Kentucky Power Company

2016 Annual Report

Audited Financial Statements

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GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
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 competitive 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.
ASU	Accounting Standards Update.
CWIP	Construction Work in Progress.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
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.
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.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky 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.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_x	Nitrogen oxide.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.

Term	Meaning
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.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
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.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholder of
Kentucky Power Company:

We have audited the accompanying financial statements of Kentucky Power Company (the "Company"), which comprise the balance sheets as of December 31, 2016 and 2015, and the related statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2016, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016 in accordance with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Columbus, Ohio
February 27, 2017

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2016, 2015 and 2014
(in thousands)

	Years Ended December 31,		
	2016	**2015**	**2014**
REVENUES			
Electric Generation, Transmission and Distribution	$ 645,678	$ 641,550	$ 773,795
Sales to AEP Affiliates	8,286	11,814	7,514
Other Revenues	1,066	795	669
TOTAL REVENUES	655,030	654,159	781,978
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	119,694	167,096	283,751
Purchased Electricity for Resale	43,671	39,228	14,389
Purchased Electricity from AEP Affiliates	97,941	99,475	116,243
Other Operation	96,777	80,825	84,491
Maintenance	72,068	76,957	71,812
Depreciation and Amortization	84,859	87,470	95,059
Taxes Other Than Income Taxes	21,315	22,352	21,308
TOTAL EXPENSES	536,325	573,403	687,053
OPERATING INCOME	118,705	80,756	94,925
Other Income (Expense):			
Interest Income	39	100	178
Carrying Costs Income	23	2,364	59
Allowance for Equity Funds Used During Construction	852	1,158	4,009
Interest Expense	(45,816)	(44,549)	(38,356)
INCOME BEFORE INCOME TAX EXPENSE	73,803	39,829	60,815
Income Tax Expense	23,593	11,938	22,437
NET INCOME	$ 50,210	$ 27,891	$ 38,378

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

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2016, 2015 and 2014
(in thousands)

	Years Ended December 31,		
	2016	2015	2014
Net Income	$ 50,210	$ 27,891	$ 38,378
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $32, $32 and $20 in 2016, 2015 and 2014, Respectively	60	60	38
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $9, $36 and $252 in 2016, 2015 and 2014, Respectively	17	67	468
Pension and OPEB Funded Status, Net of Tax of $115, $(281) and $(600) in 2016, 2015 and 2014, Respectively	214	(522)	(1,114)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	291	(395)	(608)
TOTAL COMPREHENSIVE INCOME	$ 50,501	$ 27,496	$ 37,770

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2016, 2015 and 2014
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2013	$ 50,450	$ 614,648	$ 179,691	$ (5,420)	$ 839,369
Capital Contribution Returned to Parent		(100,000)			(100,000)
Common Stock Dividends			(115,000)		(115,000)
Other Changes in Common Shareholder's Equity		2,812			2,812
Net Income			38,378		38,378
Other Comprehensive Loss				(608)	(608)
Pension and OPEB Adjustment Related to Kammer Plant				(1,308)	(1,308)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2014	50,450	517,460	103,069	(7,336)	663,643
Capital Contribution from Parent		9,849			9,849
Common Stock Dividends			(44,000)		(44,000)
Net Income			27,891		27,891
Other Comprehensive Loss				(395)	(395)
Pension and OPEB Adjustment Related to Mitchell Plant				6,086	6,086
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2015	50,450	527,309	86,960	(1,645)	663,074
Capital Contribution Returned to Parent		(1,174)			(1,174)
Common Stock Dividends			(44,000)		(44,000)
Net Income			50,210		50,210
Other Comprehensive Income				291	291
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 50,450	$ 526,135	$ 93,170	$ (1,354)	$ 668,401

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2016 and 2015
(in thousands)

	December 31, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 859	$ 867
Accounts Receivable:		
Customers	14,608	13,747
Affiliated Companies	29,519	20,373
Accrued Unbilled Revenues	4,542	53
Miscellaneous	380	110
Allowance for Uncollectible Accounts	(66)	(243)
Total Accounts Receivable	48,983	34,040
Fuel	19,823	22,085
Materials and Supplies	16,540	26,705
Risk Management Assets – Nonaffiliated	457	2,869
Risk Management Assets – Affiliated	—	173
Accrued Tax Benefits	574	47,812
Prepayments and Other Current Assets	8,347	4,623
TOTAL CURRENT ASSETS	95,583	139,174
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,182,212	1,118,837
Transmission	574,703	568,963
Distribution	783,283	756,631
Other Property, Plant and Equipment	67,248	58,294
Construction Work in Progress	27,380	59,351
Total Property, Plant and Equipment	2,634,826	2,562,076
Accumulated Depreciation and Amortization	879,253	847,675
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,755,573	1,714,401
OTHER NONCURRENT ASSETS		
Regulatory Assets	576,131	557,956
Long-term Risk Management Assets – Nonaffiliated	—	12
Employee Benefits and Pension Assets	5,891	6,939
Deferred Charges and Other Noncurrent Assets	26,787	17,774
TOTAL OTHER NONCURRENT ASSETS	608,809	582,681
TOTAL ASSETS	$ 2,459,965	$ 2,436,256

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2016 and 2015

	December 31, 2016	December 31, 2015
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 1,807	$ 18,692
Accounts Payable:		
General	52,601	36,882
Affiliated Companies	28,579	25,139
Long-term Debt Due Within One Year – Nonaffiliated	390,000	65,000
Risk Management Liabilities – Nonaffiliated	53	1,002
Customer Deposits	26,625	26,916
Accrued Taxes	28,379	26,867
Accrued Interest	8,127	7,928
Other Current Liabilities	44,302	51,110
TOTAL CURRENT LIABILITIES	580,473	259,536
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	477,164	801,451
Long-term Risk Management Liabilities – Nonaffiliated	313	11
Deferred Income Taxes	666,902	636,158
Asset Retirement Obligations	46,657	55,151
Employee Benefits and Pension Obligations	14,516	13,536
Deferred Credits and Other Noncurrent Liabilities	5,539	7,339
TOTAL NONCURRENT LIABILITIES	1,211,091	1,513,646
TOTAL LIABILITIES	1,791,564	1,773,182
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	526,135	527,309
Retained Earnings	93,170	86,960
Accumulated Other Comprehensive Income (Loss)	(1,354)	(1,645)
TOTAL COMMON SHAREHOLDER'S EQUITY	668,401	663,074
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,459,965	$ 2,436,256

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2016, 2015 and 2014
(in thousands)

	Years Ended December 31,		
	2016	2015	2014
OPERATING ACTIVITIES			
Net Income	$ 50,210	$ 27,891	$ 38,378
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	84,859	87,470	95,059
Deferred Income Taxes	18,572	75,638	9,157
Carrying Costs Income	(23)	(2,364)	(59)
Allowance for Equity Funds Used During Construction	(852)	(1,158)	(4,009)
Mark-to-Market of Risk Management Contracts	1,951	1,642	203
Pension Contributions to Qualified Plan Trust	(1,509)	(1,900)	(1,923)
Deferred Fuel Over/Under-Recovery, Net	(3,508)	(217)	(1,081)
Provision for Refund	—	(31,033)	31,033
Big Sandy Decommissioning Costs	(17,666)	(1,830)	—
Change in Other Noncurrent Assets	(14,305)	(26,115)	(4,372)
Change in Other Noncurrent Liabilities	(9,378)	(1,765)	8,506
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(14,943)	19,612	(25,128)
Fuel, Materials and Supplies	3,970	26,480	56,498
Accounts Payable	18,784	(4,973)	1,265
Accrued Taxes, Net	48,750	(28,874)	(7,591)
Accrued Interest	199	105	1,146
Other Current Assets	(2,560)	516	(1,044)
Other Current Liabilities	(4,713)	(4,368)	17,230
Net Cash Flows from Operating Activities	157,838	134,757	213,268
INVESTING ACTIVITIES			
Construction Expenditures	(99,428)	(114,194)	(101,898)
Proceeds from Sales of Assets	2,611	1,337	307
Other Investing Activities	666	222	(884)
Net Cash Flows Used for Investing Activities	(96,151)	(112,635)	(102,475)
FINANCING ACTIVITIES			
Capital Contribution Returned to Parent	—	—	(100,000)
Issuance of Long-term Debt – Nonaffiliated	—	49,456	288,344
Change in Advances from Affiliates, Net	(16,885)	(26,436)	36,564
Retirement of Long-term Debt – Nonaffiliated	—	—	(200,000)
Retirement of Long-term Debt – Affiliated	—	—	(20,000)
Principal Payments for Capital Lease Obligations	(985)	(1,148)	(2,079)
Dividends Paid on Common Stock	(44,000)	(44,000)	(115,000)
Other Financing Activities	175	78	1,430
Net Cash Flows Used for Financing Activities	(61,695)	(22,050)	(110,741)
Net Increase (Decrease) in Cash and Cash Equivalents	(8)	72	52
Cash and Cash Equivalents at Beginning of Period	867	795	743
Cash and Cash Equivalents at End of Period	$ 859	$ 867	$ 795
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 44,601	$ 43,426	$ 36,062
Net Cash Paid (Received) for Income Taxes	(43,032)	(27,317)	18,545
Noncash Acquisitions Under Capital Leases	761	244	1,471
Construction Expenditures Included in Current Liabilities as of December 31,	11,929	14,112	17,626
Noncash Capital Contribution from (returned to) Parent	(1,174)	9,849	—

See Notes to Financial Statements beginning on page 10.

