STITES & HARBISON PLLC
ATTORNEYS

RECEIVED
APR 30 2019
PUBLIC SERVICE COMMISSION

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April 30, 2019

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HAND DELIVERY

Gwen R. Pinson
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Kentucky Power Company's 2018 Public Service Commission Annual Report and Related Filings

Dear Ms. Pinson:

Enclosed please find and accept for filing the original and ten copies of Kentucky Power Company's 2018 Annual Resource Assessment in accordance with the Commission's March 29, 2004 Order in Administrative Case No. 387. These are being filed as a supplement to Company's 2018 Public Service Commission Annual Report in accordance with the Commission's October 7, 2005 order closing Administrative Case No. 387 and directing that future Administrative Case No. 387 periodic updates be filed annually as a supplement to the Company's annual report.

Also being filed is the original and ten copies of the Company's motion for confidential treatment with respect to portions of its response to Data Requests Nos. 6 and 9. It is being filed without a case number in light of the Commission's October 7, 2005 order closing Administrative Case No. 387.

A copy of the Company's 2018 FERC Form-1 and the 2018 Annual Public Service Commission Utility Financial Report for Kentucky Power are also enclosed. Kentucky Power's 2018 Annual Public Service Commission Utility Financial Report previously was filed electronically on April 25, 2019.

Kentucky Power currently is required to provide information concerning the operation of the "AEP-East Power Pool" as part of its periodic filings in accordance with the Commission's March 29, 2004 Order in Administrative Case No. 387. The AEP Interconnection Agreement terminated on January 1, 2014 and the AEP-East Power Pool no longer exists.

Mr. Pinney suggested that I notify you of the termination of the of the AEP Interconnection Agreement and request formal acknowledgement that the Company may amend its periodic Administrative Case No. 387 filings beginning next year to eliminate those portions of the requests seeking information regarding the AEP-East Power Pool. To extent this request cannot be addressed administratively, and instead requires a formal motion to the Commission, please so advise and indicate in what proceeding the motion should be filed.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

Mark R. Overstreet

MRO

cc: J.E.B. Pinney

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APR 30 2019

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

Kentucky Power Company's 2017 Filing In Response To The Commission's Order In Administrative Case No. 387	)))	Case No. 2019-00___

Kentucky Power Company's Motion for Confidential Treatment

Kentucky Power Company moves the Public Service Commission of Kentucky pursuant 807 KAR 5:001, Section 13 for confidential treatment of portions of: (a) Confidential Attachment 2 to the Company's response to Data Request No. 6; and Confidential Attachment 1 to the Company's response to Data Request No. 9.

1. The information for which confidential treatment is being sought is being filed in accordance with the Commission's Order in Administrative Case No. 387, *A Review Of The Adequacy Of Kentucky's Generation And Transmission System*. By order dated October 7, 2005 the Commission closed Administrative Case No. 387 and directed that the "updated information that is currently required to be filed annually in this case shall be filed as a supplement to the filer's annual report."[1] Accordingly, there is no open proceeding in which Kentucky Power can file this motion for confidential treatment.

2. Pursuant to 807 KAR 5:001, Section 13, Kentucky Power is filing under seal, with the confidential portions highlighted in yellow, those portions of Attachment 1 to its response to Data Request No. 9 for which it is seeking confidential treatment. Kentucky Power is also filing ten copies of the redacted version of the data request response for which confidential treatment is

[1] Order, *A Review Of The Adequacy Of Kentucky's Generation And Transmission System* at 1 Adm. Case No. 387 (Ky. P.S.C. October 7, 2007).

being sought. Kentucky Power will notify the Commission when it determines the information for which confidential treatment is sought is no longer confidential.

A. <u>The Requests and the Statutory Standard</u>.

3. The identified portions of the Company's responses to Data Request 6 and Data Request 9 are required to be excluded from the public record and public disclosure. KRS 61.878(1)(c)(1) excludes from the Open Records Act:

> "[r]ecords confidentially disclosed to an agency or required by an agency to be disclosed to it, generally recognized as confidential or proprietary, which if openly disclosed would present an unfair commercial advantage to competitors of the entity that disclosed the records.

This exception applies to the identified portions of Kentucky Power's responses to Data Request No. 6 and Data Request No. 9.

1. <u>Confidential Attachment 2 To The Response To Data Request No. 6</u>.

4. Confidential Attachment 2 to the Company's response to Data Request No. 6 details the specific timing of planned maintenance outages for Kentucky Power's generation units through 2023. The rise of competitive markets such as PJM has placed a premium on generating unit data. Public disclosure of information about unit availability could adversely affect Kentucky Power's customers by providing data that could provide a competitive advantage to Kentucky Power's direct competitors thereby affecting Kentucky Power's ability to minimize costs for its rate paying customers.

5. Unit availability information is especially useful for competition as savvy marketers can estimate Kentucky Power's generation position and raise generation offers if the marketers believe Kentucky Power will be energy short, resulting in the Company paying higher prices to procure energy to serve its customers. This type of data is highly valued by competing

energy marketers and traders who speculate in forward energy transactions. Using forecasted unit availability data, other parties could improve their forecast accuracy of future Kentucky Power operations and utilize the resulting intelligence to influence negatively the Company's costs of providing electricity to its customers. Such actions would ultimately raise the cost to Kentucky Power's customers.

6. Confidential Attachment 2 to the Company's response to Data Request No. 6 should be kept confidential for the period covered by the response (through the end of calendar 2023).[2] At such time there will no longer be any competitive advantage to be gained from the information.

2. Confidential Attachment 1 To The Response To Data Request No. 9.

7. Confidential Attachment 1 to Kentucky Power's response to Data Request No. 9 provides information regarding planned transmission projects that have yet to be publicly disclosed. The wholesale power market is extremely competitive. In addition to sales and purchases by utilities, competitive power providers, and electricity marketers, investment banks and other financial traders take financial positions, such as futures contracts and derivatives, including options, price swaps, basis swaps, and forward contracts, with respect to the wholesale electricity market.

8. The wholesale price of electricity, as well as associated financial instruments, can be affected by the capacity and availability of transmission facilities. Information regarding

[2] The Commission granted confidential treatment to similar information pertaining to planned future outages in its August 23, 2017 order in Case No. 2017-00001. *See* Order, *In the Matter of: Electronic Examination Of The Application Of The Fuel Adjustment Clause Of Kentucky Power Company From November 1, 2014 Through April 30, 2016*, Case No. 2018-00216 (Ky. P.S.C. August 23, 2017).

planned changes or upgrades to transmission facilities can be used by market participants in making their pricing decisions.

9. Kentucky Power seeks confidential treatment of the identified information included in Attachment 1 to its response to Data Request No. 9 until the information is made public through the PJM Interconnection, L.L.C. transmission planning process.

B. <u>The Identified Information is Generally Recognized As Confidential and Proprietary and Public Disclosure Of It Will Result In An Unfair Commercial Advantage.</u>

10. The identified information required to be disclosed by Kentucky Power in response to the two data requests is confidential and not generally known or readily ascertainable by other parties through normal or proper means. No reasonable amount of legitimate independent research could yield this confidential information to other parties. Dissemination of the information for which confidential treatment is being requested is restricted by Kentucky Power, its affiliated operating companies, American Electric Power Company, Inc. ("AEP"), and American Electric Power Service Corporation ("AEPSC" together, the "AEP Entities"). The AEP Entities take all reasonable measures to prevent its disclosure to the public as well as persons within the AEP Entities who do not have a need for the information. The information is not disclosed to persons outside the AEP Entities. Within those organizations, the information is available only upon a confidential need-to-know basis that does not extend beyond those employees with a legitimate business need to know and act upon the identified information.

C. <u>The Identified Information Is Required To Be Disclosed To An Agency.</u>

11. The identified information is by the terms of the Commission's Order in Administrative Case No. 387 required to be disclosed to the Commission. The Commission is a "public agency" as that term is defined at KRS 61.870(1). Any filing should be subject to a

confidentiality order and any party requesting such information should be required to enter into an appropriate confidentiality agreement.

WHEREFORE, Kentucky Power Company respectfully requests the Commission to enter an Order:

1. According confidential status to and withholding from public inspection the identified information; and

2. Granting Kentucky Power all further relief to which it may be entitled.

Respectfully submitted,

Mark R. Overstreet
STITES & HARBISON PLLC
421 West Main Street
P. O. Box 634
Frankfort, Kentucky 40602-0634
Telephone: (502) 223-3477

COUNSEL FOR KENTUCKY POWER COMPANY

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APR 30 2019
PUBLIC SERVICE
COMMISSION

Kentucky Power Company

2018 Annual Report

Audited Financial Statements

KENTUCKY POWER
An AEP Company
BOUNDLESS ENERGY

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	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary that acquired the generation assets and liabilities of OPCo.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ASU	Accounting Standards Update.
CWIP	Construction Work in Progress.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.
IRS	Internal Revenue Service.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_x	Nitrogen oxide.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.

