Kentucky Power Company

2013 Annual Report

Audited Financial Statements

TABLE OF CONTENTS

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP 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 integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West Companies	PSO, SWEPCo, TCC and TNC.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a nonregulated AEP subsidiary that acquired the generation assets and liabilities of OPCo.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
CO_2	Carbon dioxide and other greenhouse gases.
CWIP	Construction Work in Progress.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
FAC	Fuel Adjustment Clause.
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.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IAA	AEP System Interim Allowance Agreement.
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 generating 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.

Term	Meaning
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PCA	Power Coordination Agreement.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utility Commission of Ohio.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,310 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, 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.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

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, 2013 and 2012, 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, 2013, 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, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013 in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

The financial statements give retroactive effect to the transfer of a fifty percent interest in Units 1 and 2 of the Mitchell Plant to the Company on December 31, 2013, which has been accounted for at historical cost as a transfer between entities under common control as described in Note 1 to the financial statements. Our opinion is not modified with respect to this matter.

Deloitte & Touche LLP

Columbus, Ohio
February 25, 2014

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2013, 2012 and 2011
(in thousands)

	Years Ended December 31,		
	2013	**2012**	**2011**
REVENUES			
Electric Generation, Transmission and Distribution	$ 721,840	$ 753,095	$ 847,867
Sales to AEP Affiliates	103,731	70,776	104,682
Other Revenues	684	546	494
TOTAL REVENUES	826,255	824,417	953,043
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	200,139	219,328	336,164
Purchased Electricity for Resale	11,003	11,319	23,924
Purchased Electricity from AEP Affiliates	269,088	223,649	210,299
Other Operation	75,038	75,410	77,804
Maintenance	66,977	63,125	67,094
Asset Impairments and Other Related Charges	32,847	-	-
Depreciation and Amortization	91,692	87,995	86,498
Taxes Other Than Income Taxes	20,272	19,659	18,567
TOTAL EXPENSES	767,056	700,485	820,350
OPERATING INCOME	59,199	123,932	132,693
Other Income (Expense):			
Interest Income	231	351	2,324
Allowance for Equity Funds Used During Construction	1,367	1,574	1,229
Interest Expense	(44,509)	(49,375)	(51,101)
INCOME BEFORE INCOME TAX EXPENSE	16,288	76,482	85,145
Income Tax Expense	7,382	23,507	31,169
NET INCOME	$ 8,906	$ 52,975	$ 53,976

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

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2013, 2012 and 2011
(in thousands)

	Years Ended December 31, 2013	2012	2011
Net Income	$ 8,906	$ 52,975	$ 53,976
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $113, $117 and $94 in 2013, 2012 and 2011, Respectively	210	216	(174)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $755, $687 and $540 in 2013, 2012 and 2011, Respectively	1,402	1,275	1,002
Pension and OPEB Funded Status, Net of Tax of $4,168, $1,801 and $400 in 2013, 2012 and 2011, Respectively	7,741	3,345	(743)
TOTAL OTHER COMPREHENSIVE INCOME	9,353	4,836	85
TOTAL COMPREHENSIVE INCOME	$ 18,259	$ 57,811	$ 54,061

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, 2013, 2012 and 2011
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2010	$ 50,450	$ 478,022	$ 157,467	$ (24,915)	$ 661,024
Capital Contribution from Parent		41,972			41,972
Common Stock Dividends			(39,602)		(39,602)
Net Income			53,976		53,976
Other Comprehensive Income				85	85
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2011	50,450	519,994	171,841	(24,830)	717,455
Capital Contribution from Parent		11,542			11,542
Common Stock Dividends			(33,997)		(33,997)
Net Income			52,975		52,975
Other Comprehensive Income				4,836	4,836
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2012	50,450	531,536	190,819	(19,994)	752,811
Capital Contribution from Parent		83,112			83,112
Common Stock Dividends			(20,034)		(20,034)
Net Income			8,906		8,906
Other Comprehensive Income				9,353	9,353
Pension and OPEB Adjustment Related to Mitchell Plant				5,221	5,221
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$ 50,450	$ 614,648	$ 179,691	$ (5,420)	$ 839,369

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2013 and 2012
(in thousands)

	December 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 743	$ 1,482
Accounts Receivable:		
Customers	17,889	25,826
Affiliated Companies	9,781	53,285
Accrued Unbilled Revenues	857	4,472
Miscellaneous	75	249
Allowance for Uncollectible Accounts	(78)	(164)
Total Accounts Receivable	28,524	83,668
Fuel	92,313	98,717
Materials and Supplies	43,940	38,306
Risk Management Assets	4,356	6,175
Accrued Tax Benefits	5,249	5,186
Prepayments and Other Current Assets	3,284	6,791
TOTAL CURRENT ASSETS	178,409	240,325
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,052,757	1,438,999
Transmission	507,844	495,981
Distribution	693,481	652,615
Other Property, Plant and Equipment (Including Plant to be Retired)	480,759	65,150
Construction Work in Progress	128,599	87,924
Total Property, Plant and Equipment	2,863,440	2,740,669
Accumulated Depreciation and Amortization	943,889	884,016
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,919,551	1,856,653
OTHER NONCURRENT ASSETS		
Regulatory Assets	216,360	213,734
Long-term Risk Management Assets	3,484	6,882
Employee Benefits and Pension Assets	11,446	-
Deferred Charges and Other Noncurrent Assets	20,207	54,986
TOTAL OTHER NONCURRENT ASSETS	251,497	275,602
TOTAL ASSETS	$ 2,349,457	$ 2,372,580

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2013 and 2012

	December 31, 2013	December 31, 2012
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 8,564	$ 13,359
Accounts Payable:		
General	21,619	75,444
Affiliated Companies	39,171	56,256
Long-term Debt Due Within One Year – Nonaffiliated	-	250,000
Risk Management Liabilities	1,828	3,320
Customer Deposits	25,211	23,485
Deferred Income Taxes	6,486	2,376
Accrued Taxes	20,801	16,650
Accrued Interest	6,678	12,002
Regulatory Liability for Over-Recovered Fuel Costs	2,851	7,928
Other Current Liabilities	19,411	29,480
TOTAL CURRENT LIABILITIES	152,620	490,300
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	729,389	529,195
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	2,105	3,700
Deferred Income Taxes	549,672	503,147
Regulatory Liabilities and Deferred Investment Tax Credits	22,926	26,159
Employee Benefits and Pension Obligations	6,041	32,387
Deferred Credits and Other Noncurrent Liabilities	27,335	14,881
TOTAL NONCURRENT LIABILITIES	1,357,468	1,129,469
TOTAL LIABILITIES	1,510,088	1,619,769
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
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	614,648	531,536
Retained Earnings	179,691	190,819
Accumulated Other Comprehensive Income (Loss)	(5,420)	(19,994)
TOTAL COMMON SHAREHOLDER'S EQUITY	839,369	752,811
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,349,457	$ 2,372,580

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2013, 2012 and 2011
(in thousands)