INDEX OF NOTES TO FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 169,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

Effective January 2014, the FERC approved a PCA among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Effective May 2015, the PCA was revised and approved by the FERC to include WPCo. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. Further, the Restated and Amended PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo 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 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 would 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 the PJM Planning year that ended May 31, 2015.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo and WPCo. Effective January 2014, and revised in May 2015, power and natural gas risk management activities are allocated based on the member companies' respective equity positions. Risk management activities primarily include the power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts. KPCo shared in the revenues and expenses associated with these risk management activities with the member companies.

Under a unit power agreement with AEGCo, an affiliated company, KPCo purchases 390 MWs of Rockport Plant capacity which is 30% of AEGCo's 50% share of the 2,620 MW Rockport Plant. The unit power agreement expires in December 2022. KPCo pays a demand charge for the right to receive the power, which is payable even if the power is not taken.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including KPCo, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

KPCo's rates are regulated by the FERC and the KPSC. The FERC also regulates KPCo's 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 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 KPSC also regulates certain intercompany transactions under its 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, wholesale power transactions and wholesale transmission operations and rates. KPCo's wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when KPCo negotiates and files a cost-based contract with the FERC or the FERC determines that KPCo has "market power" in the region where the transaction occurs. KPCo has entered into wholesale power supply contracts with various municipalities that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually.

The KPSC regulates all of the distribution operations and rates and retail transmission rates on a cost basis. The KPSC also regulates retail generation/power supply operations and rates.

In addition, the FERC regulates the SIA and the Transmission Agreement, which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. In 2013, the FERC issued orders approving the creation of a PCA, effective January 2014. Also effective January 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent. Effective June 2014, the FERC approved the cancellation of the System Transmission Integration Agreement.

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated electric public utility company, KPCo's 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," KPCo records 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 accounting principles generally accepted in the United States of America (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, 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.

Inventory

Fossil fuel inventories and 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 risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, KPCo accrues and recognizes, 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 KPCo. See "Sale of Receivables - AEP Credit" section of Note 13 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense related to receivables purchased from KPCo under a sale of receivables agreement. For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. 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.

Concentrations of Credit Risk and Significant Customers

KPCo has a significant customer which accounts for the following percentage of total operating revenues for the year ended December 31, 2016 and Accounts Receivable – Customers as of December 31, 2016:

Significant Customer of KPCo: Marathon Petroleum Company	**2016**
Percentage of Operating Revenues	11%
Percentage of Accounts Receivable – Customers	39%

KPCo did not have any significant customers that comprised 10% or more of its operating revenues for the years ended December 31, 2015 and 2014.

Management monitors credit levels and the financial condition of KPCo's customers on a continuing basis to minimize credit risk. The KPSC allows recovery in rates for a reasonable level of bad debt costs. Management believes adequate provision for credit loss has been made in the accompanying financial statements.

Emission Allowances

KPCo records emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. KPCo follows the inventory model for these allowances. Allowances expected to be consumed within one year are reported in Materials and Supplies. Allowances with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets. These allowances are consumed in the production of energy and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost. The purchases and sales of allowances are reported in the Operating Activities section of the statements of cash flows. The net margin on sales of emission allowances is included in Electric Generation, Transmission and Distribution Revenues for nonaffiliated transactions and in Sales to AEP Affiliates Revenues for affiliated transactions because of its integral nature to the production process of energy and KPCo's revenue optimization strategy for 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.

Property, Plant and Equipment

Electric utility property, plant and equipment 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 removal cost incurred and salvage received. These rates and the related lives are subject to periodic review. Removal costs accrued are typically recorded as regulatory liabilities when removal costs accrued exceed actual removal costs incurred. The asset removal costs liability is relieved as removal costs are incurred. A regulatory asset balance will occur if actual removal costs incurred exceed accumulated removal costs accrued.

The costs of labor, materials and overhead incurred to operate and maintain plant and equipment 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.

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, 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 in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction

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. KPCo records 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.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Advances from Affiliates and Accounts Payable approximate fair value because of the short-term maturity of these instruments.

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 and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors. The AEP System's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Vice Chairman, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer.

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

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

Assets in the benefits trusts are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalent funds. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are primarily real estate, infrastructure and private equity investments that are valued using methods requiring judgment including appraisals. The fair value of real estate and infrastructure investments is measured using market capitalization rates, recent sales of comparable investments and independent third-party appraisals. The fair value of private equity investments is measured using cost and purchase multiples, operating results, discounted future cash flows and market based comparable data. Depending on the specific situation, one or multiple approaches are used to determine the valuation of a real estate, infrastructure or private equity investment.

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. Fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) 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 KPSC's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the KPSC. On a routine basis, the KPSC reviews and/or audits KPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. Changes in fuel costs, including purchased power, are reflected in rates in a timely manner through the FAC. A portion of margins from off-system sales are given to customers through the FAC.

Revenue Recognition

Regulatory Accounting

KPCo's 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, KPCo records them as assets on its balance sheets. KPCo tests 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, KPCo writes off that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

KPCo recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues on the statements of income upon delivery of the energy to the customer and includes unbilled as well as billed amounts. Wholesale transmission revenue is based on FERC approved formula rate filings made for each calendar year using estimated costs. The annual rate filing is compared to actual costs with an over- or under-recovery being trued-up with interest and refunded or recovered in a future year's rates.

Most of the power produced at KPCo's generation plants is sold to PJM. KPCo purchases power from PJM to supply power to its customers. Generally, these power sales and purchases are reported on a net basis in 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.

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 facts and circumstances. 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, KPCo records 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. KPCo defers the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

KPCo engages in power marketing as a major power producer and participant in electricity markets. KPCo also engages in power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity risk management activities focused on markets where the AEP System owns assets and adjacent markets. These 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. Certain energy marketing and risk management transactions are with RTOs.

KPCo recognizes revenues and expenses from marketing and risk management transactions that are not derivatives upon delivery of the commodity. KPCo uses MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. The realized gains and losses on marketing and risk management transactions are included in revenues or expense based on the transaction's facts and circumstances. The unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying 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). In the event KPCo designates a cash flow hedge, the effective portion of the cash flow hedge's gain or loss is initially recorded as a component of AOCI. When the forecasted transaction is realized and affects net income, KPCo subsequently reclassifies 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. KPCo defers the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 9.

Maintenance

Maintenance costs are expensed as incurred. If it becomes probable that KPCo will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues.

Income Taxes and Investment Tax Credits

KPCo uses the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided 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), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits (ITC) were historically accounted for under the flow-through method, except where regulatory commissions reflected ITC in the rate-making process. In the third quarter of 2016, KPCo and other AEP subsidiaries changed accounting for the recognition of ITC and elected to apply the preferred deferral methodology. This change had no financial impact to KPCo.

Deferred ITC is amortized to income tax expense over the life of the asset. Amortization of deferred ITC begins when the asset is placed into service, except where regulatory commissions reflect ITC in the rate-making process, then amortization begins when the cash tax benefit is recognized.

KPCo accounts for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." KPCo classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Other Operation expense.

Excise Taxes

As an agent for some state and local governments, KPCo collects from customers certain excise taxes levied by those state or local governments on customers. KPCo does not recognize these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt is refinanced, the reacquisition costs are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates.

Debt discount or premium and debt issuance expenses are deferred and amortized 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. The net amortization expense is included in Interest Expense on the statements of income.

Pension and OPEB Plans

KPCo participates in an AEP sponsored qualified pension plan and an unfunded nonqualified pension plan. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and nonqualified pension plans. KPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees. KPCo is allocated a proportionate share of benefit costs and accounts for its participation in these plans as multiple-employer plans. See Note 7 - Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk 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. Management regularly reviews the actual asset allocations and periodically rebalances 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 AEP's 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 objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	25%
Fixed Income	59%
Other Investments	15%
Cash and Cash Equivalents	1%

OPEB Plans Assets	Target
Equity	65%
Fixed Income	33%
Cash and Cash Equivalents	2%

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, the 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.

For equity investments, the concentration 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% and 7% for pension and OPEB investments, respectively, 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, each investment manager's portfolio is compared to investment grade, diversified long and intermediate benchmark indices.

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, 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. The 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.

AEP participates 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. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the 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.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association 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.

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).

Earnings Per Share (EPS)

KPCo is a wholly-owned subsidiary of AEP. Therefore, KPCo is not required to report EPS.

Supplementary Income Statement Information

The following table provides the components of Depreciation and Amortization for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
Depreciation and Amortization	**2016**	**2015**	**2014**
		(in thousands)	
Depreciation and Amortization of Property, Plant and Equipment	$ 82,291	$ 86,679	$ 94,770
Amortization of Regulatory Assets and Liabilities	2,568	791	289
Total Depreciation and Amortization	$ 84,859	$ 87,470	$ 95,059

Subsequent Events

Management reviewed subsequent events through February 27, 2017, the date that KPCo's 2016 annual report was issued.

2. NEW ACCOUNTING PRONOUNCEMENTS

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

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

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

The FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, "Revenue from Contracts with Customers (Topic: 606): Deferral of the Effective Date." The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted.

Management continues to analyze the impact of the new revenue standard and related ASUs. During 2016, initial revenue contract assessments were completed. Material revenue streams were identified within the AEP System and representative contract/transaction types were sampled. Performance obligations identified within each material revenue stream were evaluated to determine whether the obligations were satisfied at a point in time or over time. Contracts determined to be satisfied over time generally qualified for the invoicing practical expedient since the invoiced amounts reasonably represented the value to customers of performance obligations fulfilled to date. Based upon the completed assessments, management does not expect a material impact to the timing of revenue recognized or net income and plans to elect the modified retrospective transition approach upon adoption. Management also continues to monitor unresolved industry implementation issues, including items related to collectability and alternative revenue programs, and will analyze the related impacts to revenue recognition. Management plans to adopt ASU 2014-09 effective January 1, 2018.

