AMERICAN ELECTRIC POWER CO INC
Form 10-Q
October 25, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended September 30, 2013
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

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

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

Yes X No

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

Yes X No

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

X Accelerated filer

Large accelerated filer			
Non-accelerated filer		Smaller reporting company	

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

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

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

Yes		No	X

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

	Number of shares of common stock outstanding of the registrants as of October 24, 2013
American Electric Power Company, Inc.	487,290,382
	($6.50 par value)
Appalachian Power Company	13,499,500
	(no par value)
Indiana Michigan Power Company	1,400,000
	(no par value)
Ohio Power Company	27,952,473
	(no par value)
Public Service Company of Oklahoma	9,013,000
	($15 par value)
Southwestern Electric Power Company	7,536,640
	($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF QUARTERLY REPORTS ON FORM 10-Q
September 30, 2013

Part II. OTHER INFORMATION

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

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP 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.
AEPGenCo	AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation and Marketing segment.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Transmission Holding Company	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	American Electric Power Transmission Company, a wholly-owned subsidiary of AEP Transmission Holding Company.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
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.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO2	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	Competitive Retail Electric 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.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC and DCC Fuel V LLC, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.

DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
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, defining the sharing of costs and benefits associated with their respective generating plants.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NOx	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
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 generating plant, consisting of two 1,300 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.
SO2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant, a 543 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.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas restructuring law.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations" of the 2012 Annual Report, but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements r 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 generating capacity and the performance of our generating plants.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating 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 and cost recovery of our 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 generating 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 and the legal separation of generation in Ohio, including the implementation of ESPs and the successful approval, where applicable, and transfer of such Ohio generation assets and liabilities to regulated and nonregulated entities at book value.
- Our ability to successfully manage negotiations with stakeholders and obtain regulatory approval to terminate the Interconnection Agreement.
- 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 the 2012 Annual Report and in Part II of this report.

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

EXECUTIVE OVERVIEW

Corporate Separation, Plant Transfers and Termination of Interconnection Agreement

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 at net book value (NBV) to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. 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 October 2013, OPCo filed an application with the PUCO to amend the corporate separation plan by permitting OPCo to retain certain rights to purchase power from OVEC.

Also 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 NBV approximately 9,200 MW of OPCo-owned generation assets to AEPGenCo. The AEP East Companies also requested FERC approval to transfer at NBV OPCo's current two-thirds ownership in Amos Plant, Unit 3 to APCo and transfer at NBV OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests. In December 2012, APCo and KPCo filed requests with their respective commissions for the approval of these plant transfers.

In April 2013, the FERC issued orders approving the merger of APCo and WPCo and approving the transfer of OPCo's generation assets to AEPGenCo and the Amos Plant and Mitchell Plant asset transfers to APCo and KPCo, to be effective using our requested date of December 31, 2013. In May 2013, the IEU petitioned the FERC for rehearing of its order granting OPCo authority to implement corporate separation by transferring its generation assets to AEPGenCo. OPCo has contested the petition for rehearing, which remains pending before the FERC. In July 2013, the Virginia SCC approved the transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo but, for rate purposes, reduced the proposed transfer price by $83 million pretax. Additionally, the Virginia SCC denied the proposed transfer of OPCo's one-half interest in the Mitchell Plant to APCo. APCo plans to pursue cost recovery of the transferred interest in the Amos Plant in Virginia in the 2014 biennial filing. Management is currently evaluating the implications of this order while awaiting a final decision from the WVPSC. Hearings in the plant transfer case were held at the WVPSC in July 2013. In September 2013, a WVPSC staff brief advocated for the approval of the transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo, also at a reduced amount for rate purposes, and the denial of the proposed transfer of OPCo's one-half interest in the Mitchell Plant to APCo. Any disallowance related to recovery of Amos Plant, Unit 3, as a result of Virginia SCC or WVPSC orders, would be recorded upon the transfer, expected in the fourth quarter of 2013. In October 2013, the KPSC issued an order approving a modified settlement agreement that included a limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by the pending WVPSC order. Additionally, the order rejected our request to defer FGD project costs for Big Sandy Plant, Unit 2. As a result of this order, in the third quarter of 2013, KPCo recorded a pretax impairment of $33 million in Asset Impairments and Other Related Charges on the statement of income. See the "Plant Transfers" sections of APCo and WPCo Rate Matters and KPCo Rate Matters in Note 3 and the "2013 Kentucky Base Rate Case" section below.

The AEP East Companies also requested FERC approval, effective January 1, 2014, to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' 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. In March 2013, a revised PCA was filed at the FERC that included certain clarifying wording changes agreed upon by intervenors. A decision is pending at the FERC. See the “Corporate Separation and Termination of Interconnection Agreement” section of Note 3.

Additionally, FERC approval was sought for a power supply agreement between AEPGenCo and OPCo. This agreement provides for AEPGenCo 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 an auction from January 1, 2014 through December 31, 2014.

In October 2013, the AEP East Companies submitted additional filings with the FERC updating the October 2012 filings to reflect changes necessitated by recent 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. 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 corporate separation is approved as filed, for any AEPGenCo generation not serving OPCo’s retail load, AEPGenCo’s results of operations will be largely determined by prevailing market conditions effective January 1, 2014. If incurred costs are not ultimately recovered, it could reduce future net income and cash flows and impact financial condition.

Ohio Electric Security Plan Filing

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 September 30, 2013, OPCo’s net deferred fuel balance was $467 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 up to the total 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, which 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. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio. As of September 30, 2013, OPCo’s incurred deferred capacity costs balance was $228 million, including debt carrying costs.

As part of the August 2012 ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In April and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO’s ESP order, including the RSR.

