COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) Approval Of A Certificate Of Public Convenience And Necessity; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2020-00174

SECTION II
FILING REQUIREMENTS

VOLUME 5 OF 5

June 29, 2020

Kentucky Power Company

2018 Second Quarter Report

Financial Statements

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GLOSSARY OF TERMS

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

Term	Meaning
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 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.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ASU	Accounting Standards Update.
FASB	Financial Accounting Standards Board.
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.
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.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MWh	Megawatthour.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2018 and 2017
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	**2017**	**2018**	**2017**
REVENUES				
Electric Generation, Transmission and Distribution	$ 148,779	$ 141,164	$ 322,277	$ 303,702
Sales to AEP Affiliates	2,909	5,228	6,147	8,479
Other Revenues	259	223	539	447
TOTAL REVENUES	151,947	146,615	328,963	312,628
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	22,941	25,914	38,846	49,350
Purchased Electricity for Resale	13,330	8,016	32,691	22,431
Purchased Electricity from AEP Affiliates	25,918	21,393	52,231	44,497
Other Operation	22,151	33,529	49,103	61,687
Maintenance	20,245	17,312	37,949	37,624
Depreciation and Amortization	21,232	21,329	49,526	43,424
Taxes Other Than Income Taxes	6,098	5,670	12,170	11,405
TOTAL EXPENSES	131,915	133,163	272,516	270,418
OPERATING INCOME	20,032	13,452	56,447	42,210
Other Income (Expense):				
Interest Income	8	8	24	111
Carrying Costs Income	5	368	10	821
Allowance for Equity Funds Used During Construction	587	226	988	438
Non-Service Cost Components of Net Periodic Benefit Cost	1,013	405	2,026	810
Interest Expense	(9,519)	(12,363)	(18,893)	(23,832)
INCOME BEFORE INCOME TAX EXPENSE (CREDIT)	12,126	2,096	40,602	20,558
Income Tax Expense (Credit)	(1,898)	721	2,080	7,070
NET INCOME	$ 14,024	$ 1,375	$ 38,522	$ 13,488

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

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2018 and 2017
(in thousands)
(Unaudited)

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Net Income	$ 14,024	$ 1,375	$ 38,522	$ 13,488
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $8 for the Three Months Ended June 30, 2018 and 2017, Respectively, and $0 and $16 for the Six Months Ended June 30, 2018 and 2017, Respectively	—	14	—	30
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(6) and $5 for the Three Months Ended June 30, 2018 and 2017, Respectively, and $(12) and $9 for the Six Months Ended June 30, 2018 and 2017, Respectively	(22)	8	(44)	16
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(22)	22	(44)	46
TOTAL COMPREHENSIVE INCOME	$ 14,002	$ 1,397	$ 38,478	$ 13,534

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2018 and 2017
(in thousands)
(Unaudited)

	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			(17,500)		(17,500)
Net Income			13,488		13,488
Other Comprehensive Income				46	46
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2017	$ 50,450	$ 526,135	$ 89,158	$ (1,308)	$ 664,435
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			38,522		38,522
Other Comprehensive Loss				(44)	(44)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2018	$ 50,450	$ 526,135	$ 131,882	$ 274	$ 708,741

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2018 and December 31, 2017
(in thousands)
(Unaudited)

	June 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 856	$ 909
Accounts Receivable:		
Customers	23,447	13,007
Affiliated Companies	20,365	32,019
Accrued Unbilled Revenues	6,297	6,667
Miscellaneous	56	179
Allowance for Uncollectible Accounts	(74)	(44)
Total Accounts Receivable	50,091	51,828
Fuel	21,855	18,006
Materials and Supplies	16,248	16,626
Risk Management Assets	6,209	1,851
Accrued Tax Benefits	8,814	6,909
Regulatory Asset for Under-Recovered Fuel Costs	2,270	82
Margin Deposits	2,011	2,880
Prepayments and Other Current Assets	4,440	12,975
TOTAL CURRENT ASSETS	112,794	112,066
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,191,169	1,186,796
Transmission	585,828	579,144
Distribution	824,750	812,757
Other Property, Plant and Equipment	89,551	84,024
Construction Work in Progress	80,196	52,142
Total Property, Plant and Equipment	2,771,494	2,714,863
Accumulated Depreciation and Amortization	943,697	922,493
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,827,797	1,792,370
OTHER NONCURRENT ASSETS		
Regulatory Assets	362,959	353,568
Long-term Risk Management Assets	376	203
Employee Benefits and Pension Assets	23,178	21,720
Deferred Charges and Other Noncurrent Assets	24,891	25,966
TOTAL OTHER NONCURRENT ASSETS	411,404	401,457
TOTAL ASSETS	$ 2,351,995	$ 2,305,893

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2018 and December 31, 2017
(Unaudited)

	June 30, 2018	December 31, 2017
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 15,435	$ 9,641
Accounts Payable:		
General	47,045	48,331
Affiliated Companies	26,594	34,944
Long-term Debt Due Within One Year – Nonaffiliated	75,000	75,000
Risk Management Liabilities	234	402
Customer Deposits	29,047	28,444
Accrued Taxes	19,126	24,785
Accrued Interest	7,976	7,848
Asset Retirement Obligations	16,323	19,735
Other Current Liabilities	20,934	24,634
TOTAL CURRENT LIABILITIES	257,714	273,764
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	792,405	792,188
Long-term Risk Management Liabilities	82	36
Deferred Income Taxes	405,479	394,786
Regulatory Liabilities and Deferred Investment Tax Credits	148,013	130,162
Asset Retirement Obligations	22,732	31,503
Employee Benefits and Pension Obligations	6,458	6,932
Deferred Credits and Other Noncurrent Liabilities	10,371	6,259
TOTAL NONCURRENT LIABILITIES	1,385,540	1,361,866
TOTAL LIABILITIES	1,643,254	1,635,630
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	526,135	526,135
Retained Earnings	131,882	93,416
Accumulated Other Comprehensive Income (Loss)	274	262
TOTAL COMMON SHAREHOLDER'S EQUITY	708,741	670,263
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,351,995	$ 2,305,893

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2018 and 2017
(in thousands)
(Unaudited)

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
OPERATING ACTIVITIES		
Net Income	$ 38,522	$ 13,488
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	49,526	43,424
Deferred Income Taxes	3,765	10,821
Allowance for Equity Funds Used During Construction	(988)	(438)
Mark-to-Market of Risk Management Contracts	(4,653)	(2,906)
Pension Contributions to Qualified Plan Trust	—	(2,226)
Property Taxes	7,224	7,614
Deferred Fuel Over/Under-Recovery, Net	(2,755)	2,670
Change in Other Noncurrent Assets	(20,039)	3,675
Change in Other Noncurrent Liabilities	(3,100)	962
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	10,389	12,029
Fuel, Materials and Supplies	(2,852)	(1,344)
Accounts Payable	(7,409)	(13,270)
Accrued Taxes, Net	(7,938)	(16,994)
Other Current Assets	9,424	1,654
Other Current Liabilities	(5,990)	(4,175)
Net Cash Flows from Operating Activities	63,126	54,984
INVESTING ACTIVITIES		
Construction Expenditures	(69,079)	(39,969)
Other Investing Activities	523	208
Net Cash Flows Used for Investing Activities	(68,556)	(39,761)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	64,834
Change in Advances from Affiliates, Net	5,794	2,774
Retirement of Long-term Debt – Nonaffiliated	—	(65,000)
Principal Payments for Capital Lease Obligations	(455)	(497)
Dividends Paid on Common Stock	—	(17,500)
Other Financing Activities	38	55
Net Cash Flows from (Used for) Financing Activities	5,377	(15,334)
Net Decrease in Cash and Cash Equivalents	(53)	(111)
Cash and Cash Equivalents at Beginning of Period	909	859
Cash and Cash Equivalents at End of Period	$ 856	$ 748
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 18,532	$ 22,680
Net Cash Paid (Received) for Income Taxes	(266)	3,341
Noncash Acquisitions Under Capital Leases	115	212
Construction Expenditures Included in Current Liabilities as of June 30,	17,123	12,270

See Condensed Notes to Condensed Financial Statements beginning on page 8.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three and six months ended June 30, 2018 is not necessarily indicative of results that may be expected for the year ending December 31, 2018. The condensed financial statements are unaudited and should be read in conjunction with the audited 2017 financial statements and notes thereto, which are included in KPCo's 2017 Annual Report.

Subsequent Events

Management reviewed subsequent events through July 26, 2018, the date that the second quarter 2018 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, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts.

Management adopted ASU 2014-09 effective January 1, 2018, by means of the modified retrospective approach for all contracts. 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 12 - 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 lease terms of 12 months or longer will be subject to the new requirements. Fundamentally, the criteria used to determine lease classification will remain the same, but will be more subjective under the new standard.

The new accounting guidance is effective for annual periods beginning after December 15, 2019, with early adoption permitted. Initial decisions were made to apply the guidance by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented; however, the FASB is currently evaluating draft guidance which would provide an optional expedient to adopt the new lease requirements through a cumulative-effect adjustment in the period of adoption. Management continues to monitor these standard-setting activities that may impact the transition requirements of the lease standard.