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

In July 2015, the FASB issued ASU 2015-11 simplifying the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first-out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. Management adopted ASU 2015-11 prospectively, effective January 1, 2017. There was no impact on results of operations, financial position or cash flows at adoption.

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

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

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

ASU 2016-02 "Accounting for Leases" (ASU 2016-02)

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

The new accounting guidance is effective for annual periods beginning after December 15, 2018 with early adoption permitted. The guidance will be applied by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented.

Management continues to analyze the impact of the new lease standard. During 2016, initial lease contract assessments were completed. The AEP System lease population was identified and representative lease contracts were sampled. Based upon the completed assessments, management prepared a system gap analysis to outline new disclosure compliance requirements compared to current system capabilities. Lease system options are currently being evaluated. Management plans to elect certain of the following practical expedients upon adoption:

Practical Expedient	Description
Overall Expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to reassess whether any expired or existing contracts are/or contain leases, do not need to reassess the lease classification for any expired or existing leases and do not need to reassess initial direct costs for any existing leases.
Lease and Non-lease Components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component.
Short-term Lease (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases.
Lease term	Elect to use hindsight to determine the lease term.

Management expects the new standard to impact financial position, but not results of operations or cash flows. Management also continues to monitor unresolved industry implementation issues, including items related to renewables and Purchase Power and Sale Agreements, pole attachments, easements and right-of-ways, and will analyze the related impacts to lease accounting. Management plans to adopt ASU 2016-02 effective January 1, 2019.

ASU 2016-09 "Compensation – Stock Compensation" (ASU 2016-09)

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

The new accounting guidance is effective for annual periods beginning after December 15, 2016. Early adoption is permitted in any interim or annual period. Certain provisions require retrospective/modified retrospective transition while others are to be applied prospectively. Management adopted ASU 2016-09 effective January 1, 2017. There was no impact on results of operations, financial position or cash flows at adoption.

ASU 2016-13 "Measurement of Credit Losses on Financial Instruments" (ASU 2016-13)

In June 2016, the FASB issued ASU 2016-13 requiring an allowance to be recorded for all expected credit losses for financial assets. The allowance for credit losses is based on historical information, current conditions and reasonable and supportable forecasts. The new standard also makes revisions to the other than temporary impairment model for available-for-sale debt securities. Disclosures of credit quality indicators in relation to the amortized cost of financing receivables are further disaggregated by year of origination.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019 with early adoption permitted for interim and annual periods beginning after December 15, 2018. The amendments will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-13 effective January 1, 2020.

ASU 2016-18 "Restricted Cash" (ASU 2016-18)

In November 2016, the FASB issued ASU 2016-18 clarifying the treatment of restricted cash on the statements of cash flows. Under the new standard, amounts considered restricted cash will be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts on the statements of cash flows.

The new accounting guidance is effective for annual periods beginning after December 15, 2017. Early adoption is permitted in any interim or annual period. The guidance will be applied by means of a retrospective approach. Management is analyzing the impact of the new standard. Management plans to adopt ASU 2016-18 effective for the 2017 Annual Report.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2016, 2015 and 2014. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 for additional details.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in thousands)		
Balance in AOCI as of December 31, 2015	$ —	$ (101)	$ 3,212	$ (4,756)	$ (1,645)
Change in Fair Value Recognized in AOCI	—	—	—	214	214
Amount of (Gain) Loss Reclassified from AOCI					
Interest Expense	—	93	—	—	93
Amortization of Prior Service Cost (Credit)	—	—	(222)	—	(222)
Amortization of Actuarial (Gains)/Losses	—	—	248	—	248
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	93	26	—	119
Income Tax (Expense) Credit	—	33	9	—	42
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	60	17	—	77
Net Current Period Other Comprehensive Income	—	60	17	214	291
Balance in AOCI as of December 31, 2016	$ —	$ (41)	$ 3,229	$ (4,542)	$ (1,354)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2015

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in thousands)		
Balance in AOCI as of December 31, 2014	$ —	$ (161)	$ 3,145	$ (10,320)	$ (7,336)
Change in Fair Value Recognized in AOCI	—	—	—	(522)	(522)
Amount of (Gain) Loss Reclassified from AOCI					
Interest Expense	—	93	—	—	93
Amortization of Prior Service Cost (Credit)	—	—	(41)	—	(41)
Amortization of Actuarial (Gains)/Losses	—	—	141	—	141
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	93	100	—	193
Income Tax (Expense) Credit	—	33	33	—	66
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	60	67	—	127
Net Current Period Other Comprehensive Income (Loss)	—	60	67	(522)	(395)
Pension and OPEB Adjustment Related to Mitchell Plant	—	—	—	6,086	6,086
Balance in AOCI as of December 31, 2015	$ —	$ (101)	$ 3,212	$ (4,756)	$ (1,645)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2014

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
	(in thousands)				
Balance in AOCI as of December 31, 2013	$ 23	$ (222)	$ 2,677	$ (7,898)	$(5,420)
Change in Fair Value Recognized in AOCI	347	—	—	(1,114)	(767)
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity for Resale	(513)	—	—	—	(513)
Other Operation Expense	(3)	—	—	—	(3)
Maintenance Expense	(5)	—	—	—	(5)
Property, Plant and Equipment	(6)	—	—	—	(6)
Regulatory Assets/(Liabilities), Net (a)	(43)	—	—	—	(43)
Interest Expense	—	93	—	—	93
Amortization of Prior Service Cost (Credit)	—	—	(214)	—	(214)
Amortization of Actuarial (Gains)/Losses	—	—	935	—	935
Reclassifications from AOCI, before Income Tax (Expense) Credit	(570)	93	721	—	244
Income Tax (Expense) Credit	(200)	32	253	—	85
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(370)	61	468	—	159
Net Current Period Other Comprehensive Income (Loss)	(23)	61	468	(1,114)	(608)
Pension and OPEB Adjustment Related to Kammer Plant	—	—	—	(1,308)	(1,308)
Balance in AOCI as of December 31, 2014	$ —	$ (161)	$ 3,145	$ (10,320)	$(7,336)

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

4. RATE MATTERS

KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. Rate matters can have a material impact on net income, cash flows and possibly financial condition. KPCo's recent significant rate orders and pending rate filings are addressed in this note.

FERC Transmission Complaint and Proposed Modifications to Transmission Rates

In October 2016, several parties filed a joint complaint with the FERC claiming that the base return on common equity used by various AEP affiliates in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In November 2016, AEP affiliates filed an application with the FERC to modify the FERC formula transmission rate calculation, including adjustments for certain tax issues and a shift from historical to estimated expenses with a proposed effective date of January 1, 2017. The rates will be implemented based upon the date provided in the pending FERC order, subject to refund. Management believes its financial statements adequately address the impact of the complaint and the proposed modifications to AEP's transmission rates in PJM. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	**December 31, 2016**	**December 31, 2015**	**Remaining Recovery Period**
	(in thousands)		
Current Regulatory Assets			
Under-recovered Fuel Costs - does not earn a return	$ 1,955	$ —	1 year
Total Current Regulatory Assets	1,955	—	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	$ 4,377	$ 4,377	
Other Regulatory Assets Pending Final Regulatory Approval	52	—	
Total Regulatory Assets Pending Final Regulatory Approval	4,429	4,377	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs	212,380	192,536	24 years
Asset Removal Costs	20,946	40,055	(a)
Plant Retirement Costs - Asset Retirement Obligation Costs	18,344	7,640	24 years
Plant Retirement Costs - Materials and Supplies	3,903	4,485	24 years
Other Regulatory Assets Approved for Recovery	1,203	1,207	various
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	172,528	160,246	22 years
Pension and OPEB Funded Status	57,544	52,687	12 years
Plant Retirement Costs - Asset Retirement Obligation Costs	48,942	58,031	24 years
Peak Demand Reduction/Energy Efficiency	9,075	4,332	2 years
Storm Related Costs	8,502	10,931	4 years
Environmental Costs	5,677	6,365	1 year
Big Sandy Plant, Unit 1 Operating Rider	3,898	4,903	2 years
Postemployment Benefits	3,288	4,557	5 years
Medicare Subsidy	1,733	1,950	8 years
IGCC Pre-Construction Costs	1,251	1,305	24 years
Other Regulatory Assets Approved for Recovery	2,488	2,349	various
Total Regulatory Assets Approved for Recovery	571,702	553,579	
Total Noncurrent Regulatory Assets	$ 576,131	$ 557,956	

(a) As a regulated entity, removal costs accrued are typically recorded as regulatory liabilities when removal costs accrued exceed actual removal costs incurred. The asset removal costs liability is relieved as removal costs are incurred. As of December 31, 2016, KPCo's accumulated actual removal cost incurred exceeded accumulated removal cost accrued, creating an asset balance. As a result, the balance was reclassified to a regulatory asset. Within the next two years, KPCo's removal costs accrued are expected to exceed removal costs incurred resulting in a regulatory liability.

