest rate risk.

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

We employ risk management contracts including physical forward purchase-and-sale contracts and financial forward purchase-and-sale contracts. We engage in risk management of power, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply, and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of our 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 our Chief Operating Officer, Chief Financial Officer, Executive Vice President of Energy Supply, Senior Vice President of Commercial Operations and Chief Risk Officer. 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 mark-to-market (MTM) value as compared to December 31, 2012:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2013

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation and Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets as of December 31, 2012	$ 39	$ (1)	$ 158	$ 196
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(16)	1	(32)	(47)
Fair Value of New Contracts at Inception When Entered During the Period (a)	-	-	16	16
Changes in Fair Value Due to Market Fluctuations During the Period (b)	-	-	15	15
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	9	3	-	12
Total MTM Risk Management Contract Net Assets as of December 31, 2013	$ 32	$ 3	$ 157	192
Commodity Cash Flow Hedge Contracts				1
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(2)

Fair Value Hedge Contracts	(10)
Collateral Deposits	9
Total MTM Derivative Contract Net Assets as of December 31, 2013	$ 190

(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 statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 10 – Derivatives and Hedging and Note 11 – 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 December 31, 2013, our credit exposure net of collateral to sub investment grade counterparties was approximately 8.7%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2013, 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	$ 630	$ 7	$ 623	2	$ 290
Split Rating	-	-	-	-	-
Noninvestment Grade	-	-	-	-	-
No External Ratings:					
Internal Investment Grade	79	-	79	4	45
Internal Noninvestment Grade	78	11	67	3	46
Total as of December 31, 2013	$ 787	$ 18	$ 769	9	$ 381
Total as of December 31, 2012	$ 807	$ 13	$ 794	7	$ 338

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 December 31, 2013, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

The following table shows the end, high, average and low market risk as measured by VaR for the trading portfolio for the periods indicated:

VaR Model

Twelve Months Ended **Twelve Months Ended**

December 31, 2013				December 31, 2012			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ -	$ 1	$ -	$ -	$ -	$ 1	$ -	$ -

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

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

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which our interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of December 31, 2013 and 2012, the estimated EaR on our debt portfolio for the following twelve months was $32 million and $42 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2013 and 2012,and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 25, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the internal control over financial reporting of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2013, based on criteria established in *Internal Control — Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2013 of the Company and our report dated February 25, 2014 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 25, 2014

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a- 15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO 1992) in Internal Control – Integrated Framework. Based on management's assessment, AEP's internal control over financial reporting was effective as of December 31, 2013.

AEP's independent registered public accounting firm has issued an attestation report on AEP's internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2013, 2012 and 2011
(in millions, except per-share and share amounts)

	Years Ended December 31, 2013	2012	2011
REVENUES			
Vertically Integrated Utilities	$ 9,347	$ 8,785	$ 8,942
Transmission and Distribution Utilities	4,279	4,659	4,982
Generation & Marketing	1,208	882	563
Other Revenues	523	619	629
TOTAL REVENUES	15,357	14,945	15,116
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	4,068	4,111	4,421
Purchased Electricity for Resale	1,491	1,169	1,191
Other Operation	2,904	2,962	2,868
Maintenance	1,179	1,115	1,236
Asset Impairments and Other Related Charges	226	300	139
Depreciation and Amortization	1,743	1,782	1,655
Taxes Other Than Income Taxes	891	850	824
TOTAL EXPENSES	12,502	12,289	12,334
OPERATING INCOME	2,855	2,656	2,782
Other Income (Expense):			
Interest and Investment Income	58	8	27
Carrying Costs Income	30	53	393
Allowance for Equity Funds Used During Construction	73	93	98
Interest Expense	(906)	(988)	(933)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	2,110	1,822	2,367
Income Tax Expense	684	604	818
Equity Earnings of Unconsolidated Subsidiaries	58	44	27
INCOME BEFORE EXTRAORDINARY ITEM	1,484	1,262	1,576
EXTRAORDINARY ITEM, NET OF TAX	-	-	373
NET INCOME	1,484	1,262	1,949
Net Income Attributable to Noncontrolling Interests	4	3	3
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,480	1,259	1,946

Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	-	5
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,480	$ 1,259	$ 1,941
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	486,619,555	484,682,469	482,169,282
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Item	$ 3.04	$ 2.60	$ 3.25
Extraordinary Item, Net of Tax	-	-	0.77
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.04	$ 2.60	$ 4.02
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	487,040,956	485,084,694	482,460,328
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Item	$ 3.04	$ 2.60	$ 3.25
Extraordinary Item, Net of Tax	-	-	0.77
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.04	$ 2.60	$ 4.02

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2013, 2012 and 2011
(in millions)

	Years Ended December 31,		
	2013	2012	2011
Net Income	$ 1,484	$ 1,262	$ 1,949
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $8, $8 and $18 in 2013, 2012 and 2011, Respectively	15	(15)	(34)
Securities Available for Sale, Net of Tax of $1, $1 and $1 in 2013, 2012 and 2011, Respectively	3	2	(2)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $12, $16 and $13 in 2013, 2012 and 2011, Respectively	22	31	24
Pension and OPEB Funded Status, Net of Tax of $95, $62 and $41 in 2013, 2012 and 2011, Respectively	177	115	(77)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	217	133	(89)
TOTAL COMPREHENSIVE INCOME	1,701	1,395	1,860
Total Comprehensive Income Attributable to Noncontrolling Interests	4	3	3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,697	1,392	1,857
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	-	5
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,697	$ 1,392	$ 1,852

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2013, 2012 and 2011
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2010	501	$ 3,257	$ 5,904	$ 4,842	$ (381)	$ -	$ 13,622
Issuance of Common Stock	3	17	75				92
Common Stock Dividends ($1.85/share)				(894)		(4)	(898)
Preferred Stock Dividend Requirements of Subsidiaries				(2)			(2)
Loss on Reacquired Preferred Stock			(4)				(4)
Capital Stock Expense			(16)				(16)
Other Changes in Equity			11	(2)		2	11
Net Income				1,946		3	1,949
Other Comprehensive Loss					(89)		(89)
TOTAL EQUITY – DECEMBER 31, 2011	504	3,274	5,970	5,890	(470)	1	14,665
Issuance of Common Stock	2	15	68				83
Common Stock Dividends ($1.88/share)				(913)		(3)	(916)
Other Changes in Equity			11			(1)	10
Net Income				1,259		3	1,262
Other Comprehensive Income					133		133
TOTAL EQUITY – DECEMBER 31, 2012	506	3,289	6,049	6,236	(337)	-	15,237
Issuance of Common Stock	2	14	70				84
Common Stock Dividends ($1.95/share)				(950)		(4)	(954)
Other Changes in Equity			12			1	13
Net Income				1,480		4	1,484
Other Comprehensive Income					217		217
Pension and OPEB Adjustment Related to Mitchell Plant					5		5
TOTAL EQUITY – DECEMBER 31, 2013	508	$ 3,303	$ 6,131	$ 6,766	$ (115)	$ 1	$ 16,086

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2013 and 2012
(in millions)

		December 31,		
		2013		2012
CURRENT ASSETS				
Cash and Cash Equivalents	$	118	$	279
Other Temporary Investments (December 31, 2013 and 2012 Amounts Include $335 and $311, Respectively, Related to Transition Funding, Phase-in-Recovery Funding, Consumer Rate Relief Funding and EIS)		353		324
Accounts Receivable:				
Customers		746		685
Accrued Unbilled Revenues		157		195
Pledged Accounts Receivable - AEP Credit		945		856
Miscellaneous		72		171
Allowance for Uncollectible Accounts		(60)		(36)
Total Accounts Receivable		1,860		1,871
Fuel		701		844
Materials and Supplies		722		675
Risk Management Assets		160		191
Regulatory Asset for Under-Recovered Fuel Costs		80		88
Margin Deposits		70		76
Prepayments and Other Current Assets		246		241
TOTAL CURRENT ASSETS		4,310		4,589
PROPERTY, PLANT AND EQUIPMENT				
Electric:				
Generation		25,074		26,279
Transmission		10,893		9,846
Distribution		16,377		15,565
Other Property, Plant and Equipment (Including Plant to be Retired, Coal Mining and Nuclear Fuel)		5,470		3,945
Construction Work in Progress		2,471		1,819
Total Property, Plant and Equipment		60,285		57,454
Accumulated Depreciation and Amortization		19,288		18,691
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET		40,997		38,763
OTHER NONCURRENT ASSETS				
Regulatory Assets		4,376		5,106
Securitized Assets		2,373		2,117
Spent Nuclear Fuel and Decommissioning Trusts		1,932		1,706
Goodwill		91		91

Long-term Risk Management Assets	297	368
Deferred Charges and Other Noncurrent Assets	2,038	1,627
TOTAL OTHER NONCURRENT ASSETS	11,107	11,015
TOTAL ASSETS	$ 56,414	$ 54,367

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2013 and 2012
(dollars in millions)

	December 31, 2013	December 31, 2012
CURRENT LIABILITIES		
Accounts Payable	$ 1,266	$ 1,169
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	700	657
Other Short-term Debt	57	324
Total Short-term Debt	757	981
Long-term Debt Due Within One Year (December 31, 2013 and 2012 Amounts Include $416 and $367, Respectively, Related to Transition Funding, DCC Fuel, Phase-in-Recovery Funding, Consumer Rate Relief Funding and Sabine)	1,549	2,171
Risk Management Liabilities	90	155
Customer Deposits	299	316
Accrued Taxes	822	747
Accrued Interest	245	269
Regulatory Liability for Over-Recovered Fuel Costs	119	47
Other Current Liabilities	965	968
TOTAL CURRENT LIABILITIES	6,112	6,823
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2013 and 2012 Amounts Include $2,532 and $2,227, Respectively, Related to Transition Funding, DCC Fuel, Phase-in-Recovery Funding, Consumer Rate Relief Funding and Sabine)	16,828	15,586
Long-term Risk Management Liabilities	177	214
Deferred Income Taxes	10,300	9,252
Regulatory Liabilities and Deferred Investment Tax Credits	3,694	3,544
Asset Retirement Obligations	1,835	1,696
Employee Benefits and Pension Obligations	415	1,075
Deferred Credits and Other Noncurrent Liabilities	967	940
TOTAL NONCURRENT LIABILITIES	34,216	32,307
TOTAL LIABILITIES	40,328	39,130
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2013	**2012**

Shares Authorized	600,000,000	600,000,000		
Shares Issued	508,113,964	506,004,962		
(20,336,592 Shares were Held in Treasury as of December 31, 2013 and 2012)			3,303	3,289
Paid-in Capital			6,131	6,049
Retained Earnings			6,766	6,236
Accumulated Other Comprehensive Income (Loss)			(115)	(337)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			16,085	15,237
Noncontrolling Interests			1	-
TOTAL EQUITY			16,086	15,237
TOTAL LIABILITIES AND EQUITY			$ 56,414	$ 54,367

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2013, 2012 and 2011
(in millions)

	Years Ended December 31,		
	2013	2012	2011
OPERATING ACTIVITIES			
Net Income	$ 1,484	$ 1,262	$ 1,949
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,743	1,782	1,655
Deferred Income Taxes	709	636	794
Gain on Settlement with BOA and Enron	-	-	(51)
Settlement of Litigation with BOA and Enron	-	-	(211)
Extraordinary Item, Net of Tax	-	-	(373)
Asset Impairments and Other Related Charges	226	300	139
Carrying Costs Income	(30)	(53)	(393)
Allowance for Equity Funds Used During Construction	(73)	(93)	(98)
Mark-to-Market of Risk Management Contracts	38	57	37
Amortization of Nuclear Fuel	131	136	137
Pension Contributions to Qualified Plan Trust	-	(200)	(450)
Property Taxes	(35)	(19)	(15)
Fuel Over/Under-Recovery, Net	62	157	(25)
Deferral of Ohio Capacity Costs, Net	(214)	(65)	-
Change in Other Noncurrent Assets	(184)	(171)	(112)
Change in Other Noncurrent Liabilities	3	127	307
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	5	(16)	107
Fuel, Materials and Supplies	122	(224)	176
Accounts Payable	95	(60)	(44)
Accrued Taxes, Net	85	174	193
Other Current Assets	5	(3)	37
Other Current Liabilities	(66)	77	29
Net Cash Flows from Operating Activities	4,106	3,804	3,788
INVESTING ACTIVITIES			
Construction Expenditures	(3,624)	(3,025)	(2,669)
Change in Other Temporary Investments, Net	(11)	(27)	8
Purchases of Investment Securities	(927)	(1,047)	(1,321)
Sales of Investment Securities	858	988	1,379
Acquisitions of Nuclear Fuel	(154)	(107)	(106)
Acquisitions of Assets/Businesses	(32)	(94)	(19)
Acquisition of Cushion Gas from BOA	-	-	(214)
Insurance Proceeds Related to Cook Plant Fire	72	-	-
Proceeds from Sales of Assets	21	18	123
Other Investing Activities	(21)	(97)	(71)
Net Cash Flows Used for Investing Activities	(3,818)	(3,391)	(2,890)

FINANCING ACTIVITIES			
Issuance of Common Stock, Net	84	83	92
Issuance of Long-term Debt	3,207	2,856	1,328
Commercial Paper and Credit Facility Borrowings	17	25	488
Change in Short-term Debt, Net	(221)	(654)	744
Retirement of Long-term Debt	(2,598)	(1,643)	(1,665)
Retirement of Cumulative Preferred Stock	-	-	(64)
Proceeds from Nuclear Fuel Sale/Leaseback	110	-	-
Commercial Paper and Credit Facility Repayments	(20)	(40)	(928)
Principal Payments for Capital Lease Obligations	(82)	(71)	(71)
Dividends Paid on Common Stock	(954)	(916)	(898)
Dividends Paid on Cumulative Preferred Stock	-	-	(2)
Other Financing Activities	8	5	5
Net Cash Flows Used for Financing Activities	(449)	(355)	(971)
Net Increase (Decrease) in Cash and Cash Equivalents	(161)	58	(73)
Cash and Cash Equivalents at Beginning of Period	279	221	294
Cash and Cash Equivalents at End of Period	$ 118	$ 279	$ 221

See Notes to Consolidated Financial Statements beginning on page 60.

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

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

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

Our principal business is the generation, transmission and distribution of electric power. The subsidiaries that conduct most of these activities are regulated by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with the FERC and other regulatory guidelines. Most of these companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We provide competitive electric supply for residential, commercial and industrial customers in Ohio, Illinois and other deregulated electricity markets and also provide energy management solutions throughout the United States, including energy efficiency services through our independent retail electric supplier.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States and provide various energy-related services. In addition, our operations include nonregulated wind farms and barging operations.

Corporate Separation

Background

On December 31, 2013, based on FERC and PUCO orders which approved corporate separation of generation assets and associated liabilities, OPCo transferred its generation assets and related generation liabilities at net book value to AGR. In accordance with Ohio law, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. Effective January 1, 2014, OPCo will purchase power from both affiliated and nonaffiliated entities, subject to PUCO approval, to meet the energy and capacity needs of customers.

On December 31, 2013, subsequent to the transfer of OPCo's generation assets and associated liabilities to AGR, AGR transferred at net book value its ownership (867 MW) in Amos Plant, Unit 3 to APCo. The transfer of these generation assets and associated liabilities was approved by the FERC, the Virginia SCC and the WVPSC.

On December 31, 2013, subsequent to the transfer of OPCo's generation assets and associated liabilities to AGR, AGR transferred at net book value a one-half interest (780 MW) in the Mitchell Plant to KPCo. The transfer of these generation assets and associated liabilities was approved by the FERC and the KPSC.

Other Impacts of Corporate Separation

In accordance with our December 2010 announcement and our October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

Effective January 1, 2014, the FERC approved:

- PCA among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, APCo, I&M and KPCo will be individually responsible for planning their respective capacity obligations and there will be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

- Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance

Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to meet capacity obligations of member companies through May 31, 2015.

- Power Supply Agreement (PSA) between AGR and OPCo for AGR to supply capacity for OPCo's switched (at $188.88/MW day) and non-switched retail load for the period January 1, 2014 through May 31, 2015 and to supply the energy needs of OPCo's non-switched retail load that is not acquired through auctions from January 1, 2014 through December 31, 2014.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

Our public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in our eleven state operating territories. The FERC also regulates our affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of our public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires a nonregulated affiliate to bill an affiliated public utility company at no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. Our wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when we negotiate and file a cost-based contract with the FERC or the FERC determines that we have "market power" in the region where the transaction occurs. We have entered into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually. Our wholesale power transactions in the SPP region are currently cost-based within our balancing authority due to the FERC's finding that PSO and SWEPCo have market power in the SPP region.

The state regulatory commissions regulate all of the distribution operations and rates of our retail public utilities on a cost basis. The state regulatory commissions also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. The ESP rates in Ohio continue the process of transitioning generation/power supply rates over time to market rates. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing and is conducted by Texas Retail Electric Providers (REPs). Through our nonregulated subsidiaries, we enter into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT. We have no active REPs in ERCOT.

The FERC also regulates our wholesale transmission operations and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia, I&M's retail transmission rates in Michigan and TCC's and TNC's retail transmission rates in Texas are unbundled. OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia and I&M's retail transmission rates in Michigan are based on formula rates included in the PJM OATT that are cost-based. Although TCC's and TNC's retail transmission rates in Texas are unbundled, retail transmission rates are regulated, on a cost basis, by the PUCT. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions. Transmission rates for our seven wholly-owned transmission subsidiaries within our AEP

Transmission Holdco segment are based on formula rates included in the applicable RTO's OATT that are cost-based.

In addition, the FERC regulates the SIA, the Operating Agreement, the System Transmission Integration Agreement, the Transmission Agreement and the Transmission Coordination Agreement, all of which are still active and allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement. In accordance with management's December 2010 announcement and October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance

Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated. In December 2013, the FERC issued orders approving the creation of a PCA, effective January 1, 2014. Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent.

Principles of Consolidation

Our consolidated financial statements include our wholly-owned and majority-owned subsidiaries and VIEs of which we are the primary beneficiary. Intercompany items are eliminated in consolidation. We use the equity method of accounting for equity investments where we exercise significant influence but do not hold a controlling financial interest. Such investments are recorded as Deferred Charges and Other Noncurrent Assets on the balance sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. We have ownership interests in generating units that are jointly-owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included on the statements of income and our proportionate share of the assets and liabilities are reflected on the balance sheets.

Accounting for the Effects of Cost-Based Regulation

As the owner of rate-regulated electric public utility companies, our financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," we record regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

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.

We classify our investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of "Investments – Debt and Equity Securities" accounting guidance. We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in AOCI. Held-to-maturity securities reflected in Other Temporary Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method.

In evaluating potential impairment of securities with unrealized losses, we considered, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, our intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions. See “Fair Value Measurements of Other Temporary Investments” in Note 11.