During 2016 and 2017, lease contract assessments were completed. The AEP System lease population was identified and representative lease contracts were sampled. Based upon the completed assessments, management prepared a system gap analysis to outline new disclosure compliance requirements compared to current system capabilities. Multiple lease system options were also evaluated. Management plans to elect certain of the following practical expedients upon adoption:

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

Evaluation of new lease contracts and the process of implementing a compliant lease system solution continues. Management expects the new standard to impact financial position and, at this time, cannot estimate the impact. Management expects no impact to results of operations or cash flows.

In July 2018, the FASB issued ASU 2018-10 “Codification Improvements to Topic 842, Leases” to clarify certain narrow aspects of the guidance in ASU 2016-02. The effective date and transmission requirements in ASU 2018-10 are the same as the requirements in ASU 2016-02. Management is currently assessing the potential impacts of ASU 2018-10 in context of the overall adoption of the new accounting guidance for leases. In addition, management continues to monitor both the FASB’s ongoing standard-setting activities that may result in the issuance of additional targeted improvements, as well as potential industry implementation issues. Management plans to adopt ASU 2016-02 and ASU 2018-10 effective January 1, 2019.

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 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 will be 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 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 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 around the assessment 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. Further, given the lack of 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 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 AEP'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.

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 three and six months ended June 30, 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 6 - Benefit Plans for additional details.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2018

	Pension and OPEB
	(in thousands)
Balance in AOCI as of March 31, 2018	$ 296
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(56)
Amortization of Actuarial (Gains)/Losses	28
Reclassifications from AOCI, before Income Tax (Expense) Credit	(28)
Income Tax (Expense) Credit	(6)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(22)
Net Current Period Other Comprehensive Income (Loss)	(22)
Balance in AOCI as of June 30, 2018	$ 274

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2017

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
		(in thousands)	
Balance in AOCI as of March 31, 2017	$ (25)	$ (1,305)	$ (1,330)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	23	—	23
Amortization of Prior Service Cost (Credit)	—	(56)	(56)
Amortization of Actuarial (Gains)/Losses	—	68	68
Reclassifications from AOCI, before Income Tax (Expense) Credit	23	12	35
Income Tax (Expense) Credit	9	4	13
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	14	8	22
Net Current Period Other Comprehensive Income (Loss)	14	8	22
Balance in AOCI as of June 30, 2017	$ (11)	$ (1,297)	$ (1,308)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2018

	Pension and OPEB
	(in thousands)
Balance in AOCI as of December 31, 2017	$ 262
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(112)
Amortization of Actuarial (Gains)/Losses	56
Reclassifications from AOCI, before Income Tax (Expense) Credit	(56)
Income Tax (Expense) Credit	(12)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(44)
Net Current Period Other Comprehensive Income (Loss)	(44)
ASU 2018-02 Adoption (b)	56
Balance in AOCI as of June 30, 2018	$ 274

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2017

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
		(in thousands)	
Balance in AOCI as of December 31, 2016	$ (41)	$ (1,313)	$ (1,354)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	46	—	46
Amortization of Prior Service Cost (Credit)	—	(111)	(111)
Amortization of Actuarial (Gains)/Losses	—	135	135
Reclassifications from AOCI, before Income Tax (Expense) Credit	46	24	70
Income Tax (Expense) Credit	16	8	24
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	30	16	46
Net Current Period Other Comprehensive Income (Loss)	30	16	46
Balance in AOCI as of June 30, 2017	$ (11)	$ (1,297)	$ (1,308)

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

4. RATE MATTERS

As discussed in KPCo's 2017 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2017 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2018 and updates KPCo's 2017 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	June 30, 2018	December 31, 2017
	(in thousands)	
Regulatory Assets Currently Earning a Return		
Rockport Deferral	$ 6,816	$ —
Regulatory Assets Currently Not Earning a Return		
Big Sandy, Unit 1 Operating Rider	1,083	—
Other Regulatory Assets Pending Final Regulatory Approval	63	50
Total Regulatory Assets Pending Final Regulatory Approval	$ 7,962	$ 50

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

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 UPA 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 and requested an additional $2.3 million of annual revenue increases related to: (a) the calculation of federal income tax expense, (b) recovery of purchased power costs associated with forced outages and (c) capital structure adjustments. Also in February 2018, an intervenor filed for rehearing recommending that the reduced corporate federal income tax rate be reflected in lower purchased power expense related to the Rockport UPA.

In April 2018, KPCo and the intervenor filed a settlement agreement with the KPSC in which KPCo withdrew its requested increase related to the recovery of purchased power costs associated with forced outages and the intervenor withdrew its claim regarding the impact of the reduced corporate federal income tax rates on purchased power costs related to the Rockport UPA.

In June 2018, the KPSC issued an order approving the settlement agreement including KPCo's requested additional revenue increase of $765 thousand related to the calculation of federal income tax expense. This rate increase was effective June 28, 2018.

Also in June 2018, the KPSC issued an order approving a settlement agreement between KPCo and an intervenor that stipulates that KPCo will refund Excess ADIT associated with certain depreciable property using ARAM and Excess ADIT that is not subject to rate normalization requirements over 18 years. The refund was effective July 1, 2018.

PJM Transmission Rates

In June 2016, PJM transmission owners, including AEP's transmission owning subsidiaries within PJM, 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 July 2016, certain parties filed comments at the FERC contesting the settlement agreement. In May 2018, the FERC approved the contested 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 primarily be returned to retail customers through existing state rider mechanisms and has recorded $9.6 million to Customer Accounts Receivable and $4.6 million to Deferred Charges and Other Noncurrent Assets, with offsets primarily to Regulatory Liabilities and Deferred Investment Tax Credits.

FERC Transmission Complaint - AEP's PJM Participants

In October 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 in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In November 2017, a FERC order set the matter for hearing and settlement procedures. In March 2018, AEP's transmission owning subsidiaries within PJM 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 ROE 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 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 ALJ 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.

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. A decision from the FERC is pending.

Modifications to AEP's PJM Transmission Rates

In November 2016, AEP's transmission owning subsidiaries within PJM 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. In March 2017, the FERC accepted the proposed modifications effective January 1, 2017, subject to refund, and set this matter for hearing and settlement procedures. The modified PJM OATT formula rates are based on projected calendar year financial activity and projected plant balances. In December 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. 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. The Commitments, Guarantees and Contingencies note within KPCo's 2017 Annual Report should be read in conjunction with this report.

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 June 30, 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.

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 June 30, 2018, the maximum potential loss for these lease agreements was $1.6 million assuming the fair value of the equipment is zero at the end of the lease term.

6. BENEFIT 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.

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost (credit) for the plans:

	Pension Plans		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Service Cost	$ 703	$ 729	$ 82	$ 83
Interest Cost	1,686	1,787	432	540
Expected Return on Plan Assets	(2,652)	(2,575)	(986)	(960)
Amortization of Prior Service Cost (Credit)	—	12	(606)	(606)
Amortization of Net Actuarial Loss	755	720	90	347
Net Periodic Benefit Cost (Credit)	$ 492	$ 673	$ (988)	$ (596)

	Pension Plans		OPEB	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Service Cost	$ 1,406	$ 1,458	$ 164	$ 166
Interest Cost	3,372	3,574	863	1,079
Expected Return on Plan Assets	(5,303)	(5,150)	(1,972)	(1,920)
Amortization of Prior Service Cost (Credit)	—	24	(1,212)	(1,212)
Amortization of Net Actuarial Loss	1,510	1,439	181	695
Net Periodic Benefit Cost (Credit)	$ 985	$ 1,345	$ (1,976)	$ (1,192)

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

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

Notional Volume of Derivative Instruments

	Volume		
Primary Risk Exposure	**June 30, 2018**	**December 31, 2017**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	21,431	10,812	MWhs
Natural Gas	647	206	MMBtus
Heating Oil and Gasoline	320	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 June 30, 2018 and December 31, 2017 balance sheets, KPCo netted $142 thousand and $379 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $2 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
June 30, 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	$ 12,165	$ (5,956)	$ 6,209
Long-term Risk Management Assets	1,663	(1,287)	376
Total Assets	13,828	(7,243)	6,585
Current Risk Management Liabilities	6,069	(5,835)	234
Long-term Risk Management Liabilities	1,350	(1,268)	82
Total Liabilities	7,419	(7,103)	316
Total MTM Derivative Contract Net Assets (Liabilities)	$ 6,409	$ (140)	$ 6,269

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)	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
	(in thousands)			
Electric Generation, Transmission and Distribution Revenues	$ (123)	$ 44	$ (289)	$ 82
Purchased Electricity for Resale	37	832	96	2,334
Other Operation	17	5	30	8
Maintenance	22	5	36	10
Regulatory Assets (a)	—	(20)	—	(6)
Regulatory Liabilities (a)	3,551	637	7,731	962
Total Gain on Risk Management Contracts	$ 3,504	$ 1,503	$ 7,604	$ 3,390

(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 three and six months ended June 30, 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 three and six months ended June 30, 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 is no impact of cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCO's balance sheets as of June 30, 2018 and December 31, 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 June 30, 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 Moody's Investor Service Inc., S&P Global Inc. and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

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

Collateral Triggering Events

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 June 30, 2018 and December 31, 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:

	June 30, 2018	December 31, 2017
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 37	$ 120
Additional Settlement Liability if Cross Default Provision is Triggered	14	104

8. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

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.