Regulatory Liabilities:	December 31, 2016	2015	Remaining Refund Period
	(in thousands)		
Current Regulatory Liability			
Over-recovered Fuel Costs - does not pay a return	$ —	$ 1,553	
Total Current Regulatory Liabilities	$ —	$ 1,553	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Gain on Forward Commitments	$ 89	$ 1,550	2 years
Other Regulatory Liabilities Approved for Payment	157	58	various
Total Regulatory Liabilities Approved for Payment	246	1,608	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 246	$ 1,608	

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

COMMITMENTS

Construction and Commitments

KPCo has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, KPCo contractually commits to third-party construction vendors for certain material purchases and other construction services. KPCo also purchases fuel, materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following table summarizes KPCo's actual contractual commitments as of December 31, 2016:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 184,784	$ 190,884	$ 187,736	$ 67,069	$ 630,473
Energy and Capacity Purchase Contracts	39,283	82,418	81,994	41,088	244,783
Total	$ 224,067	$ 273,302	$ 269,730	$ 108,157	$ 875,256

(a) Represents contractual commitments to purchase coal and other consumables as fuel for electric generation along with related transportation of the fuel.

GUARANTEES

Liabilities for guarantees are recorded 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.

Letter of Credit

KPCo has $65 million of variable rate Pollution Control Bonds supported by a bilateral letter of credit for $66 million. The letter of credit matures in June 2017.

Indemnifications and Other Guarantees

Contracts

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

KPCo is jointly and severally liable for activity conducted by AEPSC on behalf of AEP companies related to power purchase and sale activity.

Lease Obligations

KPCo leases certain equipment under master lease agreements. See "Master Lease Agreements" section of Note 12 for disclosure of lease residual value guarantees.

CONTINGENCIES

Insurance and Potential Losses

KPCo maintains insurance coverage normal and customary for an electric utility, subject to various deductibles. KPCo also maintains property and casualty insurance that may cover certain physical damage or third-party injuries caused by cyber security incidents. Insurance coverage includes all risks of physical loss or damage to 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. The insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of KPCo's retentions. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

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 a cyber security incident. 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.

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 and sludge. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. KPCo currently incurs costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2016, there is one site for which KPCo has received an information request which could lead to a Potentially Responsible Party designation. In the instance where KPCo has been named a defendant, 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.

Management evaluates the potential liability for each site separately, but several general statements can be made about 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 for each site and several of the parties are financially sound enterprises. At present, management's estimates do not anticipate material cleanup costs for identified sites.

7. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Fair Value Measurements of Assets and Liabilities" and "Investments Held in Trust for Future Liabilities" sections of Note 1.

KPCo participates in an AEP sponsored qualified pension plan and an unfunded nonqualified pension plan. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and nonqualified pension plans. KPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

KPCo recognizes its funded status associated with defined benefit pension and OPEB plans in its balance sheets. Disclosures about the plans are required by the "Compensation - Retirement Benefits" accounting guidance. KPCo recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status and recognizes, 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. KPCo records a regulatory asset instead of other comprehensive income for qualifying benefit costs of 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 used in the measurement of benefit obligations are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
Assumptions	**2016**	**2015**	**2016**	**2015**
Discount Rate	4.05%	4.30%	4.10%	4.30%
Rate of Compensation Increase	4.40% (a)	4.35% (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.

A duration-based method is used to determine the discount rate for the 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 2016, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 12% per year, with an average increase of 4.4%.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions used in the measurement of benefit costs are shown in the following table:

	Pension Plans			Other Postretirement Benefit Plans		
			January 1,			
Assumptions	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Discount Rate	4.30%	4.00%	4.70%	4.30%	4.00%	4.70%
Expected Return on Plan Assets	6.00%	6.00%	6.00%	7.00%	6.75%	6.75%
Rate of Compensation Increase	4.40% (a)	4.35% (a)	4.50% (a)	NA	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.

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 used for OPEB plans measurement purposes are shown below:

	January 1,	
Health Care Trend Rates	**2016**	**2015**
Initial	7.00%	6.25%
Ultimate	5.00%	5.00%
Year Ultimate Reached	2024	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 thousands)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 76	$ (56)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	1,733	(1,528)

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. The plans are monitored to control security diversification and ensure compliance with the investment policy. As of December 31, 2016, 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

The following table provides a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status. 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	
	2016	2015	2016	2015
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1,	$ 178,076	$ 189,224	$ 50,890	$ 50,818
Service Cost	2,461	2,680	283	343
Interest Cost	7,489	7,326	2,150	1,952
Actuarial (Gain) Loss	3,943	(10,971)	1,939	972
Benefit Payments	(11,233)	(10,183)	(4,850)	(4,352)
Participant Contributions	—	—	1,418	1,150
Medicare Subsidy	—	—	19	7
Benefit Obligation as of December 31,	$ 180,736	$ 178,076	$ 51,849	$ 50,890
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 173,368	$ 184,842	$ 57,829	$ 63,628
Actual Gain (Loss) on Plan Assets	10,403	(3,191)	3,343	(2,597)
Company Contributions	1,509	1,900	—	—
Participant Contributions	—	—	1,418	1,150
Benefit Payments	(11,233)	(10,183)	(4,850)	(4,352)
Fair Value of Plan Assets as of December 31,	$ 174,047	$ 173,368	$ 57,740	$ 57,829
Funded (Underfunded) Status as of December 31,	$ (6,689)	$ (4,708)	$ 5,891	$ 6,939

Amounts Recognized on the Balance Sheets

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2016	2015	2016	2015
	(in thousands)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ —	$ —	$ 5,891	$ 6,939
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(6,689)	(4,708)	—	—
Funded (Underfunded) Status	$ (6,689)	$ (4,708)	$ 5,891	$ 6,939

Amounts Included in AOCI and Regulatory Assets

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2016	2015	2016	2015
Components	(in thousands)			
Net Actuarial Loss	$ 55,653	$ 54,923	$ 21,098	$ 19,699
Prior Service Cost (Credit)	48	100	(17,233)	(19,658)
Recorded as				
Regulatory Assets	$ 53,550	$ 52,058	$ 3,994	$ 629
Deferred Income Taxes	753	1,038	(44)	(205)
Net of Tax AOCI	1,398	1,927	(85)	(383)

Components of the change in amounts included in AOCI and Regulatory Assets are as follows:

Components	Pension Plans		Other Postretirement Benefit Plans	
	2016	2015	2016	2015
	(in thousands)			
Actuarial Loss During the Year	$ 3,673	$ 2,201	$ 2,550	$ 7,400
Amortization of Actuarial Loss	(2,943)	(3,784)	(1,151)	(622)
Amortization of Prior Service Credit (Cost)	(52)	(53)	2,425	2,424
Change for the Year Ended December 31,	$ 678	$ (1,636)	$ 3,824	$ 9,202

Pension and Other Postretirement Benefits Plans' Assets

The fair value tables within Pension and Other Postretirement Benefits Plans' Assets present the classification of assets for AEP within the fair value hierarchy. All Level 1, 2, 3 and Other amounts can be allocated to KPCo using the percentages below:

Pension Plan		Other Postretirement Benefit Plans	
December 31,			
2016	2015	2016	2015
3.6%	3.6%	3.7%	3.7%

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2016:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 354.7	$ —	$ —	$ —	$ 354.7	7.3 %
International	439.2	—	—	—	439.2	9.1 %
Options	—	20.0	—	—	20.0	0.4 %
Real Estate Investment Trusts	3.1	—	—	—	3.1	0.1 %
Common Collective Trusts (c)	—	14.0	—	400.5	414.5	8.6 %
Subtotal – Equities	797.0	34.0	—	400.5	1,231.5	25.5 %
Fixed Income:						
Common Collective Trust – Debt (c)	—	—	—	32.3	32.3	0.7 %
United States Government and Agency Securities (c)	—	423.3	—	17.7	441.0	9.1 %
Corporate Debt (c)	—	1,932.2	—	10.0	1,942.2	40.2 %
Foreign Debt (c)	—	373.7	—	12.1	385.8	8.0 %
State and Local Government	—	11.5	—	—	11.5	0.2 %
Other – Asset Backed (c)	—	5.4	—	7.4	12.8	0.3 %
Subtotal – Fixed Income	—	2,746.1	—	79.5	2,825.6	58.5 %
Infrastructure	—	—	57.6	—	57.6	1.2 %
Real Estate	—	—	254.9	—	254.9	5.3 %
Alternative Investments	—	—	411.1	—	411.1	8.5 %
Securities Lending	—	161.6	—	—	161.6	3.4 %
Securities Lending Collateral (a)	—	—	—	(163.3)	(163.3)	(3.4)%
Cash and Cash Equivalents (c)	—	—	—	29.7	29.7	0.6 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	18.6	18.6	0.4 %
Total	$ 797.0	$ 2,941.7	$ 723.6	$ 365.0	$ 4,827.3	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share in accordance with ASU 2015-07, Disclosure for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), which was retrospectively applied to prior periods.