Inventory

Fossil fuel inventories are generally carried at average cost with the exception of AGR and TNC which are carried at the lower of average cost or market. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

We recognize revenue from electric power sales when we deliver power to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, for I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo’s accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the billed and unbilled receivables AEP Credit acquires from affiliated utility subsidiaries.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. For receivables related to APCo’s West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables related to our risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For the wires business of TCC and TNC, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

Emission Allowances

In regulated jurisdictions, we record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. For our nonregulated business, we record allowances at the lower of cost or market. We follow the inventory model for these allowances. We record allowances expected to be consumed within one year in Materials and Supplies and allowances with expected consumption beyond one year in Deferred Charges and Other Noncurrent Assets on the balance sheets. We record the consumption of allowances in the production of energy in Fuel and Other Consumables Used for Electric Generation on the statements of income at an average cost. We report the purchases and sales of allowances in the Operating Activities section of the statements of cash flows. We record the net margin on sales of emission allowances in Vertically Integrated Utilities Revenue on the statements of income because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment and Equity Investments

Regulated

Electric utility property, plant and equipment for our rate-regulated operations are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain our plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense. Equity investments are required to be tested for impairment when it is determined there may be an other-than-temporary loss in value.

The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Nonregulated

Our nonregulated operations generally follow the policies of our rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations and equity investments (included in Deferred Charges and Other Noncurrent Assets) are stated at fair value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. For nonregulated plant assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

For regulated operations, AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. We record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense. For nonregulated operations, including certain generating assets, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest."

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Accounts Payable and Short-term Debt approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Fair Value Measurements of Assets and Liabilities

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

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 benefit plan and 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 benefits and 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. Benefit plan assets included in Level 3 are primarily real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit our fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a FAC under-recovery is no longer probable of recovery, we adjust our FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes.

Changes in fuel costs, including purchased power in Kentucky for KPCo, in Indiana and Michigan for I&M, in Ohio (beginning in 2012 through the ESP related to non-auction standard service offer load served) for OPCo, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO and in Virginia and West Virginia (upon securitization in November 2013) for APCo are reflected in rates in a timely manner generally through the FAC. Changes in fuel costs, including purchased power in Ohio (beginning in 2009 through 2011) for OPCo and in West Virginia (prior to securitization in November 2013) for APCo are reflected in rates through FAC phase-in plans. The FAC generally includes some sharing of off-system sales. In West Virginia for APCo, all of the profits from off-system sales are given to customers through the FAC. None of the profits from off-system sales are given to customers through the FAC in Ohio for OPCo. A portion of profits from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas for SWEPCo, Kentucky for KPCo, Virginia for APCo and in Indiana and Michigan for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

Our financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheets. We test for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

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. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Most of the power produced at the generation plants in the east service territory is sold to PJM. We purchase power from PJM to supply our customers. Generally, these power sales and purchases are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on the statements of income. Other RTOs in which we participate do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's economic substance. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, we record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

We engage in wholesale power, coal and natural gas marketing and risk management activities focused on wholesale markets where we own assets and adjacent markets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. We engage in certain energy marketing and risk management transactions with RTOs.

We recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. We include unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in Revenues on the statements of income on a net basis. In jurisdictions subject to cost-based regulation, we defer unrealized MTM amounts and some realized gains and losses as regulatory assets (for losses) and regulatory liabilities (for gains). We include unrealized MTM gains and losses resulting from derivative contracts on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). We initially record the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, we subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on the statements of income. Excluding those jurisdictions subject to cost-based regulation, we recognize the ineffective portion of the gain or loss in revenues or expense immediately on the statements of income, depending on the specific nature of the associated hedged risk. In regulated jurisdictions, we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 10.

Barging Activities

AEP River Operations' revenue is recognized based on percentage of voyage completion. The proportion of freight transportation revenue to be recognized is determined by applying a percentage to the contractual charges for such services. The percentage is determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer's freight contract. The position of the barge at accounting period end is determined by our computerized barge tracking system.

Levelization of Nuclear Refueling Outage Costs

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

Maintenance

We expense maintenance costs as incurred. If it becomes probable that we will recover specifically-incurred costs through future rates, we establish a regulatory asset to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. In certain regulatory jurisdictions, we defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, we provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), we record deferred income taxes and establish related regulatory assets and liabilities to match the regulated revenues and tax expense.

We account for investment tax credits under the flow-through method except where regulatory commissions reflect investment tax credits in the rate-making process on a deferral basis. We amortize deferred investment tax credits over the life of the plant investment.

We account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." We classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation expense.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. We do not recognize these taxes as revenue or expense.

Debt

We defer gains and losses from the reacquisition of debt used to finance regulated electric utility plants and amortize the deferral over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If we refinance the reacquired debt associated with the regulated business, the reacquisition costs attributable to the portions of the business subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Operations not subject to cost-based rate regulation report gains and losses on the reacquisition of debt in Interest Expense on the statements of income upon reacquisition.

We defer debt discount or premium and debt issuance expenses and amortize generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. We include the net amortization expense in Interest Expense on the statements of income.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. We do not amortize goodwill and intangible assets with indefinite lives. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. We test goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods. We amortize intangible assets with finite lives over their respective estimated lives to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

Investments Held in Trust for Future Liabilities

We have several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and spent nuclear fuel disposal. All of our trust funds' investments are diversified and managed in compliance with all laws and regulations. Our investment strategy for trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. We regularly review the actual asset allocations and periodically rebalance the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for our benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The investment policy for the pension fund allocates assets based on the funded status of the pension plan. The objective of the asset allocation policy is to reduce the investment volatility of the plan over time. Generally, more of the investment mix will be allocated to fixed income investments as the plan becomes better funded. Assets will be transferred away from equity investments into fixed income investments based on the market value of plan assets compared to the plan's projected benefit obligation. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	30.0 %
Fixed Income	55.0 %
Other Investments	15.0 %

OPEB Plans Assets	Target
Equity	66.0 %
Fixed Income	33.0 %
Cash	1.0 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, our investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, the concentration limits must not exceed:

- 3% in any single issuer
- 5% for private placements
- 5% for convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers, the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
  Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.

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- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. Our private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

We participate in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. We lend securities to borrowers approved by BNY Mellon in exchange for cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

We hold trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association (VEBA) trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Nuclear Trust Funds

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. The trust assets may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

We record securities held in these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets. We record these securities at fair value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. We record unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Stock-Based Compensation Plans

As of December 31, 2013, we had performance units and restricted stock units outstanding under the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP). This plan was last approved by shareholders in April 2010. Upon vesting, performance units are paid in cash and restricted stock units are settled in AEP Common Shares, except for restricted stock units granted after January 1, 2013 and vesting to executive officers, which are paid in cash.

We maintain a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes career share accounts maintained under the American Electric Power System Stock Ownership Requirement Plan, which facilitates executives in meeting minimum stock ownership requirements assigned to them by the Human Resources Committee of the Board of Directors. Career shares are derived from vested performance units granted to employees under the LTIP. Career shares are equal in value to shares of AEP common stock and become payable to executives in cash after their service ends. Dividends paid on career shares are reinvested as additional career shares.

We compensate our non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to directors after their service ends.

In January 2006, we adopted accounting guidance for "Compensation - Stock Compensation" which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including stock options, based on estimated fair values.

We recognize compensation expense for all share-based awards with service only vesting conditions granted on or after January 2006 using the straight-line single-option method. Stock-based compensation expense recognized on the statements of income for the years ended December 31, 2013, 2012 and 2011 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect estimated forfeitures. Accounting guidance for "Compensation - Stock Compensation" requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For the years ended December 31, 2013, 2012 and 2011, compensation expense is included in Net Income for the performance units, career shares, restricted shares, restricted stock units and the non-employee director's stock units. See Note 15 for additional discussion.

Earnings Per Share (EPS)

Shown below are income statement amounts attributable to AEP common shareholders:

Amounts Attributable to AEP Common Shareholders	Years Ended December 31, 2013	2012	2011
		(in millions)	
Income Before Extraordinary Item	$ 1,480	$ 1,259	$ 1,568
Extraordinary Item, Net of Tax	-	-	373
Earnings Attributable to AEP Common Shareholders	$ 1,480	$ 1,259	$ 1,941

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

The following table presents our basic and diluted EPS calculations included on the statements of income:

	Years Ended December 31, 2013		2012		2011	
	(in millions, except per share data)					
		$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,480		$ 1,259		$ 1,941	
Weighted Average Number of Basic Shares Outstanding	486.6	$ 3.04	484.7	$ 2.60	482.2	$ 4.02
Weighted Average Dilutive Effect of:						
Stock Options	-	-	-	-	0.1	-
Restricted Stock Units	0.4	-	0.4	-	0.2	-
Weighted Average Number of Diluted Shares Outstanding	487.0	$ 3.04	485.1	$ 2.60	482.5	$ 4.02

There were no antidilutive shares outstanding as of December 31, 2013, 2012 and 2011.

OPCo Revised Depreciation Rates

Effective December 1, 2011, we revised book depreciation rates for certain of OPCo's generation plants consistent with shortened depreciable lives for the generating units. This change in depreciable lives resulted in a $52 million increase in depreciation expense in 2012.

In the fourth quarter of 2012, we impaired certain Ohio generating units (see Note 7). As a result of this impairment of the full book value of these assets, we ceased depreciation on these generating units effective December 1, 2012.

In the second quarter of 2013, we impaired Muskingum River Plant, Unit 5 (MR5). As a result of this impairment of the full book value of this generating unit, we ceased depreciation on MR5 effective July 1, 2013.

Supplementary Related Party Information

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2013, AEP's ownership and investment in OVEC were 43.47% and $4.4 million, respectively.

OVEC's owners are members to an intercompany power agreement. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,200 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and provide a return on capital. In 2011, the intercompany power agreement was extended until June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests and OVEC's Board of Directors authorized capital expenditures totaling $1.4 billion in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at OVEC's two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2013, both generation plants were operating with new environmental controls.

The following details related party transactions for the years ended December 31, 2013, 2012 and 2011:

Related Party Transactions	Years Ended December 31, 2013	2012	2011
		(in millions)	
AEP Consolidated Revenues – Other Revenues			
OVEC – Barging and Other Transportation Services	$ 21	$ 30	$ 37
AEP Consolidated Expenses – Purchased Electricity for Resale:			
OVEC	289	273	383 (a)

(a) The parties to the Interconnection Agreement purchased power from OVEC to serve retail sales in 2011. The total amount reported in 2011 includes $66 million related to this agreement.

Supplementary Cash Flow Information

Cash Flow Information	Years Ended December 31, 2013	2012	2011
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 882	$ 931	$ 900
Income Taxes	(55)	(82)	(118)
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	182	63	54
Construction Expenditures Included in Current Liabilities as of December 31,	492	439	380
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	-	35	1
Assumption of Liabilities Related to Acquisitions	-	56	-
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	4	30	-

2. EXTRAORDINARY ITEM

TCC Texas Restructuring

In February 2006, the PUCT issued an order that denied recovery of capacity auction true-up amounts. Based on the February 2006 PUCT order, TCC recorded the disallowance as a $421 million ($273 million, net of tax) extraordinary loss in the December 31, 2005 financial statements. In July 2011, the Supreme Court of Texas reversed the PUCT's February 2006 disallowance of capacity auction true-up amounts and remanded for reconsideration the treatment of certain tax balances under normalization rules. Based upon the Supreme Court of Texas reversal of the PUCT's capacity auction true-up disallowance, TCC recorded a pretax gain of $421 million ($273 million, net of tax) in Extraordinary Item, Net of Tax on the statements of income in 2011.

Following a remand proceeding, the PUCT allowed TCC to retain contested tax balances in full satisfaction of its true-up proceeding, including carrying charges. Based upon the PUCT order, TCC recorded the reversal of regulatory credits of $65 million ($42 million, net of tax) and the reversal of $89 million of accumulated deferred investment tax credits ($58 million, net of tax) in Extraordinary Item, Net of Tax on the statements of income in 2011.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following table provides the components of changes in AOCI for the year ended December 31, 2013. All amounts in the following table are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2013

	Cash Flow Hedges			Pension and OPEB		
	Commodity	**Interest Rate and Foreign Currency**	**Securities Available for Sale**	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
			(in millions)			
Balance in AOCI as of December 31, 2012	$ (8)	$ (30)	$ 4	$ 112	$ (415)	$ (337)
Change in Fair Value Recognized in AOCI	10	2	3	-	177	192
Amounts Reclassified from AOCI	(2)	5	-	22	-	25
Net Current Period Other Comprehensive Income	8	7	3	22	177	217
Pension and OPEB Adjustment Related to Mitchell Plant	-	-	-	-	5	5
Balance in AOCI as of December 31, 2013	$ -	$ (23)	$ 7	$ 134	$ (233)	$ (115)

Reclassifications from Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the year ended December 31, 2013. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Year Ended December 31, 2013

Gains and Losses on Cash Flow Hedges	**Amount of (Gain) Loss Reclassified from AOCI (in millions)**
Commodity:	
Vertically Integrated Utilities Revenues	$ (1)
Generation & Marketing Revenues	(10)
Purchased Electricity for Resale	8
Property, Plant and Equipment	-
Regulatory Assets/(Liabilities), Net (a)	-
Subtotal - Commodity	(3)
Interest Rate and Foreign Currency:	
Interest Expense	7
Subtotal - Interest Rate and Foreign Currency	7
Reclassifications from AOCI, before Income Tax (Expense) Credit	4
Income Tax (Expense) Credit	1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	3
Gains and Losses on Securities Available for Sale	
Interest Income	-
Interest Expense	-
Reclassifications from AOCI, before Income Tax (Expense) Credit	-
Income Tax (Expense) Credit	-
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	-
Pension and OPEB	
Amortization of Prior Service Cost (Credit)	(21)
Amortization of Actuarial (Gains)/Losses	55
Reclassifications from AOCI, before Income Tax (Expense) Credit	34
Income Tax (Expense) Credit	12
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	22
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 25

Represents realized gains and losses subject to regulatory accounting treatment recorded as either

(a) current or noncurrent on the balance sheets.

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2012 and 2011. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2012

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2011	$ (3)	$ (20)	$ (23)
Changes in Fair Value Recognized in AOCI	(15)	(14)	(29)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Vertically Integrated Utilities Revenues	-	-	-
Generation & Marketing Revenues	(5)	-	(5)
Purchased Electricity for Resale	13	-	13
Other Operation Expense	-	-	-
Maintenance Expense	-	-	-
Interest Expense	-	4	4
Property, Plant and Equipment	-	-	-
Regulatory Assets (a)	2	-	2
Balance in AOCI as of December 31, 2012	$ (8)	$ (30)	$ (38)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2011

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2010	$ 7	$ 4	$ 11
Changes in Fair Value Recognized in AOCI	(5)	(28)	(33)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Vertically Integrated Utilities Revenues	1	-	1
Generation & Marketing Revenues	(3)	-	(3)
Purchased Electricity for Resale	(2)	-	(2)
Other Operation Expense	(1)	-	(1)
Maintenance Expense	(1)	-	(1)
Interest Expense	-	4	4
Property, Plant and Equipment	(1)	-	(1)
Regulatory Assets (a)	2	-	2
Balance in AOCI as of December 31, 2011	$ (3)	$ (20)	$ (23)

Represents realized gains and losses subject to regulatory accounting treatment recorded as either

(a) current or noncurrent on the balance sheets.

The following table provides details of changes in unrealized gains and losses related to Securities Available for Sale and the reasons for changes for the year ended December 31, 2012. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Securities Available for Sale
Year Ended December 31, 2012

		(in millions)
Balance in AOCI as of December 31, 2011	$	2
Changes in Fair Value Recognized in AOCI		2
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income:		
Interest Income		-
Balance in AOCI as of December 31, 2012	$	4

4. RATE MATTERS

Our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. Our recent significant rate orders and pending rate filings are addressed in this note.

OPCo Rate Matters

Ohio Electric Security Plan Filings

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018. The PUCO's March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers' Counsel (OCC) and the IEU filed appeals of that order with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance. As of December 31, 2013, OPCo's net deferred fuel balance was $445 million, excluding unrecognized equity carrying costs. In February 2014, the Supreme Court of Ohio affirmed the PUCO's decision and rejected all appeals filed by the OCC and the IEU. In February 2014, the IEU filed for reconsideration of the Supreme Court of Ohio decision.

In August 2012, the PUCO issued an order in a separate proceeding which implemented a Phase-In Recovery Rider (PIRR) to recover deferred fuel costs in rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. In November 2012, OPCo filed an appeal at the Supreme Court of Ohio related to the PUCO decision in the PIRR proceeding claiming a long-term debt rate modified the previously adjudicated 2009 – 2011 ESP order, which granted a weighted average cost of capital rate. In November 2012, the IEU and the OCC filed appeals regarding the PUCO decision in the PIRR proceeding. These appeals principally argued that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues which could reduce OPCo's net deferred fuel balance up to the total balance. These intervenors' appeals also argued that carrying costs should be reduced due to an accumulated deferred income tax credit which, as of December 31, 2013, could reduce carrying costs by $31 million including $16 million of unrecognized equity carrying costs. A decision from the Supreme Court of Ohio is pending.

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

In July 2011, OPCo filed its 2010 SEET filing with the PUCO. In October 2013, the PUCO issued an order on the 2010 SEET filing that determined there were excessive earnings of $7 million, which were primarily offset against deferred fuel, as ordered. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. In November 2013, OPCo filed its 2011 and 2012 SEET filings with the PUCO. In February 2014, the PUCO staff filed testimony asserting that no significantly excessive earnings had occurred in 2011 for CSPCo or OPCo and that no significantly excessive earnings had occurred in 2012 for OPCo. In February 2014, OPCo entered into a stipulation agreement with the PUCO staff in which both parties agree that there were no significantly excessive earnings in 2011 for CSPCo or OPCo. A hearing at the PUCO related to the 2011 SEET filing is scheduled for February 2014. Management does not believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo or in either 2012 or 2013 for OPCo.

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

June 2012 – May 2015 ESP Including Capacity Charge

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

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (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 RPM price is approximately $33/MW day through May 2014 and $148/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 Retail Stability Rider (RSR), effective September 2012. The RSR is being collected from customers at $3.50/MWh through May 2014 and will be collected at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. As of December 31, 2013, OPCo's incurred deferred capacity costs balance of $288 million, including debt carrying costs, was recorded in Regulatory Assets on the balance sheet.

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

In November 2013, the PUCO issued an order approving OPCo's CBP with modifications. The modifications include the delay of the energy auctions that were originally ordered in the ESP order. OPCo must conduct an energy-only auction for 10% of the SSO load with delivery beginning April 2014 through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning November 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit. In December 2013, the PUCO granted applications for rehearing for further consideration filed by OPCo and intervenors. 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.

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

Proposed June 2015 – May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that includes proposed rate adjustments and the continuation and modification of certain existing riders, including the Distribution Investment Rider (DIR), effective June 2015 through May 2018. This filing is consistent with the PUCO's objective for a full transition from FAC and base generation rates to market. The proposal includes a recommended auction schedule, a return on common equity of 10.65% on capital costs for certain riders and estimates an average decrease in rates of 9% over the three-year term of the plan for customers who receive their RPM and energy auction-based generation through OPCo. Additionally, the application identifies OPCo's intention to submit a separate application to continue the RSR established in the June 2012 – May 2015 ESP in which the unrecovered portion of the deferred capacity costs will continue to be collected at the rate of $4.00/MWh until the balance of the capacity deferrals has been collected. Management intends to file this application in the first quarter of 2014.