	Years Ended December 31,		
	2013	2012	2011
OPERATING ACTIVITIES			
Net Income	$ 8,906	$ 52,975	$ 53,976
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	91,692	87,995	86,498
Deferred Income Taxes	12,440	10,168	33,153
Asset Impairments and Other Related Charges	32,847	-	-
Allowance for Equity Funds Used During Construction	(1,367)	(1,574)	(1,229)
Mark-to-Market of Risk Management Contracts	2,357	2,510	(220)
Pension Contributions to Qualified Plan Trust	-	(5,547)	(18,239)
Fuel Over/Under-Recovery, Net	(5,078)	4,790	2,274
Change in Other Noncurrent Assets	7,334	(13,338)	(10,711)
Change in Other Noncurrent Liabilities	(2,953)	697	2,927
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	55,144	(7,523)	14,707
Fuel, Materials and Supplies	3,130	(55,120)	(3,618)
Accounts Payable	(68,480)	3,429	(9,748)
Accrued Taxes, Net	4,013	(11,400)	(2,152)
Accrued Interest	(5,324)	(545)	131
Other Current Assets	3,817	607	730
Other Current Liabilities	(9,186)	2,974	4,363
Net Cash Flows from Operating Activities	129,292	71,098	152,842
INVESTING ACTIVITIES			
Construction Expenditures	(141,832)	(130,964)	(83,902)
Change in Advances to Affiliates, Net	-	70,332	(3,272)
Acquisitions of Assets	(563)	(419)	(1,289)
Proceeds from Sales of Assets	5,566	1,032	439
Net Cash Flows Used for Investing Activities	(136,829)	(60,019)	(88,024)
FINANCING ACTIVITIES			
Capital Contribution from Parent	83,112	11,542	41,972
Issuance of Long-term Debt – Nonaffiliated	199,700	-	-
Change in Advances from Affiliates, Net	(4,795)	13,359	-
Retirement of Long-term Debt – Nonaffiliated	(250,000)	-	(65,000)
Principal Payments for Capital Lease Obligations	(1,440)	(1,503)	(1,742)
Dividends Paid on Common Stock	(20,034)	(33,997)	(39,602)
Other Financing Activities	255	224	51
Net Cash Flows from (Used for) Financing Activities	6,798	(10,375)	(64,321)
Net Increase (Decrease) in Cash and Cash Equivalents	(739)	704	497
Cash and Cash Equivalents at Beginning of Period	1,482	778	281
Cash and Cash Equivalents at End of Period	$ 743	$ 1,482	$ 778
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 48,602	$ 48,740	$ 50,429
Net Cash Paid for Income Taxes	6,100	23,089	7,785
Noncash Acquisitions Under Capital Leases	3,448	2,136	621
Construction Expenditures Included in Current Liabilities as of December 31,	7,253	28,565	13,735

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 172,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

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

Effective January 1, 2014, the FERC approved a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, APCo, I&M and KPCo will be individually responsible for planning their respective capacity obligations and there will be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to meet capacity obligations of member companies.

Effective January 1, 2014, AEPSC conducts power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M and KPCo. Power and natural gas risk management activities are allocated based on the three member companies' respective equity positions and the SIA. KPCo shared in coal risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and, to a lesser extent, natural gas and coal. The power, natural gas and coal contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts. For contracts entered and settled prior to January 1, 2014, power and natural gas risk management activities were allocated based on the Interconnection Agreement and the SIA. For contracts entered prior to January 1, 2014 and settled after January 1, 2014, power and natural gas risk management activities are allocated based on frozen MLR ratios as of December 31, 2013. KPCo shared in the revenues and expenses associated with these risk management activities with the other AEP East Companies, PSO and SWEPCo.

Under a unit power agreement with AEGCo, an affiliated company that was not a member of the Interconnection Agreement, KPCo purchases 30% of AEGCo's 50% share of the total output of the 2,600 MW Rockport Plant capacity. Therefore, KPCo purchases 390 MWs of Rockport Plant capacity. 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 the AEP East Companies 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 the AEP East Companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months.

Prior to January 1, 2014, the Interconnection Agreement permitted the AEP East Companies to pool their generation assets on a cost basis. It established an allocation method for generating capacity among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. Members of the Interconnection Agreement were compensated for their costs of energy delivered and charged for energy received. The capacity reserve relationship of the Interconnection Agreement members changed as generating assets were added, retired or sold and relative peak demand changed. The Interconnection Agreement calculated each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation was the MLR, which determined each member's percentage share of revenues and costs.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East Companies, as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East Companies against all balances due to the AEP East Companies and to hold PJM harmless from actions that any one or more AEP East Companies may take with respect to PJM.

Corporate Separation

Background

On December 31, 2013, based on FERC and PUCO orders which approved the corporate separation of OPCo's generation assets and generation liabilities, OPCo transferred its generation assets and related generation liabilities at net book value to AGR. Also on December 31, 2013, AGR subsequently transferred at net book value a one-half interest (780 MW) in the Mitchell Plant to KPCo. The transfer of these generation assets and associated liabilities was approved by the FERC and the KPSC.

Significant Accounting Issues

AGR's transfer of a one-half ownership in the Mitchell Plant to KPCo at net book value qualifies as an acquisition of a business under common control. Pursuant to "Business Combinations" accounting guidance, KPCo retrospectively adjusted its financial statements as if the transfer had occurred at the beginning of the earliest period presented.

None of the OPCo regulatory assets and regulatory liabilities were transferred to KPCo. As previously approved by the PUCO, these regulatory assets and liabilities will be recovered/refunded primarily through OPCo non-bypassable riders.

Substantially all of the current income tax receivables and payables related to OPCo's generation activities prior to December 31, 2013 will remain on OPCo's balance sheet. These current income tax receivables and payables are the responsibility of OPCo. Deferred tax assets and liabilities related to KPCo's acquired share of the Mitchell Plant were transferred to KPCo based upon the Mitchell Plant's related asset and liability values. Following these transfers, KPCo adjusted its deferred tax balances and related regulatory assets to reflect its respective deferred state tax rates.

Long-term Debt

On December 31, 2013, KPCo was assigned $200 million of Long-term Debt – Nonaffiliated from AGR related to a term credit facility.

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 the 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 the retail generation/power supply operations and rates.

In addition, the FERC regulates the SIA, the System Transmission Integration Agreement and the Transmission Agreement, all of which are still active and allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement. In accordance with management's December 2010 announcement and October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated. In December 2013, the FERC issued orders approving the creation of a Power Coordination Agreement (PCA), effective January 1, 2014. Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent.

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 does not have any significant customers that comprise 10% or more of its operating revenues as of December 31, 2013.

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 salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain the plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense.

The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction (AFUDC)

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, Advances to/from Affiliates, Accounts Receivable 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 daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer.

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 significant portion of the Level 3 instruments have been economically hedged which greatly 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 equivalents funds. Fixed income securities do not trade on an exchange and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are primarily real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended. These deferrals are amortized when refunded or when billed to customers in later months with the 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. When a FAC under-recovery is no longer probable of recovery, KPCo adjusts its FAC deferrals and records a provision for estimated refunds to recognize these probable outcomes. Changes in fuel costs, including purchased power, are reflected in rates in a timely manner through the FAC. A portion of profits 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.

Most of the power produced at the generation plants of the AEP East Companies is sold to PJM. The AEP East Companies purchase power from PJM to supply power to their 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. Other RTOs in which KPCo participates do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's economic substance. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, 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

AEPSC, on behalf of the AEP East Companies, engages in wholesale power, coal and natural gas marketing and risk management activities focused on wholesale 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 wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. KPCo uses MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. The realized gains and losses on wholesale marketing and risk management transactions are included in Revenues on the statements of income on a net basis. 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 wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). KPCo initially records the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, 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 are accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are amortized over the life of the plant investment.

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.

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 trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. 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 investment policy for the pension fund allocates assets based on the funded status of the pension plan. The objective of the asset allocation policy is to reduce the investment volatility of the plan over time. Generally, more of the investment mix will be allocated to fixed income investments as the plan becomes better funded. Assets will be transferred away from equity investments into fixed income investments based on the market value of plan assets compared to the plan's projected benefit obligation. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	30.0 %
Fixed Income	55.0 %
Other Investments	15.0 %

OPEB Plans Assets	Target
Equity	66.0 %
Fixed Income	33.0 %
Cash	1.0 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, 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. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, the concentration limits must not exceed:

- 3% in any single issuer
- 5% for private placements
- 5% for convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers, the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
- Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.
- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and development risk classifications and some investments in Real Estate Investment Trusts, 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 cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

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.

Subsequent Events

Management reviewed subsequent events through February 25, 2014, the date that KPCo's 2013 annual report was issued.

2. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following table provides the components of changes in AOCI for the year ended December 31, 2013. All amounts in the following tables are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2013

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate and Foreign Currency	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in thousands)		
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ 1,275	$ (20,860)	$ (19,994)
Change in Fair Value Recognized in AOCI	152	-	-	7,741	7,893
Amounts Reclassified from AOCI	(2)	60	1,402	-	1,460
Net Current Period Other Comprehensive Income	150	60	1,402	7,741	9,353
Pension and OPEB Adjustment Related to Mitchell Plant	-	-	-	5,221	5,221
Balance in AOCI as of December 31, 2013	$ 23	$ (222)	$ 2,677	$ (7,898)	$ (5,420)

Reclassifications from Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the year ended December 31, 2013.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Year Ended December 31, 2013

Gains and Losses on Cash Flow Hedges	Amount of (Gain) Loss Reclassified from AOCI (in thousands)
Commodity:	
Electric Generation, Transmission and Distribution Revenues	$ (64)
Purchased Electricity for Resale	84
Other Operation Expense	(8)
Maintenance Expense	(5)
Property, Plant and Equipment	(11)
Subtotal - Commodity	(4)
Interest Rate and Foreign Currency:	
Interest Expense	93
Subtotal - Interest Rate and Foreign Currency	93
Reclassifications from AOCI, before Income Tax (Expense) Credit	89
Income Tax (Expense) Credit	31
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	58
Pension and OPEB	
Amortization of Prior Service Cost (Credit)	(364)
Amortization of Actuarial (Gains)/Losses	2,521
Change in Funded Status	-
Reclassifications from AOCI, before Income Tax (Expense) Credit	2,157
Income Tax (Expense) Credit	755
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1,402
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 1,460

The following tables provide details on designated, 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 for the years ended December 31, 2012 and 2011. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2012

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2011	$ (283)	$ (342)	$ (625)
Changes in Fair Value Recognized in AOCI	(246)	-	(246)
Amount of (Gain) or Loss Reclassified from AOCI			
to Statement of Income/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	(16)	-	(16)
Purchased Electricity for Resale	427	-	427
Other Operation Expense	(5)	-	(5)
Maintenance Expense	-	-	-
Interest Expense	-	60	60
Property, Plant and Equipment	(4)	-	(4)
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ (409)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2011

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2010	$ (48)	$ (403)	$ (451)
Changes in Fair Value Recognized in AOCI	(431)	-	(431)
Amount of (Gain) or Loss Reclassified from AOCI			
to Statement of Income/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	205	-	205
Purchased Electricity for Resale	51	-	51
Other Operation Expense	(32)	-	(32)
Maintenance Expense	(37)	-	(37)
Interest Expense	-	61	61
Property, Plant and Equipment	(47)	-	(47)
Regulatory Assets (a)	56	-	56
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2011	$ (283)	$ (342)	$ (625)

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

3. 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.

Plant Transfer

In October 2012, the AEP East Companies submitted several filings with the FERC. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters. In December 2012, KPCo filed a request with the KPSC for approval to transfer at net book value to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of December 31, 2013, the net book value of Big Sandy Plant, Unit 2 was $249 million, before cost of removal, including materials and supplies inventory and CWIP. In March 2013, KPCo issued a Request for Proposal (RFP) to purchase up to 250 MW of long-term capacity and energy to replace a portion of the capacity from Big Sandy Plant, Unit 1. In June 2013, KPCo filed the results of its RFP with the KPSC.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. The WVPSC order was subsequently issued in December 2013, but the WVPSC deferred a decision on the transfer of the one-half interest in the Mitchell Plant to APCo. The settlement also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set in the next base rate case (no earlier than June 2015), but rejected KPCo's request to defer FGD project costs for Big Sandy Plant, Unit 2. As a result of this order, in 2013, KPCo recorded a pretax regulatory disallowance of $33 million in Asset Impairments and Other Related Charges on the statement of income. In November 2013, the KPSC denied the Attorney General's petition for rehearing. In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In December 2013, KPCo filed motions with the Franklin County Circuit Court to dismiss the appeal. A hearing on the motions to dismiss was held in January 2014. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed.

2013 Kentucky Base Rate Case

In June 2013, KPCo filed a request with the KPSC for an annual increase in base rates of $114 million based upon a return on common equity of 10.65% to be effective January 2014. The proposed revenue increase included cost recovery of the proposed transfer of the one-half interest in the Mitchell Plant (780 MW). In October 2013, the KPSC issued an order in the plant transfer case which modified and approved a settlement agreement that included the approval of the proposed transfer of the one-half interest in the Mitchell Plant to KPCo. The modified and approved settlement agreement also included KPCo's agreement to withdraw this base rate case request and file a base case proceeding no later than December 2014 with its current base rates to remain in effect until at least May 2015. In November 2013, KPCo withdrew this base rate request and the withdrawal was approved by the KPSC.

FERC Rate Matters

Corporate Separation and Termination of Interconnection Agreement

In October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations and to transfer at net book value AGR's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each), to be effective December 31, 2013. In April 2013, the FERC issued orders approving the transfer of OPCo's generation assets to AGR, and the

Mitchell Plant assets to APCo and KPCo. In January 2014, the FERC dismissed an Industry Energy Users-Ohio petition for rehearing of its order granting OPCo authority to implement corporate separation by transferring its generation assets to AGR. In December 2013, the transfer of the Mitchell Plant to KPCo was completed. See the "Plant Transfer" section of Rate Matters.

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

In December 2013, the FERC issued orders approving the creation of a Power Coordination Agreement (PCA), effective January 1, 2014, conditioned upon certain compliance filings which were filed with the FERC in January 2014. The PCA was established among APCo, I&M and KPCo with AEPSC as the agent to coordinate their respective power supply resources. Under the PCA, KPCo would be individually responsible for planning its respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to meet capacity obligations of member companies through May 31, 2015.

In October 2013, the AEP East Companies submitted additional filings with the FERC updating the October 2012 filings to reflect changes necessitated by orders from the Virginia SCC and the KPSC related to the proposed asset transfers and to position the company for the final stages of corporate separation. In December 2013, the FERC issued an order approving these additional filings. See the "Plant Transfers" section of Rate Matters.

If KPCo experiences decreases in revenues or increases in expenses as a result of changes to its relationship with affiliates and is unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce future net income and cash flows.

4. EFFECTS OF REGULATION

Regulated Generating Unit to be Retired Before or During 2016

The following regulated generating unit is probable of abandonment. Accordingly, CWIP and Plant in Service has been reclassified as Other Property, Plant and Equipment on the balance sheet as of December 31, 2013. The following table summarizes the plant investment and cost of removal, currently being recovered, for the generating unit as of December 31, 2013.

Plant Name and Unit	Gross Investment	Accumulated Depreciation	Net Investment	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
		(in thousands)				
Big Sandy Plant, Unit 2	$ 423,687	$ 180,192	$ 243,495	$ 47,181	2015	27 years
Total	$ 423,687	$ 180,192	$ 243,495	$ 47,181		

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	**December 31, 2013**	**2012**	**Remaining Recovery Period**
	(in thousands)		
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	$ 12,146	$ 12,146	
Mountaineer Carbon Capture and Storage Commercial Scale Facility	-	873	
Total Regulatory Assets Not Yet Being Recovered	12,146	13,019	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Other Regulatory Assets Being Recovered	1,422	1,668	various
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	154,603	127,489	22 years
Pension and OPEB Funded Status	32,458	52,048	11 years
Storm Related Costs	7,048	11,746	2 years
Postemployment Benefits	4,530	5,230	5 years
Medicare Subsidy	2,383	-	11 years
Peak Demand Reduction/Energy Efficiency	914	1,589	1 year
Other Regulatory Assets Being Recovered	856	945	various
Total Regulatory Assets Being Recovered	204,214	200,715	
Total Noncurrent Regulatory Assets	$ 216,360	$ 213,734	

Regulatory Liabilities:	**December 31, 2013**	**2012**	**Remaining Refund Period**
	(in thousands)		
Current Regulatory Liability			
Over-recovered Fuel Costs - does not pay a return	$ 2,851	$ 7,928	1 year
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 19,231	$ 21,066	(a)
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Gain on Forward Commitments	3,259	4,288	4 years
Deferred Investment Tax Credits	126	356	7 years
Other Regulatory Liabilities Being Paid	310	449	various
Total Regulatory Liabilities Being Paid	22,926	26,159	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 22,926	$ 26,159	

(a) Relieved as removal costs are incurred.

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

The following table summarizes KPCo's actual contractual commitments as of December 31, 2013:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 198,192	$ 246,401	$ 232,240	$ 348,360	$ 1,025,193
Energy and Capacity Purchase Contracts	35,144	70,156	69,993	139,846	315,139
Construction Contracts for Capital Assets (b)	1,786	-	-	-	1,786
Total	$ 235,122	$ 316,557	$ 302,233	$ 488,206	$ 1,342,118

(a) Represents contractual commitments to purchase coal and other consumables as fuel for electric generation along with related transportation of the fuel.
(b) Represents only capital assets for which there are signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

GUARANTEES

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.

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, 2013, there were no material liabilities recorded for any indemnifications.

KPCo is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East Companies related to power purchase and sale activity pursuant to the SIA.