The following table sets forth a reconciliation of changes in the fair value of AEP's assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Foreign Debt	Infrastructure	Real Estate	Alternative Investments	Total Level 3
			(in millions)		
Balance as of January 1, 2016	$ 0.1	$ 42.0	$ 253.7	$ 378.7	$ 674.5
Actual Return on Plan Assets					
Relating to Assets Still Held as of the Reporting Date	—	5.9	5.3	13.7	24.9
Relating to Assets Sold During the Period	—	0.9	23.2	21.1	45.2
Purchases and Sales	(0.1)	8.8	(27.3)	(2.4)	(21.0)
Transfers into Level 3	—	—	—	—	—
Transfers out of Level 3	—	—	—	—	—
Balance as of December 31, 2016	$ —	$ 57.6	$ 254.9	$ 411.1	$ 723.6

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2016:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 517.1	$ —	$ —	$ —	$ 517.1	33.5 %
International	435.5	—	—	—	435.5	28.2 %
Options	—	15.2	—	—	15.2	1.0 %
Common Collective Trusts (b)	—	10.9	—	20.5	31.4	2.0 %
Subtotal – Equities	952.6	26.1	—	20.5	999.2	64.7 %
Fixed Income:						
Common Collective Trust Debt (b)	—	—	—	93.7	93.7	6.0 %
United States Government and Agency Securities	—	64.7	—	—	64.7	4.2 %
Corporate Debt	—	121.6	—	—	121.6	7.9 %
Foreign Debt	—	18.6	—	—	18.6	1.2 %
State and Local Government	—	3.0	—	—	3.0	0.2 %
Other – Asset Backed	—	5.9	—	—	5.9	0.4 %
Subtotal – Fixed Income	—	213.8	—	93.7	307.5	19.9 %
Trust Owned Life Insurance:						
International Equities (b)	—	—	—	110.1	110.1	7.1 %
United States Bonds (b)	—	—	—	97.4	97.4	6.3 %
Subtotal – Trust Owned Life Insurance	—	—	—	207.5	207.5	13.4 %
Cash and Cash Equivalents	24.0	10.5	—	—	34.5	2.2 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(2.8)	(2.8)	(0.2)%
Total	$ 976.6	$ 250.4	$ —	$ 318.9	$ 1,545.9	100.0 %

(a) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.

(b) Amounts in “Other” column represent investments for which fair value is measured using net asset value per share in accordance with ASU 2015-07, Disclosure for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), which was retrospectively applied to prior periods.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2015:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 315.7	$ —	$ —	$ —	$ 315.7	6.6 %
International	402.3	—	—	—	402.3	8.4 %
Options	—	15.6	—	—	15.6	0.3 %
Real Estate Investment Trusts	4.0	—	—	—	4.0	0.1 %
Common Collective Trusts (c)	—	16.1	—	369.7	385.8	8.1 %
Subtotal – Equities	722.0	31.7	—	369.7	1,123.4	23.5 %
Fixed Income:						
Common Collective Trust – Debt (c)	—	—	—	34.2	34.2	0.7 %
United States Government and Agency Securities (c)	—	397.8	—	24.1	421.9	8.9 %
Corporate Debt (c)	—	1,964.2	—	19.0	1,983.2	41.6 %
Foreign Debt (c)	—	405.4	0.1	16.0	421.5	8.8 %
State and Local Government	—	12.8	—	—	12.8	0.3 %
Other – Asset Backed (c)	—	15.8	—	7.6	23.4	0.5 %
Subtotal – Fixed Income	—	2,796.0	0.1	100.9	2,897.0	60.8 %
Infrastructure	—	—	42.0	—	42.0	0.9 %
Real Estate	—	—	253.7	—	253.7	5.3 %
Alternative Investments	—	—	378.7	—	378.7	8.0 %
Securities Lending	—	263.0	—	—	263.0	5.5 %
Securities Lending Collateral (a)	—	—	—	(264.7)	(264.7)	(5.5)%
Cash and Cash Equivalents (c)	—	1.2	—	47.4	48.6	1.0 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	25.9	25.9	0.5 %
Total	$ 722.0	$ 3,091.9	$ 674.5	$ 279.2	$ 4,767.6	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share in accordance with ASU 2015-07, Disclosure for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), which was retrospectively applied to prior periods.

The following table sets forth a reconciliation of changes in the fair value of AEP's assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Foreign Debt	Infrastructure	Real Estate	Alternative Investments	Total Level 3
			(in millions)		
Balance as of January 1, 2015	$ 0.1	$ 12.5	$ 235.8	$ 378.9	$ 627.3
Actual Return on Plan Assets					
Relating to Assets Still Held as of the Reporting Date	—	(3.6)	12.5	(25.9)	(17.0)
Relating to Assets Sold During the Period	—	0.3	23.8	37.6	61.7
Purchases and Sales	—	32.8	(18.4)	(11.9)	2.5
Transfers into Level 3	—	—	—	—	—
Transfers out of Level 3	—	—	—	—	—
Balance as of December 31, 2015	$ 0.1	$ 42.0	$ 253.7	$ 378.7	$ 674.5

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2015:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 465.1	$ —	$ —	$ —	$ 465.1	29.5%
International	484.3	—	—	—	484.3	30.7%
Options	—	15.6	—	—	15.6	1.0%
Common Collective Trusts (b)	—	12.6	—	19.0	31.6	2.0%
Subtotal – Equities	949.4	28.2	—	19.0	996.6	63.2%
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	100.9	100.9	6.4%
United States Government and Agency Securities	—	58.4	—	—	58.4	3.7%
Corporate Debt	—	117.7	—	—	117.7	7.4%
Foreign Debt	—	20.7	—	—	20.7	1.3%
State and Local Government	—	4.2	—	—	4.2	0.3%
Other – Asset Backed	—	8.4	—	—	8.4	0.5%
Subtotal – Fixed Income	—	209.4	—	100.9	310.3	19.6%
Trust Owned Life Insurance:						
International Equities (b)	—	—	—	28.3	28.3	1.8%
United States Bonds (b)	—	—	—	184.3	184.3	11.7%
Subtotal – Trust Owned Life Insurance	—	—	—	212.6	212.6	13.5%
Cash and Cash Equivalents	44.9	7.2	—	—	52.1	3.3%
Other – Pending Transactions and Accrued Income (a)	—	—	—	5.8	5.8	0.4%
Total	$ 994.3	$ 244.8	$ —	$ 338.3	$ 1,577.4	100.0%

(a) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in “Other” column represent investments for which fair value is measured using net asset value per share in accordance with ASU 2015-07, Disclosure for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), which was retrospectively applied to prior periods.

Determination of Pension Expense

The determination of pension expense or income is based 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:

	December 31, 2016	December 31, 2015
	(in thousands)	
Qualified Pension Plan	$ 177,235	$ 174,946
Nonqualified Pension Plan	13	5
Total Accumulated Benefit Obligation	$ 177,248	$ 174,951

For the 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 were as follows:

	Underfunded Pension Plans December 31, 2016		Underfunded Pension Plans December 31, 2015	
	(in thousands)			
Projected Benefit Obligation	$	180,736	$	178,076
Accumulated Benefit Obligation	$	177,248	$	174,951
Fair Value of Plan Assets		174,047		173,368
Underfunded Accumulated Benefit Obligation	$	(3,201)	$	(1,583)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the pension plans of $1.8 million during 2017. The estimated contributions to the pension trust are at least the minimum amount required by the Employee Retirement Income Security Act and additional discretionary contributions may also be made to maintain the funded status of the plan.

The table below reflects the total benefits expected to be paid from the plan or from KPCo's assets. The payments include the participants' contributions to the plan for their share of the cost. 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:

	Estimated Payments: Pension Plans		Estimated Payments: Other Postretirement Benefit Plans	
	(in thousands)			
2017	$	10,127	$	5,126
2018		10,530		5,106
2019		11,241		5,101
2020		11,137		5,164
2021		11,964		5,268
Years 2022 to 2026, in Total		61,649		26,493

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost (credit):

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2016	2015	2014	2016	2015	2014
	(in thousands)					
Service Cost	$ 2,461	$ 2,680	$ 2,299	$ 283	$ 343	$ 472
Interest Cost	7,489	7,326	8,041	2,150	1,952	2,405
Expected Return on Plan Assets	(10,133)	(9,981)	(9,672)	(3,954)	(4,059)	(4,239)
Amortization of Prior Service Cost (Credit)	52	53	57	(2,425)	(2,424)	(2,424)
Amortization of Net Actuarial Loss	2,943	3,784	4,466	1,151	622	746
Net Periodic Benefit Cost (Credit)	2,812	3,862	5,191	(2,795)	(3,566)	(3,040)
Capitalized Portion	(962)	(1,364)	(1,809)	956	1,259	1,059
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 1,850	$ 2,498	$ 3,382	$ (1,839)	$ (2,307)	$ (1,981)

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2017 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 2,966	$ 1,280
Prior Service Cost (Credit)	48	(2,425)
Total Estimated 2017 Amortization	$ 3,014	$ (1,145)
Expected to be Recorded as		
Regulatory Asset	$ 2,952	$ (1,136)
Deferred Income Taxes	22	(3)
Net of Tax AOCI	40	(6)
Total	$ 3,014	$ (1,145)

American Electric Power System Retirement Savings Plan

KPCo participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for matching contributions. 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 $2.3 million in 2016, $2.3 million in 2015 and $2.5 million in 2014.

8. BUSINESS SEGMENTS

KPCo has one reportable segment, an integrated electricity generation, transmission and distribution business. KPCo's other activities are insignificant.

9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of KPCo.

KPCo is exposed to certain market risks as a major power producer and participant in the electricity, natural gas, coal and emission allowance markets. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact KPCo due to changes in the underlying market prices or rates. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, KPCo primarily employs 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.

KPCo utilizes power, capacity, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. KPCo utilizes interest rate derivative contracts in order to manage the interest rate exposure associated with its commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. KPCo also utilizes derivative contracts to manage interest rate risk associated with debt financing. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with the established risk management policies as approved by the Finance Committee of the Board of Directors.