Term	Meaning
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
OTC	Over the counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

pwc

Report of Independent Auditors

To the Board of Directors and Management of
Kentucky Power Company

We have audited the accompanying financial statements of Kentucky Power Company, which comprise the balance sheets as of December 31, 2018 and 2017, and the related statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows for the years then ended.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the 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 the 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 our 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, we consider 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, 2018 and 2017, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

February 21, 2019

PricewaterhouseCoopers LLP, 41 South High Street, Columbus, OH 43215
T: (614) 225 8700, F: (614) 224 1044, www.pwc.com/us

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2018 and 2017
(in thousands)

	Years Ended December 31, 2018	2017
REVENUES		
Electric Generation, Transmission and Distribution	$ 628,673	$ 625,201
Sales to AEP Affiliates	12,330	16,697
Other Revenues	1,068	891
TOTAL REVENUES	642,071	642,789
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	102,103	121,776
Purchased Electricity for Resale	50,599	33,052
Purchased Electricity from AEP Affiliates	101,961	95,957
Other Operation	94,474	117,214
Maintenance	70,282	68,999
Depreciation and Amortization	97,770	88,004
Taxes Other Than Income Taxes	23,854	24,129
TOTAL EXPENSES	541,043	549,131
OPERATING INCOME	101,028	93,658
Other Income (Expense):		
Interest Income	44	175
Carrying Costs Income	17	1,059
Allowance for Equity Funds Used During Construction	2,002	933
Non-Service Cost Components of Net Periodic Benefit Cost	4,052	1,621
Interest Expense	(37,998)	(44,650)
INCOME BEFORE INCOME TAX EXPENSE	69,145	52,796
Income Tax Expense	5,999	17,550
NET INCOME	$ 63,146	$ 35,246

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

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2018 and 2017
(in thousands)

	Years Ended December 31, 2018	2017
Net Income	$ 63,146	$ 35,246
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of $0 and $22 in 2018 and 2017, Respectively	—	41
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(24) and $17 in 2018 and 2017, Respectively	(89)	31
Pension and OPEB Funded Status, Net of Tax of $(117) and $831 in 2018 and 2017, Respectively	(441)	1,544
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(530)	1,616
TOTAL COMPREHENSIVE INCOME	$ 62,616	$ 36,862

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, 2018 and 2017
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 50,450	$ 526,135	$ 93,170	$ (1,354)	$ 668,401
Common Stock Dividends			(35,000)		(35,000)
Net Income			35,246		35,246
Other Comprehensive Income				1,616	1,616
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	50,450	526,135	93,416	262	670,263
ASU 2018-02 Adoption			(56)	56	—
Net Income			63,146		63,146
Other Comprehensive Loss				(530)	(530)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 50,450	$ 526,135	$ 156,506	$ (212)	$ 732,879

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2018 and 2017
(in thousands)

	December 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,168	$ 909
Accounts Receivable:		
Customers	20,242	13,007
Affiliated Companies	29,018	32,019
Accrued Unbilled Revenues	8,931	6,667
Miscellaneous	57	179
Allowance for Uncollectible Accounts	(85)	(44)
Total Accounts Receivable	58,163	51,828
Fuel	10,621	18,006
Materials and Supplies	17,207	16,626
Risk Management Assets	5,722	1,851
Accrued Tax Benefits	2,732	6,909
Regulatory Asset for Under-Recovered Fuel Costs	2,379	82
Margin Deposits	882	2,880
Prepayments and Other Current Assets	3,203	12,975
TOTAL CURRENT ASSETS	102,077	112,066
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,195,701	1,186,796
Transmission	603,317	579,144
Distribution	845,821	812,757
Other Property, Plant and Equipment	98,280	84,024
Construction Work in Progress	84,748	52,142
Total Property, Plant and Equipment	2,827,867	2,714,863
Accumulated Depreciation and Amortization	961,457	922,493
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,866,410	1,792,370
OTHER NONCURRENT ASSETS		
Regulatory Assets	391,745	353,568
Long-term Risk Management Assets	159	203
Employee Benefits and Pension Assets	15,819	21,720
Deferred Charges and Other Noncurrent Assets	36,221	25,966
TOTAL OTHER NONCURRENT ASSETS	443,944	401,457
TOTAL ASSETS	$ 2,412,431	$ 2,305,893

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2018 and 2017
(dollars in thousands)

	December 31, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$ 27,871	$ 9,641
Accounts Payable:		
General	51,022	48,331
Affiliated Companies	30,615	34,944
Long-term Debt Due Within One Year – Nonaffiliated	—	75,000
Risk Management Liabilities	95	402
Customer Deposits	30,149	28,444
Accrued Taxes	30,479	24,785
Accrued Interest	6,550	7,848
Asset Retirement Obligations	20,961	19,735
Other Current Liabilities	24,213	24,634
TOTAL CURRENT LIABILITIES	221,955	273,764
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	867,128	792,188
Long-term Risk Management Liabilities	44	36
Deferred Income Taxes	402,070	394,786
Regulatory Liabilities and Deferred Investment Tax Credits	155,682	130,162
Asset Retirement Obligations	20,720	31,503
Employee Benefits and Pension Obligations	5,989	6,932
Deferred Credits and Other Noncurrent Liabilities	5,964	6,259
TOTAL NONCURRENT LIABILITIES	1,457,597	1,361,866
TOTAL LIABILITIES	1,679,552	1,635,630
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	526,135	526,135
Retained Earnings	156,506	93,416
Accumulated Other Comprehensive Income (Loss)	(212)	262
TOTAL COMMON SHAREHOLDER'S EQUITY	732,879	670,263
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,412,431	$ 2,305,893

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018 and 2017
(in thousands)

	Years Ended December 31, 2018		Years Ended December 31, 2017	
OPERATING ACTIVITIES				
Net Income	$	63,146	$	35,246
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:				
Depreciation and Amortization		97,770		88,004
Deferred Income Taxes		5,459		29,079
Carrying Costs Income		(17)		(1,059)
Allowance for Equity Funds Used During Construction		(2,002)		(933)
Mark-to-Market of Risk Management Contracts		(4,126)		(1,526)
Pension Contributions to Qualified Plan Trust		—		(2,226)
Deferred Fuel Over/Under-Recovery, Net		(2,865)		2,441
Deferred Rockport Capacity Costs		(14,477)		—
Change in Other Noncurrent Assets		(26,149)		10,906
Change in Other Noncurrent Liabilities		(23,880)		(11,412)
Changes in Certain Components of Working Capital:				
Accounts Receivable, Net		396		(2,845)
Fuel, Materials and Supplies		7,583		2,150
Accounts Payable		(2,136)		(4,633)
Accrued Taxes, Net		9,871		(9,929)
Accrued Interest		(1,298)		(279)
Other Current Assets		11,826		(9,438)
Other Current Liabilities		(1,178)		141
Net Cash Flows from Operating Activities		117,923		123,687
INVESTING ACTIVITIES				
Construction Expenditures		(136,016)		(95,156)
Proceeds from Sales of Assets		627		620
Other Investing Activities		745		24
Net Cash Flows Used for Investing Activities		(134,644)		(94,512)
FINANCING ACTIVITIES				
Issuance of Long-term Debt – Nonaffiliated		74,498		388,782
Change in Advances from Affiliates, Net		18,230		7,834
Retirement of Long-term Debt – Nonaffiliated		(75,000)		(390,000)
Principal Payments for Capital Lease Obligations		(845)		(992)
Dividends Paid on Common Stock		—		(35,000)
Other Financing Activities		97		251
Net Cash Flows from (Used for) Financing Activities		16,980		(29,125)
Net Increase in Cash and Cash Equivalents		259		50
Cash and Cash Equivalents at Beginning of Period		909		859
Cash and Cash Equivalents at End of Period	$	1,168	$	909
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	38,671	$	43,394
Net Cash Paid (Received) for Income Taxes		(3,303)		(2,874)
Noncash Acquisitions Under Capital Leases		596		1,093
Construction Expenditures Included in Current Liabilities as of December 31,		21,849		17,643

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 166,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

Under the FERC approved PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

The FERC also approved a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement that amongst other things addresses the treatment of purchases and sales made by AEPSC on behalf of the member companies that extend beyond termination of the Interconnection Agreement.

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

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

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

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

KPCo's rates are regulated by the FERC and the KPSC. The FERC also regulates KPCo's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires a nonregulated affiliate to bill an affiliated public utility company at no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The KPSC also regulates certain intercompany transactions under its affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

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

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

In addition, the FERC regulates the SIA and the Transmission Agreement, which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. The FERC also regulates the PCA and Bridge Agreement, see Note 13 - Related Party Transactions for additional information.

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 "Securitized Accounts Receivables - AEP Credit" section of Note 12 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 had a significant customer which accounts for the following percentages of Total Revenues for the years ended December 31 and Accounts Receivable – Customers as of December 31:

Significant Customer of KPCo: Marathon Petroleum Company	2018	2017
Percentage of Total Revenues	12%	12%
Percentage of Accounts Receivable – Customers	24%	38%

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

Emission Allowances

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

Property, Plant and Equipment

Electric utility property, plant and equipment are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of removal cost incurred and salvage received. These rates and the related lives are subject to periodic review. Removal costs accrued are typically recorded as regulatory liabilities when the revenue received for removal costs accrued exceeds actual removal costs incurred. The asset removal costs liability is relieved as removal costs are incurred. A regulatory asset balance will occur if actual removal costs incurred exceed accumulated removal costs accrued.

The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed or is not probable, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense.

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

Allowance for Funds Used During Construction

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. KPCo records the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances 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.

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

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

Assets in the benefits trusts are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and 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. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Investments classified as Other are valued using Net Asset Value as a practical expedient. Items classified as Other are primarily cash equivalent funds, common collective trusts, commingled funds, structured products, private equity, real estate, infrastructure and alternative credit investments. These investments do not have a readily determinable fair value or they contain redemption restrictions which may include the right to suspend redemptions under certain circumstances. Redemption restrictions may also prevent certain investments from being redeemed at the reporting date for the underlying value.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a commission-approved plan to delay refunds or recoveries beyond a one year period. These deferrals are amortized when refunded or when billed to customers in later months with the KPSC's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the KPSC. On a routine basis, the KPSC reviews and/or audits KPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. Changes in fuel costs, including purchased power, are reflected in rates in a timely manner through the FAC. A portion of margins from off-system sales are given to customers through the FAC.

Revenue Recognition

Regulatory Accounting

KPCo's financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses or alternative revenues recognized in accordance with the guidance for "Regulated Operations") 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 revenue 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 derecognizes that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

KPCo recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues on the statements of income upon delivery of the energy to the customer and includes unbilled as well as billed amounts. Wholesale transmission revenue is based on FERC approved formula rate filings made for each calendar year using estimated costs. The annual rate filing is compared to actual costs with an over- or under-recovery being trued-up with interest and refunded or recovered in a future year's rates. In accordance with the accounting guidance for "Regulated Operations - Revenue Recognition", KPCo recognizes revenue and expense related to the rate true-ups immediately following the annual FERC filings. Any portion of the true-ups applicable to an affiliated company is recorded as Accounts Receivable - Affiliated Companies or Accounts Payable - Affiliated Companies on the balance sheets. Any portion of the true-ups applicable to third parties is recorded as Regulatory Assets or Regulatory Liabilities on the balance sheets.