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 April 2013, the FERC issued orders approving the transfer of OPCo's generation assets 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, the PUCO approved OPCo's application to amend the corporate separation plan by permitting OPCo to retain certain rights to purchase power from OVEC. The approval is subject to the condition that energy from the OVEC entitlements are sold into the day-ahead or real-time PJM energy markets, or on a forward basis through a bilateral arrangement. In December 2013, corporate separation of OPCo's generation assets was completed. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters.

Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates. The SDRR seeks recovery of 2012 incremental storm distribution expenses over twelve months starting with the effective date of the SDRR as approved by the PUCO. In December 2013, a stipulation agreement was reached between OPCo, the PUCO staff and all intervenors except the OCC. The stipulation included a $6 million reduction in the amount of 2012 storm expenses to be recovered and for recovery of those expenses to take place over a 12-month period. The agreement also states that carrying charges using a long-term debt rate will be assessed from April 2013 until recovery begins, but no additional carrying charges will accrue during the actual recovery period. In December 2013, the OCC filed testimony opposing the stipulation. The testimony recommended the disallowance of approximately $18 million of the 2012 storm expenses and that the remaining 2012 storm expenses be offset by an additional $20 million that OPCo was ordered to spend on a solar project in OPCo's 2009 SEET filing. See the "2009-2011 ESP" section above. Hearings were held at the PUCO in January 2014 related to the settlement agreement and to address issues presented in the OCC's testimony. As of December

31, 2013, OPCo has deferred $56 million in Regulatory Assets on the balance sheet related to 2012 storm damage. If OPCo is not ultimately permitted to recover these storm costs, it could reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

In January 2012, the PUCO issued an order in OPCo's 2009 FAC that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. As a result, OPCo recorded a $30 million net favorable adjustment on the statement of income in 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of any future consultant recommendation regarding valuation of the coal reserve. 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.

In August 2012, intervenors filed an appeal with the Supreme Court of Ohio claiming the settlement credit ordered by the PUCO should have reflected the remaining gain not already flowed through the FAC with carrying charges, which, if ordered, would be $35 million plus carrying charges. If the Supreme Court of Ohio ultimately determines that additional amounts should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audit reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes with the use of a weighted average cost of capital (WACC). The PUCO subsequently ruled in the PIRR proceeding that the fuel clause for these years was approved with a WACC carrying cost and that the carrying costs on the balance should not be net of accumulated income taxes. Hearings at the PUCO were held in November 2013. If the PUCO orders result in a reduction to the FAC deferral, it could reduce future net income and cash flows and impact financial condition. See the 2009-2011 ESP section of the "Ohio Electric Security Plan Filing" related to the PUCO order in the PIRR proceeding.

Ormet

Ormet, a large aluminum company, had a contract to purchase power from OPCo through 2018. In February 2013, Ormet filed Chapter 11 bankruptcy proceedings in the state of Delaware. In October 2013, Ormet announced that it was unable to emerge from bankruptcy and shut down operations effective immediately. Based upon previous PUCO rulings providing rate assistance to Ormet, the PUCO is expected to permit OPCo to recover unpaid Ormet amounts through the Economic Development Rider, except where recovery from ratepayers is limited to $20 million related to previously deferred payments from Ormet's October and November 2012 power bills. OPCo expects that any additional unpaid generation usage by Ormet will be recoverable as a regulatory asset through the Economic Development Rider (EDR). In February 2014, a stipulation agreement between OPCo and Ormet was filed with the PUCO. The stipulation recommends approval of OPCo's right to fully recover approximately $49 million of foregone revenues through the EDR which, as of December 31, 2013, is recorded in regulatory assets on the balance sheet. Also in February 2014, intervenor comments were filed objecting to full recovery of these forgone revenues.

In addition, in the 2009 – 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related revenues under a previous interim arrangement (effective from January 2009 through September 2009) and requested that the PUCO prevent OPCo from collecting Ormet-related revenues in the future. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred

FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. The PUCO did not take any action on this request. The intervenors raised this issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement.

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

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. As of December 31, 2013, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions with the PUCO requesting that OPCo refund all collected pre-construction costs to Ohio ratepayers with interest.

Management cannot predict the outcome of this proceeding concerning the Ohio IGCC plant or what effect, if any, this proceeding could have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

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. As of December 31, 2013, SWEPCo's share of incurred construction expenditures for the Turk Plant was approximately $1.758 billion. As of December 31, 2013, a pretax provision of $59 million has been recorded for costs incurred in excess of a Texas cost cap, resulting in total net capitalized expenditures of $1.699 billion.

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 Turk Plant output that is currently not subject to cost-based rate recovery and is being sold into the wholesale market.

The PUCT approved a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated $1.522 billion projected cash construction cost, excluding related transmission costs, (b) a cap on recovery of annual CO_2 emission costs at $28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. The PUCT decision was upheld on appeal. See the "2012 Texas Base Rate Case" disclosure below for a discussion of a PUCT order on the Texas capital cost cap.

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

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million, primarily due to the Turk Plant, based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share (approximately 33%) of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. The filing also (a) increased depreciation expense due to the decrease in the average remaining life of the Welsh Plant to account for the change in the retirement date of the Welsh Plant, Unit 2 from 2040 to 2016 and (b) included a return on and of the Stall Unit as of December 2011 and associated operation and maintenance costs.

In October 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determining that the Turk Plant Texas capital cost cap established in the Certificate of Convenience and Necessity (CCN) case discussed above (the Texas capital cost cap) also limited SWEPCo's recovery of AFUDC in addition to its recovery of cash construction costs. As a result of the determination that AFUDC was to be included in the cap, in the third quarter of 2013, SWEPCo recorded an additional pretax regulatory disallowance of $111 million. The order approved an annual rate increase of approximately $39 million based upon a return on common equity of 9.65%, including an unfavorable consolidated income tax adjustment of $5 million. As a result of this approval, SWEPCo retroactively applied the rate increase to the end of January 2013. The order also provided that there would be no disallowance to the existing book investment in the Stall Unit and that the Turk Plant related transmission line investment that was not in service at the end of the test year would be excluded from rate base. SWEPCo has since sought approval to recover this transmission investment through a Transmission Cost Recovery Rider in a filing made in December 2013. 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 December 31, 2013, the net book value of Welsh Plant, Unit 2 was $87 million, before cost of removal, including materials and supplies inventory and CWIP.

In October 2013, SWEPCo filed a motion for rehearing with the PUCT. In December 2013, the PUCT issued an order granting rehearing and reversed its decision on consolidated tax savings increasing SWEPCo's annual revenues by $5 million. In January 2014, the PUCT determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result of these rulings, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. These rulings also increased SWEPCo's previously approved annual base rates by a total of $13 million, which was also retroactively applied to the end of January 2013. The resulting annual base rate increase is approximately $52 million.

If SWEPCo cannot ultimately recover its Texas jurisdictional share of the investment and expenses related to the Welsh Plant, Unit 2 and its retirement-related costs, it could reduce future net income and cash flows and impact financial condition.

2013 Texas Transmission Costs Recovery Factor Filing

In December 2013, SWEPCo filed an application to implement its initial transmission cost recovery factor (TCRF) requesting additional annual revenue of $10 million. The TCRF is designed to recover increases from the amounts included in SWEPCo's Texas retail base rates for transmission infrastructure improvement costs and wholesale transmission charges under a tariff approved by the FERC. SWEPCo's application included Turk Plant transmission-related costs. In January and February 2014, intervenors filed motions with the PUCT opposing SWEPCo's filing. In February 2014, an Administrative Law Judge issued an order requesting additional information from SWEPCo related to this filing. If the PUCT were to disallow any portion of the TCRF, it could reduce future net income and cash flows.

2012 Louisiana Formula Rate Filing

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

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is $408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at $204 million. In July 2013, the APSC approved the request to install environmental controls at the Flint Creek Plant.

APCo and WPCo Rate Matters

Plant Transfers

In October 2012, the AEP East Companies submitted several filings with the FERC regarding the transfer of certain generation plants within the AEP System. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters. In December 2012, APCo and WPCo filed requests with the Virginia SCC and the WVPSC for approval to transfer at net book value to APCo a two-thirds interest in Amos Plant, Unit 3 and a one-half interest in the Mitchell Plant, comprising 1,647 MW of generating capacity. In July 2013, the Virginia SCC approved the transfer of the two-thirds interest in the Amos Plant, Unit 3 to APCo, but directed that an amount equal to $83 million pretax be removed from the proposed transfer price. The Virginia jurisdictional share of the disallowance was approximately $39 million. The Virginia SCC also denied the proposed transfer of the one-half interest in the Mitchell Plant to APCo.

In December 2013, the WVPSC approved the transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo but deferred a final decision related to the recovery of West Virginia's jurisdictional share of the $83 million pretax Virginia SCC disallowance until APCo's next West Virginia base rate case which APCo has agreed to file no later than June 2014. The West Virginia and FERC jurisdictional share of the potential disallowance is approximately $44 million pretax. Additionally, the WVPSC order also approved a rate surcharge for Amos Plant, Unit 3 effective January 2014 and deferred ruling on the transfer of the one-half interest in the Mitchell Plant to APCo. The surcharge was offset by an equal reduction in ENEC revenue with no overall change in total revenue.

In December 2013, the transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo was completed. As a result of the Virginia order, in the fourth quarter of 2013, APCo recorded a pretax regulatory disallowance of $39 million in Asset Impairments and Other Related Charges on the statement of income. Management continues to review its options related to the remaining one-half interest in the Mitchell Plant currently owned by AGR. If APCo and WPCo are not ultimately permitted to recover their Amos Plant, Unit 3 incurred costs in West Virginia and FERC, it could reduce future net income and cash flows and impact financial condition.

APCo IGCC Plant

As of December 31, 2013, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $10 million applicable to its Virginia jurisdiction. If the costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2013 Virginia Environmental Rate Adjustment Clause (Environmental RAC) Filing

In March 2013, APCo filed with the Virginia SCC for approval of an environmental RAC to recover $39 million related to 2012 and 2011 environmental compliance costs, including carrying costs. In March 2013, the environmental RAC surcharge expired related to the collection of 2009 and 2010 environmental compliance costs. In November 2013, the Virginia SCC approved a settlement agreement which recommended approval of an environmental RAC to recover $38 million of the 2012 and 2011 environmental compliance costs, effective January 2014 for a one-year period. The order also states that APCo must file its next environmental RAC petition on or before May 1, 2015. As of December 31, 2013, APCo has deferred $28 million for the Virginia portion of unrecovered environmental RAC costs incurred in 2012 and 2011, excluding $10 million of unrecognized equity carrying costs.

2013 Virginia Generation Rate Adjustment Clause (Generation RAC)Filing

In March 2013, APCo filed with the Virginia SCC to increase its generation RAC revenues by $12 million for a total of $38 million to collect costs related to the Dresden Plant. In December 2013, the Virginia SCC approved a settlement agreement that included an increase in the generation RAC to $39 million. Per the approved settlement agreement, the generation RAC increase was effective in February 2014 for a period of one year at which time the component to collect an under-recovery of approximately $10 million will cease and the remaining annual $29 million revenue to recover on-going Dresden Plant costs will continue. As of December 31, 2013, APCo has deferred $6 million for the Virginia portion of unrecovered costs of the Dresden Plant, excluding $5 million of unrecognized equity carrying costs.

2013 Virginia Transmission Rate Adjustment Clause (Transmission RAC)

In December 2013, APCo filed with the Virginia SCC to increase its transmission RAC revenues by $50 million annually. The increase in the transmission RAC is expected to be effective May 2014. In February 2014, a hearing was held at the Virginia SCC in which a stipulation agreement between APCo and the Virginia SCC staff was submitted to the Virginia SCC that recommended approval to increase the transmission RAC revenues by $49 million annually, subject to true-up. The stipulation included the Virginia SCC staff's commitment to fully audit APCo's transmission RAC under-recoveries and report its findings and recommendations in testimony in APCo's next transmission RAC filing in 2015. As of December 31, 2013, APCo has deferred $47 million for the Virginia portion of unrecovered transmission RAC costs. If the Virginia SCC were to disallow any portion of the transmission RAC, it could reduce future net income and cash flows.

2013 West Virginia Expanded Net Energy Charge (ENEC) Filing

In March 2012, West Virginia passed securitization legislation which allowed the WVPSC to establish a regulatory framework for electric utilities to securitize certain deferred ENEC balances and other ENEC-related assets. In August 2013, the WVPSC approved a settlement that included (a) a $56 million reduction in ENEC revenues, offset by a $6 million annual increase in construction surcharges, effective September 2013 and subject to true-up, (b) an agreement to file a base case no later than June 2014 and (c) the deferral of $21 million from the ENEC recovery balance with the ability to include that amount in the ENEC recovery balance upon reaching certain coal inventory levels at the Amos Plant. In September 2013, the WVPSC approved a settlement agreement filed by APCo, WPCo and intervenors which authorized APCo to securitize $376 million, plus upfront financing costs, primarily related to the December 2011 under-recovered ENEC deferral balance. In November 2013, APCo issued $380 million of Securitization Bonds to securitize the under-recovered ENEC deferral balance, including $4 million of upfront financing costs, with a final maturity date of August 2031. APCo implemented a new securitization rider which was offset by an equal reduction in ENEC revenues, with no overall change in total revenues.

As of December 31, 2013, APCo's ENEC net over-recovery balance was $86 million, of which $107 million was recorded in Regulatory Liabilities and $21 million was recorded in Regulatory Assets on the balance sheet.

Virginia Storm Costs

In March 2013, due to the 2013 enactment of a Virginia law, APCo wrote off $30 million of previously deferred 2012 Virginia storm costs. The change in law affected the test years to be included in APCo's next biennial Virginia base rate filing in March 2014 and the determination of how these costs are treated in the Virginia jurisdictional biennial earnings test for 2012 and 2013. As of December 31, 2013, APCo has not deferred any Virginia storm costs incurred in 2012 or 2013 based on actual 2012 and estimated 2013 Virginia jurisdictional earnings. The 2012 and 2013 earnings test will be filed in the first quarter of 2014 as part of APCo's biennial Virginia base rate filing.

PSO Rate Matters

2014 Oklahoma Base Rate Case

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

Oklahoma Environmental Compliance Plan

In September 2012, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES), Unit 4 in 2016 and additional environmental controls on NES, Unit 3 to continue operations through 2026. As of December 31, 2013, the net book values of NES, Units 3 and 4 were $208 million and $106 million, respectively, before cost of removal, including materials and supplies inventory and CWIP. In August 2013, the OCC dismissed PSO's environmental compliance plan case without prejudice but will permit PSO to seek recovery in a future proceeding. PSO will address the environmental compliance plan issues in future regulatory proceedings when it seeks cost recovery of the plan. If PSO is ultimately not permitted to fully recover its net book value of NES, Units 3 and 4 and other environmental compliance costs, it could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters

2011 Indiana Base Rate Case

In February 2013, the IURC issued an order that granted an $85 million annual increase in base rates based upon a return on common equity of 10.2%. In a March 2013 order, the IURC approved an adjustment which increased the authorized annual increase in base rates from $85 million to $92 million. In March 2013, the Indiana Office of Utility Consumer Counselor (OUCC) filed a request for reconsideration with the IURC, which was denied. Also in March 2013, the OUCC filed an appeal of the order with the Indiana Court of Appeals. In September 2013, the OUCC filed a brief on appeal that included objections to the inclusion of a prepaid pension asset in rate base, the use of an end-of-test-year amount for materials and supplies instead of a thirteen-month average and the application of an "outdated" capital structure. If any part of the IURC order is overturned by the Indiana Court of Appeals, it could reduce future net income and cash flows.

Cook Plant Life Cycle Management Project (LCM Project)

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the LCM Project, which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life (2034 for Unit 1 and 2037 for Unit 2). The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. As of December 31, 2013, I&M has incurred costs of $380 million related to the LCM Project, including AFUDC.

In July 2013, the IURC approved I&M's proposed project with the exception of an estimated $23 million related to certain items that might accommodate a future potential power uprate which the IURC stated I&M could seek recovery of in a subsequent base rate case. I&M will recover approved costs through an LCM rider which will be determined in semi-annual proceedings. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in rates. In October 2013, I&M filed an application with the IURC for LCM rider rates effective January 2014. In November 2013, the OUCC filed testimony identifying concerns related to the LCM rider that included the use of forecasted capital expenditures and the method used to calculate carrying charges. In December 2013, the IURC issued an interim order authorizing the implementation of LCM rider rates effective January 2014, subject to reconciliation upon the issuance of a final order by the IURC.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project and authorized deferral accounting for costs incurred related to the approved projects effective January 2013 until these costs are included in rates. In February 2013, intervenors filed appeals with the Michigan Court of Appeals objecting to the issuance of the CON as well as the amount of the CON related to the LCM Project.

If I&M is not ultimately permitted to recover its LCM Project costs, it could reduce future net income and cash flows and impact financial condition.

Rockport Plant Clean Coal Technology Project (CCT Project)

In April 2013, I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit both units of the Rockport Plant with a dry sorbent injection system. The estimated cost in the application was $285 million, excluding AFUDC, to be shared equally between I&M and AEGCo. The application requested deferral treatment of any unrecovered carrying costs incurred during construction and incremental post in-service depreciation expense and operation and maintenance expenses until such costs are recognized and recovered in a rider. I&M also requested cost recovery associated with the retrofit using the Clean Coal Technology Rider recovery mechanism.

In November 2013, the IURC approved a settlement agreement that included the approval of the CPCN with an updated estimated CCT Project cost of $258 million, excluding AFUDC, and the recovery of the Indiana jurisdictional share of I&M's ownership share. The settlement agreement specifies that 80% of the recoverable I&M direct ownership share of CCT Project costs will be recovered through a Federal Mandate Rider with the remaining 20% deferred until rates are established in a subsequent rate case. I&M's Indiana jurisdictional allocated share of the CCT Project costs received in the form of purchased power from AEGCo will be recovered in subsequent I&M rate cases. As of December 31, 2013, we have incurred costs of $109 million related to the CCT Project, including AFUDC.

Tanners Creek Plant, Units 1 - 4

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

In December 2013, I&M filed an application with the MPSC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and Tanners Creek Plant due to the retirement of the Tanners Creek Plant in 2015. Upon the retirement of the Tanners Creek Plant, I&M proposes that the net book value of the Tanners Creek Plant will be recovered over the remaining life of the Rockport Plant. I&M requested to have the impact of these new depreciation rates incorporated into the rates set in its next rate case. The new depreciation rates result in a decrease in I&M's Michigan jurisdictional electric depreciation expense which I&M proposes to implement in the month following a MPSC order in the revised depreciation case.

As of December 31, 2013, the net book value of the Tanners Creek Plant was $341 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.