The following table represents the gross notional volume of KPCo's outstanding derivative contracts:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2016	Volume December 31, 2015	Unit of Measure
	(in thousands)		
Commodity:			
Power	10,562	7,864	MWhs
Natural Gas	—	64	MMBtus
Heating Oil and Gasoline	339	341	Gallons
Interest Rate	$ 22	$ 500	USD

Cash Flow Hedging Strategies

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

KPCo utilizes a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo also utilizes interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. KPCo does not hedge all interest rate exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON KPCo's 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 the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2016 and 2015 balance sheets, KPCo netted $119 thousand and $0 , respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $134 thousand and $656 thousand, 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 of KPCo's derivative activity on the balance sheets:

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts- Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in thousands)	
Current Risk Management Assets - Nonaffiliated	$ 4,698	$ (4,241)	$ 457
Long-term Risk Management Assets - Nonaffiliated	359	(359)	—
Total Assets	5,057	(4,600)	457
Current Risk Management Liabilities - Nonaffiliated	4,306	(4,253)	53
Long-term Risk Management Liabilities - Nonaffiliated	675	(362)	313
Total Liabilities	4,981	(4,615)	366
Total MTM Derivative Contract Net Assets	$ 76	$ 15	$ 91

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts- Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in thousands)	
Current Risk Management Assets - Nonaffiliated and Affiliated	$ 5,017	$ (1,975)	$ 3,042
Long-term Risk Management Assets - Nonaffiliated	59	(47)	12
Total Assets	5,076	(2,022)	3,054
Current Risk Management Liabilities - Nonaffiliated	3,621	(2,619)	1,002
Long-term Risk Management Liabilities - Nonaffiliated	69	(58)	11
Total Liabilities	3,690	(2,677)	1,013
Total MTM Derivative Contract Net Assets	$ 1,386	$ 655	$ 2,041

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

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

The table below presents KPCo's activity of derivative risk management contracts:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2016	2015	2014
	(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 421	$ 2,289	$ 13,303
Sales to AEP Affiliates	434	1,178	—
Other Operation Expense	(51)	(115)	—
Maintenance Expense	(90)	(151)	—
Purchased Electricity for Resale	2,815	3,983	—
Fuel and Other Consumables Used for Electric Generation	—	(20)	(9)
Regulatory Assets (a)	150	1,671	(2,778)
Regulatory Liabilities (a)	967	(2,922)	2,304
Total Gain on Risk Management Contracts	$ 4,646	$ 5,913	$ 12,820

(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.

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

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

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

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), KPCo initially reports 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. KPCo would recognize any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains) if applicable.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on KPCo's statements of income or in Regulatory Assets or Regulatory Liabilities on KPCo's balance sheets, depending on the specific nature of the risk being hedged. During 2016 and 2015, KPCo did not apply cash flow hedging to outstanding power derivatives. During 2014, KPCo applied cash flow hedging to outstanding power derivatives.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on its balance sheets into Interest Expense on its statements of income in those periods in which hedged interest payments occur. During 2016, 2015 and 2014, KPCo did not apply cash flow hedging to outstanding interest rate derivatives.

During 2016, 2015 and 2014, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

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

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets were:

Impact of Cash Flow Hedges on the Balance Sheets

	Interest Rate	
	December 31, 2016	December 31, 2015
	(in thousands)	
AOCI Loss Net of Tax	$ (41)	$ (101)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(40)	(60)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's balance sheets.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of December 31, 2016, KPCo is not hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions.

Credit Risk

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

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

Collateral Triggering Events

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

	December 31,	
	2016	2015
	(in thousands)	
Amount of Collateral KPCo Would Have Been Required to Post Attributable to RTOs and ISOs	$ 195	$ 1,003
Amount of Collateral Attributable to Other Contracts	1,657	23

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following 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 posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements:

	December 31,	
	2016	2015
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 25	$ 750
Amount of Cash Collateral Posted	—	—
Additional Settlement Liability if Cross Default Provision is Triggered	—	750

10. 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 could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt are summarized in the following table:

	December 31,			
	2016		2015	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 867,164	$ 965,423	$ 866,451	$ 963,639

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

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets – Nonaffiliated					
Risk Management Commodity Contracts (a) (b)	$ —	$ 4,395	$ 616	$ (4,554)	$ 457
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (a) (b)	$ —	$ 4,517	$ 418	$ (4,569)	$ 366

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets – Nonaffiliated and Affiliated					
Risk Management Commodity Contracts (a) (b)	$ 36	$ 2,692	$ 2,338	$ (2,012)	$ 3,054
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (a) (b)	$ 43	$ 3,545	$ 92	$ (2,667)	$ 1,013

(a) 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."
(b) Substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the years ended December 31, 2016, 2015 and 2014.

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

Year Ended December 31, 2016	Net Risk Management Assets (Liabilities) (a)
	(in thousands)
Balance as of December 31, 2015	$ 2,246
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	1,387
Settlements	(3,658)
Transfers out of Level 3 (e)	22
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	201
Balance as of December 31, 2016	$ 198

Year Ended December 31, 2015	Net Risk Management Assets (Liabilities) (a)
	(in thousands)
Balance as of December 31, 2014	$ 3,927
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	766
Settlements	(4,313)
Transfers out of Level 3 (e)	240
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	1,626
Balance as of December 31, 2015	$ 2,246

Year Ended December 31, 2014	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2013	$ 2,171
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	5,490
Settlements	(6,084)
Transfers into Level 3 (d) (e)	(750)
Transfers out of Level 3 (e)	(7)
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	3,107
Balance as of December 31, 2014	$ 3,927

(a) Includes both affiliated and nonaffiliated transactions.
(b) Included in revenues on KPCo’s statements of income.
(c) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(d) Represents 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) Relates to the net gains (losses) of those contracts that are not reflected on KPCo’s statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

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

Significant Unobservable Inputs
December 31, 2016

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 94	$ 81	Discounted Cash Flow	Forward Market Price	$ 19.68	$ 48.55	$ 36.34
FTRs	522	337	Discounted Cash Flow	Forward Market Price	0.01	8.91	0.96
Total	$ 616	$ 418					

Significant Unobservable Inputs
December 31, 2015

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 1,580	$ 37	Discounted Cash Flow	Forward Market Price	$ 12.61	$ 47.24	$ 32.38
FTRs	758	55	Discounted Cash Flow	Forward Market Price	(6.96)	8.43	1.34
Total	$ 2,338	$ 92					

(a) Represents market prices in dollars per MWh.

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

Sensitivity of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

11. INCOME TAXES

The details of KPCo's income taxes as reported are as follows:

	Year Ended December 31, 2016 (in thousands)
Federal:	
Current	$ 4,893
Deferred	21,067
Deferred Investment Tax Credits	(3)
Total Federal	25,957
State and Local:	
Current	131
Deferred	(2,495)
Deferred Investment Tax Credits	—
Total State and Local	(2,364)
Income Tax Expense	$ 23,593

	Years Ended December 31,	
	2015	2014
	(in thousands)	
Income Tax Expense (Credit):		
Current	$ (63,674)	$ 13,376
Deferred	75,638	9,157
Deferred Investment Tax Credits	(26)	(96)
Income Tax Expense	$ 11,938	$ 22,437

The following is a reconciliation of the 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,		
	2016	2015	2014
		(in thousands)	
Net Income	$ 50,210	$ 27,891	$ 38,378
Income Tax Expense	23,593	11,938	22,437
Pretax Income	$ 73,803	$ 39,829	$ 60,815
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 25,831	$ 13,940	$ 21,285
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	1,300	1,361	2,474
AFUDC	(537)	(638)	(1,623)
Removal Costs	(1,681)	(1,832)	(2,816)
Investment Tax Credits, Net	(3)	(26)	(96)
State and Local Income Taxes, Net	(1,536)	(4,601)	2,973
Tax Adjustments	97	3,407	372
Other	122	327	(132)
Income Tax Expense	$ 23,593	$ 11,938	$ 22,437
Effective Income Tax Rate	32.0 %	30.0 %	36.9 %

The following table shows elements of KPCo's net deferred tax liability and significant temporary differences:

	December 31, 2016	December 31, 2015
	(in thousands)	
Deferred Tax Assets	$ 58,627	$ 62,995
Deferred Tax Liabilities	(725,529)	(699,153)
Net Deferred Tax Liabilities	$ (666,902)	$ (636,158)
Property Related Temporary Differences	$ (425,415)	$ (409,787)
Amounts Due from Customers for Future Federal Income Taxes	(29,389)	(27,631)
Deferred State Income Taxes	(95,704)	(90,541)
Deferred Income Taxes on Other Comprehensive Loss	729	886
Regulatory Assets	(124,041)	(115,803)
All Other, Net	6,918	6,718
Net Deferred Tax Liabilities	$ (666,902)	$ (636,158)

AEP System Tax Allocation Agreement

KPCo joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. 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 consolidated net operating loss of the AEP System is allocated to each company in the consolidated group with taxable losses. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the allocation of the consolidated AEP System net operating loss and 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

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011, 2012 and 2013 started in April 2014. AEP and subsidiaries received a Revenue Agents Report in April 2016, completing the 2011 through 2013 audit cycle indicating an agreed upon audit. The 2011 through 2013 audit was submitted to the Congressional Joint Committee on Taxation for approval. The Joint Committee referred the audit back to the IRS exam team for further consideration. 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, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

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

Net Income Tax Operating Loss Carryforward

KPCo has Kentucky state net income tax operating loss carryforwards of $89 million. As a result, KPCo recognized deferred state income tax benefits in 2016 and 2015 of $5 million. Management anticipates future taxable income will be sufficient to realize the state net income tax operating loss tax benefits before the state carryforward expires for Kentucky in 2036.