Most of the power produced at KPCo's generation plants is sold to PJM. KPCo purchases power from PJM to supply power to its customers. Generally, these power sales and purchases are reported on a net basis in revenues on the statements of income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on the statements of income.

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

In general, KPCo records expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting. KPCo defers the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

KPCo engages in power marketing as a major power producer and participant in electricity markets. KPCo also engages in power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity risk management activities focused on markets where the AEP System owns assets and adjacent markets. These activities include the purchase-and-sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

KPCo recognizes revenues from marketing and risk management transactions that are not derivatives as the performance obligation of delivering the commodity is satisfied. Expenses from marketing and risk management transactions that are not derivatives are also recognized upon delivery of the commodity.

KPCo uses MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. The realized gains and losses on marketing and risk management transactions are included in revenues or expense based on the transaction's facts and circumstances. The unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). In the event KPCo designates a cash flow hedge, the cash flow hedge's gain or loss is initially recorded as a component of AOCI. When the forecasted transaction is realized and affects net income, KPCo subsequently reclassifies the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on the statements of income. See "Accounting for Cash Flow Hedging Strategies" section of Note 8.

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. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled. KPCo revalued deferred tax assets and liabilities at the new federal corporate income tax rate of 21% in December 2017. See Note 10 for additional information related to Tax Reform.

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.

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

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

Excise Taxes

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

Debt

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

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The net amortization expense is included in Interest Expense on the statements of income.

Pension and OPEB Plans

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

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

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

OPEB Plans Assets	**Target**
Equity	49%
Fixed Income	49%
Cash and Cash Equivalents	2%

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law.

For equity investments, the concentration limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% and 7% for pension and OPEB investments, respectively, of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, each investment manager's portfolio is compared to investment grade, diversified long and intermediate benchmark indices.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and opportunistic 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.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2018 and 2017, the fair value of securities on loan as part of the program was \$240.7 million and \$491.8 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2018 and 2017.

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 non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Earnings Per Share (EPS)

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

Supplementary Income Statement Information

The following table provides the components of Depreciation and Amortization for the years ended December 31, 2018 and 2017:

Depreciation and Amortization	Years Ended December 31, 2018	2017
	(in thousands)	
Depreciation and Amortization of Property, Plant and Equipment	$ 89,798	$ 85,030
Amortization of Regulatory Assets and Liabilities	7,972	2,974
Total Depreciation and Amortization	$ 97,770	$ 88,004

Subsequent Events

Management reviewed subsequent events through February 21, 2019, the date that KPCo's 2018 annual report was available to be issued.

2. NEW ACCOUNTING PRONOUNCEMENTS

During FASB's standard-setting process and upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to KPCo's business. The following pronouncements will impact the financial statements.

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

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

Management adopted ASU 2014-09 effective January 1, 2018, by means of the modified retrospective approach for all contracts within the scope of the new standard. The adoption of ASU 2014-09 did not have a material impact on results of operations, financial position or cash flows. In that regard, the application of the new standard did not cause any significant differences in any individual financial statement line items had those line items been presented in accordance with the guidance that was in effect prior to the adoption of the new standard. Further, given the lack of material impact to the financial statements, the adoption of the new standard did not give rise to any material changes in KPCo's previously established accounting policies for revenue. See Note 16 - Revenue from Contracts with Customers for additional disclosures required by the new standard.

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

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

New leasing standard implementation activities included the identification of the lease population within the AEP System as well as the sampling of representative lease contracts to analyze accounting treatment under the new accounting guidance. Based upon the completed assessments, management also prepared a gap analysis to outline new disclosure compliance requirements.

Management adopted ASU 2016-02 effective January 1, 2019 by means of a cumulative-effect adjustment to the balance sheet. Management elected the following practical expedients upon adoption:

Practical Expedient	Description
Overall Expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to reassess whether any expired or existing contracts are/or contain leases, do not need to reassess the lease classification for any expired or existing leases and do not need to reassess initial direct costs for any existing leases.
Lease and Non-lease Components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component.
Short-term Lease (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases.
Existing and expired land easements not previously accounted for as leases	Elect optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840.
Cumulative-effect adjustment in the period of adoption	Elect the optional transition practical expedient to adopt the new lease requirements through a cumulative-effect adjustment on the balance sheet in the period of adoption.

Management concluded that the result of adoption would not materially change the volume of contracts that qualify as leases going forward. The adoption of the new standard did not materially impact results of operations or cash flows, but did have a material impact on the balance sheet. The impact to the balance sheet has been estimated for the first quarter of 2019 as $9.6 million.

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

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

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

ASU 2017-07 "Compensation - Retirement Benefits" (ASU 2017-07)

In March 2017, the FASB issued ASU 2017-07 requiring that an employer report the service cost component of pension and postretirement benefits in the same line item or items as other compensation costs. The other components of net benefit cost are required to be presented on the statements of income separately from the service cost component and outside of a subtotal of income from operations. In addition, only the service cost component is eligible for capitalization as applicable following labor.

Management adopted ASU 2017-07 effective January 1, 2018. Presentation of the non-service components on a separate line outside of operating income was applied on a retrospective basis, using the amounts disclosed in the benefit plan note for the estimation basis as a practical expedient. Capitalization of only the service cost component was applied on a prospective basis.

ASU 2017-12 "Derivatives and Hedging" (ASU 2017-12)

In August 2017, the FASB issued ASU 2017-12 amending the recognition and presentation requirements for hedge accounting activities. The objectives of the new standard are to improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements and to reduce the complexity of applying hedge accounting. Among other things, ASU 2017-12: (a) expands the types of transactions eligible for hedge accounting, (b) eliminates the separate measurement and presentation of hedge ineffectiveness, (c) simplifies the requirements for assessments of hedge effectiveness, (d) provides companies more time to finalize hedge documentation and (e) enhances presentation and disclosure requirements.

Management early adopted ASU 2017-12 in the second quarter of 2018, effective January 1, 2018, by means of a modified retrospective approach. The adoption of ASU 2017-12 did not have an impact on results of operations, financial position or cash flows. The adoption of the new standard did not give rise to any material changes to KPCo's previously established accounting policies for derivatives and hedging.

ASU 2018-02 "Reclassification of Certain Tax Effects from AOCI" (ASU 2018-02)

In February 2018, the FASB issued ASU 2018-02 allowing a reclassification from AOCI to Retained Earnings for stranded tax effects resulting from Tax Reform. The accounting guidance for "Income Taxes" requires deferred tax assets and liabilities to be adjusted for the effect of a change in tax law or rates with the effect included in income from continuing operations in the reporting period that includes the enactment date of the tax change. This guidance is applicable for the tax effects of items in AOCI that were originally recognized in Other Comprehensive Income. As a result, and absent the new guidance in this ASU, the tax effects of items within AOCI would not reflect the newly enacted corporate tax rate.

Management adopted ASU 2018-02 effective January 1, 2018, electing to reclassify the effects of the change in the federal corporate tax rate due to Tax Reform from AOCI to Retained Earnings. A portion of the reclassification was recorded to Regulatory Liabilities to adjust the tax effects of certain interest rate hedges in KPCo's regulated jurisdictions that were previously deferred as a part of the accounting for Tax Reform. There were no other effects from Tax Reform that impacted AOCI. Management applied the new guidance at the beginning of the period of adoption. The adoption of the new standard did not have a material impact on the statement of financial position and did not impact results of operations or cash flows.

ASU 2018-14 "Disclosure Framework: Changes to the Disclosure Requirements for Defined Benefit Plans" (ASU 2018-14)

In August 2018, the FASB issued ASU 2018-14 modifying the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The amendments in this Update to Subtopic 715-20 remove disclosures that no longer are considered cost beneficial, clarify the specific requirements of disclosures and add disclosure requirements identified as relevant.

Management early adopted ASU 2018-14 for the 2018 Annual Report and applied the new standard retrospectively for all periods presented. As a result of adoption, KPCo's disclosures were updated as follows:

- Amended the disclosure to remove the amounts in AOCI expected to be recognized as components of net periodic benefit cost over the next fiscal year.
- Amended the disclosure to remove the effects of a one-percentage-point change in assumed health care cost trend rates on the (a) aggregate of the service and interest cost components of net periodic benefit costs and (b) benefit obligation for postretirement health care benefits.
- Amended the disclosure to include the weighted-average interest crediting rates for cash balance plans and other plans with promised interest crediting rates.
- Amended the disclosure to include an explanation of the reasons for significant gains and losses related to changes in the benefit obligation for the period.

See Note 7 - Benefit Plans for updates to the disclosures required by the new standard.