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. 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. 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.

Carbon Dioxide Public Nuisance Claims

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. In March 2012, the court granted the defendants' motion for dismissal on several grounds, including the doctrine of collateral estoppel and the applicable statute of limitations. In May 2013, the U.S. Court of Appeals for the Fifth Circuit affirmed the district court's dismissal of the complaint. The plaintiffs did not appeal to the U.S. Supreme Court.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. In September 2012, the Ninth Circuit Court of Appeals affirmed the trial court's decision, holding that the CAA displaced Kivalina's claims for damages. Plaintiffs filed seeking further review in the U.S. Supreme Court. In May 2013, the U.S. Supreme Court denied the plaintiffs' request for review.

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

By-products from the generation of electricity include materials such as ash, slag 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 generating 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 have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. As of December 31, 2013, 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.

6. IMPAIRMENT

2013

Big Sandy Plant, Unit 2 FGD Project

In the third quarter of 2013, KPCo recorded a pretax write-off of $33 million in Asset Impairments and Other Related Charges on the statement of income primarily related to the Big Sandy Plant, Unit 2 FGD project. See the "Plant Transfer" section of Note 3.

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 "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and 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 as of December 31 of each year used in the measurement of KPCo's benefit obligations are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2013**	**2012**	**2013**	**2012**
Discount Rate	4.70 %	3.95 %	4.70 %	3.95 %
Rate of Compensation Increase	4.50 % (a)	4.50 % (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 2013, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 4.5%.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1 of each year used in the measurement of KPCo's benefit costs are shown in the following table:

	Pension Plans			Other Postretirement Benefit Plans		
	2013	2012	2011	2013	2012	2011
Discount Rate	3.95 %	4.55 %	5.05 %	3.95 %	4.75 %	5.25 %
Expected Return on Plan Assets	6.50 %	7.25 %	7.75 %	7.00 %	7.25 %	7.50 %
Rate of Compensation Increase	4.50 %	4.50 %	4.50 %	NA	NA	NA

NA Not applicable.

The expected return on plan assets for 2013 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation and current prospects for economic growth.

The health care trend rate assumptions as of January 1 of each year used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2013	2012
Initial	6.75 %	7.00 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2020	2020

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in thousands)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 164	$ (108)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	2,101	(1,710)

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, 2013, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2013 and 2012

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status as of December 31. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		Other Postretirement Benefit Plans	
	2013	2012	2013	2012
Change in Benefit Obligation		(in thousands)		
Benefit Obligation as of January 1,	$ 183,994	$ 170,910	$ 66,513	$ 83,480
Service Cost	1,763	2,231	750	1,636
Interest Cost	7,074	7,762	2,491	3,821
Actuarial (Gain) Loss	(13,578)	15,617	(15,950)	437
Plan Amendment Prior Service Credit	-	-	-	(19,043)
Benefit Payments	(9,821)	(12,526)	(4,423)	(5,319)
Participant Contributions	-	-	1,198	1,194
Medicare Subsidy	-	-	227	307
Benefit Obligation as of December 31,	$ 169,432	$ 183,994	$ 50,806	$ 66,513
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 165,534	$ 151,450	$ 60,402	$ 55,418
Actual Gain on Plan Assets	13,865	21,063	5,748	5,752
Company Contributions	-	5,547	-	3,357
Participant Contributions	-	-	1,198	1,194
Benefit Payments	(9,821)	(12,526)	(4,423)	(5,319)
Fair Value of Plan Assets as of December 31,	$ 169,578	$ 165,534	$ 62,925	$ 60,402
Funded (Underfunded) Status as of December 31,	$ 146	$ (18,460)	$ 12,119	$ (6,111)

Amounts Recognized on the Balance Sheets as of December 31, 2013 and 2012

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	2012	2013	2012
		(in thousands)		
Employee Benefits and Pension Assets - Prepaid Benefit Costs	$ 146	$ -	$ 11,300	$ -
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	-	(18,460)	819	(6,111)
Funded (Underfunded) Status	$ 146	$ (18,460)	$ 12,119	$ (6,111)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2013 and 2012

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	2012	2013	2012
Components		(in thousands)		
Net Actuarial Loss	$ 51,587	$ 75,591	$ 12,769	$ 32,797
Prior Service Cost (Credit)	203	259	(24,069)	(26,468)
Recorded as				
Regulatory Assets	$ 42,089	$ 47,519	$ (9,631)	$ 4,529
Deferred Income Taxes	3,395	9,916	(584)	630
Net of Tax AOCI	6,306	18,415	(1,085)	1,170

Components of the change in amounts included in AOCI and Regulatory Assets during the years ended December 31, 2013 and 2012 are as follows:

Components	Pension Plans 2013	Pension Plans 2012	Other Postretirement Benefit Plans 2013	Other Postretirement Benefit Plans 2012
	Years Ended December 31, (in thousands)			
Actuarial (Gain) Loss During the Year	$ (17,611)	$ 5,845	$ (17,745)	$ (1,467)
Prior Service Credit	-	-	-	(19,043)
Amortization of Actuarial Loss	(6,393)	(5,225)	(2,283)	(2,117)
Amortization of Prior Service Credit (Cost)	(56)	(120)	2,399	676
Change for the Year	$ (24,060)	$ 500	$ (17,629)	$ (21,951)

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy as of December 31, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 39,294	$ -	$ -	$ -	$ 39,294	23.2 %
International	18,522	-	-	-	18,522	10.9 %
Real Estate Investment Trusts	2,084	-	-	-	2,084	1.2 %
Common Collective Trust - International	-	352	-	-	352	0.2 %
Subtotal - Equities	59,900	352	-	-	60,252	35.5 %
Fixed Income:						
Common Collective Trust - Debt	-	933	-	-	933	0.5 %
United States Government and Agency Securities	-	13,922	-	-	13,922	8.2 %
Corporate Debt	-	57,592	-	-	57,592	34.0 %
Foreign Debt	-	12,372	-	-	12,372	7.3 %
State and Local Government	-	1,007	-	-	1,007	0.6 %
Other - Asset Backed	-	1,198	-	-	1,198	0.7 %
Subtotal - Fixed Income	-	87,024	-	-	87,024	51.3 %
Real Estate	-	-	8,575	-	8,575	5.0 %
Alternative Investments	-	-	11,865	-	11,865	7.0 %
Securities Lending	-	1,266	-	-	1,266	0.8 %
Securities Lending Collateral (a)	-	-	-	(1,627)	(1,627)	(0.9)%
Cash and Cash Equivalents	-	1,749	-	-	1,749	1.0 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	474	474	0.3 %
Total	$ 59,900	$ 90,391	$ 20,440	$ (1,153)	$ 169,578	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.

(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

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

	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2013	$ 7,740	$ 6,894	$ 14,634
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	1,197	532	1,729
Relating to Assets Sold During the Period	-	537	537
Purchases and Sales	(362)	3,902	3,540
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2013	$ 8,575	$ 11,865	$ 20,440

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 17,535	$ -	$ -	$ -	$ 17,535	27.9 %
International	22,796	-	-	-	22,796	36.2 %
Common Collective Trust - Global	-	544	-	-	544	0.9 %
Subtotal - Equities	40,331	544	-	-	40,875	65.0 %
Fixed Income:						
Common Collective Trust - Debt	-	3,255	-	-	3,255	5.2 %
United States Government and Agency Securities	-	2,093	-	-	2,093	3.3 %
Corporate Debt	-	4,078	-	-	4,078	6.5 %
Foreign Debt	-	796	-	-	796	1.2 %
State and Local Government	-	171	-	-	171	0.3 %
Other - Asset Backed	-	301	-	-	301	0.5 %
Subtotal - Fixed Income	-	10,694	-	-	10,694	17.0 %
Trust Owned Life Insurance:						
International Equities	-	490	-	-	490	0.8 %
United States Bonds	-	7,836	-	-	7,836	12.4 %
Cash and Cash Equivalents	2,527	325	-	-	2,852	4.5 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	178	178	0.3 %
Total	$ 42,858	$ 19,889	$ -	$ 178	$ 62,925	100.0 %

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

The following table presents the classification of pension plan assets within the fair value hierarchy as of December 31, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 46,114	$ -	$ -	$ -	$ 46,114	27.9 %
International	17,512	-	-	-	17,512	10.5 %
Real Estate Investment Trusts	3,192	-	-	-	3,192	1.9 %
Common Collective Trust - International	-	153	-	-	153	0.1 %
Subtotal - Equities	66,818	153	-	-	66,971	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	1,118	-	-	1,118	0.7 %
United States Government and Agency Securities	-	25,215	-	-	25,215	15.2 %
Corporate Debt	-	43,539	-	-	43,539	26.3 %
Foreign Debt	-	7,002	-	-	7,002	4.2 %
State and Local Government	-	1,550	-	-	1,550	0.9 %
Other - Asset Backed	-	1,255	-	-	1,255	0.8 %
Subtotal - Fixed Income	-	79,679	-	-	79,679	48.1 %
Real Estate	-	-	7,740	-	7,740	4.7 %
Alternative Investments	-	-	6,894	-	6,894	4.2 %
Securities Lending	-	2,832	-	-	2,832	1.7 %
Securities Lending Collateral (a)	-	-	-	(3,203)	(3,203)	(1.9)%
Cash and Cash Equivalents	-	4,433	-	-	4,433	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	188	188	0.1 %
Total	$ 66,818	$ 87,097	$ 14,634	$ (3,015)	$ 165,534	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.