KPCo Rate Matters

Plant Transfer

In October 2012, the AEP East Companies submitted several filings with the FERC. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters. In December 2012, KPCo filed a request with the KPSC for approval to transfer at net book value to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of December 31, 2013, the net book value of Big Sandy Plant, Unit 2 was $249 million, before cost of removal, including materials and supplies inventory and CWIP. In March 2013, KPCo issued a Request for Proposal (RFP) to purchase up to 250 MW of long-term capacity and energy to replace a portion of the capacity from Big Sandy Plant, Unit 1. In June 2013, KPCo filed the results of its RFP with the KPSC.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. The WVPSC order was subsequently issued in December 2013, but the WVPSC deferred a decision on the transfer of the one-half interest in the Mitchell Plant to APCo. The settlement also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set in the next base rate case (no earlier than June 2015), but rejected KPCo's request to defer FGD project costs for Big Sandy Plant, Unit 2. As a result of this order, in 2013, KPCo recorded a pretax regulatory disallowance of $33 million in Asset Impairments and Other Related Charges on the statement of income. In November 2013, the KPSC denied the Attorney General's petition for rehearing. In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In December 2013, KPCo filed motions with the Franklin County Circuit Court to dismiss the appeal. A hearing on the motions to dismiss was held in January 2014. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed.

2013 Kentucky Base Rate Case

In June 2013, KPCo filed a request with the KPSC for an annual increase in base rates of $114 million based upon a return on common equity of 10.65% to be effective January 2014. The proposed revenue increase included cost recovery of the proposed transfer of the one-half interest in the Mitchell Plant (780 MW). In October 2013, the KPSC issued an order in the plant transfer case which modified and approved a settlement agreement that included the approval of the proposed transfer of the one-half interest in the Mitchell Plant to KPCo. The modified and approved settlement agreement also included KPCo's agreement to withdraw this base rate case request and file a base case proceeding no later than December 2014 with its current base rates to remain in effect until at least May 2015. In November 2013, KPCo withdrew this base rate request and the withdrawal was approved by the KPSC.

FERC Rate Matters

Corporate Separation and Termination of Interconnection Agreement

In October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations. The filings requested approval to transfer at net book value (NBV) approximately 9,200 MW of OPCo-owned generation assets and associated liabilities to AGR. The AEP East Companies also requested FERC approval to transfer at NBV two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and transfer the Mitchell Plant at NBV to APCo and KPCo in equal one-half interests (780 MW each) to be effective December 31, 2013. In April 2013, the FERC issued orders approving the transfer of OPCo's generation assets to AGR, the transfers of the Amos Plant and Mitchell Plant to APCo and KPCo, respectively, and the merger of APCo and WPCo. In January 2014, the FERC dismissed an IEU petition for rehearing of its order granting OPCo authority to implement corporate separation by transferring its generation assets to AGR. Similar asset transfer filings were made at the KPSC, the Virginia SCC and the WVPSC. In December 2013, corporate separation of OPCo's generation assets was completed. See the "Plant Transfers" section of APCo and WPCo Rate Matters and the "Plant Transfer" section of KPCo Rate Matters.

In accordance with our December 2010 announcement and our October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

In December 2013, the FERC issued orders approving the creation of the PCA, effective January 1, 2014, conditioned upon certain compliance filings which were filed with the FERC in January 2014. The PCA was established among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, APCo, I&M and KPCo would be individually responsible for planning their respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to meet capacity obligations of member companies through May 31, 2015.

Additionally, FERC approval was sought for a Power Supply Agreement (PSA) between AGR and OPCo. This agreement provides for AGR to supply capacity for OPCo's switched (at $188.88/MW day) and non-switched retail load for the period January 1, 2014 through May 31, 2015 and to supply the energy needs of OPCo's non-switched retail load that is not acquired through an auction from January 1, 2014 through December 31, 2014. In December 2013, the FERC issued an order approving the PSA. The order conditioned the acceptance of the PSA on the revision of the agreement to reflect the PUCO's current and future underlying rates and rate structure. In January 2014, initial revisions to reflect current underlying rates and rate structure were filed at the FERC.

In October 2013, the AEP East Companies submitted additional filings with the FERC updating the October 2012 filings to reflect changes necessitated by orders from the Virginia SCC and the KPSC related to the proposed asset transfers and to position the company for the final stages of corporate separation. In December 2013, the FERC issued an order approving these additional filings. See the "Plant Transfers" section of APCo and WPCo Rate Matters and the "Plant Transfer" section of KPCo Rate Matters for a discussion of those orders.

If incurred costs are not ultimately recovered, it could reduce future net income and cash flows and impact financial condition.

5. EFFECTS OF REGULATION

Regulated Generating Units to be Retired Before or During 2016

The following regulated generating units are probable of abandonment. Accordingly, CWIP and Plant in Service has been reclassified as Other Property, Plant and Equipment on the balance sheet as of December 31, 2013. The following table summarizes the plant investment and cost of removal, currently being recovered, for each generating unit as of December 31, 2013.

Plant Name and Unit	Company	Gross Investment	Accumulated Depreciation	Net Investment	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
			(in millions)				
Tanners Creek Plant, Units 1-4	I&M	$ 681	$ 354	$ 327	$ 87	2015	17 years
Big Sandy Plant, Unit 2	KPCo	424	180	244	47	2015	27 years
Northeastern Station, Unit 4	PSO	182	89	93	11	2016	27 years
Welsh Plant, Unit 2	SWEPCo	175	93	82	19	2016	27 years
Total		$ 1,462	$ 716	$ 746	$ 164		

In accordance with accounting guidance for "Regulated Operations", APCo regulated generating units expected to be retired before or during 2016 are not considered probable of abandonment.

Regulatory Assets

Regulatory assets are comprised of the following items:

	December 31, 2013	2012	Remaining Recovery Period
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 61	$ 86	1 year
Under-recovered Fuel Costs - does not earn a return	19	2	1 year
Total Current Regulatory Assets	$ 80	$ 88	
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Earning a Return			
Storm Related Costs	$ 22	$ 23	
Ohio Economic Development Rider	14	13	
Other Regulatory Assets Not Yet Being Recovered	4	1	
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	161	172	
Ormet Special Rate Recovery Mechanism	36	5	
Indiana Under-Recovered Capacity Costs	22	-	
Expanded Net Energy Charge - Coal Inventory	21	-	
Mountaineer Carbon Capture and Storage Product Validation Facility	13	14	
Virginia Environmental Rate Adjustment Clause	2	29	
Litigation Settlement	-	11	
Other Regulatory Assets Not Yet Being Recovered	35	36	
Total Regulatory Assets Not Yet Being Recovered	330	304	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Ohio Fuel Adjustment Clause	445	519	5 years
Ohio Capacity Deferral	288	66	5 years
Ohio Transmission Cost Recovery Rider	87	49	2 years
Unamortized Loss on Reacquired Debt	81	82	30 years
Texas Meter Replacement Costs	77	47	15 years
Ohio Distribution Decoupling	31	-	2 years
Storm Related Costs	17	36	5 years
RTO Formation/Integration Costs	12	15	6 years
Red Rock Generating Facility	10	10	43 years
West Virginia Expanded Net Energy Charge	-	273	
Ohio Deferred Asset Recovery Rider	-	152	
Other Regulatory Assets Being Recovered	18	15	various
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	1,390	1,353	55 years

Pension and OPEB Funded Status	1,157	1,896	11 years
Cook Nuclear Plant Refueling Outage Levelization	58	27	3 years
Medicare Subsidy	51	-	11 years
Virginia Transmission Rate Adjustment Clause	47	33	2 years
Peak Demand Reduction/Energy Efficiency	44	12	2 years
Postemployment Benefits	40	45	5 years
United Mine Workers of America Pension Withdrawal	27	-	12 years
Virginia Environmental Rate Adjustment Clause	27	8	1 year
Under-Recovery of Transmission Cost Recovery Factor	20	6	1 year
Storm Related Costs	18	27	5 years
Vegetation Management	14	13	1 year
Deferred Restructuring Costs	11	15	5 years
Litigation Settlement	10	-	12 years
Under-Recovered Distribution Investment Rider	9	1	1 year
Asset Retirement Obligation	8	9	33 years
West Virginia Expanded Net Energy Charge	-	26	
Ohio Distribution Decoupling	-	16	
Deferred PJM Fees	-	14	
Unrealized Loss on Forward Commitments	-	8	
Other Regulatory Assets Being Recovered	49	29	various
Total Regulatory Assets Being Recovered	4,046	4,802	
Total Noncurrent Regulatory Assets	$ 4,376	$ 5,106	

Regulatory Liabilities

Regulatory liabilities are comprised of the following items:

	December 31, 2013	December 31, 2012	Remaining Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 9	$ 25	1 year
Over-recovered Fuel Costs - does not pay a return	110	22	1 year
Total Current Regulatory Liabilities	$ 119	$ 47	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
Louisiana Refundable Construction Financing Costs	$ -	$ 96	
Other Regulatory Liabilities Not Yet Being Paid	5	4	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Not Yet Being Paid	3	9	
Total Regulatory Liabilities Not Yet Being Paid	8	109	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,589	2,511	(a)
Louisiana Refundable Construction Financing Costs	78	-	5 years
Advanced Metering Infrastructure Surcharge	68	83	7 years
Deferred Investment Tax Credits	29	23	47 years
Excess Earnings	12	12	40 years
Other Regulatory Liabilities Being Paid	1	1	various
Regulatory Liabilities Currently Not Paying a Return			
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability	597	436	(b)
Deferred Investment Tax Credits	121	136	49 years
Spent Nuclear Fuel Liability	43	43	(b)
Over-Recovery of Transition Charges	40	57	14 years
Unrealized Gain on Forward Commitments	35	46	4 years
Deferred State Income Tax Coal Credits	28	29	10 years
Peak Demand Reduction/Energy Efficiency	18	31	1 year
Over-Recovery of PJM Expense	14	-	2 years
Other Regulatory Liabilities Being Paid	13	27	various
Total Regulatory Liabilities Being Paid	3,686	3,435	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 3,694	$ 3,544	

(a) Relieved as removal costs are incurred.
(b) Relieved when plant is decommissioned.

6. 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.

COMMITMENTS

Construction and Commitments

The AEP System has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, we contractually commit to third-party construction vendors for certain material purchases and other construction services. The subsidiaries purchase fuel, materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes our actual contractual commitments as of December 31, 2013:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 2,387	$ 3,358	$ 2,189	$ 2,480	$ 10,414
Energy and Capacity Purchase Contracts	195	410	457	2,634	3,696
Construction Contracts for Capital Assets (b)	146	-	-	-	146
Total	$ 2,728	$ 3,768	$ 2,646	$ 5,114	$ 14,256

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.

(b) Represents only capital assets for which we have signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

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 natural 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 December 31, 2013, the maximum future payments for letters of credit issued under the revolving credit facilities were $170 million with maturities ranging from February 2014 to April 2015.

In January 2014, we issued letters of credit utilizing the entire amount available under an $85 million uncommitted facility signed in October 2013. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

We have $352 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $356 million. The letters of credit have maturities ranging from March 2014 to March 2015. In February 2014, $106 million of bilateral letters of credit maturing in March 2014 were extended to March 2017.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of \$115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study completed in 2010, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately \$58 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of December 31, 2013, SWEPCo has collected approximately \$62 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 \$46 million is recorded in Asset Retirement Obligations on the balance sheets.

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

Indemnifications and Other Guarantees

Contracts

We enter into several 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 December 31, 2013, there were no material liabilities recorded for any indemnifications.

Lease Obligations

We lease certain equipment under master lease agreements. See “Master Lease Agreements” and “Railcar Lease” sections of Note 13 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance Claims

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs’ complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court’s decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. In March 2012, the court granted the defendants’ motion for dismissal on several grounds, including the doctrine of collateral estoppel and the applicable statute of limitations. In May 2013, the U.S. Court of Appeals for the Fifth Circuit affirmed the district court’s dismissal of the complaint. The plaintiffs did not appeal to the U.S. Supreme

Court.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. In September 2012, the Ninth Circuit Court of Appeals affirmed the trial court's decision, holding that the CAA displaced Kivalina's claims for damages. Plaintiffs filed seeking further review in the U.S. Supreme Court. In May 2013, the U.S. Supreme Court denied the plaintiffs' request for review.

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.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. As of December 31, 2013, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for five sites for which alleged liability is unresolved. There are eight additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at three sites under state law including the I&M site discussed in the next paragraph. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

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. I&M's reserve is approximately $8 million. As the remediation work is completed, I&M's cost may change as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. We cannot predict the amount of additional cost, if any.

We evaluate the potential liability for each Superfund site separately, but several general statements can be made about our potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. At present, our estimates do not anticipate material cleanup costs for any of our identified Superfund sites, except the I&M site discussed above.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). 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 generating 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 liability could be substantial.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2012. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $1.3 billion to $1.7 billion in 2012 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $10 million, $14 million and $14 million for the years ended December 31, 2013, 2012 and 2011, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2013 and 2012, the total decommissioning trust fund balance was $1.6 billion and $1.4 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income and cash flows would be reduced and financial condition could be impacted if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

The Federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. As of December 31, 2013 and 2012, fees and related interest of $265 million and $265 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $309 million and $308 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the Federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delays in accepting SNF for permanent storage. Under the settlement agreement, I&M received $31 million, $20 million and $14 million in 2013, 2012 and 2011, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2016. The proceeds reduced costs for dry cask storage. As of December 31, 2013, I&M has deferred $22 million in Prepayments and Other Current Assets and $7 million in Deferred Charges and Other Noncurrent Assets on the balance sheet of dry cask storage and related operation and maintenance costs for recovery under this agreement.

See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Nuclear Incident Liability

I&M carries insurance coverage for a nuclear incident at the Cook Plant for property damage, decommissioning and decontamination in the amount of $2.8 billion. Insurance coverage for a nonnuclear incident at the Cook Plant is $1.7 billion. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $39 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $13.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $375 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $121 million on each licensed reactor in the U.S. payable in annual installments of $19 million. As a result, I&M could be assessed $242 million per nuclear incident payable in annual installments of $38 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is initially covered for the first $375 million through commercially available insurance. The next level of liability coverage of up to $13.2 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made under the Price-Anderson Act, I&M would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

We maintain insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. Our insurance includes coverage for all risks of physical loss or damage to our nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. Our insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by us. Coverage is generally provided by a combination of our protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

See “Nuclear Contingencies” section of this footnote for a discussion of nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

Rockport Plant Litigation

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

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases.

We settled, received summary judgment or were dismissed from all of these cases. The plaintiffs appealed the Nevada federal district court's dismissal of several cases involving AEP companies to the U.S. Court of Appeals for the Ninth Circuit. In April 2013, the appellate court reversed in part, and affirmed in part, the district court's orders in these cases. The appellate court reversed the district court's holding that the state antitrust claims were preempted by the Natural Gas Act and the order dismissing AEP from two of the cases on personal jurisdiction grounds and affirmed the decision denying leave to the plaintiffs to amend their complaints in two of the cases. AEP filed a motion with the appellate court for rehearing on the issue of whether the district court had personal jurisdiction of AEP in the two referenced cases. No decision has been rendered on that motion. Defendants in these cases, including AEP, filed a petition seeking further review with the U.S. Supreme Court on the preemption issue, which is pending. We will continue to defend the cases. We believe the provision we have is adequate. We are unable to determine a range of potential losses that are reasonably possible of occurring.

7. ACQUISITIONS AND IMPAIRMENTS

ACQUISITIONS

2012

BlueStar Energy (Generation & Marketing segment)

In March 2012, we completed the acquisition of BlueStar Energy Holdings, Inc. (BlueStar) and its independent retail electric supplier BlueStar Energy Solutions for $70 million. This transaction also included goodwill of $15 million, intangible assets associated with sales contracts and customer accounts of $58 million and liabilities associated with supply contracts of $25 million. BlueStar has been in operation since 2002. Beginning in June 2012, BlueStar began doing business as AEP Energy. AEP Energy provides electric supply for retail customers in Ohio, Illinois and other deregulated electricity markets and also provides energy solutions throughout the United States, including demand response and energy efficiency services.

Other Matters

Enron Bankruptcy (Corporate and Other)

In February 2011, we reached a $425 million settlement covering all claims with BOA and Enron related to our purchase of Houston Pipeline Company (HPL) from Enron in 2001. As part of the settlement, we received title to the 55 billion cubic feet of natural gas in the Bammel storage facility and recorded this asset at fair value. Under the HPL sales agreement, we have a service obligation to the buyer for the right to use the cushion gas through May 2031. We recognized the obligation as a liability and will amortize it over the life of the agreement.

The settlement resulted in a pretax gain of $51 million and a net loss after tax of $22 million primarily due to an unrealized capital loss valuation allowance of $56 million.

IMPAIRMENTS

2013

Amos Plant, Unit 3 (Vertically Integrated Utilities segment)

In July 2013, the Virginia SCC approved the transfer of a two-thirds interest in the Amos Plant, Unit 3 to APCo but, for rate purposes, reduced the proposed transfer price by $83 million pretax. The Virginia jurisdictional share of the reduced price is approximately $39 million. In December 2013, the WVPSC issued an order that approved the transfer of a two-thirds interest in the Amos Plant, Unit 3 to APCo but deferred a final decision related to the $83 million pretax reduction in transfer price until APCo's next base rate case. The West Virginia and FERC jurisdictional share of the potential reduced transfer price is approximately $44 million. Upon evaluation, management believes the West Virginia jurisdictional share is probable of recovery. As a result of the Virginia order, in the fourth quarter of 2013, we recorded a pretax impairment of $39 million in Asset Impairments and Other Related Charges on the statement of income. See the "Plant Transfer" section of Note 4.

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

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

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

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

<u>2012</u>

Beckjord Plant, Unit 6, Conesville Plant, Unit 3, Kammer Plant, Units 1-3, Muskingum River Plant, Units 1-4, Sporn Plant, Units 2 and 4 and Picway Plant, Unit 5 (Generation & Marketing segment)

In October 2012, we filed applications with the FERC proposing to terminate the Interconnection Agreement and seeking to complete the corporate separation of OPCo's generation assets. Based on the intention to terminate the Interconnection Agreement and the FERC filing, we performed an evaluation of the recoverability of generation assets. As a result, in November 2012, we, using generating unit specific estimated future cash flows, concluded that we had a material impairment of certain Ohio generation assets. Under a market-based value approach, using level 3 unobservable inputs, we determined that the fair value of these generating units was zero based on the lack of installed environmental control equipment and the nature and condition of these generating units. In the fourth quarter of 2012, we recorded a pretax impairment of $287 million in Asset Impairments and Other Related Charges on the statement of income related to Beckjord Plant, Unit 6, Conesville Plant, Unit 3, Kammer Plant, Units 1-3, Muskingum River Plant, Units 1-4, Sporn Plant, Units 2 and 4 and Picway Plant, Unit 5 generating units which includes $13 million of related material and supplies inventory.

Turk Plant (Vertically Integrated Utilities segment)

In 2012, SWEPCo recorded a pretax write-off of $13 million in Asset Impairments and Other Related Charges on the statement of income related to unrecoverable construction costs subject to the Texas capital costs cap portion of the Turk Plant.

<u>2011</u>

Turk Plant (Vertically Integrated Utilities segment)

In the fourth quarter of 2011, SWEPCo recorded a pretax write-off of $49 million in Asset Impairments and Other Related Charges on the statement of income related to the Texas jurisdictional portion of the Turk Plant as a result of the November 2011 Texas Court of Appeals decision upholding the Texas capital cost cap.