In June 2013, intervenors in the competitive bid process (CBP) docket filed recommendations that include prospective rate reductions for capacity and non-energy FAC issues. OPCo maintains that the August 2012 ESP order fixed OPCo’s non-energy generation rates through December 31, 2014 and ordered the application of a $188.88/MW day price for capacity for non-shopping customers effective January 1, 2015. However, intervenors maintained that OPCo’s non-energy generation rates should be reduced prior to January 1, 2015 to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned (10% prior to June 2014 and 60% for the period June 1, 2014 through December 31, 2014). Depending upon actual customer switching levels and the timing of the auctions, OPCo estimates that these capacity issues could reduce OPCo’s projected future revenues by up to approximately $155 million for the period January 2014 through May 2015, if adopted by the PUCO. An additional proposal to prospectively offset deferred capacity costs based upon the results of the energy-only auctions was not quantified and OPCo maintains that proposal should not be adopted in light of prior PUCO orders. Hearings related to the CBP were held at the PUCO in June and July 2013. A decision from the PUCO is pending.

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 3.

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) Retail Stability Rider collections and (e) revenues from AEP Energy. AEP Energy is our CRES provider and part of our Generation and 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 were down 1.5% and 1.9% for the three and nine months ended September 30, 2013, respectively. Our industrial sales declined 3.9% and 5.1%, respectively, partially due to lower production levels at Ormet, a large aluminum company. Ormet has a contract to purchase power from OPCo through 2018. In October 2013, Ormet announced that it is unable to emerge from bankruptcy and that it has 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.

PJM Capacity Market

If corporate separation and asset transfers are approved as filed, AEPGenCo will be subject to the PJM capacity auction prices after May 2015 for the majority of the current OPCo-owned generation assets. Under the previously approved June 2012 – May 2015 ESP, OPCo is allowed to receive revenues through May 2015 for the generation assets from base generation rates and allowed to defer incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The PJM base capacity price for the planning year June 2015 through May 2016 was previously announced as $136.00/MW day. In May 2013, PJM announced the base capacity auction price for the June 2016 through May 2017 planning period would be $59.37/MW day.

Significantly Excessive Earnings Test

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO’s 2009 order. In October 2013, the PUCO issued an order on the 2010 SEET filing. As a result, the PUCO ordered a $7 million refund of pretax earnings to customers. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo or in 2012 for OPCo. Additionally, management does not currently believe that there will be significantly excessive earnings in 2013 for OPCo. Depending on the rulings in these proceedings, it could reduce future net income and cash flows and impact financial condition. See the “Ohio Electric Security Plan Filing” section of Note 3.

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 September 30, 2013, SWEPCo’s share of incurred construction expenditures for the Turk Plant was approximately $1.8 billion, including AFUDC and capitalized interest of $328 million and related transmission costs of $118 million. As of September 30, 2013, a provision of $173 million has been recorded for costs incurred in excess of a Texas cost cap, resulting in total capitalized expenditures of $1.6 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. The Arkansas portion of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the wholesale market. If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it could reduce future net income and cash flows and impact financial condition. See the "Turk Plant" section of Note 3.

2012 Texas Base Rate Case

In 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million 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 of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. In September 2012, an Administrative Law Judge (ALJ) issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates. In May 2013, the ALJ issued a proposal for decision recommending a rate increase but found SWEPCo imprudent for failing to cancel the Turk Plant in 2010.

The PUCT rejected the ALJ's imprudence recommendation, but during a September 2013 open meeting, the PUCT stated that it would limit the recovery of the investment in the Turk Plant by imposing a Texas jurisdictional cost cap established in the recently concluded Certificate of Convenience and Necessity (CCN) case appeal (the Texas capital cost cap). The PUCT also provided new details on how the cost cap would be applied. In October 2013, the PUCT issued an order with the determination that the Turk Plant 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 impairment of $111 million in Asset Impairments and Other Related Charges on the statement of income. The order approved an annual rate increase of approximately $39 million based upon a return on common equity of 9.65%. As a result of this approval, SWEPCo retroactively applied these rates back to the end of January 2013. The approval also provided for the following: (a) no disallowances to the existing book investment in the Stall Plant, and (b) the exclusion, until SWEPCo files and obtains approval of a Transmission Cost Recovery Rider, of the Turk Plant transmission line investment that was not in service at the end of the test year. Additionally, the PUCT determined that it would defer consideration of the requested increase in depreciation expense related to the change in the 2016 retirement date of the Welsh Plant, Unit 2. Requests for rehearing may be filed within 30 days of receipt of the PUCT order. SWEPCo intends to file a motion for rehearing with the PUCT in late October 2013.

If SWEPCo cannot ultimately recover its Texas jurisdictional share of the investment and expenses related to the Turk Plant, transmission lines or Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition. See the "2012 Texas Base Rate Case" section of Note 3.

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 prudence review of the Turk Plant. If the LPSC orders refunds based upon the pending staff review of the cost of service or the prudence 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 3.

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 to $92 million. In March 2013, the Indiana Office of Utility Consumer

Counselor (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 certain aspects of the rate case. If the 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 3.

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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 includes cost recovery of the pending transfer of the one-half interest in the Mitchell Plant (780 MW). In October 2013, the KPSC issued an order which modified and approved a settlement agreement relating to the proposed transfer of the one-half interest in the Mitchell Plant, in which KPCo agreed to withdraw this base rate case request. KPCo intends to withdraw this base rate request following the resolution of any potential requests for rehearing or appeals of the KPSC order. Assuming KPCo withdraws the base rate case, current base rates will remain in effect until at least May 2015.

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 extended 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 September 30, 2013, I&M has incurred $285 million related to the LCM Project, including AFUDC.