(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

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

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2012	$ 224	$ 5,757	$ 5,652	$ 11,633
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	1,049	355	1,404
Relating to Assets Sold During the Period	(79)	-	172	93
Purchases and Sales	(145)	934	715	1,504
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 7,740	$ 6,894	$ 14,634

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 16,255	$ -	$ -	$ -	$ 16,255	26.9 %
International	19,436	-	-	-	19,436	32.2 %
Subtotal - Equities	35,691	-	-	-	35,691	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	2,795	-	-	2,795	4.6 %
United States Government and Agency Securities	-	3,166	-	-	3,166	5.2 %
Corporate Debt	-	5,964	-	-	5,964	9.9 %
Foreign Debt	-	1,008	-	-	1,008	1.7 %
State and Local Government	-	280	-	-	280	0.5 %
Other - Asset Backed	-	379	-	-	379	0.6 %
Subtotal - Fixed Income	-	13,592	-	-	13,592	22.5 %
Trust Owned Life Insurance:						
International Equities	-	1,985	-	-	1,985	3.3 %
United States Bonds	-	6,263	-	-	6,263	10.3 %
Cash and Cash Equivalents	2,391	439	-	-	2,830	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	41	41	0.1 %
Total	$ 38,082	$ 22,279	$ -	$ 41	$ 60,402	100.0 %

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

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 plan is as follows:

Accumulated Benefit Obligation	December 31, 2013	December 31, 2012
	(in thousands)	
Qualified Pension Plan	$ 166,951	$ 180,892
Total	$ 166,951	$ 180,892

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 as of December 31, 2012 were as follows:

	Underfunded Pension Plans
	2012
	(in thousands)
Projected Benefit Obligation	$ 183,994
Accumulated Benefit Obligation	$ 180,892
Fair Value of Plan Assets	165,534
Underfunded Accumulated Benefit Obligation	$ (15,358)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the pension plans of $2.7 million during 2014. 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. In November 2012, changes to the retiree medical coverage were announced. Effective for retirements after December 2012, contributions to retiree medical coverage were capped reducing exposure to future medical cost inflation. Effective for employees hired after December 2013, retiree medical coverage will not be provided. The impact of the changes is reflected in the Benefit Plan Obligation table as plan amendments. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Estimated Payments	
	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
2014	$ 10,760	$ 4,508
2015	11,334	4,820
2016	11,489	5,126
2017	11,946	5,385
2018	12,674	5,538
Years 2019 to 2023, in Total	64,896	30,389

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost (credit) for the years ended December 31, 2013, 2012 and 2011:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2013	2012	2011	2013	2012	2011
	(in thousands)					
Service Cost	$ 1,763	$ 2,231	$ 2,188	$ 750	$ 1,636	$ 1,513
Interest Cost	7,074	7,762	8,105	2,491	3,821	4,082
Expected Return on Plan Assets	(9,832)	(11,290)	(10,847)	(3,999)	(3,931)	(4,255)
Amortization of Prior Service Cost (Credit)	56	120	194	(2,399)	(676)	(46)
Amortization of Net Actuarial Loss	6,393	5,225	4,155	2,283	2,117	1,055
Net Periodic Benefit Cost (Credit)	5,454	4,048	3,795	(874)	2,967	2,349
Capitalized Portion	(2,372)	(1,388)	(1,139)	380	(1,018)	(705)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3,082	$ 2,660	$ 2,656	$ (494)	$ 1,949	$ 1,644

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2014 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 4,335	$ 734
Prior Service Cost (Credit)	55	(2,443)
Total Estimated 2014 Amortization	$ 4,390	$ (1,709)
Expected to be Recorded as		
Regulatory Asset	$ 3,731	$ (1,595)
Deferred Income Taxes	231	(40)
Net of Tax AOCI	428	(74)
Total	$ 4,390	$ (1,709)

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 2013, $2.3 million in 2012 and $2.2 million in 2011.

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

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

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, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of KPCo. To accomplish these objectives, AEPSC, on behalf of 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.

AEPSC, on behalf of KPCo, enters into power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo's commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. 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 AEP's Board of Directors.

The following table represents the gross notional volume of KPCo's outstanding derivative contracts as of December 31, 2013 and 2012:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2013	Volume December 31, 2012	Unit of Measure
	(in thousands)		
Commodity:			
Power	10,071	18,838	MWhs
Coal	2	247	Tons
Natural Gas	509	2,018	MMBtus
Heating Oil and Gasoline	261	269	Gallons
Interest Rate	$ 2,615	$ 4,836	USD

Fair Value Hedging Strategies

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

Cash Flow Hedging Strategies

AEPSC, on behalf of KPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. 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 fuel or energy purchases. KPCo does not hedge all commodity price risk.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activities as "Commodity." KPCo does not hedge all fuel price risk.

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

At times, KPCo is exposed to foreign currency exchange rate risks primarily when KPCo purchases certain fixed assets from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of KPCo, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. KPCo does not hedge all foreign currency 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 KPCo's 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, 2013 and 2012 balance sheets, KPCo netted $0 and $253 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $1 million and $2.2 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of KPCo's derivative activity on the balance sheets as of December 31, 2013 and 2012:

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 9,520	$ 85	$ -	$ 9,605	$ (5,249)	$ 4,356
Long-term Risk Management Assets	4,306	-	-	4,306	(822)	3,484
Total Assets	13,826	85	-	13,911	(6,071)	7,840
Current Risk Management Liabilities	7,583	65	-	7,648	(5,820)	1,828
Long-term Risk Management Liabilities	2,970	-	-	2,970	(865)	2,105
Total Liabilities	10,553	65	-	10,618	(6,685)	3,933
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,273	$ 20	$ -	$ 3,293	$ 614	$ 3,907

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 25,448	$ 72	$ -	$ 25,520	$ (19,345)	$ 6,175
Long-term Risk Management Assets	12,117	43	-	12,160	(5,278)	6,882
Total Assets	37,565	115	-	37,680	(24,623)	13,057
Current Risk Management Liabilities	23,806	239	-	24,045	(20,725)	3,320
Long-term Risk Management Liabilities	9,469	85	-	9,554	(5,854)	3,700
Total Liabilities	33,275	324	-	33,599	(26,579)	7,020
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,290	$ (209)	$ -	$ 4,081	$ 1,956	$ 6,037

(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 for the years ended December 31, 2013, 2012 and 2011:

Amount of Gain (Loss) Recognized on
Risk Management Contracts

	Years Ended December 31,		
Location of Gain (Loss)	**2013**	**2012**	**2011**
		(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 1,483	$ (1,597)	$ 2,248
Sales to AEP Affiliates	-	-	31
Fuel and Other Consumables Used for Electric Generation	-	-	(3)
Regulatory Assets (a)	-	-	93
Regulatory Liabilities (a)	(1,029)	1,047	(1,158)
Total Gain (Loss) on Risk Management Contracts	$ 454	$ (550)	$ 1,211

(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.

KPCo's 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. 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."

Accounting for Fair Value Hedging Strategies

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

KPCo records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on KPCo's statements of income. During 2013, 2012 and 2011, KPCo did not designate any fair value hedging strategies.