ASU 2018-15 "Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract" (ASU 2018-15)

In August 2018, the FASB issued ASU 2018-15 aligning the requirements for capitalizing implementation costs incurred in a cloud computing arrangement (hosting arrangement) that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The new standard requires an entity (customer) in a hosting arrangement that is a service contract to follow the accounting guidance for "Internal-Use Software" to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. To eliminate diversity in practice, the new standard changes the presentation of implementation costs for cloud service arrangements that are service contracts without the purchase of a license. Implementation costs for cloud service contracts will be presented on the balance sheets in the same manner as a prepayment. KPCo currently presents implementation costs in property, plant and equipment on the balance sheets. Under the new standard, amortization of capitalized implementation costs of a hosting arrangement will be recorded in Operation and Maintenance expense over the term of the cloud service arrangement, rather than Depreciation and Amortization expense on the statements of income. Payments for capitalized implementation costs in the statement of cash flows will be classified in the same manner as payments made for fees associated with the hosting element.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2020, with early adoption permitted. The amendments may be applied either retrospectively or prospectively to applicable implementation costs incurred after the date of adoption. Management is analyzing the impact of this new standard and at this time, cannot estimate the impact of adoption on results of operations, financial position or cash flows. Management plans to adopt ASU 2018-15 prospectively, effective January 1, 2020.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2018 and 2017. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 - Benefit Plans for additional details.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

	Pension and OPEB		
	Amortization of Deferred Costs	Changes in Funded Status	Total
	(in thousands)		
Balance in AOCI as of December 31, 2017	$ 3,260	$ (2,998)	$ 262
Change in Fair Value Recognized in AOCI	—	(441)	(441)
Amount of (Gain) Loss Reclassified from AOCI			
Amortization of Prior Service Cost (Credit)	(224)	—	(224)
Amortization of Actuarial (Gains) Losses	111	—	111
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(113)	—	(113)
Income Tax (Expense) Benefit	(24)	—	(24)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(89)	—	(89)
Net Current Period Other Comprehensive Income (Loss)	(89)	(441)	(530)
ASU 2018-02 Adoption (b)	—	56	56
Balance in AOCI as of December 31, 2018	$ 3,171	$ (3,383)	$ (212)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

		Pension and OPEB		
	Cash Flow Hedge - Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in thousands)		
Balance in AOCI as of December 31, 2016	$ (41)	$ 3,229	$ (4,542)	$ (1,354)
Change in Fair Value Recognized in AOCI	—	—	1,544	1,544
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	62	—	—	62
Amortization of Prior Service Cost (Credit)	—	(222)	—	(222)
Amortization of Actuarial (Gains) Losses	—	270	—	270
Reclassifications from AOCI, before Income Tax (Expense) Benefit	62	48	—	110
Income Tax (Expense) Benefit	21	17	—	38
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	41	31	—	72
Net Current Period Other Comprehensive Income (Loss)	41	31	1,544	1,616
Balance in AOCI as of December 31, 2017	$ —	$ 3,260	$ (2,998)	$ 262

(a) Amounts reclassified to the referenced line item on the statements of income.
(b) See Note 2 - New Accounting Pronouncements for additional information.

4. RATE MATTERS

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

2017 Kentucky Base Rate Case

In January 2018, the KPSC issued an order approving a non-unanimous settlement agreement with certain modifications resulting in an annual revenue increase of $12 million, effective January 2018, based on a 9.7% return on equity. The KPSC's primary revenue requirement modification to the settlement agreement was a $14 million annual revenue reduction for the decrease in the corporate federal income tax rate due to Tax Reform. The KPSC approved: (a) the deferral of a total of $50 million of Rockport Plant Unit Power Agreement expenses for the years 2018 through 2022, with the manner and timing of recovery of the deferral to be addressed in KPCo's next base rate case, (b) the recovery/return of 80% of certain annual PJM OATT expenses above/below the corresponding level recovered in base rates, (c) KPCo's commitment to not file a base rate case for three years with rates effective no earlier than 2021 and (d) increased depreciation expense based upon updated Big Sandy Plant, Unit 1 depreciation rates using a 20-year depreciable life.

In February 2018, KPCo filed with the KPSC for rehearing of the January 2018 base case order. In June 2018, the KPSC issued an order approving an additional revenue increase of $765 thousand related to the calculation of federal income tax expense. This rate increase was effective June, 2018.

Kentucky Tax Reform

In June 2018, the KPSC issued an order approving a settlement agreement between KPCo and an intervenor that stipulates that KPCo will refund an estimated $82 million of Excess ADIT associated with certain depreciable property using the Average Rate Assumption Method (ARAM) and an estimated $93 million of Excess Accumulated Deferred Income Tax that is not subject to rate normalization requirements over 18 years. The refund was effective July 1, 2018.

PJM Transmission Rates

In 2016, PJM transmission owners, including KPCo and various state commissions filed a settlement agreement at the FERC to resolve outstanding issues related to cost responsibility for charges to transmission customers for certain transmission facilities that operate at or above 500 kV. In May 2018, the FERC approved the settlement agreement. PJM implemented a transmission enhancement charge adjustment through the PJM OATT, which will be billable through 2025. Management expects that any refunds received would generally be returned to retail customers through existing state rider mechanisms and has recorded $5.6 million to Customer Accounts Receivable and $3.9 million to Deferred Charges and Other Noncurrent Assets, with offsets to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018.

FERC Transmission Complaint

In 2016, seven parties filed a complaint at the FERC that alleged the base return on common equity used by AEP's transmission owning subsidiaries within PJM, including KPCo, in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In 2017, a FERC order set the matter for hearing and settlement procedures. In March 2018, AEP's transmission owning subsidiaries within PJM, including KPCo, and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). If approved by the FERC, the settlement agreement: (a) establishes a base return on equity for AEP's transmission owning subsidiaries within PJM of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%), effective January 1, 2018, (b) requires AEP's transmission owning subsidiaries within PJM to provide a one-time refund of $50 million, attributable from the date of the complaint through December 31, 2017, which was credited to customer bills in the second quarter of 2018 and (c) increases the cap on the equity portion of the capital structure to 55% from 50%. As part of the settlement agreement, AEP's transmission owning subsidiaries within PJM, including KPCo, also filed updated transmission formula rates incorporating the reduction in the corporate federal income tax rate due to Tax Reform, effective January 1, 2018 and providing for the amortization of the portion of the

Excess ADIT that is not subject to the normalization method of accounting, ratably over a ten-year period through credits to the federal income tax expense component of the revenue requirement. In April 2018, an administrative law judge accepted the interim settlement rates, which included the $50 million one-time refund that occurred in the second quarter of 2018. These interim rates are subject to refund or surcharge, with interest.

In April 2018, certain intervenors filed comments at the FERC recommending a base ROE of 8.48% and a one-time refund of $184 million. The FERC trial staff filed comments recommending a base ROE of 8.41% and one-time refund of $175 million. Another intervenor recommended the refund be calculated in accordance with the base ROE that will ultimately be approved by the FERC. In May 2018, management filed reply comments providing further support for the 9.85% base ROE agreed to in the settlement agreement. In February 2019, the FERC issued an order that neither approved or denied the settlement and directed the parties to file additional information.

If the FERC orders revenue reductions in excess of the terms of the settlement agreement, it could reduce future net income and cash flows and impact financial condition.

Modifications to PJM Transmission Rates

In 2016, AEP's transmission owning subsidiaries within PJM, including KPCo, filed an application at the FERC to modify the PJM OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. The modified PJM OATT formula rates are based on projected calendar year financial activity and projected plant balances. In 2017, AEP's transmission owning subsidiaries within PJM filed an uncontested settlement agreement with the FERC resolving all outstanding issues. In April 2018, the FERC approved the uncontested settlement agreement and rates were implemented effective January 1, 2018.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2018	2017	Remaining Recovery Period
	(in thousands)		
Current Regulatory Assets			
Under-recovered Fuel Costs - does not earn a return	$ 2,379	$ 82	1 year
Total Current Regulatory Assets	$ 2,379	$ 82	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Kentucky Deferred Purchased Power Expenses	$ 14,477	$ —	
Total Regulatory Assets Currently Earning a Return	14,477	—	
Regulatory Assets Currently Not Earning a Return			
Other Regulatory Assets Pending Final Regulatory Approval	1,148	50	
Total Regulatory Assets Currently Not Earning a Return	1,148	50	
Total Regulatory Assets Pending Final Regulatory Approval	15,625	50	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs	210,123	212,466	22 years
Plant Retirement Costs - Asset Retirement Obligation Costs	64,332	34,334	22 years
Plant Retirement Costs - Materials and Supplies	3,016	3,555	22 years
Asset Removal Costs	—	1,192	(a)
Other Regulatory Assets Approved for Recovery	1,049	1,104	various
Total Regulatory Assets Currently Earning a Return	278,520	252,651	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	46,613	39,431	12 years
Plant Retirement Costs - Asset Retirement Obligation Costs	28,707	37,165	22 years
Storm Related Costs	8,366	10,450	5 years
Environmental Costs	4,644	6,032	2 years
Postemployment Benefits	2,809	2,547	4 years
Other Regulatory Assets Approved for Recovery	6,461	5,242	various
Total Regulatory Assets Currently Not Earning a Return	97,600	100,867	
Total Regulatory Assets Approved for Recovery	376,120	353,518	
Total Noncurrent Regulatory Assets	$ 391,745	$ 353,568	

(a) As a regulated entity, removal costs accrued are typically recorded as regulatory liabilities when revenue received for removal costs accrued exceeds actual removal costs incurred. The asset removal costs liability is relieved as removal costs are incurred. As of December 31, 2017, KPCo's accumulated actual removal cost incurred exceeded accumulated removal cost accrued, creating an asset balance. As a result, the balance was reclassified to a regulatory asset.

Regulatory Liabilities:	December 31, 2018	December 31, 2017	Remaining Refund Period
	(in thousands)		
Current Regulatory Liability			
Over-recovered Fuel Costs - does not pay a return	$ —	$ 567	
Total Current Regulatory Liabilities	$ —	$ 567	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ 1,465	$ 145,986	
Excess ADIT that is Not Subject to Rate Normalization Requirements	—	122,448	
Total Regulatory Liabilities Pending Final Regulatory Determination	1,465	268,434	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	10,265	—	(b)
Total Regulatory Liabilities Currently Paying a Return	10,265	—	
Regulatory Liabilities Currently Not Paying a Return			
PJM Transmission Enhancement Refund	7,615	—	7 years
Unrealized Gain on Forward Commitments	4,085	191	6 years
Purchased Power Adjustment Rider	3,864	—	2 year
Other Regulatory Liabilities Approved for Payment	2,280	432	various
Total Regulatory Liabilities Currently Not Paying a Return	17,844	623	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	134,360	—	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	135,911	—	18 years
Income Taxes Subject to Flow Through	(144,163)	(138,895)	22 years
Total Income Tax Related Regulatory Liabilities	126,108	(138,895)	
Total Regulatory Liabilities Approved for Payment	154,217	(138,272)	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 155,682	$ 130,162	

(a) This balance primarily represents regulatory liabilities for excess accumulated deferred income taxes (Excess ADIT) as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 10 for additional information.

(b) As a regulated entity, removal costs accrued are typically recorded as regulatory liabilities when revenue received for removal costs accrued exceeds actual removal costs incurred. As of December 31, 2017, KPCo's accumulated actual removal cost incurred exceeded accumulated removal cost accrued, creating an asset balance. As a result, the balance was reclassified to a regulatory asset.