Muskingum River Plant, Unit 5 FGD Project (MR5) (Generation & Marketing segment)

In September 2011, subsequent to the stipulation agreement filed with the PUCO, we determined that we were not likely to complete the previously suspended MR5 project and that the project's preliminary engineering costs were no longer probable of being recovered. As a result, in the third quarter of 2011, we recorded a pretax write-off of $42 million in Asset Impairments and Other Related Charges on the statement of income.

Sporn Plant, Unit 5 (Generation & Marketing segment)

In the third quarter of 2011, we decided to no longer offer the output of Sporn Plant, Unit 5 into the PJM Reliability Pricing Model auction. Sporn Plant, Unit 5 is not expected to operate in the future, resulting in the removal of Sporn Plant, Unit 5 from the Interconnection Agreement. As a result, in the third quarter of 2011, we recorded a pretax write-off of $48 million in Asset Impairments and Other Related Charges on the statement of income.

8. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1.

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.

We recognize the funded status associated with our defined benefit pension and OPEB plans in the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. We record a regulatory asset instead of other comprehensive income for qualifying benefit costs of our regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31 of each year used in the measurement of our benefit obligations are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2013**	**2012**	**2013**	**2012**
Discount Rate	4.70 %	3.95 %	4.70 %	3.95 %
Rate of Compensation Increase	4.85 % (a)	4.95 % (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

NA Not applicable.

We use a duration-based method to determine the discount rate for our plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2013, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 4.85%.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1 of each year used in the measurement of our benefit costs are shown in the following table:

	Pension Plans			Other Postretirement Benefit Plans		
	2013	**2012**	**2011**	**2013**	**2012**	**2011**
Discount Rate	3.95 %	4.55 %	5.05 %	3.95 %	4.75 %	5.25 %
Expected Return on Plan Assets	6.50 %	7.25 %	7.75 %	7.00 %	7.25 %	7.50 %
Rate of Compensation Increase	4.95 %	4.85 %	4.85 %	NA	NA	NA

NA Not applicable.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation and current prospects for economic growth.

The health care trend rate assumptions as of January 1 of each year used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2013	2012
Initial	6.75 %	7.00 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2020	2020

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 6	$ (4)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	74	(59)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. We monitor the plans to control security diversification and ensure compliance with our investment policy. As of December 31, 2013, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2013 and 2012

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status as of December 31. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		Other Postretirement Benefit Plans	
	2013	**2012**	**2013**	**2012**
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 5,205	$ 4,991	$ 1,849	$ 2,227
Service Cost	69	76	23	47
Interest Cost	203	223	71	103
Actuarial (Gain) Loss	(305)	299	(395)	148
Plan Amendment Prior Service Credit	-	-	-	(570)
Curtailment and Settlements	-	(1)	-	-
Benefit Payments	(331)	(383)	(140)	(151)
Participant Contributions	-	-	39	35
Medicare Subsidy	-	-	9	10
Benefit Obligation as of December 31,	$ 4,841	$ 5,205	$ 1,456	$ 1,849
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 4,696	$ 4,303	$ 1,568	$ 1,410
Actual Gain on Plan Assets	340	560	208	178
Company Contributions	6	216	24	96
Participant Contributions	-	-	39	35
Benefit Payments	(331)	(383)	(140)	(151)
Fair Value of Plan Assets as of December 31,	$ 4,711	$ 4,696	$ 1,699	$ 1,568
Funded (Underfunded) Status as of December 31,	$ (130)	$ (509)	$ 243	$ (281)

Amounts Recognized on the Balance Sheets as of December 31, 2013 and 2012

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	**2012**	**2013**	**2012**
	(in millions)			
Deferred Charges and Other Noncurrent Assets - Prepaid Benefit Costs	$ -	$ -	$ 264	$ -
Other Current Liabilities - Accrued Short-term Benefit Liability	(7)	(7)	(4)	(4)
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(123)	(502)	(17)	(277)
Funded (Underfunded) Status	$ (130)	$ (509)	$ 243	$ (281)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2013 and 2012

Components	Pension Plans 2013	Pension Plans 2012	Other Postretirement Benefit Plans 2013	Other Postretirement Benefit Plans 2012
	December 31,			
	(in millions)			
Net Actuarial Loss	$ 1,561	$ 2,111	$ 428	$ 989
Prior Service Cost (Credit)	8	11	(693)	(762)
Recorded as				
Regulatory Assets	$ 1,343	$ 1,774	$ (191)	$ 108
Deferred Income Taxes	79	122	(26)	42
Net of Tax AOCI	147	226	(48)	77

Components of the change in amounts included in AOCI and Regulatory Assets during the years ended December 31, 2013 and 2012 are as follows:

Components	Pension Plans 2013	Pension Plans 2012	Other Postretirement Benefit Plans 2013	Other Postretirement Benefit Plans 2012
	Years Ended December 31,			
	(in millions)			
Actuarial (Gain) Loss During the Year	$ (367)	$ 58	$ (496)	$ 67
Prior Service Credit	-	-	-	(570)
Amortization of Actuarial Loss	(183)	(155)	(65)	(57)
Amortization of Prior Service Credit (Cost)	(3)	1	69	18
Amortization of Transition Obligation	-	-	-	(1)
Change for the Year	$ (553)	$ (96)	$ (492)	$ (543)

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy as of December 31, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,092	$ -	$ -	$ -	$ 1,092	23.2 %
International	514	-	-	-	514	10.9 %
Real Estate Investment Trusts	58	-	-	-	58	1.2 %
Common Collective Trust - International	-	10	-	-	10	0.2 %
Subtotal - Equities	1,664	10	-	-	1,674	35.5 %
Fixed Income:						
Common Collective Trust - Debt	-	26	-	-	26	0.5 %
United States Government and Agency Securities	-	387	-	-	387	8.2 %
Corporate Debt	-	1,600	-	-	1,600	34.0 %
Foreign Debt	-	344	-	-	344	7.3 %
State and Local Government	-	28	-	-	28	0.6 %
Other - Asset Backed	-	33	-	-	33	0.7 %
Subtotal - Fixed Income	-	2,418	-	-	2,418	51.3 %
Real Estate	-	-	238	-	238	5.0 %
Alternative Investments	-	-	330	-	330	7.0 %
Securities Lending	-	35	-	-	35	0.8 %
Securities Lending Collateral (a)	-	-	-	(45)	(45)	(0.9)%
Cash and Cash Equivalents	-	48	-	-	48	1.0 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	13	13	0.3 %
Total	$ 1,664	$ 2,511	$ 568	$ (32)	$ 4,711	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.

(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Real Estate	Alternative Investments	Total Level 3

Balance as of January 1, 2013	$ 220	$ 195	$ 415
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	26	15	41
Relating to Assets Sold During the Period	-	15	15
Purchases and Sales	(8)	105	97
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2013	$ 238	$ 330	$ 568

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 473	$ -	$ -	$ -	$ 473	27.9 %
International	616	-	-	-	616	36.2 %
Common Collective Trust - Global	-	15	-	-	15	0.9 %
Subtotal - Equities	1,089	15	-	-	1,104	65.0 %
Fixed Income:						
Common Collective Trust - Debt	-	88	-	-	88	5.2 %
United States Government and Agency Securities	-	56	-	-	56	3.3 %
Corporate Debt	-	110	-	-	110	6.5 %
Foreign Debt	-	22	-	-	22	1.2 %
State and Local Government	-	5	-	-	5	0.3 %
Other - Asset Backed	-	8	-	-	8	0.5 %
Subtotal - Fixed Income	-	289	-	-	289	17.0 %
Trust Owned Life Insurance:						
International Equities	-	13	-	-	13	0.8 %
United States Bonds	-	211	-	-	211	12.4 %
Cash and Cash Equivalents	68	9	-	-	77	4.5 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	5	5	0.3 %
Total	$ 1,157	$ 537	$ -	$ 5	$ 1,699	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of pension plan assets within the fair value hierarchy as of December 31, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,308	$ -	$ -	$ -	$ 1,308	27.9 %
International	497	-	-	-	497	10.5 %
Real Estate Investment Trusts	91	-	-	-	91	1.9 %
Common Collective Trust - International	-	4	-	-	4	0.1 %
Subtotal - Equities	1,896	4	-	-	1,900	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	32	-	-	32	0.7 %
United States Government and Agency Securities	-	715	-	-	715	15.2 %
Corporate Debt	-	1,235	-	-	1,235	26.3 %
Foreign Debt	-	199	-	-	199	4.2 %
State and Local Government	-	44	-	-	44	0.9 %
Other - Asset Backed	-	36	-	-	36	0.8 %
Subtotal - Fixed Income	-	2,261	-	-	2,261	48.1 %
Real Estate	-	-	220	-	220	4.7 %
Alternative Investments	-	-	195	-	195	4.2 %
Securities Lending	-	80	-	-	80	1.7 %
Securities Lending Collateral (a)	-	-	-	(91)	(91)	(1.9)%
Cash and Cash Equivalents	-	126	-	-	126	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	5	5	0.1 %
Total	$ 1,896	$ 2,471	$ 415	$ (86)	$ 4,696	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.

(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in millions)		
Balance as of January 1, 2012	$ 6	$ 163	$ 161	$ 330

Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	30	10	40
Relating to Assets Sold During the Period	(2)	-	4	2
Purchases and Sales	(4)	27	20	43
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 220	$ 195	$ 415

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 422	$ -	$ -	$ -	$ 422	26.9 %
International	505	-	-	-	505	32.2 %
Subtotal - Equities	927	-	-	-	927	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	72	-	-	72	4.6 %
United States Government and Agency Securities	-	82	-	-	82	5.2 %
Corporate Debt	-	155	-	-	155	9.9 %
Foreign Debt	-	26	-	-	26	1.7 %
State and Local Government	-	7	-	-	7	0.5 %
Other - Asset Backed	-	10	-	-	10	0.6 %
Subtotal - Fixed Income	-	352	-	-	352	22.5 %
Trust Owned Life Insurance:						
International Equities	-	52	-	-	52	3.3 %
United States Bonds	-	163	-	-	163	10.3 %
Cash and Cash Equivalents	62	11	-	-	73	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	1	1	0.1 %
Total	$ 989	$ 578	$ -	$ 1	$ 1,568	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

Determination of Pension Expense

We base our determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

The accumulated benefit obligation for the pension plans is as follows:

Accumulated Benefit Obligation	December 31, 2013	December 31, 2012
	(in millions)	
Qualified Pension Plan	$ 4,638	$ 5,001
Nonqualified Pension Plans	77	82

Total	$ 4,715	$ 5,083

For our underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans as of December 31, 2013 and 2012 were as follows:

	Underfunded Pension Plans December 31, 2013	2012
	(in millions)	
Projected Benefit Obligation	$ 4,841	$ 5,205
Accumulated Benefit Obligation	$ 4,715	$ 5,083
Fair Value of Plan Assets	4,711	4,696
Underfunded Accumulated Benefit Obligation	$ (4)	$ (387)

Estimated Future Benefit Payments and Contributions

We expect contributions and payments for the pension plans of $80 million and the OPEB plans of $6 million during 2014. For the pension plans, this amount includes the payment of unfunded nonqualified benefits plus contributions to the qualified trust fund of at least the minimum amount required by the Employee Retirement Income Security Act. For the qualified pension plan, we may also make additional discretionary contributions to maintain the funded status of the plan. For the OPEB plans, expected payments include the payment of unfunded benefits.

The table below reflects the total benefits expected to be paid from the plan or from our assets. The payments include the participants' contributions to the plan for their share of the cost. In November 2012, we announced changes to our retiree medical coverage. Effective for retirements after December 2012, our contribution to retiree medical coverage was capped reducing our exposure to future medical cost inflation. Effective for employees hired after December 2013, we will not provide retiree medical coverage. The impact of the changes is reflected in the Benefit Plan Obligation table as plan amendments. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2014	$ 355	$ 140	$ -
2015	363	145	-
2016	368	149	-
2017	372	152	-
2018	377	156	-
Years 2019 to 2023, in Total	1,857	809	2

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost (credit) for the plans for the years ended December 31, 2013, 2012 and 2011:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2013	**2012**	**2011**	**2013**	**2012**	**2011**
	(in millions)					
Service Cost	$ 69	$ 76	$ 72	$ 23	$ 47	$ 42
Interest Cost	203	223	237	71	103	109
Expected Return on Plan Assets	(278)	(319)	(314)	(107)	(101)	(109)
Curtailment	-	-	-	-	-	1
Amortization of Transition Obligation	-	-	-	-	1	2
Amortization of Prior Service Cost (Credit)	3	(1)	1	(69)	(18)	(1)
Amortization of Net Actuarial Loss	183	155	122	65	57	29
Net Periodic Benefit Cost (Credit)	180	134	118	(17)	89	73
Capitalized Portion	(56)	(42)	(37)	5	(28)	(22)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 124	$ 92	$ 81	$ (12)	$ 61	$ 51

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2014 are shown in the following table:

Components	**Pension Plans**	**Other Postretirement Benefit Plans**
	(in millions)	
Net Actuarial Loss	$ 125	$ 21
Prior Service Cost (Credit)	2	(69)
Total Estimated 2014 Amortization	$ 127	$ (48)
Expected to be Recorded as		
Regulatory Asset	$ 107	$ (34)
Deferred Income Taxes	7	(5)
Net of Tax AOCI	13	(9)
Total	$ 127	$ (48)

American Electric Power System Retirement Savings Plan

We sponsor the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not members of the United Mine Workers of America (UMWA). It is a qualified plan offering participants an opportunity to contribute a portion of their pay with features under Section 401(k) of the Internal Revenue Code. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions totaled $67 million in 2013, $66 million in 2012 and $64 million in 2011.

UMWA Benefits

We provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by us and benefits are paid from our general assets.

The UMWA pension benefits are administered through a multiemployer plan that is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. Required contributions not made by any employer may result in other employers bearing the unfunded plan obligations, while a withdrawing employer may be subject to a withdrawal liability. UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-

1050282, Plan Number 002), which under the Pension Protection Act of 2006 (PPA) was in Seriously Endangered Status for the plan years ending June 30, 2013 and 2012, without utilization of extended amortization provisions. The Plan adopted a funding improvement plan in May 2012, as required under the PPA.

Contributions to the UMWA pension plan in 2013, 2012 and 2011 were made under a collective bargaining agreement that is scheduled to expire December 31, 2017. We contributed immaterial amounts in 2013, 2012 and 2011 that represent less than 5% of the total contributions in the plan's latest annual report for the years ended June 30, 2013, 2012 and 2011. The contributions we made did not include a surcharge. There are no minimum contributions for future years.

Based upon the plan to retrofit the Rockport Plant with dry sorbent injection technology to meet environmental emission control requirements, the timing of the closure of Cook Coal Terminal is expected to be in or after 2025. Due to the estimated closure date and the ability to estimate the amount of the withdrawal liability, we recorded a liability of $39 million during 2013 and a related regulatory asset of $30 million. The regulatory asset should be recovered in future billings for transloading services before the planned closure.

9. BUSINESS SEGMENTS

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

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

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
- OPCo purchases energy and capacity to serve remaining generation service customers.

Generation & Marketing

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

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.

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 management and professional services to AEP provided at cost to AEP subsidiaries and 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 information for the years ended December 31, 2013, 2012 and 2011 and balance sheet information as of December 31, 2013 and 2012. These amounts include certain estimates and allocations where necessary.

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments	C
				(in millions)				
Year Ended December 31, 2013								
Revenues from:								
External Customers	$ 9,347	$ 4,279	$ 27	$ 544	$ 1,208	$ 32	$ (80)(b)	$
Other Operating Segments	645	199	51	19	2,457	57	(3,428)	
Total Revenues	$ 9,992	$ 4,478	$ 78	$ 563	$ 3,665	$ 89	$ (3,508)	$
Asset Impairments and Other Related Charges	$ 72	$ -	$ -	$ -	$ 154	$ -	$ -	$
Depreciation and Amortization	941	591	10	31	236	-	(66)(c)	
Interest Income	7	2	-	-	2	69	(22)	
Carrying Costs Income	14	16	-	-	-	-	-	
Interest Expense	540	292	10	17	55	27	(35)(c)	
Income Tax Expense	398	198	29	7	112	(60)	-	
Net Income	681	358	80	12	228	125	-	

Gross Property Additions	1,822	871	843	7	185	9	(81)

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments	C
				(in millions)				
Year Ended December 31, 2012								
Revenues from:								
External Customers	$ 8,785	$ 4,659	$ 7	$ 647	$ 882	$ 25	$ (60)(b)	$
Other Operating Segments	633	159	17	20	2,585	58	(3,472)	
Total Revenues	$ 9,418	$ 4,818	$ 24	$ 667	$ 3,467	$ 83	$ (3,532)	$
Asset Impairments and Other Related Charges	$ 13	$ -	$ -	$ -	$ 287	$ -	$ -	$
Depreciation and Amortization	873	561	3	29	349	-	(33)(c)	
Interest Income	5	4	-	-	1	22	(24)	
Carrying Costs Income	28	24	1	-	-	-	-	
Interest Expense	520	291	3	17	83	112	(38)(c)	
Income Tax Expense	345	201	17	7	15	19	-	
Net Income (Loss)	803	389	43	15	100	(88)	-	
Gross Property Additions	1,801	664	392	31	249	2	(20)	

Year Ended December 31, 2011	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments
				(in millions)			
Revenues from:							
External Customers	$ 8,942	$ 4,982	$ 3	$ 697	$ 563	$ 24	$ (95)(b)
Other Operating Segments	760	174	5	19	3,331	59	(4,348)
Total Revenues	$ 9,702	$ 5,156	$ 8	$ 716	$ 3,894	$ 83	$ (4,443)
Asset Impairments and Other Related Charges	$ 49	$ -	$ -	$ -	$ 90	$ -	$ -
Depreciation and Amortization	785	549	-	28	304	2	(13)(c)
Interest Income	13	7	-	-	4	22	(19)
Carrying Costs Income	17	376	-	-	-	-	-
Interest Expense	514	293	1	17	87	56	(35)(c)
Income Tax Expense	312	220	2	24	166	94	-
Income (Loss) Before Extraordinary Item	$ 710	$ 404	$ 30	$ 45	$ 439	$ (52)	$ -
Extraordinary Item, Net of Tax	-	373	-	-	-	-	-
Net Income (Loss)	$ 710	$ 777	$ 30	$ 45	$ 439	$ (52)	$ -
Gross Property Additions	$ 1,733	$ 544	$ 263	$ 18	$ 156	$ 219	$ (31)

December 31, 2013	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments (c)
				(in millions)			
Total Property, Plant and Equipment	$ 37,545	$ 12,143	$ 1,636	$ 638	$ 8,277	$ 315	$ (269)
Accumulated Depreciation and Amortization	12,250	3,342	10	189	3,409	173	(85)
Total Property, Plant and Equipment - Net	$ 25,295	$ 8,801	$ 1,626	$ 449	$ 4,868	$ 142	$ (184)
Total Assets	$ 32,791	$ 14,165	$ 2,245	$ 673	$ 6,426	$ 19,645	$ (19,531)(d)
Investments in Equity Method Investees	24	-	480	54	-	11	-

December 31, 2012	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments (c)
				(in millions)			
Total Property, Plant and Equipment	$ 36,066	$ 11,461	$ 748	$ 636	$ 8,529	$ 280	$ (266)
Accumulated Depreciation and Amortization	11,733	3,232	4	161	3,465	168	(72)
Total Property, Plant and Equipment - Net	$ 24,333	$ 8,229	$ 744	$ 475	$ 5,064	$ 112	$ (194)
Total Assets	$ 32,008	$ 13,516	$ 1,216	$ 670	$ 6,664	$ 19,179	$ (18,886)(d)

Investments in Equity Method Investees	24	-	393	43	-	5	-

(a) Corporate and Other includes management and professional services to AEP provided at cost to AEP subsidiaries and 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) Reconciling Adjustments for External Customers primarily include eliminations as a result of corporate separation.