Tax Credit Carryforward

As of December 31, 2016 and 2015, KPCo had unused federal income tax credits of $14 thousand and $203 thousand, respectively, not all of which have an expiration date. Included in the credit carryforward are federal general business tax credits of $0 and $189 thousand as of December 31, 2016 and 2015, respectively. The federal general business tax credits were fully utilized in 2016.

Uncertain Tax Positions

KPCo recognizes 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,		
	2016	**2015**	**2014**
		(in thousands)	
Interest Expense	$ 7	$ —	$ 20
Interest Income	6	—	—
Reversal of Prior Period Interest Expense	—	—	71

The following table shows balances for amounts accrued for the receipt of interest and the payment of interest and penalties:

	December 31,	
	2016	**2015**
	(in thousands)	
Accrual for Receipt of Interest	$ —	$ —
Accrual for Payment of Interest and Penalties	17	—

The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2016	**2015**	**2014**
		(in thousands)	
Balance as of January 1,	$ —	$ —	$ 608
Increase – Tax Positions Taken During a Prior Period	—	—	—
Decrease – Tax Positions Taken During a Prior Period	—	—	—
Increase – Tax Positions Taken During the Current Year	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—
Increase – Settlements with Taxing Authorities	—	—	2
Decrease – Settlements with Taxing Authorities	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	—	—	(610)
Balance as of December 31,	$ —	$ —	$ —

The total amount of unrecognized tax benefits (costs) that, if recognized, would affect the effective tax rate is $0 for 2016, 2015 and 2014. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

The Tax Increase Prevention Act of 2014 (the 2014 Act) was enacted in December 2014. Included in the 2014 Act was a one-year extension of the 50% bonus depreciation. The 2014 Act also retroactively extended the life of research and development, employment and several energy tax credits, which expired at the end of 2013. The enacted provisions did not materially impact KPCo's net income or financial condition but did have a favorable impact on cash flows in 2015.

The Protecting Americans from Tax Hikes Act of 2015 (PATH) included an extension of the 50% bonus depreciation for three years through 2017, phasing down to 40% in 2018 and 30% in 2019. PATH also provided for the extension of research and development, employment and several energy tax credits for 2015. PATH also includes provisions to extend the wind energy production tax credit through 2016 with a three-year phase-out (2017-2019), and to extend the 30% temporary solar investment tax credit for three years through 2019 and with a two-year phase-out (2020-2021). PATH also provided for a permanent extension of the Research and Development tax credit. The enacted provisions did not materially impact KPCo's net income or financial condition but will have a favorable impact on future cash flows.

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. These final regulations did not materially impact KPCo's net income, cash flows or financial condition.

State Tax Legislation

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 was reduced from 7% to 6.5% in 2014. The enacted provision did not materially impact KPCo's net income, cash flows or financial condition.

12. LEASES

Leases of property, plant and equipment are for remaining periods up to 10 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. For capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. The components of rental costs are as follows:

Lease Rental Costs	Years Ended December 31, 2016	2015	2014
		(in thousands)	
Net Lease Expense on Operating Leases	$ 1,886	$ 1,603	$ 1,466
Amortization of Capital Leases	995	1,148	1,112
Interest on Capital Leases	114	171	189
Total Lease Rental Costs	$ 2,995	$ 2,922	$ 2,767

The following table shows the property, plant and equipment under capital leases and related obligations recorded on KPCo's balance sheets. Capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on KPCo's balance sheets.

	December 31, 2016	2015
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Generation	$ 2,146	$ 2,338
Other Property, Plant and Equipment	3,400	2,920
Total Property, Plant and Equipment Under Capital Leases	5,546	5,258
Accumulated Amortization	2,858	2,354
Net Property, Plant and Equipment Under Capital Leases	$ 2,688	$ 2,904
Obligations Under Capital Leases		
Noncurrent Liability	$ 1,749	$ 2,008
Liability Due Within One Year	939	896
Total Obligations Under Capital Leases	$ 2,688	$ 2,904

Future minimum lease payments consisted of the following as of December 31, 2016:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2017	$ 1,029	$ 1,965
2018	701	1,715
2019	365	1,533
2020	288	1,350
2021	248	1,066
Later Years	307	2,139
Total Future Minimum Lease Payments	2,938	$ 9,768
Less Estimated Interest Element	250	
Estimated Present Value of Future Minimum Lease Payments	$ 2,688	

Master Lease Agreements

KPCo leases 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, KPCo is 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, 2016, the maximum potential loss for these lease agreements was $1.6 million assuming the fair value of the equipment is zero at the end of the lease term.

13. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding:

Type of Debt	Maturity	Weighted Average Interest rate as of December 31, 2016	Interest Rate Ranges as of December 31, 2016	Interest Rate Ranges as of December 31, 2015	Outstanding as of December 31, 2016	Outstanding as of December 31, 2015
					(in thousands)	
Senior Unsecured Notes	2017-2039	5.81%	4.18%-8.13%	4.18%-8.13%	$ 728,033	$ 727,472
Pollution Control Bonds (a)	2016-2036 (b)	0.73%	0.73%	0.02%	64,375	64,355
Other Long-term Debt	2018	2.39%	2.39%	1.83%-2.11%	74,756	74,624
Total Long-term Debt Outstanding					$ 867,164	$ 866,451

(a) For KPCo's pollution control bond, the interest rate is subject to periodic adjustment and may be purchased on demand at periodic interest adjustment dates. Insurance policies support certain series.

(b) KPCo's pollution control bond is subject to redemption earlier than the maturity date. Consequently, this bond has been classified for maturity purposes as Long-term Debt Due Within One Year - Nonaffiliated on KPCo's balance sheets.

Long-term debt outstanding as of December 31, 2016 is payable as follows:

	2017	2018	2019	2020	2021	After 2021	Total
				(in thousands)			
Principal Amount	$ 390,000	$ 75,000	$ —	$ —	$ 40,000	$ 365,000	$ 870,000
Unamortized Discount, Net and Debt Issuance Costs							(2,836)
Total Long-term Debt Outstanding							$ 867,164

Dividend Restrictions

KPCo pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KPCo to transfer funds to Parent in the form of dividends.

Federal Power Act

The Federal Power Act prohibits KPCo from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." This restriction does not limit the ability of KPCo to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, KPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. As of December 31, 2016, none of KPCo's retained earnings have restrictions related to the payment of dividends to Parent.

Corporate Borrowing Program – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2016 and 2015 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits are described in the following table:

Years Ended December 31,	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
2016	39,102	15,557	12,628	6,593	1,807	225,000
2015	52,477	25,768	19,242	10,409	18,692	225,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

Years Ended December 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2016	1.02%	0.69%	0.90%	0.75%	0.79%	0.87%
2015	0.87%	0.37%	0.54%	0.40%	0.48%	0.44%
2014	0.59%	0.24%	0.33%	0.26%	0.31%	0.28%

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest Income, respectively, on KPCo's statements of income. For amounts borrowed from and advanced to the Utility Money Pool, KPCo incurred the following amounts of interest expense and earned the following amounts of interest income:

	Years Ended December 31,		
	2016	2015	2014
		(in thousands)	
Interest Expense	$ 89	$ 80	$ 46
Interest Income	8	10	47

Securitized Accounts Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's statements of income. KPCo manages and services its accounts receivable sold.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement was increase in June 2014 from $700 million and expires in June 2018.

KPCo's amounts of accounts receivable and accrued unbilled revenues under the sale of receivables agreement were $49 million and $38 million as of December 31, 2016 and 2015, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $3 million, $3 million and $3 million, respectively, for each of the years ended December 31, 2016, 2015 and 2014.

KPCo's proceeds on the sale of receivables to AEP Credit were $583 million, $528 million and $604 million for the years ended December 31, 2016, 2015 and 2014, respectively.

14. RELATED PARTY TRANSACTIONS

For other related party transactions, also see “AEP System Tax Allocation Agreement” section of Note 11 in addition to “Utility Money Pool – AEP System” and “Sale of Receivables – AEP Credit” sections of Note 13.

Interconnection 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.

APCo, I&M, KPCo, OPCo and AEPSC were parties to the Interconnection Agreement which defined the sharing of costs and benefits associated with the respective generation plants. This sharing was based upon each AEP utility subsidiary’s MLR and was calculated monthly on the basis of each AEP utility subsidiary’s maximum peak demand in relation to the sum of the maximum peak demands of all four AEP utility subsidiaries during the preceding 12 months.

Effective January 1, 2014, the FERC approved the following agreements. See “Organization” section of Note 1.

- A Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants’ respective power supply resources. Effective May 2015, the PCA was revised and approved by the FERC to include WPCo. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. Further, the Restated and Amended PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo 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.
- A 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 would fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR committed to use its capacity to help meet the PJM capacity obligations of member companies through the PJM planning year that ended May 31, 2015.
- A Power Supply Agreement (PSA) between AGR and OPCo that provided 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 was not acquired through auctions in 2014.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Effective January 1, 2014 and revised in May 2015, power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies’ respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement. Prior to January 1, 2014, power and natural gas risk management activities were allocated under the SIA to former members of the Interconnection Agreement, PSO and SWEPCo. Risk management activities primarily include power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

Operating Agreement

PSO, SWEPCo and AEPSC are parties to the Operating Agreement which was approved by the FERC. The Operating Agreement requires PSO and SWEPCo to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. In January 2014, the FERC approved a modification of the Operating Agreement to address changes resulting from an anticipated March 2014 SPP power market change. Subsequently and in March 2014, SPP changed from an energy imbalance service market to a fully integrated power market. In alignment with the new SPP integrated power market and according to the modified Operating Agreement, PSO and SWEPCo operate as standalone entities and offer their respective generation into the SPP power market. SPP then economically dispatches resources. By offering their resources separately, PSO and SWEPCo no longer purchase or sell energy to each other to serve their respective internal load or off-system sales.