(c) Refunded using Average Rate Assumption Method.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

COMMITMENTS

KPCo has substantial commitments to support its business. KPCo purchases fuel, energy and capacity contracts as part of its normal course of business. Certain contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following table summarizes KPCo's actual contractual commitments as of December 31, 2018:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 135,783	$ 109,332	$ 57,766	$ 50,676	$ 353,557
Energy and Capacity Purchase Contracts	41,955	88,353	45,615	—	175,923
Total	$ 177,738	$ 197,685	$ 103,381	$ 50,676	$ 529,480

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

GUARANTEES

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

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, 2018, there were no material liabilities recorded for any indemnifications.

AEPSC conducts power purchase and sale activity on behalf of APCo, I&M, KPCo and WPCo, who are jointly and severally liable for activity conducted on their behalf.

Lease Obligations

KPCo leases certain equipment under master lease agreements. See "Master Lease Agreements" section of Note 11 for additional information.

CONTINGENCIES

Insurance and Potential Losses

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

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cyber security incident. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

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

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

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2018, 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 non-hazardous. 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. As of December 31, 2018, management's estimates do not anticipate material clean-up costs for the identified site.

7. BENEFIT PLANS

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

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

KPCo recognizes its funded status associated with defined benefit pension and OPEB plans on its balance sheets. Disclosures about the plans are required by the "Compensation - Retirement Benefits" accounting guidance. KPCo recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status and recognizes, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. KPCo records a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		OPEB	
	December 31,			
Assumptions	**2018**	**2017**	**2018**	**2017**
Discount Rate	4.30%	3.65%	4.30%	3.60%
Interest Crediting Rate	4.00%	4.00%	NA	NA
Rate of Compensation Increase	4.50% (a)	4.45% (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 2018, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 12% per year, with an average increase of 4.5%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans		OPEB	
	Year Ended December 31,			
Assumptions	**2018**	**2017**	**2018**	**2017**
Discount Rate	3.65%	4.05%	3.60%	4.10%
Interest Crediting Rate	4.00%	4.00%	NA	NA
Expected Return on Plan Assets	6.00%	6.00%	6.00%	6.75%
Rate of Compensation Increase	4.50% (a)	4.45% (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.

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

The health care trend rate assumptions used for OPEB plans measurement purposes are shown below:

	December 31,	
Health Care Trend Rates	**2018**	**2017**
Initial	6.25%	6.50%
Ultimate	5.00%	5.00%
Year Ultimate Reached	2024	2024

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, 2018, 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

For the year ended December 31, 2018, the pension and OPEB plans had an actuarial gain due to an increase in the discount rate as well as updated estimates for future medical expenses in the OPEB plans. For the year ended December 31, 2017, the pension plans had an actuarial loss due to a decrease in the discount rate. The OPEB plans had an actuarial gain primarily due to a change in medical benefits for retirees which was partially offset by a decrease in the discount rate. The following table provides a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		OPEB	
	2018	2017	2018	2017
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1,	$ 185,395	$ 180,736	$ 48,362	$ 51,849
Service Cost	2,812	2,916	328	332
Interest Cost	6,745	7,148	1,726	2,158
Actuarial (Gain) Loss	(10,039)	4,482	(2,885)	(2,488)
Benefit Payments	(11,538)	(9,887)	(5,184)	(4,962)
Participant Contributions	—	—	1,381	1,457
Medicare Subsidy	—	—	15	16
Benefit Obligation as of December 31,	$ 173,375	$ 185,395	$ 43,743	$ 48,362
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 188,876	$ 174,047	$ 66,524	$ 57,740
Actual Gain (Loss) on Plan Assets	(3,701)	22,490	(3,484)	12,289
Company Contributions	—	2,226	1	—
Participant Contributions	—	—	1,381	1,457
Benefit Payments	(11,538)	(9,887)	(5,184)	(4,962)
Fair Value of Plan Assets as of December 31,	$ 173,637	$ 188,876	$ 59,238	$ 66,524
Funded Status as of December 31,	$ 262	$ 3,481	$ 15,495	$ 18,162

Amounts Recognized on the Balance Sheets

	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
	(in thousands)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 324	$ 3,558	$ 15,495	$ 18,162
Other Current Liabilities – Accrued Short-term Benefit Liability	(1)	—	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(61)	(77)	—	—
Funded Status	$ 262	$ 3,481	$ 15,495	$ 18,162

Amounts Included in Regulatory Assets, Deferred Income Taxes, AOCI and Income Tax Expense

The following table shows the components of the plans included in Regulatory Assets, Deferred Income Taxes, AOCI and Income Tax Expense:

	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
Components	(in thousands)			
Net Actuarial Loss	$ 46,316	$ 45,067	$ 12,949	$ 8,770
Prior Service Cost (Credit)	—	1	(12,384)	(14,808)
Recorded as				
Regulatory Assets	$ 44,992	$ 43,564	$ 1,621	$ (4,133)
Deferred Income Taxes	278	316	(222)	(400)
Net of Tax AOCI	1,046	977	(834)	(1,239)
Income Tax Expense (a)	—	211	—	(266)

(a) Amounts relate to the re-measurement of Deferred Income Taxes as a result of Tax Reform. In accordance with the accounting guidance for "Income Taxes", re-measurement of Deferred Income Taxes related to AOCI must flow through the statement of income.

Components of the change in amounts included in Regulatory Assets, Deferred Income Taxes, AOCI and Income Tax Expense were as follows:

	Pension Plans		OPEB	
	2018	2017	2018	2017
Components	(in thousands)			
Actuarial (Gain) Loss During the Year	$ 4,268	$ (7,708)	$ 4,541	$ (10,937)
Amortization of Actuarial Loss	(3,019)	(2,878)	(362)	(1,391)
Amortization of Prior Service Credit (Cost)	(1)	(47)	2,424	2,425
Change for the Year Ended December 31,	$ 1,248	$ (10,633)	$ 6,603	$ (9,903)

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.

Pension and OPEB Assets

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

Pension Plan		OPEB	
December 31,			
2018	2017	2018	2017
3.7%	3.7%	3.9%	3.8%

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2018:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 277.3	$ —	$ —	$ —	$ 277.3	5.9%
International	384.1	—	—	—	384.1	8.2%
Options	—	18.3	—	—	18.3	0.4%
Common Collective Trusts (c)	—	—	—	370.1	370.1	7.9%
Subtotal – Equities	661.4	18.3	—	370.1	1,049.8	22.4%
Fixed Income (a):						
United States Government and Agency Securities	0.2	1,512.5	—	—	1,512.7	32.2%
Corporate Debt	—	1,082.9	—	—	1,082.9	23.0%
Foreign Debt	—	221.6	—	—	221.6	4.7%
State and Local Government	—	28.2	—	—	28.2	0.6%
Other – Asset Backed	—	7.4	—	—	7.4	0.2%
Subtotal – Fixed Income	0.2	2,852.6	—	—	2,852.8	60.7%
Infrastructure (c)	—	—	—	72.2	72.2	1.5%
Real Estate (c)	—	—	—	220.4	220.4	4.7%
Alternative Investments (c)	—	—	—	444.6	444.6	9.5%
Cash and Cash Equivalents (c)	(0.4)	36.3	—	11.9	47.8	1.0%
Other – Pending Transactions and Accrued Income (b)	—	—	—	8.3	8.3	0.2%
Total	$ 661.2	$ 2,907.2	$ —	$ 1,127.5	$ 4,695.9	100.0%

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2018:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 233.3	$ —	$ —	$ —	$ 233.3	15.2 %
International	185.9	—	—	—	185.9	12.1 %
Options	—	4.3	—	—	4.3	0.3 %
Common Collective Trusts (b)	—	—	—	226.2	226.2	14.7 %
Subtotal – Equities	419.2	4.3	—	226.2	649.7	42.3 %
Fixed Income:						
Common Collective Trust Debt (b)	—	—	—	163.6	163.6	10.7 %
United States Government and Agency Securities	0.2	181.5	—	—	181.7	11.8 %
Corporate Debt	—	188.6	—	—	188.6	12.3 %
Foreign Debt	—	35.0	—	—	35.0	2.3 %
State and Local Government	41.8	11.8	—	—	53.6	3.5 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.0	417.1	—	163.6	622.7	40.6 %
Trust Owned Life Insurance:						
International Equities	—	49.4	—	—	49.4	3.2 %
United States Bonds	—	154.4	—	—	154.4	10.1 %
Subtotal – Trust Owned Life Insurance	—	203.8	—	—	203.8	13.3 %
Cash and Cash Equivalents (b)	54.4	—	—	4.8	59.2	3.9 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(1.2)	(1.2)	(0.1)%
Total	$ 515.6	$ 625.2	$ —	$ 393.4	$ 1,534.2	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2017:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 318.6	$ —	$ —	$ —	$ 318.6	6.2%
International	507.7	—	—	—	507.7	9.8%
Options	—	26.9	—	—	26.9	0.5%
Common Collective Trusts (c)	—	—	—	452.9	452.9	8.7%
Subtotal – Equities	826.3	26.9	—	452.9	1,306.1	25.2%
Fixed Income (a):						
United States Government and Agency Securities	—	1,376.5	—	—	1,376.5	26.6%
Corporate Debt	—	1,277.0	—	—	1,277.0	24.7%
Foreign Debt	—	296.9	—	—	296.9	5.7%
State and Local Government	—	31.7	—	—	31.7	0.6%
Other – Asset Backed	—	10.2	—	—	10.2	0.2%
Subtotal – Fixed Income	—	2,992.3	—	—	2,992.3	57.8%
Infrastructure (c)	—	—	—	59.5	59.5	1.2%
Real Estate (c)	—	—	—	290.3	290.3	5.6%
Alternative Investments (c)	—	—	—	446.0	446.0	8.6%
Cash and Cash Equivalents (c)	0.4	35.6	—	21.2	57.2	1.1%
Other – Pending Transactions and Accrued Income (b)	—	—	—	22.7	22.7	0.5%
Total	$ 826.7	$ 3,054.8	$ —	$ 1,292.6	$ 5,174.1	100.0%