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

(d) 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.

10. 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 December 31, 2013 and 2012:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2013	Volume December 31, 2012	Unit of Measure
	(in millions)		
Commodity:			
Power	406	498	MWhs
Coal	4	10	Tons
Natural Gas	127	147	MMBtus
Heating Oil and Gasoline	6	6	Gallons
Interest Rate	$ 191	$ 235	USD

Interest Rate and Foreign Currency	$	820	$	1,199	USD

Fair Value Hedging Strategies

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

Cash Flow Hedging Strategies

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

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. For disclosure purposes, these contracts are included with other hedging activities as "Commodity." 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 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 December 31, 2013 and 2012 balance sheets, we netted $4 million and $7 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $13 million and $50 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 the balance sheets as of December 31, 2013 and 2012:

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
			(in millions)			
Current Risk Management Assets	$ 347	$ 12	$ 4	$ 363	$ (203)	$ 160
Long-term Risk Management Assets	368	3	-	371	(74)	297
Total Assets	715	15	4	734	(277)	457
Current Risk Management Liabilities	292	11	1	304	(214)	90
Long-term Risk Management Liabilities	237	3	15	255	(78)	177
Total Liabilities	529	14	16	559	(292)	267
Total MTM Derivative Contract Net Assets (Liabilities)	$ 186	$ 1	$ (12)	$ 175	$ 15	$ 190

Fair Value of Derivative Instruments
December 31, 2012

Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities	Gross Amounts Offset in the Statement of Financial	Net Amounts of Assets/Liabilities Presented in the Statement of Financial
		Interest Rate and Foreign			

Balance Sheet Location	Commodity (a)	Commodity (a)	Currency (a)	Recognized	Position (b)	Position (c)
			(in millions)			
Current Risk Management Assets	$ 589	$ 32	$ 3	$ 624	$ (433)	$ 191
Long-term Risk Management Assets	528	5	1	534	(166)	368
Total Assets	1,117	37	4	1,158	(599)	559
Current Risk Management Liabilities	546	43	35	624	(469)	155
Long-term Risk Management Liabilities	383	6	6	395	(181)	214
Total Liabilities	929	49	41	1,019	(650)	369
Total MTM Derivative Contract Net Assets (Liabilities)	$ 188	$ (12)	$ (37)	$ 139	$ 51	$ 190

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the 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 years ended December 31, 2013, 2012 and 2011:

Amount of Gain (Loss) Recognized on
Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2013	2012	2011
		(in millions)	
Vertically Integrated Utilities Revenues	$ 15	$ 10	$ 18
Generation & Marketing Revenues	49	50	48
Regulatory Assets (a)	(2)	(43)	(22)
Regulatory Liabilities (a)	(5)	8	(3)
Total Gain (Loss) on Risk Management Contracts	$ 57	$ 25	$ 41

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the 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 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 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 statements of income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies

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

We record realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on the statements of income. During 2013, we recognized a loss of $10 million on our hedging instruments and an offsetting gain of $10 million on our long-term debt. During 2012, the fair value changes for both our hedging instruments and hedged long-term debt were immaterial. During 2011, we recognized a gain of $3 million on our hedging instruments and an offsetting loss of $6 million on our long-term debt. For 2013, 2012 and 2011, 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 the balance sheets until the period the hedged item affects Net Income. We recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on the statements of income, or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During 2013, 2012 and 2011, we designated power, coal and natural gas derivatives as cash flow hedges.

We reclassify gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the statements of income. During 2013, 2012 and 2011, we designated heating oil and gasoline derivatives as cash flow hedges.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During 2013, 2012 and 2011, 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 the balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2013, we did not designate any foreign currency derivatives as cash flow hedges. During 2012 and 2011, we designated foreign currency derivatives as cash flow hedges.

During 2013, 2012 and 2011, 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 the balance sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2013, 2012 and 2011, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets as of December 31, 2013 and 2012 were:

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

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

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2012

Interest Rate

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 24	$ -	$ 24
Hedging Liabilities (a)	36	37	73
AOCI Gain (Loss) Net of Tax	(8)	(30)	(38)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(8)	(4)	(12)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the 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 December 31, 2013, 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 44 months.

Credit Risk

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

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

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to our competitive retail auction loads, we are obligated to post an additional amount of collateral if our credit ratings decline below investment grade. 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 investment grade. The following table represents: (a) our fair value of such derivative contracts, (b) the amount of collateral we would have been required to post for all derivative and non-derivative contracts if our credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2013 and 2012:

	December 31, 2013	December 31, 2012
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 3	$ 7
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	33	32
Amount Attributable to RTO and ISO Activities	28	31

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

December 31, 2013 and 2012:

	December 31, 2013	December 31, 2012
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 293	$ 469
Amount of Cash Collateral Posted	1	8
Additional Settlement Liability if Cross Default Provision is Triggered	235	328

11. FAIR VALUE MEASUREMENTS

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 December 31, 2013 and 2012 are summarized in the following table:

	December 31, 2013		December 31, 2012	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 18,377	$ 19,672	$ 17,757	$ 20,907

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. See "Other Temporary Investments" section of Note 1.

The following is a summary of Other Temporary Investments:

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

Other Temporary Investments	December 31, 2012 Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 241	$ -	$ -	$ 241
Fixed Income Securities:				
Mutual Funds	65	2	-	67
Equity Securities - Mutual Funds	10	6	-	16
Total Other Temporary Investments	$ 316	$ 8	$ -	$ 324

(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 years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31, 2013	2012	2011
		(in millions)	
Proceeds from Investment Sales	$ -	$ -	$ 268
Purchases of Investments	17	2	154
Gross Realized Gains on Investment Sales	-	-	4
Gross Realized Losses on Investment Sales	-	-	-

As of December 31, 2013 and 2012, we had no Other Temporary Investments with an unrealized loss position. As of December 31, 2013, 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.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments as of December 31, 2013 and December 31, 2012:

	December 31, 2013			2012		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
			(in millions)			
Cash and Cash Equivalents	$ 19	$ -	$ -	$ 17	$ -	$ -
Fixed Income Securities:						
United States Government	609	26	(4)	648	58	(1)
Corporate Debt	37	2	(1)	35	5	(1)
State and Local Government	255	1	-	270	1	(1)
Subtotal Fixed Income Securities	901	29	(5)	953	64	(3)
Equity Securities - Domestic	1,012	506	(82)	736	285	(77)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,932	$ 535	$ (87)	$ 1,706	$ 349	$ (80)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31, 2013	2012	2011

		(in millions)				
Proceeds from Investment Sales	$	858	$	988	$	1,111
Purchases of Investments		910		1,045		1,167
Gross Realized Gains on Investment Sales		18		25		33
Gross Realized Losses on Investment Sales		8		9		22

The adjusted cost of fixed income securities was $872 million and $889 million as of December 31, 2013 and 2012, respectively. The adjusted cost of equity securities was $506 million and $451 million as of December 31, 2013 and 2012, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2013 was as follows:

	Fair Value of Fixed Income Securities (in millions)
Within 1 year	$ 79
1 year – 5 years	384
5 years – 10 years	188
After 10 years	250
Total	$ 901

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2013 and 2012. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in our valuation techniques.

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 16	$ 1	$ -	$ 101	$ 118
Other Temporary Investments					
Restricted Cash (a)	231	8	-	11	250
Fixed Income Securities:					
Mutual Funds	80	-	-	-	80
Equity Securities - Mutual Funds (b)	23	-	-	-	23
Total Other Temporary Investments	334	8	-	11	353
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	22	549	142	(273)	440
Cash Flow Hedges:					
Commodity Hedges (c)	-	15	-	(8)	7
Fair Value Hedges	-	1	-	3	4
De-designated Risk Management Contracts (e)	-	-	-	6	6
Total Risk Management Assets	22	565	142	(272)	457
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	8	-	-	11	19
Fixed Income Securities:					
United States Government	-	609	-	-	609
Corporate Debt	-	37	-	-	37
State and Local Government	-	255	-	-	255
Subtotal Fixed Income Securities	-	901	-	-	901
Equity Securities - Domestic (b)	1,012	-	-	-	1,012
Total Spent Nuclear Fuel and Decommissioning Trusts	1,020	901	-	11	1,932

Total Assets	$ 1,392	$ 1,475	$ 142	$ (149)	$ 2,860
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 30	$ 475	$ 22	$ (282)	$ 245
Cash Flow Hedges:					
Commodity Hedges (c)	-	11	3	(8)	6
Interest Rate/Foreign Currency Hedges	-	2	-	-	2
Fair Value Hedges	-	11	-	3	14
Total Risk Management Liabilities	$ 30	$ 499	$ 25	$ (287)	$ 267

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 6	$ 1	$ -	$ 272	$ 279
Other Temporary Investments					
Restricted Cash (a)	227	5	-	9	241
Fixed Income Securities:					
Mutual Funds	67	-	-	-	67
Equity Securities - Mutual Funds (b)	16	-	-	-	16
Total Other Temporary Investments	310	5	-	9	324
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	47	938	131	(599)	517
Cash Flow Hedges:					
Commodity Hedges (c)	8	28	-	(12)	24
Fair Value Hedges	-	2	-	2	4
De-designated Risk Management Contracts (e)	-	-	-	14	14
Total Risk Management Assets	55	968	131	(595)	559
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	7	-	-	10	17
Fixed Income Securities:					
United States Government	-	648	-	-	648
Corporate Debt	-	35	-	-	35
State and Local Government	-	270	-	-	270
Subtotal Fixed Income Securities	-	953	-	-	953
Equity Securities - Domestic (b)	736	-	-	-	736
Total Spent Nuclear Fuel and Decommissioning Trusts	743	953	-	10	1,706
Total Assets	$ 1,114	$ 1,927	$ 131	$ (304)	$ 2,868
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 45	$ 838	$ 45	$ (636)	$ 292
Cash Flow Hedges:					
Commodity Hedges (c)	-	48	-	(12)	36
Interest Rate/Foreign Currency Hedges	-	37	-	-	37
Fair Value Hedges	-	2	-	2	4
Total Risk Management Liabilities	$ 45	$ 925	$ 45	$ (646)	$ 369

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.

(b) Amounts represent publicly traded equity securities and equity-based mutual funds.

(c) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."

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

(e) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.

(f) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(g) The December 31, 2012 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $9 million in 2013, $(3) million in periods 2014-2016 and $(4) million in periods 2017-2018; Level 2 matures $16 million in 2013, $61 million in periods 2014-2016, $16 million in periods 2017-2018 and $7 million in periods 2019-2030; Level 3 matures $18 million in 2013, $31 million in periods 2014-2016, $13 million in periods 2017-2018 and $24 million in periods 2019-2030. Risk management commodity contracts are substantially comprised of power contracts.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2013, 2012 and 2011.

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

Year Ended December 31, 2013	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2012	$ 86
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(9)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	37
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(3)
Purchases, Issuances and Settlements (c)	(16)
Transfers into Level 3 (d) (e)	19
Transfers out of Level 3 (e) (f)	(4)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	7
Balance as of December 31, 2013	$ 117

Year Ended December 31, 2012	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2011	$ 69
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(15)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	29
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	32
Transfers into Level 3 (d) (e)	1
Transfers out of Level 3 (e) (f)	(35)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	5
Balance as of December 31, 2012	$ 86

Year Ended December 31, 2011	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2010	$ 85
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(10)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	9
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(3)
Transfers into Level 3 (d) (e)	13
Transfers out of Level 3 (e) (f)	(12)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(13)
Balance as of December 31, 2011	$ 69

(a) Included in revenues on the statements of income.

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

The following tables quantify the significant unobservable inputs used in developing the fair value of our Level 3 positions as of December 31, 2013 and 2012:

Significant Unobservable Inputs
December 31, 2013

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

Significant Unobservable Inputs
December 31, 2012

	Fair Value Assets (in millions)	Fair Value Liabilities (in millions)	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High
Energy Contracts	$ 124	$ 38	Discounted Cash Flow	Forward Market Price (a)	$ 9.40	$ 111.97
				Counterparty Credit Risk (b)	397	
FTRs	7	7	Discounted Cash Flow	Forward Market Price (a)	(3.21)	14.79
Total	$ 131	$ 45				

(a) Represents market prices in dollars per MWh.
(b) Represents average price of credit default swaps used to calculate counterparty credit risk, reported in basis points.

12. INCOME TAXES

The details of our consolidated income taxes before extraordinary item as reported are as follows:

	Years Ended December 31, 2013	2012	2011
		(in millions)	
Federal:			
Current	$ (45)	$ (52)	$ 20
Deferred	676	698	786
Total Federal	631	646	806
State and Local:			
Current	29	35	37

Deferred	24	(77)	(25)
Total State and Local	53	(42)	12
Income Tax Expense	$ 684	$ 604	$ 818

The following is a reconciliation of our consolidated difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported:

	Years Ended December 31,		
	2013	2012	2011
		(in millions)	
Net Income	$ 1,484	$ 1,262	$ 1,949
Extraordinary Item, Net of Tax of $112 million in 2011	-	-	(373)
Income Before Extraordinary Item	1,484	1,262	1,576
Income Tax Expense	684	604	818
Pretax Income	$ 2,168	$ 1,866	$ 2,394
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 759	$ 653	$ 838
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	47	39	41
Investment Tax Credits, Net	(14)	(14)	(15)
Energy Production Credits	-	-	(18)
State and Local Income Taxes, Net	29	(33)	(22)
Removal Costs	(21)	(18)	(20)
AFUDC	(31)	(39)	(42)
Valuation Allowance	5	6	86
U.K. Windfall Tax	(80)	15	-
Other	(10)	(5)	(30)
Income Tax Expense	$ 684	$ 604	$ 818
Effective Income Tax Rate	31.5 %	32.4 %	34.2 %

The following table shows elements of the net deferred tax liability and significant temporary differences:

	December 31,	
	2013	2012
	(in millions)	
Deferred Tax Assets	$ 2,900	$ 2,900
Deferred Tax Liabilities	(13,088)	(12,098)
Net Deferred Tax Liabilities	$ (10,188)	$ (9,198)
Property Related Temporary Differences	$ (7,508)	$ (6,752)
Amounts Due from Customers for Future Federal Income Taxes	(273)	(289)
Deferred State Income Taxes	(765)	(683)
Securitized Assets	(870)	(780)
Regulatory Assets	(609)	(781)
Deferred Income Taxes on Other Comprehensive Loss	66	184
Accrued Nuclear Decommissioning	(554)	(475)
Net Operating Loss Carryforward	233	194

Tax Credit Carryforward	109	104
Valuation Allowance	(97)	(92)
All Other, Net	80	172
Net Deferred Tax Liabilities	$ (10,188)	$ (9,198)

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

We are no longer subject to U.S. federal examination for years before 2011. We completed the examination of the years 2007 and 2008 in April 2011 and settled all outstanding issues on appeal for the years 2001 through 2006 in October 2011. The settlements did not materially impact net income, cash flows or financial condition. The IRS examination of years 2009 and 2010 started in October 2011 and was completed in the second quarter of 2013. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

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

Net Income Tax Operating Loss Carryforward

In 2012 and 2011, we recognized federal net income tax operating losses of $366 million and $226 million, respectively, driven primarily by bonus depreciation, pension plan contributions and other book-versus-tax temporary differences. We also had state net income tax operating loss carryforwards as indicated in the table below.

State	State Net Income Tax Operating Loss Carryforward	Year of Expiration
	(in millions)	
Indiana	$ 50	2033
Louisiana	428	2028
Oklahoma	241	2033
Tennessee	9	2026
Virginia	301	2031
West Virginia	725	2032

As a result, we recognized deferred federal, state and local income tax benefits in 2012 and 2011. As of December 31, 2013, we have $156 million of unrealized federal net operating loss carryforward tax benefits. We anticipate future taxable income will be sufficient to realize the remaining net income tax operating loss tax benefits before the federal carryforward expires after 2032. We also anticipate future taxable income will be sufficient to realize the remaining state net income tax operating loss tax benefits before the state carryforward expires for each state.

At the end of 2013 and 2012, we had $121 million of uncertain tax positions netted against the federal net operating loss carryforward tax benefits.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2012, 2011 and 2009, along with lower federal and state taxable income in 2010, resulted in unused federal and state income tax credits. As of December 31, 2013, we have total federal tax credit carryforwards of $108 million and total state tax credit carryforwards of $98 million, not all of which are subject to an expiration date. If these credits are not utilized, the federal general business tax credits of $74 million will expire in the years 2028 through 2032 and the state coal tax credits of $29 million will expire in the years 2014 through 2022.

We anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused. We do not anticipate state taxable income will be sufficient in future periods to realize the tax benefits of all state income tax credits before they expire and we have provided a valuation allowance accordingly.

Valuation Allowance

We assess past results and future operations to estimate and evaluate available positive and negative evidence to determine whether sufficient future taxable income will be generated to use existing deferred tax assets. A significant piece of objective negative information evaluated was the net income tax operating losses sustained in 2012, 2011 and 2009. The positive evidence we considered is the history of positive pretax income and the fact that the tax losses resulted from temporary differences that will reverse in future periods. On the basis of the evaluation of all available positive and negative evidence, as of December 31, 2013, a valuation allowance of $41 million for state tax credits, net of federal tax, and $56 million for an unrealized capital loss has been recorded in order to recognize only the portion of the deferred tax assets that, more likely than not, will be realized. The amount of the deferred tax assets realizable, however, could be adjusted if estimates of future taxable income during the carryforward period are materially impacted.

For a discussion of the tax implications of the unrealized capital loss resulting from our settlement with BOA and Enron, see "Enron Bankruptcy" section of Note 7.

Uncertain Tax Positions

In May 2013, the U.S. Supreme Court decided that the U.K. Windfall Tax imposed upon U.K. electric companies privatized between 1984 and 1996 is a creditable tax for U.S. federal income tax purposes. We filed protective claims asserting the creditability of the tax, dependent upon the outcome of the case. As a result of the favorable U.S. Supreme Court decision, we recognized a tax benefit of $80 million, plus $43 million of pretax interest income in the second quarter of 2013. The tax benefit and interest income resulted in an increase in net income of $108 million, but did not result in the receipt of cash in 2013.

We recognize interest accruals related to uncertain tax positions in interest income or expense, as applicable, and penalties in Other Operation expense in accordance with the accounting guidance for "Income Taxes."