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:

	June 30, 2018		December 31, 2017	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 867,405	$ 921,448	$ 867,188	$ 976,163

Fair Value Measurements of Financial Assets and Liabilities

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
June 30, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 30	$ 6,652	$ 6,181	$ (6,278)	$ 6,585
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 9	$ 6,342	$ 103	$ (6,138)	$ 316

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
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 three and six months ended June 30, 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:

Three Months Ended June 30, 2018	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of March 31, 2018	$ 1,134
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	1,687
Settlements	(2,466)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	5,723
Balance as of June 30, 2018	$ 6,078

Three Months Ended June 30, 2017	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of March 31, 2017	$ 202
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	551
Settlements	(760)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	3,129
Balance as of June 30, 2017	$ 3,122

Six Months Ended June 30, 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)	6,790
Settlements	(8,429)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	5,904
Balance as of June 30, 2018	$ 6,078

Six Months Ended June 30, 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)	2,243
Settlements	(2,488)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	3,169
Balance as of June 30, 2017	$ 3,122

(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 liabilities/assets.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
June 30, 2018

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 272	$ 77	Discounted Cash Flow	Forward Market Price	$ 14.72	$ 63.75	$ 34.64
FTRs	5,909	26	Discounted Cash Flow	Forward Market Price	(0.38)	5.97	0.80
Total	$ 6,181	$ 103					

Significant Unobservable Inputs
December 31, 2017

	Fair Value		Valuation	Significant Unobservable	Forward Price 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 June 30, 2018 and December 31, 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)

9. INCOME TAXES

Federal Tax Reform

In December 2017, legislation referred to as Tax Reform was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, (the Code) and had a material impact on KPCo's financial statements in the reporting period of its enactment. Tax Reform lowered the corporate federal income tax rate from 35% to 21%. Tax Reform provisions related to regulated public utilities generally allow for the continued deductibility of interest expense, eliminate bonus depreciation for certain property acquired after September 27, 2017 and continue certain rate normalization requirements for accelerated depreciation benefits.

Provisional Amounts

KPCo applied Staff Accounting Bulletin 118 (SAB 118), issued by the SEC staff in December 2017, and made reasonable estimates for the measurement and accounting of the effects of Tax Reform which are reflected in the financial statements as provisional amounts based on the best information available. In January 2018, the FASB issued guidance allowing non-public entities to apply SAB 118. SAB 118 provides for up to a one year period to complete the required analysis and accounting for Tax Reform referred to as the measurement period. While KPCo was able to make reasonable estimates of the impact of Tax Reform in 2017, the final impact may differ from the recorded provisional amounts to the extent refinements are made to the estimated cumulative differences or as a result of additional guidance or technical corrections that may be issued by the IRS that may impact management's interpretation and assumptions utilized. The measurement period adjustments recorded during the second quarter of 2018 to the provisional amounts were immaterial. KPCo expects to complete the analysis of the provisional items during the second half of 2018.

Reduction in the Corporate Federal Income Tax Rate

Effective January 18, 2018, KPCo implemented new base rates to reflect the reduction in the corporate federal income tax rate from 35% to 21%.

Excess Accumulated Deferred Income Taxes

As reflected in KPCo's estimated annual ETR for 2018, KPCo began amortizing the excess accumulated deferred income taxes (Excess ADIT) associated with certain depreciable property subject to rate normalization requirements using the average rate assumption method (ARAM) during the first quarter of 2018. The amortization resulted in a reduction in the Excess ADIT balance recorded in Regulatory Liabilities and Deferred Investment Tax Credits and a reduction in Income Tax Expense. As a result of state utility commission orders or instructions, in the second quarter of 2018 KPCo recorded $1.8 million of estimated provisions for revenue refund offsetting the amortization of the Excess ADIT.

In June 2018 and effective July 1, 2018, the KPSC issued an order approving a settlement agreement between KPCo and an intervenor that stipulates that KPCo will refund excess ADIT associated with certain depreciable property using ARAM and excess ADIT that is not subject to rate normalization requirements over 18 years.

Effective Tax Rates (ETR)

KPCo's interim ETR reflects the estimated annual ETR for 2018 and 2017, adjusted for tax expense associated with certain discrete items. The interim ETR differ from the federal statutory tax rate of 21% and 35% in 2018 and 2017, respectively, primarily due to state income taxes, the amortization of excess accumulated deferred income taxes associated with certain depreciable property using ARAM, tax credits and other book/tax differences which are accounted for on a flow-through basis.

The ETR for KPCo are included in the following table. Significant variances in the ETR are described below.

Three Months Ended June 30,		Six Months Ended June 30,	
2018	**2017**	**2018**	**2017**
(15.7)%	34.4%	5.1%	34.4%

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017

The decrease in the ETR was primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and increased 2018 amortization of Excess ADIT.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

The decrease in the ETR was primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and increased 2018 amortization of Excess ADIT.

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, AEP settled all outstanding issues under audit for tax years 2011-2015 and the settlement did not materially impact KPCo's net income, cash flows or financial condition.

KPCo and other AEP subsidiaries file income tax returns in various state, local or foreign 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 2009.

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 Sec. 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.

10. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first six months of 2018.

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%. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements.

The Federal Power Act restriction does not limit the ability of KPCo 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 June 30, 2018 and December 31, 2017 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limit for the six months ended June 30, 2018 are described in the following table:

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 June 30, 2018	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 23,851	$ 13,667	$ 9,723	$ 5,017	$ 15,435	$ 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:

Six Months Ended June 30,	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	2.52%	1.83%	2.51%	1.84%	2.33%	1.93%
2017	1.44%	0.95%	1.42%	0.92%	1.29%	1.02%

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 expires in June 2019.

KPCo's amounts of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement were $46.1 million and $45.6 million as of June 30, 2018 and December 31, 2017, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended June 30, 2018 and 2017 were $899 thousand and $761 thousand, respectively, and for the six months ended June 30, 2018 and 2017 were $1.8 million and $1.6 million, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended June 30, 2018 and 2017 were $145.2 million and $136 million, respectively, and for the six months ended June 30, 2018 and 2017 were $312.1 million and $297.4 million, respectively.

11. PROPERTY, PLANT AND EQUIPMENT

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.

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

ARO as of December 31, 2017	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of June 30, 2018
		(in thousands)			
$ 51,238	$ 1,176	$ —	$ (18,217)	$ 4,858	$ 39,055

12. 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:

	Three Months Ended June 30, 2018	Six Months Ended June 30, 2018
	(in thousands)	
Retail Revenues:		
Residential Revenues	$ 58,895	$ 139,878
Commercial Revenues	39,809	80,547
Industrial Revenues	43,518	82,490
Other Retail Revenues	493	996
Total Retail Revenues	142,715	303,911
Wholesale Revenues:		
Generation Revenues	4,631	10,315
Generation Revenues – Affiliated	109	177
Transmission Revenues	2,150	5,577
Transmission Revenues – Affiliated	1,350	4,293
Total Wholesale Revenues	8,240	20,362
Other Revenues from Contracts with Customers	3,823	8,613
Other Revenues from Contracts with Customers – Affiliated	356	583
Total Revenues from Contracts with Customers	155,134	333,469
Other Revenues:		
Alternative Revenues	(3,187)	(4,506)
Total Other Revenues	(3,187)	(4,506)
Total Revenues	$ 151,947	$ 328,963

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 revenue 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 revenue table above.

Wholesale Revenues - Transmission Affiliated

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 - Affiliated in the disaggregated revenue table above.

Fixed Performance Obligations

The following table represents KPCo's remaining fixed performance obligations satisfied over time as of June 30, 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.

2018	2019-2020	2021-2022	After 2022	Total
		(in thousands)		
$ 11,849	$ 3,187	$ 2,816	$ 1,408	$ 19,260

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 June 30, 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 June 30, 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 June 30, 2018. See "Securitized Accounts Receivable - AEP Credit" section of Note 10 for additional information related to AEP Credit's securitized accounts receivable.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on KPCo's balance sheets were $7.2 million and $5.2 million, respectively, as of June 30, 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 income statements. KPCo did not have material contract costs as of June 30, 2018.