System Integration Agreement (SIA)

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity. Margins resulting from trading and marketing activities originating in PJM and MISO generally accrue to the benefit of APCo, I&M, KPCo and WPCo, while trading and marketing activities originating in SPP generally accrue to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the equity positions of these companies.

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales under the Interconnection Agreement, direct sales to affiliates, net transmission agreement sales and other revenues for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,			
Related Party Revenues	**2016**	**2015**	**2014**	
		(in thousands)		
Sales under Interconnection Agreement	$ —	$ —	$ 5,480	(a)
Auction Sales to OPCo (b)	1,670	4,183	—	
Transmission Agreement Sales	5,871	7,277	1,726	
Other Revenues	745	354	308	
Total Affiliated Revenues	$ 8,286	$ 11,814	$ 7,514	

(a) Includes December 2013 true-up activity subsequent to agreement termination.
(b) Refer to the Ohio Auctions section below for further information regarding this amount.

The following table shows the purchased power expenses incurred for purchases under the Interconnection Agreement and from affiliates for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,			
Related Party Purchases	**2016**	**2015**	**2014**	
		(in thousands)		
Purchases under Interconnection Agreement	$ —	$ —	$ 1,242	(a)
Direct Purchases from West Affiliates	—	—	—	
Direct Purchases from AEGCo (b)	97,941	99,475	115,001	
Total Affiliated Purchases	$ 97,941	$ 99,475	$ 116,243	

(a) Includes December 2013 true-up activity subsequent to agreement termination.
(b) Refer to the Unit Power Agreements section below for further information regarding this amount.

The above summarized related party revenues and expenses are reported in Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on KPCo's statements of income.

System Transmission Integration Agreement (STIA)

AEP's STIA provided for the integration and coordination of the planning, operation and maintenance of transmission facilities. Since the FERC approved the cancellation of the STIA effective June 1, 2014, the coordinated planning, operation and maintenance of transmission facilities are the responsibility of the RTOs and the STIA is no longer necessary. Similar to the SIA, the STIA functioned as an umbrella agreement in addition to the Transmission Agreement (TA) and the Transmission Coordination Agreement (TCA). The TA and TCA are both still active. The STIA contained two service schedules that governed:

- The allocation of transmission costs and revenues.
- The allocation of third-party transmission costs and revenues and AEP System dispatch costs.

APCo, I&M, KGPCo, KPCo, OPCo and WPCo are parties to the TA, effective November 2010, which defines how transmission costs through PJM OATT are allocated among the AEP East Companies, KGPCo and WPCo on a 12-month average coincident peak basis.

KPCo's net charges recorded as a result of the TA for the years ended December 31, 2016, 2015 and 2014 were $20.4 million, $13.3 million and $7.5 million, respectively, and were recorded in Other Operation expenses on KPCo's statements of income.

PSO, SWEPCo and AEPSC are parties to the TCA, dated January 1, 1997, by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the parties to the agreement.

Ohio Auctions

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. Certain affiliated entities, including KPCo, participate in the auction process and have been awarded tranches of OPCo's SSO load. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions. See Note 9 - Derivatives and Hedging for further information.

Unit Power Agreements (UPA)

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. Subsequently, I&M assigns 30% of the power to KPCo. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo and a UPA between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions. The KPCo UPA ends in December 2022.

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. KPCo recorded expenses of $5 million, $5 million and $5 million in 2016, 2015 and 2014, respectively, for urea transloading provided by I&M. These expenses were recorded as fuel expenses or other operation expenses.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet, then transfers the cost to the affiliate for reimbursement. KPCo recorded its assigned portion of these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. KPCo's billed amounts were $1.5 million, $1.3 million and $1.2 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions. The following table shows the sales and purchases, recorded at net book value, for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
	2016	2015	2014
		(in thousands)	
Sales	$ 395	$ 1,337	$ 307
Purchases	174	1,871	349

The amounts above are recorded in Property, Plant and Equipment on the balance sheets.

Intercompany Billings

KPCo performs certain utility services for other AEP subsidiaries when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

15. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a variable interest in a VIE. A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. 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 KPCo is the primary beneficiary of a VIE, management considers whether KPCo has the power to direct the most significant activities of the VIE and is obligated to absorb losses or receive the expected residual returns that are significant to the VIE. Management believes that significant assumptions and judgments were applied consistently. KPCo is not the primary beneficiary of any VIE and has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. Parent is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the years ended December 31, 2016, 2015 and 2014 were $59.8 million, $60 million and $52.7 million, respectively. The carrying amount of liabilities associated with AEPSC as of December 31, 2016 and 2015 was $8.2 million and $7.7 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to these transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the years ended December 31, 2016, 2015 and 2014 were $97.9 million, $99.5 million and $115 million, respectively. The carrying amount of liabilities associated with AEGCo as of December 31, 2016 and 2015 was $10 million and $7.7 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

16. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment is shown functionally on the face of KPCo's balance sheets. The following table includes KPCo's total plant balances as of December 31, 2016 and 2015:

	December 31, 2016	December 31, 2015
	(in thousands)	
Regulated Property, Plant and Equipment		
Generation	$ 1,182,212	$ 1,118,837
Transmission	574,703	568,963
Distribution	783,283	756,631
Other	64,426	55,472
CWIP	27,380	59,351
Less: Accumulated Depreciation	879,018	847,447
Total Regulated Property, Plant and Equipment - Net	1,752,986	1,711,807
Nonregulated Property, Plant and Equipment - Net	2,587	2,594
Total Property, Plant and Equipment - Net	**$ 1,755,573**	**$ 1,714,401**

Depreciation

KPCo provides for depreciation of Property, Plant and Equipment on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides total regulated annual composite depreciation rates and depreciable lives for KPCo. Nonregulated depreciation rate ranges and depreciable life ranges are not applicable or not meaningful for 2016, 2015 and 2014.

Functional Class of Property	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)	2015 Annual Composite Depreciation Rate	2015 Depreciable Life Ranges (in years)	2014 Annual Composite Depreciation Rate	2014 Depreciable Life Ranges (in years)
Generation	3.0%	68 - 69	0.4%	68 - 69	3.5%	40 - 60
Transmission	2.7%	37 - 75	2.2%	37 - 75	1.6%	25 - 75
Distribution	3.5%	11 - 75	3.5%	11 - 75	3.4%	11 - 75
Other	8.1%	5 - 75	10.0%	5 - 75	4.2%	20 - 75

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 on the balance sheets. 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.

Asset Retirement Obligations (ARO)

KPCo records ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for the retirement of ash disposal facilities and asbestos removal. KPCo has identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since KPCo plans to use its facilities indefinitely. The retirement obligation would only be recognized if and when KPCo abandons or ceases the use of specific easements, which is not expected.

KPCo recorded an increase in Asset Retirement Obligations in the second quarter of 2015, partially related to the final Coal Combustion Residual Rule, which was published in the Federal Register in April 2015. The Federal EPA now regulates the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The Federal EPA regulates CCR as a non-hazardous solid waste and established minimum federal solid waste management standards. Noncash increases related to the CCR Rule are recorded as Property, Plant and Equipment.

The following is a reconciliation of the 2016 and 2015 aggregate carrying amounts of ARO for KPCo:

Year	ARO as of January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of December 31,
			(in thousands)			
2016	$ 72,012	$ 3,478	$ 1,254	$ (15,018)	$ 1,268	$ 62,994
2015	65,699	3,554	4,236	(5,564)	4,087 (a)	72,012

(a) Amount includes an $8.8 million reduction in the ARO liability due to the execution of a joint use agreement with a third party.

Allowance for Funds Used During Construction (AFUDC)

KPCo's amounts of allowance for equity and borrowed funds used during construction are summarized in the following table:

	Years Ended December 31, 2016	2015	2014
		(in thousands)	
Allowance for Equity Funds Used During Construction	$ 852	$ 1,158	$ 4,009
Allowance for Borrowed Funds Used During Construction	614	799	2,048

Jointly-owned Electric Facilities

KPCo has a 50% ownership share of Units 1 and 2 at the Mitchell Generating Station. In addition to KPCo, the Mitchell Generating Station is jointly-owned by WPCo. Using its own financing, each participating company is obligated to pay its share of the costs in the same proportion as its ownership interest. KPCo's proportionate share of the operating costs associated with this facility is included in its statements of income and the investment and accumulated depreciation are reflected in its balance sheets under Property, Plant and Equipment as follows:

	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
KPCo's Share as of December 31, 2016					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,012,658	$ 4,962	$ 369,797
KPCo's Share as of December 31, 2015					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,013,825	$ 9,346	$ 353,583

(a) Operated by KPCo.

17. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. KPCo's unaudited quarterly financial information is as follows:

	2016 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in thousands)			
Total Revenues	$ 167,671	$ 146,200	$ 168,539	$ 172,620
Operating Income	41,031	22,118	31,413	24,143
Net Income	19,803	8,887	11,485	10,035

	2015 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in thousands)			
Total Revenues	$ 201,449	$ 151,276	$ 159,193	$ 142,241
Operating Income	27,932	14,266	20,913	17,645
Net Income	10,998	2,308	6,996	7,589