The following table shows amounts reported for interest expense, interest income and reversal of prior period interest expense:

	Years Ended December 31,		
	2013	**2012**	**2011**
		(in millions)	
Interest Expense	$ 1	$ 11	$ 8
Interest Income	51	-	22
Reversal of Prior Period Interest Expense	-	1	13

The following table shows balances for amounts accrued for the receipt of interest and the payment of interest and penalties:

	December 31,	
	2013	**2012**
	(in millions)	

Accrual for Receipt of Interest	$ 43	$ -
Accrual for Payment of Interest and Penalties	5	7

The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2013	2012	2011
		(in millions)	
Balance as of January 1,	$ 267	$ 168	$ 219
Increase - Tax Positions Taken During a Prior Period	-	23	51
Decrease - Tax Positions Taken During a Prior Period	(94)	(16)	(43)
Increase - Tax Positions Taken During the Current Year	2	121	10
Decrease - Tax Positions Taken During the Current Year	-	-	-
Decrease - Settlements with Taxing Authorities	-	(25)	(31)
Decrease - Lapse of the Applicable Statute of Limitations	-	(4)	(38)
Balance as of December 31,	$ 175	$ 267	$ 168

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $87 million, $149 million and $111 million for 2013, 2012 and 2011, respectively. We believe there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

The American Taxpayer Relief Act of 2012 (the 2012 Act) was enacted in January 2013. Included in the 2012 Act was a one-year extension of 50% bonus depreciation. The 2012 Act also retroactively extended the life of research and development, employment and several energy tax credits, which expired at the end of 2011. The enacted provisions will not materially impact net income or financial condition but did have a favorable impact on cash flows in 2013.

Federal Tax Regulations

In 2013, the U.S. Treasury Department issued final and re-proposed regulations regarding the deduction and capitalization of expenditures related to tangible property, effective for the tax years beginning in 2014. In addition, the IRS issued Revenue Procedures under the Industry Issue Resolutions program that provides specific guidance for the implementation of the regulations for the electric utility industry. The impact of these final regulations is not material to net income, cash flows or financial condition.

State Tax Legislation

Legislation was passed by the state of Indiana in May 2011 enacting a phased reduction in corporate income tax rate from 8.5% to 6.5%. The 8.5% Indiana corporate income tax rate will be reduced 0.5% each year beginning after June 30, 2012 with the final reduction occurring in years beginning after June 30, 2015.

In May 2011, Michigan repealed its Business Tax regime and replaced it with a traditional corporate net income tax rate of 6%, effective January 1, 2012.

During the third quarter of 2013, it was determined that the state of West Virginia had achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate will be reduced from 7.0% to 6.5% in 2014. The enacted provisions will not materially impact net income, cash flows or financial condition.

13. LEASES

Leases of property, plant and equipment are for remaining periods up to 36 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

Lease Rental Costs	Years Ended December 31, 2013	2012	2011
	(in millions)		
Net Lease Expense on Operating Leases	$ 327	$ 346	$ 343
Amortization of Capital Leases	74	73	72
Interest on Capital Leases	28	29	32
Total Lease Rental Costs	$ 429	$ 448	$ 447

The following table shows the property, plant and equipment under capital leases and related obligations recorded on the balance sheets. Capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

Property, Plant and Equipment Under Capital Leases	December 31, 2013	2012
	(in millions)	
Generation	$ 103	$ 117
Other Property, Plant and Equipment	627	495
Total Property, Plant and Equipment Under Capital Leases	730	612
Accumulated Amortization	197	173
Net Property, Plant and Equipment Under Capital Leases	$ 533	$ 439
Obligations Under Capital Leases		
Noncurrent Liability	$ 428	$ 375
Liability Due Within One Year	110	74
Total Obligations Under Capital Leases	$ 538	$ 449

Future minimum lease payments consisted of the following as of December 31, 2013:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2014	$ 135	$ 288
2015	111	268
2016	97	246
2017	79	230
2018	44	215

Later Years	215	862
Total Future Minimum Lease Payments	681	$ 2,109
Less Estimated Interest Element	143	
Estimated Present Value of Future Minimum Lease Payments	$ 538	

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 December 31, 2013, the maximum potential loss for these lease agreements was approximately $20 million assuming the fair value of the equipment is zero at the end of the lease term.

Rockport Lease

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2013 are as follows:

Future Minimum Lease Payments	**AEGCo**	**I&M**
	(in millions)	
2014	$ 74	$ 74
2015	74	74
2016	74	74
2017	74	74
2018	74	74
Later Years	295	295
Total Future Minimum Lease Payments	$ 665	$ 665

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 assignment is 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 $13 million and $15 million for I&M and SWEPCo, respectively, for the remaining railcars as of December 31, 2013. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 83% 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 approximately $9 million and $10 million for I&M and SWEPCo, respectively, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss.

Sabine Dragline Lease

During 2009, Sabine entered into capital lease arrangements with a nonaffiliated company to finance the purchase of two electric draglines to be used for Sabine's mining operations totaling $47 million. The amounts included in the lease represented the aggregate fair value of the existing equipment and a sale-and-leaseback transaction for additional dragline rebuild costs required to keep the dragline operational. These capital lease assets are included in Other Property, Plant and Equipment on our December 31, 2013 and 2012 balance sheets. The short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on our December 31, 2013 and 2012 balance sheets. The future payment obligations are included in our future minimum lease payments schedule earlier in this note.

I&M Nuclear Fuel Lease

In November 2013, I&M entered into a sale-and-leaseback transaction with IMP 11-2013, a nonaffiliated Ohio Trust, to lease nuclear fuel for I&M's Cook Plant. In November 2013, I&M sold a portion of its unamortized nuclear fuel inventory to the trust for $110 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 54 months. The future payment obligations of $110 million are included in our future minimum lease payments schedule earlier in this note. The net capital lease asset is included in Other Property, Plant and Equipment and the short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities, respectively, on our December 31, 2013 balance sheet. The future minimum lease payments for the sale-and-leaseback transaction as of December 31, 2013 are as follows, based on estimated fuel burn:

Future Minimum Lease Payments	**I&M**
	(in millions)
2014	$ 43
2015	32
2016	27
2017	6
2018	2
Total Future Minimum Lease Payments	$ 110

14. FINANCING ACTIVITIES

AEP Common Stock

Listed below is a reconciliation of common stock share activity for the years ended December 31, 2013, 2012 and 2011:

Shares of AEP Common Stock	**Issued**	**Held in Treasury**
Balance, December 31, 2010	501,114,881	20,307,725
Issued	2,644,579	-
Treasury Stock Acquired	-	28,867
Balance, December 31, 2011	503,759,460	20,336,592
Issued	2,245,502	-
Balance, December 31, 2012	506,004,962	20,336,592
Issued	2,109,002	-
Balance, December 31, 2013	508,113,964	20,336,592

Preferred Stock

In December 2011, AEP subsidiaries redeemed all of their outstanding preferred stock with a par value of $60 million at a premium, resulting in a $2.8 million loss, which is included in Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense on the statement of income.

Long-term Debt

The following details long-term debt outstanding as of December 31, 2013 and 2012:

Type of Debt and Maturity	Weighted Average Interest Rate as of December 31, 2013	Interest Rate Ranges as of December 31, 2013	2012	Outstanding as of December 31, 2013	2012
				(in millions)	
Senior Unsecured Notes (a)					
2013-2043	5.45%	1.65%-8.13%	0.685%-8.13%	$ 11,799	$ 12,712
Pollution Control Bonds (b)					
2013-2038 (c)	3.29%	0.02%-6.30%	0.11%-6.30%	1,932	1,958
Notes Payable (d)					
2013-2032	4.17%	1.164%-8.03%	1.913%-8.03%	369	427
Securitization Bonds (e)					
2013-2031	3.72%	0.88%-6.25%	0.88%-6.25%	2,686	2,281
Spent Nuclear Fuel Obligation (f)				265	265
Other Long-term Debt (a) (g)					
2015-2059	1.41%	1.15%-13.718%	1.72%-13.718%	1,360	140
Fair Value of Interest Rate Hedges				(9)	3
Unamortized Discount, Net				(25)	(29)
Total Long-term Debt Outstanding				18,377	17,757
Long-term Debt Due Within One Year				1,549	2,171
Long-term Debt				$ 16,828	$ 15,586

(a) In July 2013, AGR, APCo, KPCo and OPCo entered into a $1 billion term credit facility due in May 2015 to provide liquidity during the corporate separation process. In 2013, OPCo borrowed $1 billion under the credit facility and retired other certain debt. On December 31, 2013, OPCo assigned the $1 billion in credit facility borrowings to AGR upon the transfer of OPCo's generation assets to AGR. Also on December 31, 2013, AGR subsequently assigned a portion of the borrowings to APCo and KPCo in the amounts of $300 million and $200 million, respectively, upon AGR's transfer of certain of those generation assets.

(b) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and insurance policies support certain series.

(c) Certain pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year on the balance sheets.

(d) Notes payable represent outstanding promissory notes issued under term loan agreements and credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(e) In 2013, APCo and OPCo issued $380 million and $267 million, respectively, of Securitization Bonds (see Note 16).

(f) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 6).

(g) In 2013, PSO, TCC and TNC issued $50 million, $100 million and $75 million three-year credit facilities, respectively, to be used for general corporate purposes.

Long-term debt outstanding as of December 31, 2013 is payable as follows:

	2014	2015	2016	2017	2018	After 2018	Total
				(in millions)			
Principal Amount	$ 1,549	$ 2,519	$ 1,147	$ 1,724	$ 1,135	$ 10,328	$ 18,402
Unamortized Discount, Net							(25)
Total Long-term Debt Outstanding							$ 18,377

In January 2014 and February 2014, I&M retired $5 million and $19 million, respectively, of Notes Payable related to DCC Fuel.

In January 2014, TCC retired $112 million of its outstanding Securitization Bonds.

In January 2014, OPCo retired $225 million of 4.85% Senior Unsecured Notes due in 2014.

As of December 31, 2013, trustees held, on our behalf, $500 million of our reacquired Pollution Control Bonds.

Dividend Restrictions

Parent Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. Our income derives from our common stock equity in the earnings of our utility subsidiaries.

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

Utility Subsidiaries' Restrictions

Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends. Specifically, several of our public utility subsidiaries have credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%. As of December 31, 2013, the amount of restricted net assets of AEP's subsidiaries that may not be distributed to Parent in the form of a loan, advance or dividend was approximately $6 billion.

The Federal Power Act prohibits the utility subsidiaries from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the book value of the common stock. This restriction does not limit the ability of the utility subsidiaries to pay dividends out of retained earnings.

Lines of Credit and Short-term Debt

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. As of December 31, 2013, we had credit facilities totaling $3.5 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during 2013 was $904 million and the weighted average interest rate of commercial paper outstanding during 2013 was 0.32%. Our outstanding short-term debt was as follows:

	December 31,			
	2013		2012	
Type of Debt	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
	(in millions)		**(in millions)**	
Securitized Debt for Receivables (b)	$ 700	0.23 %	$ 657	0.26 %
Commercial Paper	57	0.29 %	321	0.42 %
Line of Credit – Sabine (c)	-	- %	3	1.82 %
Total Short-term Debt	$ 757		$ 981	

(a) Weighted average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.
(c) This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

For a discussion of credit facilities, see “Letters of Credit” section of Note 6.

Securitized Accounts Receivable – AEP Credit

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

In June 2013, we amended our receivables securitization agreement to extend through June 2014. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. We amended a commitment of $385 million to now expire in June 2014. The remaining commitment of $315 million expires in June 2015. We intend to extend or replace the agreement expiring in June 2014 on or before its maturity.

Accounts receivable information for AEP Credit is as follows:

	Years Ended December 31, 2013	2012	2011
	(dollars in millions)		
Effective Interest Rates on Securitization of Accounts Receivable	0.23 %	0.26 %	0.27 %
Net Uncollectible Accounts Receivable Written Off	$ 35	$ 29	$ 37

	December 31, 2013	2012
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 929	$ 835
Total Principal Outstanding	700	657
Delinquent Securitized Accounts Receivable	45	37
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	16	21
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	331	316

Customer accounts receivable retained and securitized for our operating companies are managed by AEP Credit. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

15. STOCK-BASED COMPENSATION

As approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) authorizes the use of 20,000,000 shares of AEP common stock for various types of stock-based compensation awards to employees. A maximum of 10,000,000 shares may be used under this plan for full value share awards, which includes performance units, restricted shares and restricted stock units. As of December 31, 2013, 15,973,699 shares remained available for issuance under the LTIP plan. The AEP Board of Directors and shareholders last approved the LTIP in 2010. The following sections provide further information regarding each type of stock-based compensation award granted by the Human Resources Committee of the Board of Directors (HR Committee).

Stock Options

We did not grant stock options in 2013, 2012 or 2011 but we did have outstanding stock options from grants in earlier periods that were exercised in these years. As of December 31, 2013 we have no outstanding stock options. The exercise price of all outstanding stock options equaled or exceeded the market price of AEP's common stock on the date of grant. All outstanding stock options were granted with a ten-year term and generally vested, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1 of the year following the first, second and third anniversary of the grant date. We record compensation cost for stock options over the vesting period based on the fair value on the grant date. The LTIP does not specify a maximum contractual term for stock options.

The total intrinsic value of options exercised is as follows:

Stock Options	Years Ended December 31, 2013	2012	2011
	(in thousands)		
Intrinsic Value of Options Exercised (a)	$ 3,105	$ 1,699	$ 1,202

(a) Intrinsic value is calculated as market price at exercise dates less the option exercise price.

A summary of AEP stock option transactions during the years ended December 31, 2013, 2012 and 2011 is as follows:

	2013		2012		2011	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
	(in thousands)		(in thousands)		(in thousands)	
Outstanding as of January 1,	188	$ 30.17	321	$ 29.35	551	$ 32.88
Granted	-	NA	-	NA	-	NA
Exercised/Converted	(187)	30.18	(128)	28.21	(104)	27.39
Forfeited/Expired	(1)	27.95	(5)	27.26	(126)	46.40
Outstanding as of December 31,	-	NA	188	30.17	321	29.35
Options Exercisable as of December 31,	-	$ NA	188	$ 30.17	321	$ 29.35

NA Not applicable.

We include the proceeds received from exercised stock options in common stock and paid-in capital.

Performance Units

Our performance units have a fair value upon vesting equal to the average closing market price of AEP common stock for the last 20 trading days of the performance period. The number of performance units held is multiplied by the performance score to determine the actual number of performance units realized. The performance score can range from 0% to 200% and is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the HR Committee. Performance units are paid in cash, unless they are needed to satisfy a participant's stock ownership requirement. In that case, the number of units needed to satisfy the participant's largest stock ownership requirement is mandatorily deferred as AEP Career Shares until after the end of the participant's AEP career. AEP Career Shares are a form of non-qualified deferred compensation that has a value equivalent to shares of AEP common stock. AEP Career Shares are paid in cash after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. We record compensation cost for performance units over the three-year vesting period. The liability for both the performance units and AEP Career Shares, recorded in Employee Benefits and Pension Obligations on the balance sheets, is adjusted for changes in value. The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.

The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2013, 2012 and 2011 as follows:

	Years Ended December 31,		
Performance Units	**2013**	**2012**	**2011**
Awarded Units (in thousands)	1,284	546	7

Weighted Average Unit Fair Value at Grant Date	$ 46.23	$ 41.38	$ 38.39
Vesting Period (in years)	3	3	3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	**Years Ended December 31, 2013**	**2012**	**2011**
Awarded Units (in thousands)	101	138	198
Weighted Average Grant Date Fair Value	$ 45.42	$ 40.97	$ 37.31
Vesting Period (in years)	(a)	(a)	(a)

(a) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP Career Shares vest immediately upon grant but are not paid in cash until after the participant's termination of employment.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures within approximately a month after the end of the performance period. The HR Committee has discretion to reduce or eliminate the number of performance units earned but may not increase the number earned. The performance scores for all open performance periods prior to those granted in 2012 are dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to the electric utility and multi utility sub-industry segments of the Standard and Poor's 500 Index and (b) three-year cumulative earnings per share measured relative to an AEP Board of Directors approved target. Starting with the performance units granted in 2012, the three-year total shareholder return peer group was changed to the S&P 500 Electric Utility Index.

The certified performance scores and units earned for the three-year periods ended December 31, 2013, 2012 and 2011 were as follows:

Performance Units	Years Ended December 31, 2013	2012	2011
Certified Performance Score	118.8 %	99.7 %	89.8 %
Performance Units Earned	749,219	1,096,572	1,216,926
Performance Units Mandatorily Deferred as AEP Career Shares	72,883	51,056	52,639
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	39,691	26,337	42,502
Performance Units to be Paid in Cash	636,645	1,019,179	1,121,785

The cash payouts for the years ended December 31, 2013, 2012 and 2011 were as follows:

Performance Units and AEP Career Shares	Years Ended December 31, 2013	2012	2011
		(in thousands)	
Cash Payouts for Performance Units	$ 43,925	$ 44,968	$ 15,985
Cash Payouts for AEP Career Share Distributions	3,675	11,027	2,777

Restricted Shares and Restricted Stock Units

In 2004, the independent members of the AEP Board of Directors granted restricted shares to the then Chairman, President and CEO upon the commencement of his AEP employment. The final 66,667 shares vested on November 30, 2011. Compensation cost for restricted shares is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of shares granted by the grant date market closing price, which was $30.76. The maximum contractual term for these restricted shares was eight years and dividends on these restricted shares were paid in cash. AEP has not granted other restricted shares.

The HR Committee also grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments. Additional RSUs granted as dividends vest on the same date as the underlying RSUs on which the dividends were awarded. Upon vesting, RSUs are converted into a share of AEP common stock, with the exception of participants subject to the disclosure requirements set forth in Section 16 of the Securities Exchange Act of 1934, who are paid in cash. For awards that are settled with shares, compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of units granted by the grant date market closing price. For awards that are paid in cash, compensation cost is recorded over the vesting period and adjusted for changes in value until vested. The fair value at vesting is determined by multiplying the number of units vested by the 20-day average closing price of AEP common stock. The maximum contractual term of outstanding RSUs is six years from the grant date.

In 2010, the HR Committee granted a total of 165,520 RSUs to four CEO succession candidates as a retention incentive for these candidates. These grants vest, subject to the candidates' continuous employment, in three approximately equal installments on August 3, 2013, August 3, 2014 and August 3, 2015. Of these RSUs, 55,172 vested on August 3, 2013 and 110,348 remain outstanding, excluding dividends.

The HR Committee awarded RSUs, including units awarded for dividends, for the years ended December 31, 2013, 2012 and 2011 as follows:

Restricted Stock Units	Years Ended December 31, 2013	2012	2011
Awarded Units (in thousands)	644	497	121
Weighted Average Grant Date Fair Value	$ 46.24	$ 40.69	$ 37.07

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2013, 2012 and 2011 were as follows:

Restricted Shares and Restricted Stock Units	Years Ended December 31, 2013	2012	2011
	(in thousands)		
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 15,325	$ 10,608	$ 7,164
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	20,378	12,157	8,017

(a) Intrinsic value is calculated as market price at exercise date.

A summary of the status of our nonvested RSUs as of December 31, 2013 and changes during the year ended December 31, 2013 are as follows:

Nonvested Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2013	1,000	$ 38.22
Granted	644	46.24
Vested	(408)	37.57
Forfeited	(31)	39.97
Nonvested as of December 31, 2013	1,205	42.64

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2013 was $56 million and the weighted average remaining contractual life was 2.09 years.