Kentucky Power Company

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GLOSSARY OF TERMS

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

Term	Meaning
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 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.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARAM	Average Rate Assumption Method, an IRS approved method used to calculate the reversal of Excess ADIT for ratemaking purposes.
ASU	Accounting Standards Update.
Excess ADIT	Excess accumulated deferred income taxes.
FASB	Financial Accounting Standards Board.
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.
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.
MWh	Megawatthour.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
ROE	Return on Equity.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SEC	U.S. Securities and Exchange Commission.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to a the "Tax Cut 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.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2018 and 2017
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
REVENUES				
Electric Generation, Transmission and Distribution	$ 154,341	$ 158,963	$ 476,618	$ 462,665
Sales to AEP Affiliates	3,122	3,964	9,269	12,443
Other Revenues	308	218	847	665
TOTAL REVENUES	157,771	163,145	486,734	475,773
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	41,677	36,216	80,523	85,566
Purchased Electricity for Resale	1,155	5,211	33,846	27,642
Purchased Electricity from AEP Affiliates	25,697	26,759	77,928	71,256
Other Operation	22,489	27,174	71,592	88,861
Maintenance	15,892	16,763	53,841	54,387
Depreciation and Amortization	23,758	22,042	73,284	65,466
Taxes Other Than Income Taxes	6,021	6,240	18,191	17,645
TOTAL EXPENSES	136,689	140,405	409,205	410,823
OPERATING INCOME	21,082	22,740	77,529	64,950
Other Income (Expense):				
Other Income (Expense)	638	(84)	1,660	1,286
Non-Service Cost Components of Net Periodic Benefit Cost	1,013	406	3,039	1,216
Interest Expense	(9,450)	(11,228)	(28,343)	(35,060)
INCOME BEFORE INCOME TAX EXPENSE	13,283	11,834	53,885	32,392
Income Tax Expense	2,232	5,373	4,312	12,443
NET INCOME	$ 11,051	$ 6,461	$ 49,573	$ 19,949

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

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2018 and 2017
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Net Income	$ 11,051	$ 6,461	$ 49,573	$ 19,949
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $6 for the Three Months Ended September 30, 2018 and 2017, Respectively, and $0 and $22 for the Nine Months Ended September 30, 2018 and 2017, Respectively	—	11	—	41
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(6) and $3 for the Three Months Ended September 30, 2018 and 2017, Respectively, and $(18) and $12 for the Nine Months Ended September 30, 2018 and 2017, Respectively	(23)	7	(67)	23
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(23)	18	(67)	64
TOTAL COMPREHENSIVE INCOME	$ 11,028	$ 6,479	$ 49,506	$ 20,013

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2018 and 2017
(in thousands)
(Unaudited)

	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			(26,250)		(26,250)
Net Income			19,949		19,949
Other Comprehensive Income				64	64
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2017	$ 50,450	$ 526,135	$ 86,869	$ (1,290)	$ 662,164
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			49,573		49,573
Other Comprehensive Loss				(67)	(67)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2018	$ 50,450	$ 526,135	$ 142,933	$ 251	$ 719,769

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2018 and December 31, 2017
(in thousands)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 698	$ 909
Accounts Receivable:		
Customers	21,885	13,007
Affiliated Companies	20,161	32,019
Accrued Unbilled Revenues	6,193	6,667
Miscellaneous	278	179
Allowance for Uncollectible Accounts	(204)	(44)
Total Accounts Receivable	48,313	51,828
Fuel	9,334	18,006
Materials and Supplies	16,247	16,626
Risk Management Assets	7,035	1,851
Accrued Tax Benefits	4,976	6,909
Regulatory Asset for Under-Recovered Fuel Costs	1,983	82
Margin Deposits	2,568	2,880
Prepayments and Other Current Assets	5,072	12,975
TOTAL CURRENT ASSETS	96,226	112,066
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,193,281	1,186,796
Transmission	588,292	579,144
Distribution	834,967	812,757
Other Property, Plant and Equipment	92,158	84,024
Construction Work in Progress	90,883	52,142
Total Property, Plant and Equipment	2,799,581	2,714,863
Accumulated Depreciation and Amortization	956,489	922,493
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,843,092	1,792,370
OTHER NONCURRENT ASSETS		
Regulatory Assets	365,572	353,568
Long-term Risk Management Assets	270	203
Employee Benefits and Pension Assets	23,915	21,720
Deferred Charges and Other Noncurrent Assets	21,030	25,966
TOTAL OTHER NONCURRENT ASSETS	410,787	401,457
TOTAL ASSETS	$ 2,350,105	$ 2,305,893

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2018 and December 31, 2017
(dollars in thousands)
(Unaudited)

	September 30, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$ 12,059	$ 9,641
Accounts Payable:		
General	44,640	48,331
Affiliated Companies	25,038	34,944
Long-term Debt Due Within One Year – Nonaffiliated	75,000	75,000
Risk Management Liabilities	695	402
Customer Deposits	29,387	28,444
Accrued Taxes	17,228	24,785
Accrued Interest	9,282	7,848
Asset Retirement Obligations	13,141	19,735
Other Current Liabilities	20,896	24,634
TOTAL CURRENT LIABILITIES	247,366	273,764
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	792,513	792,188
Long-term Risk Management Liabilities	116	36
Deferred Income Taxes	410,195	394,786
Regulatory Liabilities and Deferred Investment Tax Credits	143,417	130,162
Asset Retirement Obligations	22,626	31,503
Employee Benefits and Pension Obligations	6,251	6,932
Deferred Credits and Other Noncurrent Liabilities	7,852	6,259
TOTAL NONCURRENT LIABILITIES	1,382,970	1,361,866
TOTAL LIABILITIES	1,630,336	1,635,630
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	526,135	526,135
Retained Earnings	142,933	93,416
Accumulated Other Comprehensive Income (Loss)	251	262
TOTAL COMMON SHAREHOLDER'S EQUITY	719,769	670,263
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,350,105	$ 2,305,893

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2018 and 2017
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2018	2017
OPERATING ACTIVITIES		
Net Income	$ 49,573	$ 19,949
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	73,284	65,466
Deferred Income Taxes	2,442	16,026
Allowance for Equity Funds Used During Construction	(1,607)	(679)
Mark-to-Market of Risk Management Contracts	(4,878)	(2,139)
Pension Contributions to Qualified Plan Trust	—	(2,226)
Property Taxes	10,778	11,367
Deferred Fuel Over/Under-Recovery, Net	(2,468)	1,260
Change in Other Noncurrent Assets	(25,930)	1,700
Change in Other Noncurrent Liabilities	(12,185)	1,593
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	12,548	13,235
Fuel, Materials and Supplies	9,744	6,744
Accounts Payable	(8,536)	(19,329)
Accrued Taxes, Net	(5,998)	(15,915)
Other Current Assets	8,294	(9,598)
Other Current Liabilities	(3,696)	(6,030)
Net Cash Flows from Operating Activities	101,365	81,424
INVESTING ACTIVITIES		
Construction Expenditures	(104,412)	(64,429)
Other Investing Activities	1,035	462
Net Cash Flows Used for Investing Activities	(103,377)	(63,967)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	388,809
Change in Advances from Affiliates, Net	2,418	10,402
Retirement of Long-term Debt – Nonaffiliated	—	(390,000)
Principal Payments for Capital Lease Obligations	(655)	(743)
Dividends Paid on Common Stock	—	(26,250)
Other Financing Activities	38	236
Net Cash Flows from (Used for) Financing Activities	1,801	(17,546)
Net Decrease in Cash and Cash Equivalents	(211)	(89)
Cash and Cash Equivalents at Beginning of Period	909	859
Cash and Cash Equivalents at End of Period	$ 698	$ 770
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 26,481	$ 32,714
Net Cash Paid (Received) for Income Taxes	(166)	1,018
Noncash Acquisitions Under Capital Leases	147	623
Construction Expenditures Included in Current Liabilities as of September 30,	13,489	7,608

See Condensed Notes to Condensed Financial Statements beginning on page 8.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three and nine months ended September 30, 2018 is not necessarily indicative of results that may be expected for the year ending December 31, 2018. The condensed financial statements are unaudited and should be read in conjunction with the audited 2017 financial statements and notes thereto, which are included in KPCo's 2017 Annual Report.

Subsequent Events

Management reviewed subsequent events through October 25, 2018, the date that the third quarter 2018 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, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts.

Management adopted ASU 2014-09 effective January 1, 2018, by means of the modified retrospective approach for all contracts. 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 12 - 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.

The new accounting guidance is effective for annual periods beginning after December 15, 2019, with early adoption permitted. In July 2018, the FASB issued ASU 2018-11 "Leases (Topic 842): Targeted Improvements", which provides an optional expedient to adopt the new lease requirements through a cumulative-effect adjustment in the period of adoption. Management plans to apply the new optional transition guidance.

New leasing standard implementation activities to date include 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. A lease system was selected after reviewing multiple system options. System implementation activities of core functionality continue in the fourth quarter of 2018. Implementation of reporting functionality designed to meet new disclosure requirements is ongoing.

Management plans to elect certain of the optional 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.

Evaluation of new lease contracts will continue through the fourth quarter. Management expects the new standard to impact financial position and, at this time, cannot estimate the impact. Management does not expect any impact to results of operations or cash flows. Management plans to adopt ASU 2016-02 and its related guidance effective January 1, 2019.

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 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 will be 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 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 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 around the assessment 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. Further, given the lack of 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 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 AEP'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 2018-15 "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. Capitalized implementation costs of a hosting arrangement that is a service contract should be amortized over the term of the hosting arrangement. The expense related to the capitalized implementation costs should be presented in the same line item in the statement of income as the fees associated with the hosting element (service) of the arrangement. Payments for capitalized implementation costs in the statement of cash flows should be classified in the same manner as payments made for fees associated with the hosting element. Capitalized implementation costs in the statement of financial position should be presented in the same line item that a prepayment for the fees of the associated hosting arrangement would be presented.