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 recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on 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 2013, 2012 and 2011, KPCo designated power, coal and natural gas derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the statements of income. During 2013, 2012 and 2011, KPCo designated heating oil and gasoline derivatives as cash flow hedges.

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 2013, 2012 and 2011, KPCo did not designate any interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2013, 2012 and 2011, KPCo did not designate any foreign currency derivatives as cash flow hedges.

During 2013, 2012 and 2011, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets and the reasons for changes in cash flow hedges, see Note 2.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets as of December 31, 2013 and 2012 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2013

	Commodity	Interest Rate (in thousands)	Total
Hedging Assets (a)	$ 79	$ -	$ 79
Hedging Liabilities (a)	59	-	59
AOCI Loss Net of Tax	23	(222)	(199)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	23	(60)	(37)

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2012

	Commodity	Interest Rate (in thousands)	Total
Hedging Assets (a)	$ 63	$ -	$ 63
Hedging Liabilities (a)	272	-	272
AOCI Loss Net of Tax	(127)	(282)	(409)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(100)	(60)	(160)

(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, 2013, the maximum length of time that KPCo is hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions was 12 months.

Credit Risk

AEPSC, on behalf of KPCo, 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. AEPSC, on behalf of KPCo, 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.

When AEPSC, on behalf of KPCo, uses standardized master agreements, these agreements may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds 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, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. 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 investment grade. The following table represents: (a) KPCo's fair value of such derivative contracts, (b) the amount of collateral KPCo would have been required to post for all derivative and non-derivative contracts if the credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2013 and 2012:

	December 31, 2013	December 31, 2012
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 118	$ 432
Amount of Collateral KPCo Would Have Been Required to Post	565	741
Amount Attributable to RTO and ISO Activities	522	703

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 in excess of $50 million. 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 by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of December 31, 2013 and 2012:

	December 31, 2013	December 31, 2012
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 4,039	$ 9,907
Amount of Cash Collateral Posted	-	365
Additional Settlement Liability if Cross Default Provision is Triggered	3,817	6,041

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 as of December 31, 2013 and 2012 are summarized in the following table:

	December 31,			
	2013		2012	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 749,389	$ 841,594	$ 799,195	$ 967,366

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 of December 31, 2013 and 2012. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. 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, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 170	$ 11,168	$ 2,487	$ (6,064)	$ 7,761
Cash Flow Hedges:					
Commodity Hedges (a)	-	85	-	(6)	79
Total Risk Management Assets	$ 170	$ 11,253	$ 2,487	$ (6,070)	$ 7,840
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 144	$ 10,092	$ 316	$ (6,678)	$ 3,874
Cash Flow Hedges:					
Commodity Hedges (a)	-	65	-	(6)	59
Total Risk Management Liabilities	$ 144	$ 10,157	$ 316	$ (6,684)	$ 3,933

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 833	$ 33,315	$ 3,417	$ (24,571)	$ 12,994
Cash Flow Hedges:					
Commodity Hedges (a)	-	103	-	(40)	63
Total Risk Management Assets	$ 833	$ 33,418	$ 3,417	$ (24,611)	$ 13,057
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 392	$ 31,665	$ 1,218	$ (26,527)	$ 6,748
Cash Flow Hedges:					
Commodity Hedges (a)	-	312	-	(40)	272
Total Risk Management Liabilities	$ 392	$ 31,977	$ 1,218	$ (26,567)	$ 7,020

(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 have been no transfers between Level 1 and Level 2 during the years ended December 31, 2013, 2012 and 2011.

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

Year Ended December 31, 2013	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2012	$ 2,199
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(732)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	101
Transfers into Level 3 (d) (e)	273
Transfers out of Level 3 (e) (f)	(187)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	517
Balance as of December 31, 2013	$ 2,171

Year Ended December 31, 2012	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2011	$ 416
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(1,071)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	5
Purchases, Issuances and Settlements (c)	2,282
Transfers into Level 3 (d) (e)	309
Transfers out of Level 3 (e) (f)	(434)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	692
Balance as of December 31, 2012	$ 2,199

Year Ended December 31, 2011	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2010	$ 1,073
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(454)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(16)
Purchases, Issuances and Settlements (c)	336
Transfers into Level 3 (d) (e)	524
Transfers out of Level 3 (e) (f)	(635)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(412)
Balance as of December 31, 2011	$ 416

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

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of December 31, 2013 and 2012:

Significant Unobservable Inputs
December 31, 2013

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High
	(in thousands)					
Energy Contracts	$ 1,924	$ 198	Discounted Cash Flow	Forward Market Price	$ 13.04	$ 80.50
FTRs	563	118	Discounted Cash Flow	Forward Market Price	(5.10)	10.44
Total	$ 2,487	$ 316				

Significant Unobservable Inputs
December 31, 2012

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High
	(in thousands)					
Energy Contracts	$ 3,067	$ 786	Discounted Cash Flow	Forward Market Price	$ 9.40	$ 68.80
FTRs	350	432	Discounted Cash Flow	Forward Market Price	(3.21)	14.79
Total	$ 3,417	$ 1,218				

(a) Represents market prices in dollars per MWh.

11. INCOME TAXES

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

	Years Ended December 31,		
	2013	2012	2011
		(in thousands)	
Income Tax Expense (Credit):			
Current	$ (4,828)	$ 13,617	$ (1,625)
Deferred	12,440	10,168	33,153
Deferred Investment Tax Credits	(230)	(278)	(359)
Income Tax Expense	$ 7,382	$ 23,507	$ 31,169

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,		
	2013	2012	2011
		(in thousands)	
Net Income	$ 8,906	$ 52,975	$ 53,976
Income Tax Expense	7,382	23,507	31,169
Pretax Income	$ 16,288	$ 76,482	$ 85,145
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 5,701	$ 26,769	$ 29,801
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	2,648	2,382	2,563
AFUDC	(749)	(894)	(818)
Removal Costs	(2,475)	(3,885)	(2,010)
Investment Tax Credits, Net	(230)	(278)	(359)
State and Local Income Taxes, Net	1,581	1,535	2,261
Tax Adjustments	1,097	(1,076)	751
Other	(191)	(1,046)	(1,020)
Income Tax Expense	$ 7,382	$ 23,507	$ 31,169
Effective Income Tax Rate	45.3 %	30.7 %	36.6 %

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

	December 31, 2013	December 31, 2012
	(in thousands)	
Deferred Tax Assets	$ 56,347	$ 42,212
Deferred Tax Liabilities	(612,505)	(547,735)
Net Deferred Tax Liabilities	$ (556,158)	$ (505,523)
Property Related Temporary Differences	$ (436,812)	$ (410,100)
Amounts Due from Customers for Future Federal Income Taxes	(29,842)	(29,800)
Deferred State Income Taxes	(80,357)	(54,658)
Deferred Income Taxes on Other Comprehensive Loss	2,918	10,760
Regulatory Assets	(17,063)	(20,604)
All Other, Net	4,998	(1,121)
Net Deferred Tax Liabilities	$ (556,158)	$ (505,523)

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 tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

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. KPCo and other AEP subsidiaries completed the examination of the years 2007 and 2008 in April 2011 and settled all outstanding issues on appeal for the years 2001 through 2006 in October 2011. The settlements did not have a material impact on KPCo and other AEP subsidiaries' net income, cash flows or financial condition. The IRS examination of years 2009 and 2010 started in October 2011 and was completed in the second quarter of 2013. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, 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 and 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.

Tax Credit Carryforward

A federal income tax operating loss sustained in 2009 along with lower federal taxable income in 2012, 2011 and 2010 resulted in unused federal income tax credits of $232 thousand, not all of which have an expiration date. As of December 31, 2013, KPCo had federal general business tax credit carryforwards of $218 thousand. If these credits are not utilized, the federal general business tax credits will expire in the years 2029 through 2032.