Other Stock-Based Plans

We also have a Stock Unit Accumulation Plan for Non-employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The stock units granted to Non-employee Directors are fully vested upon grant date. Stock units are paid in cash upon termination of board service or up to 10 years later if the participant so elects. Cash payments for stock units are calculated based on the average closing price of AEP common stock for the last 20 trading days prior to the distribution date.

We record compensation cost for stock units when the units are awarded and adjust the liability for changes in value based on the current 20-day average closing price of AEP common stock on the valuation date.

We had no material cash payouts for stock unit distributions for the years ended December 31, 2013, 2012 and

2011.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2013, 2012 and 2011 as follows:

Stock Unit Accumulation Plan for Non-Employee Directors	Years Ended December 31, 2013	2012	2011
Awarded Units (in thousands)	33	52	52
Weighted Average Grant Date Fair Value	$ 45.81	$ 41.20	$ 37.72

Share-based Compensation Plans

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2013, 2012 and 2011 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2013	2012	2011
	(in thousands)		
Compensation Cost for Share-based Payment Arrangements (a)	$ 56,352	$ 51,767	$ 61,807
Actual Tax Benefit Realized	19,723	18,119	12,632
Total Compensation Cost Capitalized	13,165	10,707	11,608

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on the statements of income.

During the years ended December 31, 2013, 2012 and 2011, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2013, there was $105 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the LTIP. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the fair value is adjusted each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.66 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended December 31, 2013, 2012 and 2011 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2013	2012	2011
	(in thousands)		
Cash Received from Stock Options Exercised	$ 5,659	$ 3,598	$ 2,855
Actual Tax Benefit Realized for the Tax Deductions from Stock Options Exercised	1,040	618	411

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and RSU vesting. Although we do not currently anticipate any changes to this practice, we are permitted to use treasury shares, shares acquired in the open market specifically for distribution under the LTIP or any combination thereof for this purpose. The number of new shares issued to fulfill vesting RSUs is generally reduced to offset our tax withholding obligation.

16. VARIABLE INTEREST ENTITIES

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

We are the primary beneficiary of Sabine, DCC Fuel, AEP Credit, Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and a protected cell of EIS. In addition, we have not provided material financial or other support to Sabine, DCC Fuel, AEP Credit, Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and our protected cell of EIS that was not previously contractually required. We hold a significant variable interest in DHLC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2013, 2012 and 2011 were $155 million, $147 million and $128 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on the balance sheets.

I&M has nuclear fuel lease agreements with DCC Fuel II LLC, DCC Fuel IV LLC, DCC Fuel V LLC and DCC Fuel VI LLC (collectively DCC Fuel). DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2013, 2012 and 2011 were $153 million, $127 million and $85 million, respectively. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on our control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. In October 2013, the lease agreements ended for DCC Fuel LLC and DCC Fuel III LLC. See the tables below for the classification of DCC Fuel's assets and liabilities on the balance sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on our control of AEP Credit, management concluded that we are the primary beneficiary and are required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the balance sheets. See "Securitized Accounts Receivables – AEP Credit" section of Note 14.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. Management has concluded that TCC is the primary beneficiary of Transition Funding because TCC has the power to direct the most significant activities of the VIE and TCC's equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled $2 billion and $2.3 billion as of December 31, 2013 and 2012, respectively. Transition Funding has securitized transition assets of $1.9 billion and $2.1 billion as of December 31, 2013 and 2012, respectively. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the balance sheets.

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

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

The securitized bonds of Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding are included in current and long-term debt on the balance sheets. The securitized assets of Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding are included in securitized assets on the balance sheets.

Our subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on our control and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate EIS. Our insurance premium expense to the protected cell for the years ended December 31, 2013, 2012 and 2011 were $31 million, $32 million and $48 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

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

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

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

(a) Includes an intercompany item eliminated in consolidation of $82 million.
(b) Includes an intercompany item eliminated in consolidation of $116 million.
(c) Includes an intercompany item eliminated in consolidation of $4 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2012
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	AEP Credit	TCC Transition Funding	Protected Cell of EIS
ASSETS					
Current Assets	$ 57	$ 133	$ 843	$ 250	$ 130
Net Property, Plant and Equipment	170	176	-	-	-
Other Noncurrent Assets	55	92	1	2,167 (a)	4

Total Assets	$ 282	$ 401	$ 844	$ 2,417	$ 134
LIABILITIES AND EQUITY					
Current Liabilities	$ 32	$ 121	$ 800	$ 304	$ 43
Noncurrent Liabilities	250	280	1	2,095	66
Equity	-	-	43	18	25
Total Liabilities and Equity	$ 282	$ 401	$ 844	$ 2,417	$ 134

(a) Includes an intercompany item eliminated in consolidation of $89 million.

DHLC is a mining operator that sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and voting rights equally. Each entity guarantees 50% of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the years ended December 31, 2013, 2012 and 2011 were $60 million, $77 million and $62 million, respectively. We are not required to consolidate DHLC as we are not the primary beneficiary, although we hold a significant variable interest in DHLC. Our equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on the balance sheets.

Our investment in DHLC was:

	December 31,			
	2013		2012	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 8	$ 8	$ 8	$ 8
Retained Earnings	1	1	1	1
SWEPCo's Guarantee of Debt	-	61	-	49
Total Investment in DHLC	$ 9	$ 70	$ 9	$ 58

We and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. The "Allegheny Series" is not considered a VIE. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. We and FirstEnergy share the returns and losses equally in PATH-WV. Our subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. The entities recover costs through regulated rates.

In August 2012, the PJM board cancelled the PATH Project, our transmission joint venture with FirstEnergy, and removed it from the 2012 Regional Transmission Expansion Plan. In September 2012, the PATH Project companies submitted an application to the FERC requesting authority to recover prudently-incurred costs associated with the PATH Project. In November 2012, the FERC issued an order accepting the PATH Project's abandonment cost recovery application, subject to settlement procedures and hearing. The settlement proceedings are ongoing.

Our investment in PATH-WV was:

	December 31,			
	2013		2012	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 19	$ 19	$ 19	$ 19
Retained Earnings	6	6	12	12
Total Investment in PATH-WV	$ 25	$ 25	$ 31	$ 31

As of December 31, 2013, our $25 million investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheet. If we cannot ultimately recover our investment related to PATH-WV, it could reduce future net income and cash flows.

17. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

We provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide the annual property information:

2013	Regulated				Nonregulated		
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges
	(in millions)			(in years)	(in millions)		
Generation	$ 17,873	$ 7,168	1.7 - 3.7 %	31 - 132	$ 7,201	$ 2,969	2.6 - 3.3 %
Transmission	10,854	2,805	1.1 - 2.7 %	25 - 87	39	16	2.5 %
Distribution	16,377	3,988	2.3 - 3.8 %	11 - 75	-	-	NA
CWIP	2,326	(121)	NM	NM	145	1	NM
Other	4,116	1,931	2.0 - 7.9 %	5 - 75	1,354	531	NM
Total	$ 51,546	$ 15,771			$ 8,739	$ 3,517	

2012	Regulated				Nonregulated		
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges
	(in millions)			(in years)	(in millions)		
Generation	$ 16,973	$ 6,962	1.7 - 3.8 %	31 - 132	$ 9,306	$ 3,526	2.6 - 3.3 %
Transmission	9,846	2,720	1.2 - 2.8 %	25 - 87	-	-	NA
Distribution	15,565	3,837	2.4 - 3.9 %	11 - 75	-	-	NA
CWIP	1,600	(27)	NM	NM	219	1	NM
Other	2,644	1,238	1.8 - 9.6 %	5 - 75	1,301	434	NM
Total	$ 46,628	$ 14,730			$ 10,826	$ 3,961	

2011	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
		(in years)		(in years)

Generation	1.6 - 3.8 %	9 - 132	2.6 - 3.5 %	20 ‐ 66
Transmission	1.3 - 2.7 %	25 - 87	NA	NA
Distribution	2.4 - 4.0 %	11 - 75	NA	NA
CWIP	NM	NM	NM	NM
Other	1.7 - 9.3 %	5 - 55	NM	NM

NA Not applicable.
NM Not meaningful.

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense.

For regulated operations, the composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (ARO)

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

The following is a reconciliation of the 2013 and 2012 aggregate carrying amounts of ARO:

	Carrying Amount of ARO (in millions)
ARO as of December 31, 2011 (a)	$ 1,474
Accretion Expense	85
Liabilities Incurred	17
Liabilities Settled	(24)
Revisions in Cash Flow Estimates	144
ARO as of December 31, 2012	1,696
Accretion Expense	103
Liabilities Incurred	4
Liabilities Settled	(22)
Revisions in Cash Flow Estimates	54
ARO as of December 31, 2013	$ 1,835

(a) A current portion of ARO, totaling $2 million, is included in Other Current Liabilities on our 2011 balance sheet.

As of December 31, 2013 and 2012, our ARO liability included $1.2 billion and $1.2 billion, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2013 and 2012, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1.6 billion and $1.4 billion, respectively, and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

Our amounts of allowance for borrowed, including interest capitalized, and equity funds used during construction is summarized in the following table:

	Years Ended December 31,		
	2013	**2012**	**2011**
		(in millions)	
Allowance for Equity Funds Used During Construction	$ 73	$ 93	$ 98
Allowance for Borrowed Funds Used During Construction	40	69	63

Jointly-owned Electric Facilities

We have electric facilities that are jointly-owned with nonaffiliated companies. Using our own financing, we are obligated to pay a share of the costs of these jointly-owned facilities in the same proportion as our ownership interest. Our proportionate share of the operating costs associated with such facilities is included on the statements of income and the investments and accumulated depreciation are reflected on the balance sheets under Property, Plant and Equipment as follows:

			Company's Share as of December 31, 2013		
	Fuel Type	**Percent of Ownership**	**Utility Plant in Service**	**Construction Work in Progress**	**Accumulated Depreciation**
				(in millions)	
W.C. Beckjord Generating Station, Unit 6 (a)	Coal	12.5 %	$ -	$ -	$ -
Conesville Generating Station, Unit 4 (b)	Coal	43.5 %	335	2	55
J.M. Stuart Generating Station (c)	Coal	26.0 %	544	11	190
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	809	2	399
Dolet Hills Generating Station, Unit 1 (d)	Lignite	40.2 %	262	47	198
Flint Creek Generating Station, Unit 1 (e)	Coal	50.0 %	123	54	66
Pirkey Generating Station, Unit 1 (e)	Lignite	85.9 %	519	29	376
Oklaunion Generating Station, Unit 1 (f)	Coal	70.3 %	404	7	223
Turk Generating Plant (e)	Coal	73.33 %	1,638	13	35
Transmission	NA	(g)	78	-	50
Total			$ 4,712	$ 165	$ 1,592

			Company's Share as of December 31, 2012		
	Fuel Type	**Percent of Ownership**	**Utility Plant in Service**	**Construction Work in Progress**	**Accumulated Depreciation**
				(in millions)	
W.C. Beckjord Generating Station, Unit 6 (a)	Coal	12.5 %	$ -	$ -	$ -
Conesville Generating Station, Unit 4 (b)	Coal	43.5 %	310	26	59
J.M. Stuart Generating Station (c)	Coal	26.0 %	542	11	181
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	807	2	387
Dolet Hills Generating Station, Unit 1 (d)	Lignite	40.2 %	263	8	195
Flint Creek Generating Station, Unit 1 (e)	Coal	50.0 %	121	14	64
Pirkey Generating Station, Unit 1 (e)	Lignite	85.9 %	514	16	371
Oklaunion Generating Station, Unit 1 (f)	Coal	70.3 %	403	4	216
Turk Generating Plant (e)	Coal	73.33 %	1,613	(3)	-
Transmission	NA	(g)	69	4	50
Total			$ 4,642	$ 82	$ 1,523

(a) Operated by Duke Energy Corporation, a nonaffiliated company. AEP's portion of Beckjord Plant, Unit 6 was impaired in the fourth quarter of 2012. See "Impairments" section of Note 7.
(b) Operated by AGR.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.

(d) Operated by CLECO, a nonaffiliated company.
(e) Operated by SWEPCo.
(f) Operated by PSO and also jointly-owned (54.7%) by TNC.
(g) Varying percentages of ownership.
NANot applicable.

18. SUSTAINABLE COST REDUCTIONS

In April 2012, we initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. We selected a consulting firm to facilitate an organizational and process evaluation and a second firm to evaluate our current employee benefit programs. The process resulted in involuntary severances and was completed by the end of the first quarter of 2013. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

We recorded a charge of $47 million to Other Operation expense in 2012 primarily related to severance benefits as a result of the sustainable cost reductions initiative. In addition, the sustainable cost reduction activity for the year ended December 31, 2013 is described in the following table:

	Sustainable Cost Reduction Activity (in millions)
Balance as of December 31, 2012	$ 25
Incurred	16
Settled	(31)
Adjustments	(9)
Balance as of December 31, 2013	$ 1

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the statements of income. Of the current period expense, approximately 43% was within the Generation & Marketing segment, 36% was within the Transmission and Distribution Utilities segment and 18% was within the Vertically Integrated Utilities segment. Of the total cumulative expense, approximately 51% was within the Vertically Integrated Utilities segment, 27% was within the Transmission and Distribution Utilities segment and 19% was within the Generation & Marketing segment. The remaining liability is included in Other Current Liabilities on the balance sheets. We do not expect additional costs to be incurred related to this initiative.

19. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In our opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of our results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. Our unaudited quarterly financial information is as follows:

	2013 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,826	$ 3,582	$ 4,176	$ 3,773
Operating Income	755	547 (a)	875 (c)	678 (d) (e)
Net Income	364	339 (a) (b)	434 (c)	347 (d) (e)
Amounts Attributable to AEP Common Shareholders:				
Net Income	363	338 (a) (b)	433 (c)	346 (d) (e)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (f)	0.75	0.69	0.89	0.71
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (f)	0.75	0.69	0.89	0.71

	2012 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,625	$ 3,551	$ 4,156	$ 3,613
Operating Income	754	741	912	249 (g) (h)
Net Income	390	363	488	21 (g) (h)
Amounts Attributable to AEP Common Shareholders:				
Net Income	389	362	487	21 (g) (h)
Basic Earnings per Share Attributable to AEP				

Common Shareholders:				
Earnings per Share (f)	0.80	0.75	1.00	0.05
Diluted Earnings per Share Attributable to AEP				
Common Shareholders:				
Earnings per Share (f)	0.80	0.75	1.00	0.05

(a) Includes an impairment for Muskingum River Plant, Unit 5 (see Note 7).

(b) Includes U.K. Windfall Tax benefit (see Note 12).

(c) Includes regulatory disallowances for the Turk Plant (see Note 4) and for Big Sandy Plant, Unit 2 (see Note 7).

(d) Includes a regulatory disallowance for Amos Plant, Unit 3 (see Note 7).

(e) Includes the reversal of regulatory disallowance for the Turk Plant (see Note 4).

(f) Quarterly Earnings per Share amounts are intended to be stand-alone calculations and are not always additive to full-year amount due to rounding.

(g) Includes impairments for certain Ohio generation plants (see Note 7).

(h) See Note 18 for discussion of cost reduction programs in 2012.

20. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2013 and 2012 by operating segment are as follows:

	Vertically Integrated Utilities	AEP River Operations	Generation and Marketing	AEP Consolidated
		(in millions)		
Balance as of December 31, 2011	$ 37	$ 39	$ -	$ 76
Acquired Goodwill	-	-	15	15
Impairment Losses	-	-	-	-
Balance as of December 31, 2012	37	39	15	91
Impairment Losses	-	-	-	-
Balance as of December 31, 2013	$ 37	$ 39	$ 15	$ 91

In the fourth quarters of 2013 and 2012, we performed our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. We do not have any accumulated impairment on existing goodwill.

During 2012, the increase in goodwill of $15 million was due to the acquisition of BlueStar.

Other Intangible Assets

Acquired intangible assets subject to amortization were $10 million as of December 31, 2013, net of accumulated amortization and are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. During 2012, as a result of the acquisition of BlueStar, we acquired intangible assets associated with sales contracts and customer accounts of $58 million. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31,			
		2013		2012	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)			
Acquired Customer Contracts	5	$ 58	$ 48	$ 58	$ 34

Amortization of intangible assets was $14 million, $34 million and $1 million for the years ended December 31, 2013, 2012 and 2011, respectively. Our estimated total amortization is $6 million, $3 million and $1 million for 2014, 2015 and 2016, respectively.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Headquarters
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-1000
AEP is incorporated in the State of New York.

Stock Exchange Listing – The Company's common stock is traded principally on the New York Stock Exchange under the ticker symbol AEP.

Internet Home Page – Information about AEP, including financial documents, Securities and Exchange Commission (SEC) filings, news releases, investor presentations, shareholder information and customer service information, is available on the Company's home page on the Internet at www.AEP.com/investors.

Inquiries Regarding Your Stock Holdings – Registered shareholders (shares that you own, in your name) should contact the Company's transfer agent, listed below, if you have questions about your account, address changes, stock transfer, lost certificates, direct deposits, dividend checks and other administrative matters. You should have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
For overnight deliveries:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021-1011
Telephone Response Group:1-800-328-6955
Internet address: www.computershare.com/investor
Hearing Impaired #: TDD: 1-800-952-9245

Beneficial Holders – (Stock held in a bank or brokerage account) – When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name, and this is sometimes referred to as "street name" or a "beneficial owner." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, questions about your account should be directed to your broker.

Dividend Reinvestment and Direct Stock Purchase Plan – A Dividend Reinvestment and Direct Stock Purchase Plan is available to all investors. It is an economical and convenient method of purchasing shares of AEP common stock, through initial cash investments, cash dividends and/or additional optional cash purchases. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent or by visiting www.AEP.com/investors/buyandmanagestock.

Financial Community Inquiries – Institutional investors or securities analysts who have questions about the Company should direct inquiries to Bette Jo Rozsa, 614-716-2840, bjrozsa@AEP.com; or Julie Sherwood, 614-716-2663, jasherwood@AEP.com. Individual shareholders should contact Kathleen Kozero, 614-716-2819, klkozero@AEP.com.

Number of Shareholders – As of February 24, 2014, there were approximately 77,500 registered shareholders and approximately 446,000 shareholders holding stock in street name through a bank or broker. There were 487,820,462 shares outstanding as of February 24, 2014.

Form 10-K – Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2013. A copy can be obtained via mail with a written request to AEP Investor Relations, by telephone at 1-800-237-2667 or electronically at klkozero@AEP.com.

Executive Leadership Team

Name	Age	Office
Nicholas K. Akins	53	Chairman of the Board, President and Chief Executive Officer
Lisa M. Barton	48	Executive Vice President – Transmission
David M. Feinberg	44	Executive Vice President, General Counsel and Secretary
Lana L. Hillebrand	53	Senior Vice President and Chief Administrative Officer
Mark C. McCullough	54	Executive Vice President – Generation
Robert P. Powers	59	Executive Vice President and Chief Operating Officer
Brian X. Tierney	46	Executive Vice President and Chief Financial Officer
Dennis E. Welch	62	Executive Vice President and Chief External Officer