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 three and nine months ended September 30, 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 6 - Benefit Plans for additional details.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2018

	Pension and OPEB
	(in thousands)
Balance in AOCI as of June 30, 2018	$ 274
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(56)
Amortization of Actuarial (Gains)/Losses	27
Reclassifications from AOCI, before Income Tax (Expense) Credit	(29)
Income Tax (Expense) Credit	(6)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(23)
Net Current Period Other Comprehensive Income (Loss)	(23)
Balance in AOCI as of September 30, 2018	$ 251

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2017

	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in thousands)	
Balance in AOCI as of June 30, 2017	$ (11)	$ (1,297)	$ (1,308)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	16	—	16
Amortization of Prior Service Cost (Credit)	—	(55)	(55)
Amortization of Actuarial (Gains)/Losses	—	67	67
Reclassifications from AOCI, before Income Tax (Expense) Credit	16	12	28
Income Tax (Expense) Credit	5	5	10
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	11	7	18
Net Current Period Other Comprehensive Income (Loss)	11	7	18
Balance in AOCI as of September 30, 2017	$ —	$ (1,290)	$ (1,290)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2018

	Pension and OPEB
	(in thousands)
Balance in AOCI as of December 31, 2017	$ 262
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(168)
Amortization of Actuarial (Gains)/Losses	83
Reclassifications from AOCI, before Income Tax (Expense) Credit	(85)
Income Tax (Expense) Credit	(18)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(67)
Net Current Period Other Comprehensive Income (Loss)	(67)
ASU 2018-02 Adoption (b)	56
Balance in AOCI as of September 30, 2018	$ 251

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2017

	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in thousands)	
Balance in AOCI as of December 31, 2016	$ (41)	$ (1,313)	$ (1,354)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	62	—	62
Amortization of Prior Service Cost (Credit)	—	(166)	(166)
Amortization of Actuarial (Gains)/Losses	—	202	202
Reclassifications from AOCI, before Income Tax (Expense) Credit	62	36	98
Income Tax (Expense) Credit	21	13	34
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	41	23	64
Net Current Period Other Comprehensive Income (Loss)	41	23	64
Balance in AOCI as of September 30, 2017	$ —	$ (1,290)	$ (1,290)

(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

As discussed in KPCo's 2017 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2017 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2018 and updates KPCo's 2017 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	September 30, 2018	December 31, 2017
	(in thousands)	
Regulatory Assets Currently Earning a Return		
Rockport Deferral	$ 10,631	$ —
Regulatory Assets Currently Not Earning a Return		
Big Sandy, Unit 1 Operating Rider	1,083	—
Other Regulatory Assets Pending Final Regulatory Approval	64	50
Total Regulatory Assets Pending Final Regulatory Approval	$ 11,778	$ 50

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

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% ROE. 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 UPA 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 and requested an additional $2.3 million of annual revenue increases related to: (a) the calculation of federal income tax expense, (b) recovery of purchased power costs associated with forced outages and (c) capital structure adjustments. Also in February 2018, an intervenor filed for rehearing recommending that the reduced corporate federal income tax rate be reflected in lower purchased power expense related to the Rockport UPA.

In April 2018, KPCo and the intervenor filed a settlement agreement with the KPSC in which KPCo withdrew its requested increase related to the recovery of purchased power costs associated with forced outages and the intervenor withdrew its claim regarding the impact of the reduced corporate federal income tax rates on purchased power costs related to the Rockport UPA.

In June 2018, the KPSC issued an order approving the settlement agreement including KPCo's requested additional revenue increase of $765 thousand related to the calculation of federal income tax expense. This rate increase was effective June 28, 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 ARAM and an estimated $93 million of Excess ADIT that is not subject to rate normalization requirements over 18 years. The refund was effective July 1, 2018.

PJM Transmission Rates

In June 2016, PJM transmission owners, including AEP's transmission owning subsidiaries within PJM, 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 July 2016, certain parties filed comments at the FERC contesting the settlement agreement. In May 2018, the FERC approved the contested 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 primarily be returned to retail customers through existing state rider mechanisms and has recorded $7.6 million to Customer Accounts Receivable and $4.3 million to Deferred Charges and Other Noncurrent Assets, with offsets primarily to Regulatory Liabilities and Deferred Investment Tax Credits as of September 30, 2018.

FERC Transmission Complaint - AEP's PJM Participants

In October 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 in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In November 2017, a FERC order set the matter for hearing and settlement procedures. In March 2018, AEP's transmission owning subsidiaries within PJM 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 ROE 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 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.

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. A decision from the FERC is pending.

Modifications to AEP's PJM Transmission Rates

In November 2016, AEP's transmission owning subsidiaries within PJM 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. In March 2017, the FERC accepted the proposed modifications effective January 1, 2017, subject to refund, and set this matter for hearing and settlement procedures. The modified PJM OATT formula rates are based on projected calendar year financial activity and projected plant balances. In December 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. 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. The Commitments, Guarantees and Contingencies note within KPCo's 2017 Annual Report should be read in conjunction with this report.

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 September 30, 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.

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 September 30, 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.

6. BENEFIT 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.

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost (credit) for the plans:

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Service Cost	$ 703	$ 729	$ 82	$ 83
Interest Cost	1,687	1,787	431	539
Expected Return on Plan Assets	(2,651)	(2,575)	(985)	(960)
Amortization of Prior Service Cost (Credit)	—	12	(607)	(606)
Amortization of Net Actuarial Loss	754	719	91	348
Net Periodic Benefit Cost (Credit)	$ 493	$ 672	$ (988)	$ (596)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Service Cost	$ 2,109	$ 2,187	$ 246	$ 249
Interest Cost	5,059	5,361	1,294	1,618
Expected Return on Plan Assets	(7,954)	(7,725)	(2,957)	(2,880)
Amortization of Prior Service Cost (Credit)	—	36	(1,819)	(1,818)
Amortization of Net Actuarial Loss	2,264	2,158	272	1,043
Net Periodic Benefit Cost (Credit)	$ 1,478	$ 2,017	$ (2,964)	$ (1,788)

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

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

Notional Volume of Derivative Instruments

	Volume		
Primary Risk Exposure	**September 30, 2018**	**December 31, 2017**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	17,924	10,812	MWhs
Natural Gas	1,485	206	MMBtus
Heating Oil and Gasoline	370	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 September 30, 2018 and December 31, 2017 balance sheets, KPCo netted \$0 and \$379 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and \$67 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
September 30, 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	$ 14,742	$ (7,707)	$ 7,035
Long-term Risk Management Assets	1,085	(815)	270
Total Assets	15,827	(8,522)	7,305
Current Risk Management Liabilities	8,433	(7,738)	695
Long-term Risk Management Liabilities	968	(852)	116
Total Liabilities	9,401	(8,590)	811
Total MTM Derivative Contract Net Assets	$ 6,426	$ 68	$ 6,494

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)	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
	(in thousands)			
Electric Generation, Transmission and Distribution Revenues	$ (114)	$ 62	$ (403)	$ 144
Purchased Electricity for Resale	20	500	116	2,834
Other Operation	18	5	48	13
Maintenance	26	4	62	14
Regulatory Assets (a)	—	20	—	14
Regulatory Liabilities (a)	2,279	(326)	10,010	636
Total Gain on Risk Management Contracts	$ 2,229	$ 265	$ 9,833	$ 3,655

(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 three and nine months ended September 30, 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 three and nine months ended September 30, 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 September 30, 2018 and December 31, 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 September 30, 2018, KPCo was 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. A counterparty is required to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a 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 September 30, 2018 and December 31, 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:

	September 30, 2018	December 31, 2017
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 14	$ 120
Additional Settlement Liability if Cross Default Provision is Triggered	14	104

8. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

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.

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:

	September 30, 2018		December 31, 2017	
	Book Value	**Fair Value**	**Book Value**	**Fair Value**
	(in thousands)			
Long-term Debt	$ 867,513	$ 907,590	$ 867,188	$ 976,163

Fair Value Measurements of Financial Assets and Liabilities

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
September 30, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 37	$ 8,042	$ 7,092	$ (7,866)	$ 7,305
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 52	$ 8,537	$ 156	$ (7,934)	$ 811

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
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 three and nine months ended September 30, 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:

Three Months Ended September 30, 2018	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of June 30, 2018	$ 6,078
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	1,685
Settlements	(2,929)
Transfers out of Level 3 (c)	(1)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	2,103
Balance as of September 30, 2018	$ 6,936

Three Months Ended September 30, 2017	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of June 30, 2017	$ 3,122
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	567
Settlements	(1,423)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	82
Balance as of September 30, 2017	$ 2,348

Nine Months Ended September 30, 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)	6,704
Settlements	(8,383)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	6,802
Balance as of September 30, 2018	$ 6,936

Nine Months Ended September 30, 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)	2,295
Settlements	(2,543)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	2,398
Balance as of September 30, 2017	$ 2,348

(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) Transfers are recognized based on their value at the beginning of the period that the transfer occurred.
(d) Relates to the net gains (losses) of those contracts that are not reflected on KPCo’s statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
September 30, 2018

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 321	$ 151	Discounted Cash Flow	Forward Market Price	$ 14.98	$ 59.45	$ 36.30
FTRs	6,771	5	Discounted Cash Flow	Forward Market Price	0.06	6.21	1.26
Total	$ 7,092	$ 156					

Significant Unobservable Inputs
December 31, 2017

	Fair Value		Valuation	Significant Unobservable	Forward Price 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 September 30, 2018 and December 31, 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)

9. INCOME TAXES

Federal Tax Reform

In December 2017, Tax Reform legislation was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, and had a material impact on KPCo's financial statements in the reporting period of its enactment. Tax Reform lowered the corporate federal income tax rate from 35% to 21%. Tax Reform provisions related to regulated public utilities generally allow for the continued deductibility of interest expense, impact bonus depreciation for certain property acquired and placed in service after September 27, 2017 and continue certain rate normalization requirements for accelerated depreciation benefits.