KPCo anticipates future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

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, 2013	2012	2011
		(in thousands)	
Interest Expense	$ -	$ 23	$ 193
Interest Income	99	-	1,849
Reversal of Prior Period Interest Expense	-	-	284

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

	December 31, 2013	2012
	(in thousands)	
Accrual for Receipt of Interest	$ 1	$ 1
Accrual for Payment of Interest and Penalties	98	92

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

	2013	2012	2011
		(in thousands)	
Balance as of January 1,	$ 1,333	$ 1,608	$ 2,711
Increase - Tax Positions Taken During a Prior Period	-	-	1,604
Decrease - Tax Positions Taken During a Prior Period	(725)	(93)	(1,586)
Increase - Tax Positions Taken During the Current Year	-	-	-
Decrease - Tax Positions Taken During the Current Year	-	-	-
Decrease - Settlements with Taxing Authorities	-	(182)	(99)
Decrease - Lapse of the Applicable Statute of Limitations	-	-	(1,022)
Balance as of December 31,	$ 608	$ 1,333	$ 1,608

The total amount of unrecognized tax benefits (costs) that, if recognized, would affect the effective tax rate is $0 thousand for 2013 and 2012 and $(4) thousand for 2011. 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 American Taxpayer Relief Act of 2012 (the 2012 Act) was enacted in January 2013. Included in the 2012 Act was a one-year extension of the 50% bonus depreciation. The 2012 Act also retroactively extended the life of research and development, employment and several energy tax credits, which expired at the end of 2011. The enacted provisions will not materially impact KPCo's net income or financial condition but did have a favorable impact on cash flows in 2013.

Federal Tax Regulations

In 2013, the U.S. Treasury Department issued final and re-proposed regulations regarding the deduction and capitalization of expenditures related to tangible property, effective for the tax years beginning in 2014. In addition, the IRS issued Revenue Procedures under the Industry Issue Resolutions program that provides specific guidance for the implementation of the regulations for the electric utility industry. The impact of these final regulations is not material to net income, cash flows or financial condition.

State Tax Legislation

In May 2011, Michigan repealed its Business Tax regime and replaced it with a traditional corporate net income tax rate of 6%, effective January 1, 2012.

During the third quarter of 2013, it was determined that the state of West Virginia had achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate will be reduced from 7.0% to 6.5% in 2014. The enacted provisions will not materially impact 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:

	Years Ended December 31,		
Lease Rental Costs	**2013**	**2012**	**2011**
		(in thousands)	
Net Lease Expense on Operating Leases	$ 1,387	$ 1,141	$ 835
Amortization of Capital Leases	1,743	1,710	1,897
Interest on Capital Leases	311	311	344
Total Lease Rental Costs	$ 3,441	$ 3,162	$ 3,076

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,	
	2013	**2012**
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Generation	$ 2,854	$ 2,776
Other Property, Plant and Equipment	3,425	4,618
Total Property, Plant and Equipment Under Capital Leases	6,279	7,394
Accumulated Amortization	1,869	2,576
Net Property, Plant and Equipment Under Capital Leases	$ 4,410	$ 4,818
Obligations Under Capital Leases		
Noncurrent Liability	$ 3,420	$ 3,128
Liability Due Within One Year	990	1,729
Total Obligations Under Capital Leases	$ 4,410	$ 4,857

Future minimum lease payments consisted of the following as of December 31, 2013:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2014	$ 1,147	$ 1,324
2015	1,025	1,153
2016	812	1,091
2017	672	923
2018	471	629
Later Years	851	1,493
Total Future Minimum Lease Payments	4,978	$ 6,613
Less Estimated Interest Element	568	
Estimated Present Value of Future Minimum Lease Payments	$ 4,410	

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, 2013, the maximum potential loss for these lease agreements was approximately $1.1 million assuming the fair value of the equipment is zero at the end of the lease term.

13. FINANCING ACTIVITIES

Long-term Debt

There are certain limitations on establishing liens against KPCo's assets under its indentures. None of the long-term debt obligations of KPCo have been guaranteed or secured by AEP or any of its affiliates.

The following details long-term debt outstanding as of December 31, 2013 and 2012:

Type of Debt	Maturity	Weighted Average Interest rate as of December 31, 2013	Interest Rate Ranges as of December 31, 2013	Interest Rate Ranges as of December 31, 2012	Outstanding as of December 31, 2013	Outstanding as of December 31, 2012
					(in thousands)	
Senior Unsecured Notes	2017-2039	6.40%	5.625%-8.13%	5.625%-8.13%	$ 530,000	$ 780,000
Notes Payable - Affiliated	2015	5.25%	5.25%	5.25%	20,000	20,000
Other Long-term Debt (a)	2015	1.188%	1.188%		200,000	-
Unamortized Discount, Net					(611)	(805)
Total Long-term Debt Outstanding					749,389	799,195
Long-term Debt Due Within One Year					-	250,000
Long-term Debt					$ 749,389	$ 549,195

(a) In July 2013, AGR, APCo, KPCo and OPCo entered into a $1 billion term credit facility due in May 2015 to provide liquidity during the corporate separation process. In 2013, OPCo borrowed $1 billion under the credit facility and retired other certain debt. On December 31, 2013, OPCo assigned the $1 billion in credit facility borrowings to AGR upon the transfer of OPCo's generation assets to AGR. Also on December 31, 2013, AGR subsequently assigned a portion of the borrowings to KPCo in the amount of $200 million upon AGR's transfer of certain of those generation assets.

Long-term debt outstanding as of December 31, 2013 is payable as follows:

	2014	2015	2016	2017	2018	After 2018	Total
				(in thousands)			
Principal Amount	$ -	$ 220,000	$ -	$ 325,000	$ -	$ 205,000	$ 750,000
Unamortized Discount, Net							(611)
Total Long-term Debt Outstanding							$ 749,389

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." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the book value of the common stock. This restriction does not limit the ability of 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, 2013, none of KPCo's retained earnings have restrictions related to the payment of dividends to Parent.

Utility Money Pool – 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, 2013 and 2012 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2013 and 2012 are described in the following table:

Year	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
			(in thousands)			
2013	$ 32,649	$ 31,421	$ 10,911	$ 14,584	$ 8,564	$ 250,000
2012	13,359	80,205	9,200	46,187	13,359	250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the years ended December 31, 2013, 2012 and 2011 are summarized in the following table:

Year 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
2013	0.43 %	0.29 %	0.41 %	0.24 %	0.37 %	0.32 %
2012	0.42 %	0.42 %	0.56 %	0.39 %	0.42 %	0.48 %
2011	- %	- %	0.56 %	0.06 %	- %	0.35 %

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, respectively, for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
	2013	2012	2011
		(in thousands)	
Interest Expense	$ 12	$ 1	$ -
Interest Income	36	222	318

Sale of 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.

In June 2013, AEP Credit amended its receivables securitization agreement to extend through June 2014. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. AEP Credit amended a commitment of $385 million to now expire in June 2014. The remaining commitment of $315 million expires in June 2015. AEP Credit intends to extend or replace the agreement expiring in June 2014 on or before its maturity.

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $43 million and $46 million as of December 31, 2013 and 2012, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $2 million for each of the years ended December 31, 2013, 2012 and 2011.

KPCo's proceeds on the sale of receivables to AEP Credit were $522 million, $517 million and $579 million for the years ended December 31, 2013, 2012 and 2011, 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 generating 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 creation of the Power Coordination Agreement among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Also effective January 1, 2014, the FERC approved the Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent to address open commitments related to the termination of the Interconnection Agreement and responsibilities to PJM. See "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters in Note 3.

Prior to January 1, 2014, power, natural gas and risk management activities were conducted by AEPSC and profits and losses were allocated under the SIA to members of the Interconnection Agreement, PSO and SWEPCo. Risk management activities involved the purchase and sale of power and natural gas under physical forward contracts at fixed and variable prices. In addition, the risk management of power, and to a lesser extent natural gas contracts, included exchange traded futures and options and OTC options and swaps. The majority of these transactions represented physical forward contracts in the AEP System's traditional marketing area and were typically settled by entering into offsetting contracts. In addition, AEPSC entered into transactions for the purchase and sale of power and natural gas options, futures and swaps, and for the forward purchase and sale of power outside of the AEP System's traditional marketing area.

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. Parties are compensated for energy delivered to recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids more costly alternatives. Revenues and costs arising from third party sales are generally shared based on the amount of energy PSO or SWEPCo contributes that is sold to third parties.

System Integration Agreement (SIA)

The SIA provides for the integration and coordination of AEP East Companies' and AEP West Companies' zones. This includes joint dispatch of generation within the AEP System and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). The SIA is designed to function as an umbrella agreement in addition to the Interconnection Agreement (prior to January 1, 2014) and the Operating Agreement, each of which controls the distribution of costs and benefits within a zone.