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

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

	Infrastructure	Real Estate	Alternative Investments	Total Level 3
		(in millions)		
Balance as of January 1, 2017	$ 57.6	$ 254.9	$ 411.1	$ 723.6
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	—	—	—	—
Relating to Assets Sold During the Period	—	—	—	—
Purchases and Sales	—	—	—	—
Transfers into Level 3	—	—	—	—
Transfers out of Level 3 (a)	(57.6)	(254.9)	(411.1)	(723.6)
Balance as of December 31, 2017	$ —	$ —	$ —	$ —

(a) The classification of Level 3 assets from the prior year was corrected in the current year presentation and included within the fair value hierarchy table as of December 31, 2017 as "Other" investments for which fair value is measured using net asset value per share in accordance with ASU 2015-07, Disclosure for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent). Management concluded that these disclosure errors were immaterial individually and in the aggregate to all prior periods presented.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2017:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 307.1	$ —	$ —	$ —	$ 307.1	17.7 %
International	306.9	—	—	—	306.9	17.7 %
Options	—	9.4	—	—	9.4	0.5 %
Common Collective Trusts (b)	—	—	—	153.6	153.6	8.9 %
Subtotal – Equities	614.0	9.4	—	153.6	777.0	44.8 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	185.0	185.0	10.7 %
United States Government and Agency Securities	—	187.4	—	—	187.4	10.8 %
Corporate Debt	—	214.1	—	—	214.1	12.4 %
Foreign Debt	—	40.7	—	—	40.7	2.4 %
State and Local Government	49.7	16.8	—	—	66.5	3.8 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	49.7	459.2	—	185.0	693.9	40.1 %
Trust Owned Life Insurance:						
International Equities	—	105.4	—	—	105.4	6.1 %
United States Bonds	—	118.2	—	—	118.2	6.8 %
Subtotal – Trust Owned Life Insurance	—	223.6	—	—	223.6	12.9 %
Cash and Cash Equivalents (b)	36.7	—	—	4.2	40.9	2.4 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(2.9)	(2.9)	(0.2)%
Total	$ 700.4	$ 692.2	$ —	$ 339.9	$ 1,732.5	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

Accumulated Benefit Obligation

The accumulated benefit obligation for the pension plans is as follows:

	December 31, 2018	December 31, 2017
	(in thousands)	
Qualified Pension Plan	$ 167,534	$ 179,162
Nonqualified Pension Plan	12	33
Total Accumulated Benefit Obligation	$ 167,546	$ 179,195

Obligations in Excess of Fair Values

The tables below show the underfunded pension plans that had obligations in excess of plan assets.

Projected Benefit Obligation

	Underfunded Pension Plans December 31,	
	2018	2017
	(in thousands)	
Projected Benefit Obligation	$ 62	$ 77
Fair Value of Plan Assets	—	—
Underfunded Projected Benefit Obligation	$ (62)	$ (77)

Accumulated Benefit Obligation

	Underfunded Pension Plans December 31,	
	2018	2017
	(in thousands)	
Accumulated Benefit Obligation	$ 12	$ 33
Fair Value of Plan Assets	—	—
Underfunded Accumulated Benefit Obligation	$ (12)	$ (33)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the pension and OPEB plans of $3.1 million and $47 thousand, respectively, during 2019. The estimated contributions to the pension trust are at least the minimum amount required by the Employee Retirement Income Security Act and additional discretionary contributions may also be made to maintain the funded status of the plan.

The table below reflects the total benefits expected to be paid from the plan or from KPCo's assets. The payments include the participants' contributions to the plan for their share of the cost. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Estimated Payments	
	Pension Plans	OPEB
	(in thousands)	
2019	$ 11,707	$ 4,705
2020	11,425	4,849
2021	11,384	4,906
2022	11,785	4,858
2023	11,876	4,730
Years 2024 to 2028, in Total	64,066	22,238

Components of Net Periodic Benefit Cost

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

	Pension Plans		OPEB	
	Years Ended December 31,			
	2018	2017	2018	2017
	(in thousands)			
Service Cost	$ 2,812	$ 2,916	$ 328	$ 332
Interest Cost	6,745	7,148	1,726	2,158
Expected Return on Plan Assets	(10,605)	(10,299)	(3,944)	(3,840)
Amortization of Prior Service Cost (Credit)	1	47	(2,424)	(2,425)
Amortization of Net Actuarial Loss	3,019	2,878	362	1,391
Net Periodic Benefit Cost (Credit)	1,972	2,690	(3,952)	(2,384)
Capitalized Portion	(1,069)	(893)	(125)	791
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 903	$ 1,797	$ (4,077)	$ (1,593)

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 2018 and $2.4 million in 2017.

8. DERIVATIVES AND HEDGING

KPCo adopted ASU 2017-12 in the second quarter of 2018, effective January 1, 2018. See Note 2 - New Accounting Pronouncements for additional information.

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of KPCo.

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

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

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

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2018	Volume December 31, 2017	Unit of Measure
	(in thousands)		
Commodity:			
Power	12,140	10,812	MWhs
Natural Gas	698	206	MMBtus
Heating Oil and Gasoline	329	52	Gallons

Cash Flow Hedging Strategies

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

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

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON KPCo's FINANCIAL STATEMENTS

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

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2018 and 2017 balance sheets, KPCo netted $227 thousand and $379 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $117 thousand and $589 thousand, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value of KPCo's derivative activity on the balance sheets:

Fair Value of Derivative Instruments
December 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in thousands)	
Current Risk Management Assets	$ 15,430	$ (9,708)	$ 5,722
Long-term Risk Management Assets	546	(387)	159
Total Assets	15,976	(10,095)	5,881
Current Risk Management Liabilities	9,694	(9,599)	95
Long-term Risk Management Liabilities	430	(386)	44
Total Liabilities	10,124	(9,985)	139
Total MTM Derivative Contract Net Assets	$ 5,852	$ (110)	$ 5,742

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in thousands)	
Current Risk Management Assets	$ 12,043	$ (10,192)	$ 1,851
Long-term Risk Management Assets	469	(266)	203
Total Assets	12,512	(10,458)	2,054
Current Risk Management Liabilities	10,831	(10,429)	402
Long-term Risk Management Liabilities	275	(239)	36
Total Liabilities	11,106	(10,668)	438
Total MTM Derivative Contract Net Assets	$ 1,406	$ 210	$ 1,616

(a) Derivative instruments within this category 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) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.

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

Amount of Gain (Loss) Recognized on
Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2018	2017
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ (530)	$ 78
Other Operation	58	24
Maintenance	79	25
Purchased Electricity for Resale	140	3,065
Regulatory Assets (a)	(155)	(174)
Regulatory Liabilities (a)	12,090	510
Total Gain on Risk Management Contracts	$ 11,682	$ 3,528

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

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

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

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

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 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.

Realized gains and losses on derivative contracts for the purchase-and-sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on KPCo's statements of income or in Regulatory Assets or Regulatory Liabilities on KPCo's balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2018 and 2017 KPCo did not apply cash flow hedging to outstanding power derivatives.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on its balance sheets into Interest Expense on its statements of income in those periods in which hedged interest payments occur. During the years ended 2018 and 2017, KPCo did not apply cash flow hedging to outstanding interest rate derivatives.

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

There was no impact of cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets as of December 31, 2018 and 2017.

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, 2018, KPCo is not hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions.

Credit Risk

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

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

Collateral Triggering Events

Credit Downgrade Triggers

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. KPCo has not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. As of December 31, 2018 and 2017, KPCo did not have derivative contracts with collateral triggering events in a net liability position.

Cross-Default Triggers

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

	December 31,	
	2018	2017
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 165	$ 120
Additional Settlement Liability if Cross Default Provision is Triggered	4	104

9. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

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

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

	December 31,			
	2018		2017	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 867,128	$ 903,690	$ 867,188	$ 976,163

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Assets:					
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 23	$ 10,083	$ 5,867	$ (10,092)	$ 5,881
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 34	$ 10,024	$ 63	$ (9,982)	$ 139

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Assets:					
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 10,440	$ 2,000	$ (10,386)	$ 2,054
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 10,847	$ 187	$ (10,596)	$ 438

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the years ended December 31, 2018 and 2017.

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

Year Ended December 31, 2018	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2017	$ 1,813
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	6,645
Settlements	(8,312)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	5,658
Balance as of December 31, 2018	$ 5,804

Year Ended December 31, 2017	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2016	$ 198
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	2,298
Settlements	(2,543)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	1,860
Balance as of December 31, 2017	$ 1,813

(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) 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, 2018 and 2017:

Significant Unobservable Inputs
December 31, 2018

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 430	$ 63	Discounted Cash Flow	Forward Market Price	$ 16.82	$ 62.65	$ 37.00
FTRs	5,437	—	Discounted Cash Flow	Forward Market Price	0.05	6.21	1.62
Total	$ 5,867	$ 63					

Significant Unobservable Inputs
December 31, 2017

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 153	$ 86	Discounted Cash Flow	Forward Market Price	$ 20.52	$ 195.00	$ 33.80
FTRs	1,847	101	Discounted Cash Flow	Forward Market Price	(0.73)	5.75	0.66
Total	$ 2,000	$ 187					

(a) Represents market prices in dollars per MWh.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of December 31, 2018 and 2017:

Sensitivity of Fair Value Measurements

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

10. INCOME TAXES

Federal Tax Reform and Legislation

In December 2017, Tax Reform legislation was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, including lowering the corporate federal income tax rate from 35% to 21%. As a result of this rate change, KPCo's deferred tax assets and liabilities were remeasured using the newly enacted rate of 21% in December 2017. In response to Tax Reform, the SEC staff issued Staff Accounting Bulletin 118 (SAB 118) in December 2017. SAB 118 provided for up to a one year period (the measurement period) in which to complete the required analyses and accounting required by Tax Reform.