Provisional Amounts

KPCo applied Staff Accounting Bulletin 118 (SAB 118), issued by the SEC staff in December 2017, and made reasonable estimates for the measurement and accounting of the effects of Tax Reform which are reflected in the financial statements as provisional amounts based on the best information available. In January 2018, the FASB issued guidance allowing non-public entities to apply SAB 118. SAB 118 provides for up to a one-year period to complete the required analysis and accounting for Tax Reform referred to as the measurement period. While KPCo was able to make reasonable estimates of the impact of Tax Reform in 2017, the final impact may differ from the recorded provisional amounts to the extent refinements are made to the estimated cumulative differences or as a result of additional guidance or technical corrections that may be issued by the IRS that may impact management's interpretation and assumptions utilized. The measurement period adjustments recorded during the third quarter of 2018 to the provisional amounts were immaterial.

During the third quarter of 2018, the IRS proposed new regulations that reflect changes made by Tax Reform and affect taxpayers with qualified depreciable property acquired and placed in service after September 27, 2017. KPCo expects to complete the analysis of the provisional items, including analysis of the new regulations proposed by the IRS, during the fourth quarter of 2018.

Reduction in the Corporate Federal Income Tax Rate

Effective January 18, 2018, KPCo implemented new base rates to reflect the reduction in the corporate federal income tax rate from 35% to 21%.

Excess ADIT

In June 2018 and effective July 1, 2018, the KPSC issued an order approving a settlement agreement between KPCo and an intervenor that stipulates that KPCo will refund Excess ADIT associated with certain depreciable property using ARAM and Excess ADIT that is not subject to rate normalization requirements over 18 years. See "Kentucky Tax Reform" of Note 4 - Rate Matters for additional details.

Effective Tax Rates (ETR)

KPCo's interim ETR reflects the estimated annual ETR for 2018 and 2017, adjusted for tax expense associated with certain discrete items. As previously mentioned, effective January 1, 2018, Tax Reform lowered the corporate tax rate from 35% to 21%. The interim ETR differ from the federal statutory tax rate of 21% and 35% in 2018 and 2017, respectively, primarily due to state income taxes, the amortization of excess accumulated deferred income taxes associated with certain depreciable property using ARAM, tax credits and other book/tax differences which are accounted for on a flow-through basis.

The ETR for KPCo are included in the following table. Significant variances in the ETR are described below.

Three Months Ended September 30,		Nine Months Ended September 30,	
2018	**2017**	**2018**	**2017**
16.8%	45.4%	8.0%	38.4%

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017

The decrease in the ETR was primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and increased 2018 amortization of Excess ADIT.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

The decrease in the ETR was primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and increased 2018 amortization of Excess ADIT.

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, AEP settled all outstanding issues under audit for tax years 2011-2013, and the audit was again submitted to the Joint Committee for approval in the third quarter of 2018. The settlement did not materially impact KPCo's net income, cash flows or financial condition.

KPCo and other AEP subsidiaries file income tax returns in various state, local or foreign 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 2009. In the third quarter of 2018, AEP was notified that the IRS would commence an audit of the 2016 tax year in October 2018.

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 Sec. 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.

10. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first nine months of 2018.

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%. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements.

The Federal Power Act restriction does not limit the ability of KPCo 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 September 30, 2018 and December 31, 2017 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limit for the nine months ended September 30, 2018 are described in the following table:

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 September 30, 2018	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 23,851	$ 13,667	$ 9,289	$ 4,857	$ 12,059	$ 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:

Nine Months Ended September 30,	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	2.52%	1.81%	2.51%	1.82%	2.30%	1.96%
2017	1.49%	0.95%	1.49%	0.92%	1.34%	1.36%

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 was amended in July 2018 to include 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 sold under the sale of receivables agreement were $39.4 million and $45.6 million as of September 30, 2018 and December 31, 2017, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended September 30, 2018 and 2017 were $954 thousand and $811 thousand, respectively, and for the nine months ended September 30, 2018 and 2017 were $2.8 million and $2.4 million, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended September 30, 2018 and 2017 were $140.6 million and $139.5 million, respectively, and for the nine months ended September 30, 2018 and 2017 were $452.7 million and $436.9 million, respectively.

11. PROPERTY, PLANT AND EQUIPMENT

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.

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

ARO as of December 31, 2017	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of September 30, 2018
		(in thousands)			
$ 51,238	$ 1,652	$ —	$ (23,915)	$ 6,792	$ 35,767

12. 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:

	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018
	(in thousands)	
Retail Revenues:		
Residential Revenues	$ 57,960	$ 197,838
Commercial Revenues	38,746	119,293
Industrial Revenues	37,557	120,047
Other Retail Revenues	473	1,469
Total Retail Revenues	134,736	438,647
Wholesale Revenues:		
Generation Revenues (a)	15,201	25,693
Transmission Revenues (a)	5,303	15,173
Total Wholesale Revenues	20,504	40,866
Other Revenues from Contracts with Customers (a)	4,218	13,414
Total Revenues from Contracts with Customers	159,458	492,927
Other Revenues:		
Alternative Revenues	(1,687)	(6,193)
Total Other Revenues	(1,687)	(6,193)
Total Revenues	$ 157,771	$ 486,734

(a) Amounts included affiliated and nonaffiliated revenues.

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 revenue 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 revenue 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 revenue table above.

Fixed Performance Obligations

The following table represents KPCo's remaining fixed performance obligations satisfied over time as of September 30, 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.

2018	2019-2020	2021-2022	After 2022	Total
		(in thousands)		
$ 6,673	$ 9,196	$ 8,825	$ 4,413	$ 29,107

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 September 30, 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 September 30, 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 September 30, 2018. See "Securitized Accounts Receivable - AEP Credit" section of Note 10 for additional information related to AEP Credit's securitized accounts receivable.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on KPCo's balance sheets were \$8.6 million and \$5.2 million, respectively, as of September 30, 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 September 30, 2018.

Kentucky Power Company

2019 First Quarter Report

Financial Statements

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GLOSSARY OF TERMS

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

Term	Meaning
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 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.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ASU	Accounting Standards Update.
Excess ADIT	Excess accumulated deferred income taxes.
FASB	Financial Accounting Standards Board.
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.
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.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MWh	Megawatt-hour.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.
OTC	Over-the-counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PJM	Pennsylvania - New Jersey - Maryland regional transmission organization.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
ROE	Return on Equity.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
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.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2019 and 2018
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
REVENUES		
Electric Generation, Transmission and Distribution	$ 165,536	$ 173,498
Sales to AEP Affiliates	3,777	3,238
Other Revenues	281	280
TOTAL REVENUES	169,594	177,016
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	29,694	15,905
Purchased Electricity for Resale	9,635	19,361
Purchased Electricity from AEP Affiliates	25,595	26,313
Other Operation	26,679	26,952
Maintenance	15,899	17,704
Depreciation and Amortization	24,239	28,294
Taxes Other Than Income Taxes	7,079	6,072
TOTAL EXPENSES	138,820	140,601
OPERATING INCOME	30,774	36,415
Other Income (Expense):		
Interest Income	15	16
Carrying Costs Income	3	5
Allowance for Equity Funds Used During Construction	259	401
Non-Service Cost Components of Net Periodic Benefit Cost	954	1,013
Interest Expense	(8,866)	(9,374)
INCOME BEFORE INCOME TAX EXPENSE	23,139	28,476
Income Tax Expense	2,378	3,978
NET INCOME	$ 20,761	$ 24,498

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

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2019 and 2018
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
Net Income	$ 20,761	$ 24,498
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(2) and $(6) in 2019 and 2018, Respectively	(9)	(22)
TOTAL OTHER COMPREHENSIVE LOSS	(9)	(22)
TOTAL COMPREHENSIVE INCOME	$ 20,752	$ 24,476

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2019 and 2018
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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			24,498		24,498
Other Comprehensive Loss				(22)	(22)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2018	$ 50,450	$ 526,135	$ 117,858	$ 296	$ 694,739
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 50,450	$ 526,135	$ 156,506	$ (212)	$ 732,879
Net Income			20,761		20,761
Other Comprehensive Loss				(9)	(9)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2019	$ 50,450	$ 526,135	$ 177,267	$ (221)	$ 753,631

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2019 and December 31, 2018
(in thousands)
(Unaudited)