Power generated, allocated or provided under the Interconnection Agreement or the Operating Agreement is primarily sold to customers at rates approved by the public utility commission in the jurisdiction of sale.

Under both the Interconnection Agreement and the Operating Agreement, power generated that is not needed to serve the AEP System's native load is sold in the wholesale market by AEPSC on behalf of the generating subsidiary.

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, natural gas contracts with AEPES and other revenues for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
Related Party Revenues	**2013**	**2012**	**2011**
		(in thousands)	
Sales under Interconnection Agreement	$ 79,909	$ 60,198	$ 99,593
Direct Sales to West Affiliates	119	64	314
Transmission Agreement Sales	862	3,022	4,480
Natural Gas Contracts with AEPES	-	-	32
Other Revenues	22,841	7,492	263
Total Affiliated Revenues	$ 103,731	$ 70,776	$ 104,682

The following table shows the purchased power expenses incurred for purchases under the Interconnection Agreement and from affiliates for the years ended December 31, 2013, 2012 and 2011:

Related Party Purchases	Years Ended December 31, 2013	2012	2011
		(in thousands)	
Purchases under Interconnection Agreement	$ 161,293	$ 121,267	$ 112,217
Direct Purchases from West Affiliates	1	11	51
Purchases from AEGCo	107,794	102,371	98,031
Total Affiliated Purchases	$ 269,088	$ 223,649	$ 210,299

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

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP East Companies' and AEP West Companies' zones. Similar to the SIA, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the Transmission Agreement (TA) and the Transmission Coordination Agreement (TCA). The System Transmission Integration Agreement contains two service schedules that govern:

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

The System Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

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, 2013, 2012 and 2011 were $3 million, $1.1 million and $410 thousand, 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, revised 1999 and 2011, as restated and amended, 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.

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc. (NPC) have an agreement whereby OPCo operates a 500 MW natural gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with OPCo and NPC to manage and procure fuel for the Mone Plant. The natural gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East Companies, who have an agreement to purchase 100% of the available generating capacity from the plant through May 2014. KPCo's related purchases of natural gas managed by AEPES were $124 thousand, $173 thousand and $183 thousand for the years ended December 31, 2013, 2012 and 2011, respectively. These purchases are reflected in Purchased Electricity for Resale on KPCo's statements of income.

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. 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 $4 million, $1.6 million and $2.2 million in 2013, 2012 and 2011, 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 $1.1 million, $647 thousand and $672 thousand for the years ended December 31, 2013, 2012 and 2011, respectively.

Affiliate Railcar Agreement

KPCo has an agreement providing for the use of its affiliates' leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. KPCo recorded these costs in Fuel on the balance sheets and such costs are recoverable from customers. The following table shows the net effect of the railcar agreement on KPCo's balance sheets:

	December 31,	
Billing Company	**2013**	**2012**
	(in thousands)	
AGR	$ (20)	$ 381
APCo	26	436

Purchases from OVEC under the Interconnection Agreement

In 2011, the parties to the Interconnection Agreement purchased power from OVEC to serve off-system sales and retail sales. These purchases are reported in Purchased Electricity for Resale on KPCo's statement of income. KPCo recorded $4.5 million in expense for the year ended December 31, 2011.

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, 2013, 2012 and 2011:

		Years Ended December 31,	
	2013	**2012**	**2011**
		(in thousands)	
Sales	$ 951	$ 1,032	$ 404
Purchases	1,702	1,078	2,188

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

Global Borrowing Notes

As of December 31, 2013 and 2012, AEP has an intercompany note in place with KPCo. The debt is reflected in Long-term Debt – Affiliated on KPCo's balance sheets. KPCo accrues interest for its share of the global borrowing and remits the interest to AEP. The accrued interest is reflected in Accrued Interest on KPCo's 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 controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. 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. AEP 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, 2013, 2012 and 2011 were $38 million, $40 million and $35 million, respectively. The carrying amount of liabilities associated with AEPSC as of December 31, 2013 and 2012 was $4 million and $6 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, 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 its 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, 2013, 2012 and 2011 were $108 million, $102 million and $98 million, respectively. The carrying amount of liabilities associated with AEGCo as of December 31, 2013 and 2012 was $11 million and $10 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

16. PROPERTY, PLANT AND EQUIPMENT

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 tables provide KPCo's annual property information:

2013	Regulated (a)				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 1,052,757	$ 365,645	3.7%	40-60	$ -	$ -	NA	NA
Transmission	507,844	172,604	1.8%	25-75	-	-	NA	NA
Distribution	693,481	216,771	3.4%	11-75	-	-	NA	NA
CWIP	128,599	(8,320)	NM	NM	-	-	NA	NA
Other	475,229	196,977	4.3%	20-75	5,530	212	NM	NM
Total	$ 2,857,910	$ 943,677			$ 5,530	$ 212		

2012	Regulated				Nonregulated (a)			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 558,935	$ 221,976	3.8%	40-50	$ 880,064	$ 277,074	3.8%	60
Transmission	490,152	162,774	1.6%	25-75	5,829	3,082	2.3%	NM
Distribution	652,615	200,340	3.4%	11-75	-	-	NA	NA
CWIP	44,281	(6,327)	NM	NM	43,643	380	NM	NM
Other	57,451	24,409	7.2%	20-75	7,699	308	NM	NM
Total	$ 1,803,434	$ 603,172			$ 937,235	$ 280,844		

2011	Regulated		Nonregulated (a)	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	3.8%	40-50	3.8%	60
Transmission	1.7%	25-75	2.4%	NA
Distribution	3.5%	11-75	NA	NA
CWIP	NM	NM	NM	NM
Other	8.2%	NM	3.4%	NM

(a) For 2013, KPCo's ownership in the Mitchell Plant is included in the Regulated amounts listed above. For 2012 and 2011, KPCo's ownership in the Mitchell Plant is included in the Nonregulated amounts listed above.

NA Not applicable.

NM Not meaningful.

The composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability.

Asset Retirement Obligations (ARO)

KPCo records ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for the retirement of 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.

The following is a reconciliation of the 2013 and 2012 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)			
2013	$ 8,759	$ 742	$ -	$ (255)	$ 11,280	$ 20,526
2012	8,488	709	-	(438)	-	8,759

Allowance for Funds Used During Construction (AFUDC)

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

	Years Ended December 31, 2013	2012	2011
		(in thousands)	
Allowance for Equity Funds Used During Construction	$ 1,367	$ 1,574	$ 1,229
Allowance for Borrowed Funds Used During Construction	3,047	2,275	996

Jointly-owned Electric Facilities

KPCo has a 50.0% ownership share of Units 1 and 2 at the Mitchell Generating Station. In addition to KPCo, the Mitchell Generating Station is jointly-owned by AGR. 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, 2013					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 907,304	$ 75,253	$ 305,170
KPCo's Share as of December 31, 2012					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 878,036	$ 43,106	$ 276,658

(a) Operated by KPCo.

17. SUSTAINABLE COST REDUCTIONS

In April 2012, management initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. Management selected a consulting firm to facilitate an organizational and process evaluation and a second firm to evaluate current employee benefit programs. The process resulted in involuntary severances and was completed by the end of the first quarter of 2013. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

KPCo recorded a charge of $2 million to Other Operation expense in 2012 primarily related to severance benefits as a result of the sustainable cost reductions initiative. In addition, the sustainable cost reduction activity for the year ended December 31, 2013 is described in the following table:

Balance as of December 31, 2012	Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance as of December 31, 2013
		(in thousands)			
$ 497	$ 180	$ -	$ (276)	$ (401)	$ -

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the statements of income. Management does not expect additional costs to be incurred related to this initiative.

18. 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:

	2013 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in thousands)			
Total Revenues	$ 230,644	$ 181,549	$ 211,536	$ 202,526
Operating Income (Loss)	32,607	18,214	(14,044)(a)	22,422
Net Income (Loss)	14,403	4,985	(16,513)(a)	6,031

	2012 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in thousands)			
Total Revenues	$ 210,365	$ 185,183	$ 213,995	$ 214,874
Operating Income	29,309	33,392	34,990	26,241
Net Income	12,154	15,345	15,754	9,722

(a) Includes a regulatory disallowance for Big Sandy Plant, Unit 2 (see Note 3 and Note 6).

- THIS PAGE INTENTIONALLY LEFT BLANK -