During 2017, KPCo recorded provisional amounts for the income tax effects of Tax Reform. Throughout 2018, KPCo continued to assess the impacts of legislative changes in the tax code as well as interpretative changes of the tax code. The measurement period adjustments recorded during 2018 were immaterial.

The measurement period under SAB 118 ended in December 2018. However, Tax Reform uncertainties still remain and KPCo will continue to monitor income tax effects that may change as a result of future legislation and further interpretation of Tax Reform based on proposed U.S. Treasury regulations and guidance from the IRS and state tax authorities.

Federal Legislation

The IRS has proposed new regulations that provide guidance regarding the additional first-year depreciation deduction under Section 168(k). The proposed regulations reflect changes as a result of Tax Reform and affect taxpayers with qualified depreciable property acquired and placed in service after September 27, 2017. Generally, KPCo's regulated businesses will not be eligible for any bonus depreciation for property acquired and placed in service after January 1, 2018. However, for self-constructed property and other property placed in service in 2018 for which construction began prior to January 1, 2018, taxpayers are required to evaluate the contractual terms to determine if these additions qualify for 100% expensing under Tax Reform or 50% bonus depreciation as provided under prior tax law.

Income Tax Expense

The details of KPCo's Income Tax Expense are as follows:

	Years Ended December 31, 2018	2017
	(in thousands)	
Federal:		
Current	$ 1,103	$ (11,578)
Deferred	3,777	34,826
Deferred Investment Tax Credits	—	(1)
Total Federal	4,880	23,247
State and Local:		
Current	(563)	50
Deferred	1,682	(5,747)
Total State and Local	1,119	(5,697)
Income Tax Expense	$ 5,999	$ 17,550

The following is a reconciliation between the federal income taxes computed by multiplying pretax income by the federal statutory tax rate and the income taxes reported:

	Years Ended December 31,	
	2018	2017
	(in thousands)	
Net Income	$ 63,146	$ 35,246
Income Tax Expense	5,999	17,550
Pretax Income	$ 69,145	$ 52,796
Income Taxes on Pretax Income at Statutory Rate (21% and 35% in 2018 and 2017, Respectively)	$ 14,520	$ 18,479
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Depreciation	2,600	2,981
AFUDC	(413)	(570)
Removal Costs	(1,079)	(2,032)
State and Local Income Taxes, Net	884	(3,703)
Tax Adjustments	—	1,608
Tax Reform	—	553
Tax Reform Excess ADIT Reversal	(10,456)	—
Other	(57)	234
Income Tax Expense	$ 5,999	$ 17,550
Effective Income Tax Rate	8.7 %	33.2 %

Net Deferred Tax Liability

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

	December 31,	
	2018	2017
	(in thousands)	
Deferred Tax Assets	$ 87,019	$ 97,831
Deferred Tax Liabilities	(489,089)	(492,617)
Net Deferred Tax Liabilities	$ (402,070)	$ (394,786)
Property Related Temporary Differences	$ (281,168)	$ (272,132)
Amounts Due to Customers for Future Federal Income Taxes	53,538	47,958
Deferred State Income Taxes (a)	(107,951)	(103,952)
Deferred Income Taxes on Other Comprehensive (Income)/Loss	56	(84)
Regulatory Assets	(74,806)	(71,118)
All Other, Net	8,261	4,542
Net Deferred Tax Liabilities	$ (402,070)	$ (394,786)

(a) In 2018, KPCo recorded a $16.8 million correction related to the accounting for the impact of Tax Reform in 2017. The correction resulted in a decrease in Net Deferred Tax Liabilities with an offsetting increase to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018. Management concluded the misstatement was not material to the 2017 financial statements or the financial statements of any of the interim periods in 2018.

AEP System Tax Allocation Agreement

KPCo joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The consolidated net operating loss of the AEP System is allocated to each company in the consolidated group with taxable losses. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the allocation of the consolidated AEP System net operating loss and the loss of the Parent and tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011 through 2013 started in April 2014. KPCo and other AEP subsidiaries received a Revenue Agents Report in April 2016, completing the 2011 through 2013 audit cycle indicating an agreed upon audit. The 2011 through 2013 audit was submitted to the Congressional Joint Committee on Taxation for approval. The Joint Committee referred the audit back to the IRS exam team for further consideration. To resolve the issue under consideration, KPCo and other AEP subsidiaries and the IRS exam team agreed to utilize the Fast Track Settlement Program in December 2017. The program was completed in March 2018 and tax years 2014 and 2015 were added to the IRS examination to reflect the impact of the Fast Track changes that were carried forward to 2014 and 2015. In June 2018, KPCo and other AEP subsidiaries settled all outstanding issues under audit for tax years 2011-2015. The Joint Committee approved the settlement in November 2018. The settlement did not materially impact KPCo's net income, cash flows or financial condition. The IRS examination of 2016 began in October 2018.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. KPCo is no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2007.

Net Income Tax Operating Loss Carryforward

KPCo has Kentucky state net income tax operating loss carryforwards of $122 million and $150 million in 2018 and 2017, respectively. As a result, KPCo recognized deferred state income tax benefits in 2018 and 2017 of $6 million and $9 million, respectively. Management anticipates future taxable income will be sufficient to realize the state net income tax operating loss tax benefits before the state carryforward expires for Kentucky in 2038.

State Tax Legislation

In April 2018, the Kentucky legislature enacted House Bill (H.B.) 487. H.B. 487 adopts mandatory unitary combined reporting for state corporate income tax purposes applicable for taxable years beginning on or after January 1, 2019. H.B. 487 also adopts the 80% federal net operating loss (NOL) limitation under Internal Revenue Code Section 172(a) for NOLs generated after January 1, 2018 and the federal unlimited carryforward period for unused NOLs generated after January 1, 2018. In addition, H.B. 366 was also enacted in April 2018, which among other things, replaces the graduated corporate tax rate structure with a flat 5% tax rate for business income and adopts a single-sales factor apportionment formula for apportioning a corporation's business income to Kentucky. The enacted legislation did not materially impact KPCo's net income.

In June 2018, the United States Supreme Court issued a decision which eliminated a physical presence requirement for the imposition of sales and use tax and instead applied an economic nexus concept. Although this case was specific to sales and use taxes, many states are beginning to consider whether they could also apply this economic nexus concept to income taxes. Management continues to monitor state legislation to determine whether it could create any income tax liability in any states in which KPCo currently does not file.

11. LEASES

Leases of property, plant and equipment are for remaining periods up to 17 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 were as follows:

Lease Rental Costs	Years Ended December 31, 2018	2017
	(in thousands)	
Net Lease Expense on Operating Leases	$ 2,204	$ 2,024
Amortization of Capital Leases	845	992
Interest on Capital Leases	107	102
Total Lease Rental Costs	$ 3,156	$ 3,118

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, 2018	2017
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Generation	$ 1,949	$ 2,146
Other Property, Plant and Equipment	2,992	3,597
Total Property, Plant and Equipment Under Capital Leases	4,941	5,743
Accumulated Amortization	2,410	2,963
Net Property, Plant and Equipment Under Capital Leases	$ 2,531	$ 2,780
Obligations Under Capital Leases		
Noncurrent Liability	$ 1,929	$ 1,945
Liability Due Within One Year	602	835
Total Obligations Under Capital Leases	$ 2,531	$ 2,780

Future minimum lease payments consisted of the following as of December 31, 2018:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2019	$ 703	$ 2,196
2020	552	2,024
2021	473	1,743
2022	325	1,456
2023	220	1,165
Later Years	649	2,367
Total Future Minimum Lease Payments	2,922	$ 10,951
Less Estimated Interest Element	391	
Estimated Present Value of Future Minimum Lease Payments	$ 2,531	

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, 2018, the maximum potential loss for these lease agreements was $1.7 million assuming the fair value of the equipment is zero at the end of the lease term.

12. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding:

Type of Debt	Maturity	Weighted-Average Interest Rate as of December 31, 2018	Interest Rate Ranges as of December 31, 2018	2017	Outstanding as of December 31, 2018	2017
					(in thousands)	
Senior Unsecured Notes	2021-2047	4.69%	3.13%-8.13%	3.13%-8.13%	$ 727,678	$ 727,434
Pollution Control Bonds (a)	2020	2.00%	2.00%	2.00%	64,921	64,865
Other Long-term Debt	2018-2022	3.89%	3.89%	2.78%	74,529	74,889
Total Long-term Debt Outstanding					$ 867,128	$ 867,188

(a) KPCo's Pollution Control Bond is subject to redemption earlier than the maturity date.

As of December 31, 2018, outstanding long-term debt was payable as follows:

	2019	2020	2021	2022	2023	After 2023	Total
				(in thousands)			
Principal Amount	$ —	$ 65,000	$ 40,000	$ 75,000	$ —	$ 690,000	$ 870,000
Debt Issuance Costs							(2,872)
Total Long-term Debt Outstanding							$ 867,128

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.

All of the dividends declared by KPCo are subject to a Federal Power Act restriction that prohibits the payment of dividends out of capital accounts without regulatory approval; payment of dividends is allowed out of retained earnings only.

KPCo has credit agreements that contain a covenant that limit its debt to capitalization ratio to 67.5%. As of December 31, 2018, KPCo did not exceed its debt to capitalization limit. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The most restrictive dividend limitation for KPCo is through the Federal Power Act. As of December 31, 2018, the maximum amount of restricted net assets of KPCo that may not be distributed to Parent in the form of a loan, advance or dividend was $576.4 million.

The Federal Power Act restriction does not limit the ability of KPCo to pay dividends out of retained earnings. The credit agreement covenant restrictions can limit the ability of KPCo to pay dividends out of retained earnings. As of December 31, 2018, there were no restrictions on KPCo's ability to pay dividends out of retained earnings.