	March 31, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 747	$ 1,168
Accounts Receivable:		
Customers	19,003	20,242
Affiliated Companies	24,086	29,018
Accrued Unbilled Revenues	8,609	8,931
Miscellaneous	213	57
Allowance for Uncollectible Accounts	(127)	(85)
Total Accounts Receivable	51,784	58,163
Fuel	14,021	10,621
Materials and Supplies	16,766	17,207
Risk Management Assets	1,337	5,722
Accrued Tax Benefits	1,194	2,732
Regulatory Asset for Under-Recovered Fuel Costs	—	2,379
Margin Deposits	3,633	882
Prepayments and Other Current Assets	3,257	3,203
TOTAL CURRENT ASSETS	92,739	102,077
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,198,000	1,195,701
Transmission	607,303	603,317
Distribution	854,894	845,821
Other Property, Plant and Equipment	97,639	98,280
Construction Work in Progress	97,512	84,748
Total Property, Plant and Equipment	2,855,348	2,827,867
Accumulated Depreciation and Amortization	972,385	961,457
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,882,963	1,866,410
OTHER NONCURRENT ASSETS		
Regulatory Assets	416,480	391,745
Long-term Risk Management Assets	25	159
Employee Benefits and Pension Assets	16,394	15,819
Operating Lease Assets	9,933	—
Deferred Charges and Other Noncurrent Assets	31,216	36,221
TOTAL OTHER NONCURRENT ASSETS	474,048	443,944
TOTAL ASSETS	$ 2,449,750	$ 2,412,431

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2019 and December 31, 2018
(Unaudited)

	March 31, 2019	December 31, 2018
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 34,765	$ 27,871
Accounts Payable:		
General	48,357	51,022
Affiliated Companies	26,078	30,615
Risk Management Liabilities	87	95
Customer Deposits	30,528	30,149
Accrued Taxes	22,457	30,479
Accrued Interest	9,064	6,550
Obligations Under Operating Leases	1,875	—
Regulatory Liability for Over-Recovered Fuel Costs	558	—
Asset Retirement Obligations	31,455	20,961
Other Current Liabilities	19,375	24,213
TOTAL CURRENT LIABILITIES	224,599	221,955
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	867,234	867,128
Long-term Risk Management Liabilities	23	44
Deferred Income Taxes	405,992	402,070
Regulatory Liabilities and Deferred Investment Tax Credits	150,312	155,682
Asset Retirement Obligations	27,805	20,720
Employee Benefits and Pension Obligations	6,002	5,989
Obligations Under Operating Leases	8,035	—
Deferred Credits and Other Noncurrent Liabilities	6,117	5,964
TOTAL NONCURRENT LIABILITIES	1,471,520	1,457,597
TOTAL LIABILITIES	1,696,119	1,679,552
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	526,135	526,135
Retained Earnings	177,267	156,506
Accumulated Other Comprehensive Income (Loss)	(221)	(212)
TOTAL COMMON SHAREHOLDER'S EQUITY	753,631	732,879
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,449,750	$ 2,412,431

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2019 and 2018
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
OPERATING ACTIVITIES		
Net Income	$ 20,761	$ 24,498
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	24,239	28,294
Deferred Income Taxes	(145)	2,299
Allowance for Equity Funds Used During Construction	(259)	(401)
Mark-to-Market of Risk Management Contracts	4,490	375
Property Taxes	5,294	3,753
Deferred Fuel Over/Under-Recovery, Net	2,937	(6,135)
Deferred Rockport Capacity Costs	(3,876)	(3,031)
Change in Other Noncurrent Assets	(3,274)	(11,300)
Change in Other Noncurrent Liabilities	(8,563)	1,695
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	6,539	6,032
Fuel, Materials and Supplies	(2,937)	(2,494)
Margin Deposits	(2,751)	(3,077)
Accounts Payable	(7,427)	(11,499)
Accrued Taxes, Net	(6,484)	(3,627)
Accrued Interest	2,514	(1,071)
Other Current Assets	(106)	6,250
Other Current Liabilities	(3,864)	(5,787)
Net Cash Flows from Operating Activities	27,088	24,774
INVESTING ACTIVITIES		
Construction Expenditures	(34,519)	(35,494)
Other Investing Activities	228	212
Net Cash Flows Used for Investing Activities	(34,291)	(35,282)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	6,894	10,152
Principal Payments for Finance Lease Obligations	(165)	(238)
Other Financing Activities	53	9
Net Cash Flows from Financing Activities	6,782	9,923
Net Decrease in Cash and Cash Equivalents	(421)	(585)
Cash and Cash Equivalents at Beginning of Period	1,168	909
Cash and Cash Equivalents at End of Period	$ 747	$ 324
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 6,167	$ 10,436
Net Cash Paid for Income Taxes	470	—
Noncash Acquisitions Under Finance Leases	358	10
Construction Expenditures Included in Current Liabilities as of March 31,	21,129	12,023

See Condensed Notes to Condensed Financial Statements beginning on page 8.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three months ended March 31, 2019 is not necessarily indicative of results that may be expected for the year ending December 31, 2019. The condensed financial statements are unaudited and should be read in conjunction with the audited 2018 financial statements and notes thereto, which are included in KPCo's 2018 Annual Report.

Subsequent Events

Management reviewed subsequent events through April 25, 2019, the date that the first quarter 2019 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 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. See Note 10 - Leases for additional disclosures required by the new standard.

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 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 three months ended March 31, 2019 and 2018. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 - Benefit Plans for additional details.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2019

	Pension and OPEB
	(in thousands)
Balance in AOCI as of December 31, 2018	$ (212)
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(56)
Amortization of Actuarial (Gains) Losses	45
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(11)
Income Tax (Expense) Benefit	(2)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(9)
Net Current Period Other Comprehensive Income (Loss)	(9)
Balance in AOCI as of March 31, 2019	$ (221)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2018

	Pension and OPEB
	(in thousands)
Balance in AOCI as of December 31, 2017	$ 262
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(56)
Amortization of Actuarial (Gains) Losses	28
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(28)
Income Tax (Expense) Benefit	(6)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(22)
Net Current Period Other Comprehensive Income (Loss)	(22)
ASU 2018-2 Adoption	56
Balance in AOCI as of March 31, 2018	$ 296

4. RATE MATTERS

As discussed in KPCo's 2018 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2018 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2019 and updates KPCo's 2018 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	March 31, 2019	December 31, 2018
	(in thousands)	
Regulatory Assets Currently Earning a Return		
Kentucky Deferred Purchased Power Expenses	$ 18,353	$ 14,477
Regulatory Assets Currently Not Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	1,245	1,148
Total Regulatory Assets Pending Final Regulatory Approval	$ 19,598	$ 15,625

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC Transmission Complaint - AEP's PJM Participants

In October 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 March 2018, AEP's transmission owning subsidiaries within PJM 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 ROE 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 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 ALJ accepted the interim settlement rates. These interim rates are subject to refund or surcharge, with interest. A decision from the FERC is pending.

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.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation 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. The Commitments, Guarantees and Contingencies note within KPCo's 2018 Annual Report should be read in conjunction with this report.

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 March 31, 2019, 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.

6. BENEFIT PLANS

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

Components of Net Periodic Benefit Cost

The following table provides the components of KPCo's net periodic benefit cost (credit) for the plans:

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2019	2018	2019	2018
	(in thousands)			
Service Cost	$ 711	$ 703	$ 65	$ 82
Interest Cost	1,823	1,686	464	431
Expected Return on Plan Assets	(2,727)	(2,651)	(910)	(986)
Amortization of Prior Service Credit	—	—	(606)	(606)
Amortization of Net Actuarial Loss	505	755	214	91
Net Periodic Benefit Cost (Credit)	$ 312	$ 493	$ (773)	$ (988)

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of KPCo.

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

KPCo utilizes power, capacity, 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

	Volume		
Primary Risk Exposure	**March 31, 2019**	**December 31, 2018**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	9,074	12,140	MWhs
Natural Gas	698	698	MMBtus
Heating Oil and Gasoline	239	329	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 March 31, 2019 and December 31, 2018 balance sheets, KPCo netted $399 thousand and $227 thousand, respectively, of cash collateral received from third-parties against short-term and long-term risk management assets and $201 thousand and $117 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
March 31, 2019

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	$ 6,853	$ (5,516)	$ 1,337
Long-term Risk Management Assets	742	(717)	25
Total Assets	7,595	(6,233)	1,362
Current Risk Management Liabilities	5,472	(5,385)	87
Long-term Risk Management Liabilities	673	(650)	23
Total Liabilities	6,145	(6,035)	110
Total MTM Derivative Contract Net Assets (Liabilities)	$ 1,450	$ (198)	$ 1,252

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 (Liabilities)	$ 5,852	$ (110)	$ 5,742

(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)	Three Months Ended March 31, 2019	2018
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 7	$ (166)
Purchased Electricity for Resale	37	59
Other Operation	(15)	13
Maintenance	(14)	14
Regulatory Assets (a)	122	—
Regulatory Liabilities (a)	(1,714)	4,180
Total Gain (Loss) on Risk Management Contracts	$ (1,577)	$ 4,100

(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 three months ended March 31, 2019 and 2018, 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 three months ended March 31, 2019 and 2018, KPCo did not apply cash flow hedging to outstanding interest rate derivatives.