Corporate Borrowing Program – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2018 and 2017 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits are described in the following table:

Years Ended December 31,	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2018	$ 27,871	$ 13,667	$ 9,077	$ 4,641	$ 27,871	$ 180,000
2017	24,612	332,983	8,139	13,992	9,641	180,000

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

Years Ended December 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2018	2.97%	1.81%	2.91%	1.82%	2.32%	1.98%
2017	1.85%	0.95%	1.70%	0.92%	1.37%	1.34%

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 advances to the Utility Money Pool, KPCo incurred the following amounts of interest expense and earned the following amounts of interest income:

	Years Ended December 31, 2018	2017
	(in thousands)	
Interest Expense	$ 163	$ 77
Interest Income	2	60

Securitized Accounts Receivables – AEP Credit

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

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and includes a $125 million and a $625 million facility which expire in July 2020 and 2021, respectively.

KPCo's amounts of accounts receivable and accrued unbilled revenues under the sale of receivables agreement were $43.2 million and $45.6 million as of December 31, 2018 and 2017, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $3.8 million and $3.1 million for the years ended December 31, 2018 and 2017, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $591.3 million and $573.8 million for the years ended December 31, 2018 and 2017, respectively.

13. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 10 in addition to "Corporate Borrowing Program – AEP System" and "Securitized Accounts Receivables – AEP Credit" sections of Note 12.

Power Coordination Agreement (PCA) and Bridge Agreement

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

- Under the FERC Approved PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.
- A Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement that, amongst other things, addresses the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement.

System Integration Agreement (SIA)

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

Affiliated Revenues and Purchases

The following table shows the revenues derived from auction sales to affiliates, net transmission agreement sales and other revenues for the years ended December 31, 2018 and 2017:

Related Party Revenues	Years Ended December 31, 2018	2017
	(in thousands)	
Sales under Interconnection Agreement	$ 110	$ —
Auction Sales to OPCo (a)	1,108	1,436
Transmission Agreement Sales	10,183	14,495
Other Revenues	929	766
Total Affiliated Revenues	$ 12,330	$ 16,697

(a) Refer to the Ohio Auctions section below for further information regarding this amount.

The following table shows the purchased power expenses incurred for purchases from affiliates for the years ended December 31, 2018 and 2017:

Related Party Purchases	Years Ended December 31, 2018	2017
	(in thousands)	
Direct Purchases from AEGCo (a)	$ 101,961	$ 95,957
Total Affiliated Purchases	$ 101,961	$ 95,957

(a) Refer to the Unit Power Agreements section below for further information regarding this amount.

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

Transmission Agreement (TA)

APCo, I&M, KGPCo, KPCo, OPCo and WPCo are parties to the TA, 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, 2018 and 2017 were $24.7 million and $30.9 million, respectively, and were recorded in Other Operation expenses on KPCo's statements of income.

Ohio Auctions

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

Unit Power Agreements (UPA)

UPA between AEGCo and I&M

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.

UPA between AEGCo and KPCo

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

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. KPCo recorded expenses of $4.2 million and $5 million in 2018 and 2017, 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 and 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 $1.7 million and $1.8 million for the years ended December 31, 2018 and 2017, respectively.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions. The following table shows the sales and purchases, recorded at net book value, for the years ended December 31, 2018 and 2017:

	Years Ended December 31,	
	2018	2017
	(in thousands)	
Sales	$ 472	$ 620
Purchases	265	939

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

Intercompany Billings

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

14. VARIABLE INTEREST ENTITIES

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

AEPSC provides certain managerial and professional services to AEP's subsidiaries. Parent is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the years ended December 31, 2018 and 2017 were $71.2 million and $65.1 million, respectively. The carrying amount of liabilities associated with AEPSC as of December 31, 2018 and 2017 was $8.2 million and $8.6 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to these transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the years ended December 31, 2018 and 2017 were $102 million and $96 million, respectively. The carrying amount of liabilities associated with AEGCo as of December 31, 2018 and 2017 was $7.9 million and $10.2 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

15. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment is shown functionally on the face of KPCo's balance sheets. The following table includes KPCo's total plant balances as of December 31, 2018 and 2017:

	December 31, 2018	December 31, 2017
	(in thousands)	
Regulated Property, Plant and Equipment		
Generation	$ 1,195,701	$ 1,186,796
Transmission	603,317	579,144
Distribution	845,821	812,757
Other	89,783	75,527
CWIP	84,748	52,142
Less: Accumulated Depreciation	961,181	922,251
Total Regulated Property, Plant and Equipment - Net	1,858,189	1,784,115
Nonregulated Property, Plant and Equipment - Net	8,221	8,255
Total Property, Plant and Equipment - Net	**$ 1,866,410**	**$ 1,792,370**

Depreciation

KPCo provides for depreciation of Property, Plant and Equipment on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides total regulated annual composite depreciation rates and depreciable lives for KPCo. Nonregulated depreciation rate ranges and depreciable life ranges are not applicable or not meaningful for 2018 and 2017.

	2018		2017	
Functional Class of Property	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges**
		(in years)		(in years)
Generation	3.1%	69 - 73	3.0%	68 - 69
Transmission	2.7%	37 - 75	2.7%	37 - 75
Distribution	3.4%	11 - 75	3.4%	11 - 75
Other	9.6%	5 - 75	8.9%	5 - 75

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

Asset Retirement Obligations (ARO)

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

The following is a reconciliation of the 2018 and 2017 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)			
2018	$ 51,238	$ 2,084	$ —	$ (31,501) (a)	$ 19,860 (a)	$ 41,681
2017	62,994	2,961	—	(16,809)	2,092	51,238

(a) Primarily related to ash pond closure and asbestos abatement.

Allowance for Funds Used During Construction

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

	Years Ended December 31, 2018	2017
	(in thousands)	
Allowance for Equity Funds Used During Construction	$ 2,002	$ 933
Allowance for Borrowed Funds Used During Construction	1,197	625

Jointly-owned Electric Facilities

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

	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
KPCo's Share as of December 31, 2018					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0%	$ 1,024,359	$ 16,101	$ 418,989
KPCo's Share as of December 31, 2017					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0%	$ 1,018,359	$ 9,692	$ 396,801

(a) Operated by KPCo.

16. REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregated Revenues from Contracts with Customers

The table below represents KPCo's revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Year Ended December 31, 2018 (in thousands)
Retail Revenues:	
Residential Revenues	$ 261,184
Commercial Revenues	157,578
Industrial Revenues	159,560
Other Retail Revenues	1,971
Total Retail Revenues	580,293
Wholesale Revenues:	
Generation Revenues (a)	29,832
Transmission Revenues (b)	20,839
Total Wholesale Revenues	50,671
Other Revenues from Contracts with Customers (a)	17,249
Total Revenues from Contracts with Customers	648,213
Other Revenues:	
Alternative Revenues (a)	(6,142)
Total Other Revenues	(6,142)
Total Revenues	$ 642,071

(a) Amounts included affiliated and nonaffiliated revenues.
(b) Amounts included affiliated and nonaffiliated revenues. The affiliated revenue was $15 million.

Performance Obligations

KPCo has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for "Revenue from Contracts with Customers" allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity's measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. KPCo elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for KPCo are summarized as follows:

Retail Revenues

KPCo has performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer's usage requirements.

Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between KPCo and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice.

Wholesale Revenues - Generation

KPCo has performance obligations to sell electricity to wholesale customers from generation assets in PJM. The performance obligation to deliver electricity from generation assets is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Wholesale generation revenues are variable as they are subject to the customer's usage requirements.

KPCo also has performance obligations to stand ready in order to promote grid reliability. Stand ready services are sold into PJM's Reliability Pricing Model (RPM) capacity market. RPM entails a base auction and at least three incremental auctions for a specific PJM delivery year, with the incremental auctions spanning three years. The performance obligation to stand ready is satisfied over time and the consideration for which is variable until the occurrence of the final incremental auction, at which point the performance obligation becomes fixed.

Payments from the RTO for stand ready services are typically received within one week from the issuance of the invoice, which is typically issued weekly. Gross margin resulting from generation sales are primarily subject to margin sharing agreements with customers, where the revenues are reflected gross in the disaggregated revenues table above.

Wholesale Revenues - Transmission

KPCo has performance obligations to transmit electricity to wholesale customers through assets owned and operated by KPCo and other AEP subsidiaries. The performance obligation to provide transmission services in PJM encompass a time frame greater than a year, where the performance obligation within PJM is partially fixed for a period of one year or less. Payments from the RTO for transmission services are typically received within one week from the issuance of the invoice, which is issued weekly for PJM.

KPCo collects revenues through Transmission Formula Rates. The FERC-approved rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations," and are therefore presented as such in the disaggregated revenues table above.

APCo, I&M, KGPCo, KPCo, OPCo and WPCo (AEP East Companies) are parties to the Transmission Agreement (TA), which defines how transmission costs are allocated among the AEP East Companies on a 12-month average coincident peak basis. AEPTCo is a load serving entity within PJM providing transmission services to affiliates in accordance with the OATT and TA. Affiliate revenues as a result of the TA are reflected as Transmission Revenues in the disaggregated revenues table above.

Fixed Performance Obligations

The following table represents KPCo's remaining fixed performance obligations satisfied over time as of December 31, 2018. Fixed performance obligations primarily include wholesale transmission services, electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. The amounts shown in the table below include affiliated and nonaffiliated revenues.

2019	2020-2021	2022-2023	After 2023	Total
		(in thousands)		
$ 24,508	$ 8,825	$ 8,825	$ —	$ 42,158

Contract Assets and Liabilities

Contract assets are recognized when KPCo has a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. KPCo did not have any material contract assets as of December 31, 2018.

When KPCo receives consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheet in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. KPCo's contract liabilities typically arise from advanced payments of services provided primarily with respect to joint use agreements for utility poles. KPCo did not have any material contract liabilities as of December 31, 2018.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on KPCo's balance sheets within the Accounts Receivable - Customers line item. KPCo's balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of December 31, 2018. See "Securitized Accounts Receivable - AEP Credit" section of Note 12 for additional information.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on KPCo's balance sheets were $8.4 million and $5.2 million, respectively, as of December 31, 2018 and January 1, 2018.

Contract Costs

Contract costs to obtain or fulfill a contract are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and neither bifurcated nor reclassified between current and noncurrent assets on KPCo's balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Other Operation on KPCo's statements of income. KPCo did not have material contract costs as of December 31, 2018.