There was no impact of cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets as of March 31, 2019 and December 31, 2018.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes. As of March 31, 2019, 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 the 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 March 31, 2019 and December 31, 2018, 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:

	March 31, 2019	December 31, 2018
	(in thousands)	
Liabilities for Contracts with Cross-Default Provisions Prior to Contractual Netting Arrangements	$ 248	$ 165
Additional Settlement Liability if Cross-Default Provision is Triggered	26	4

8. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

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 derivatives 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.

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:

	March 31, 2019		December 31, 2018	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 867,234	$ 940,833	$ 867,128	$ 903,690

Fair Value Measurements of Financial Assets and Liabilities

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
March 31, 2019

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Assets:					
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 25	$ 5,283	$ 1,542	$ (5,488)	$ 1,362
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 35	$ 5,190	$ 175	$ (5,290)	$ 110

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

(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 three months ended March 31, 2019 and 2018.

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:

Three Months Ended March 31, 2019	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2018	$ 5,804
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(1,852)
Settlements	(2,631)
Transfers out of Level 3 (c)	(120)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	166
Balance as of March 31, 2019	$ 1,367

Three Months Ended March 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)	5,037
Settlements	(5,989)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	273
Balance as of March 31, 2018	$ 1,134

(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) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(d) 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 or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
March 31, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average
	(in thousands)						
Energy Contracts	$ 565	$ 60	Discounted Cash Flow	Forward Market Price	$ 17.40	$ 49.25	$ 34.91
FTRs	977	115	Discounted Cash Flow	Forward Market Price	0.02	2.11	0.63
Total	$ 1,542	$ 175					

Significant Unobservable Inputs
December 31, 2018

	Fair Value		Valuation	Significant Unobservable	Input/Range		Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	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					

(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 March 31, 2019 and December 31, 2018:

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)

9. INCOME TAXES

Effective Tax Rates (ETR)

The interim ETR for KPCo reflects the estimated annual ETR for 2019 adjusted for tax expense associated with certain discrete items. The interim ETR of 10.3% and 14% in 2019 and 2018, respectively, differs from the federal statutory tax rate of 21% primarily due to state income taxes, increased amortization of Excess ADIT and other book/tax differences which are accounted for on a flow-through basis. KPCo includes the amortization of Excess ADIT not subject to normalization requirements in the annual estimated ETR when regulatory proceedings instruct KPCo to provide the benefits of Tax Reform to customers over multiple interim periods. Certain regulatory proceedings may instruct KPCo to provide the benefits of Tax Reform to customers in a single period (e.g. by applying the Excess ADIT not subject to normalization requirements against an existing regulatory asset balance) and in these circumstances, KPCo recognizes the tax benefit discretely in the period recorded.

Three Months Ended March 31, 2019 Compared to Three Months Ended March 31, 2018

The decrease in the ETR was primarily due to increased amortization of $1.8 million Excess ADIT not subject to normalization requirements and an increase in state income taxes which impacted the ETR by (7.9)% and 1.7%, respectively. Amortization of Excess ADIT not subject to normalization requirements for the three months ended March 31, 2019 reflects Tax Reform elements of the June 2018 KPSC Tax Reform order.

Federal and State Income Tax Audit Status

The IRS has completed its examination of KPCo and other AEP subsidiaries for all years through 2016.

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.

10. LEASES

KPCo leases property, plant and equipment including, but not limited to, fleet, information technology and real estate leases. These leases require payments of non-lease components, including related property taxes, operating and maintenance costs. As of the adoption date of ASU 2016-02, management elected not to separate non-lease components from associated lease components in accordance with the accounting guidance for "Leases." Many of these leases have purchase or renewal options. Leases not renewed are often replaced by other leases. Options to renew or purchase a lease are included in the measurement of lease assets and liabilities if it is reasonably certain that KPCo will exercise the option.

Lease obligations are measured using the rate implicit in the lease when that rate is readily determinable. When the implicit rate is not readily determinable, KPCo calculates its lease obligation using its incremental borrowing rate. Spreads to estimate the discount associated with borrowing on a secured basis are incorporated into the calculation.

Lease rentals for both operating and finance leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with finance leases, a finance lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Finance leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs for were as follows:

Lease Rental Costs	Three Months Ended March 31, 2019 (in thousands)
Operating Lease Cost	$ 575
Finance Lease Cost:	
Amortization of Right-of-Use Assets	153
Interest on Lease Liabilities	29
Total Lease Rental Costs (a)	$ 757

(a) Excludes variable and short-term lease costs, which were immaterial for the three months ended March 31, 2019.

Supplemental information related to leases as of and for the three months ended March 31, 2019 are shown in the tables below.

Lease Type	Weighted-Average Remaining Lease Term (years):	Weighted-Average Discount Rate
Operating Leases	6.45	3.79%
Finance Leases	5.98	4.62%

	Three Months Ended March 31, 2019 (in thousands)
Cash paid for amounts included in the measurement of lease liabilities:	
Operating Cash Flows from Operating Leases	$ 627
Operating Cash Flows from Finance Leases	29
Financing Cash Flows from Finance Leases	165
Non-cash Acquisitions Under Operating Leases	$ 455

The following tables show the property, plant and equipment under finance leases and noncurrent assets under operating leases and related obligations recorded on KPCo's balance sheets. Unless shown as a separate line on the balance sheets due to materiality, net operating lease assets are included in Deferred Charges and Other Noncurrent Assets, current finance lease obligations are included in Other Current Liabilities and long-term finance lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets. Lease obligations are not recognized on the balance sheets for lease agreements with a lease term of less than twelve months.

	March 31, 2019 (in thousands)	
Property, Plant and Equipment Under Finance Leases		
Generation	$	1,949
Other Property, Plant and Equipment		2,821
Total Property, Plant and Equipment Under Finance Leases		4,770
Accumulated Amortization		2,047
Net Property, Plant and Equipment Under Finance Leases	$	2,723
Obligations Under Finance Leases		
Noncurrent Liability	$	2,108
Liability Due Within One Year		615
Total Obligations Under Finance Leases	$	2,723

	March 31, 2019 (in thousands)	
Operating Lease Assets	$	9,933
Obligations Under Operating Leases		
Noncurrent Liability	$	8,035
Liability Due Within One Year		1,875
Total Obligations Under Operating Leases	$	9,910

Future minimum lease payments as of March 31, 2019 are presented on a rolling 12-month basis as shown in the table below:

Future Minimum Lease Payments	Finance Leases		Noncancelable Operating Leases	
	(in thousands)			
Year 1	$	733	$	2,275
Year 2		607		2,133
Year 3		522		1,855
Year 4		362		1,495
Year 5		271		1,210
Later Years		718		2,671
Total Future Minimum Lease Payments		3,213		11,639
Less Imputed Interest		490		1,729
Estimated Present Value of Future Minimum Lease Payments	$	2,723	$	9,910

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

Future Minimum Lease Payments	Finance 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 Imputed Interest	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 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 amount guaranteed. As of March 31, 2019, 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.

Lessor Activity

KPCo's lessor activity was immaterial as of and for the three months ended March 31, 2019.

11. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first three months of 2019.

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 March 31, 2019, 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 Federal Power Act restriction does not limit the ability of KPCo 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 March 31, 2019 and December 31, 2018 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the three months ended March 31, 2019 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Average Borrowings from the Utility Money Pool	Borrowings from the Utility Money Pool as of March 31, 2019	Authorized Short-Term Borrowing Limit
	(in thousands)		
$ 35,536	$ 19,987	$ 34,765	$ 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:

Three Months Ended March 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
2019	3.02%	2.73%	—%	—%	2.86%	—%
2018	2.42%	1.83%	2.31%	1.84%	2.00%	1.92%

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 $43.8 million and $43.2 million as of March 31, 2019 and December 31, 2018, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $1.1 million and $935 thousand for the three months ended March 31, 2019 and 2018, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $156.9 million and $167 million for the three months ended March 31, 2019 and 2018, respectively.

12. PROPERTY, PLANT AND EQUIPMENT

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.

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

ARO as of December 31, 2018	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates		ARO as of March 31, 2019
			(in thousands)			
$ 41,681	$ 493	$ —	$ (4,342)	$ 21,428	(a)	$ 59,260

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

13. 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:

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
	(in thousands)	
Retail Revenues:		
Residential Revenues	$ 74,232	$ 80,983
Commercial Revenues	38,673	40,738
Industrial Revenues	39,223	38,972
Other Retail Revenues	511	503
Total Retail Revenues	152,639	161,196
Wholesale Revenues:		
Generation Revenues (a)	7,160	5,752
Transmission Revenues (b)	4,818	6,370
Total Wholesale Revenues	11,978	12,122
Other Revenues from Contracts with Customers	4,051	5,017
Total Revenues from Contracts with Customers	168,668	178,335
Other Revenues:		
Alternative Revenues	926	(1,319)
Total Other Revenues	926	(1,319)
Total Revenues	$ 169,594	$ 177,016

(a) Amounts included affiliated and nonaffiliated revenues.
(b) Amounts included affiliated and nonaffiliated revenues. The affiliated revenues were $2.3 million and $2.9 million, respectively, as of March 31, 2019 and March 31, 2018.

Fixed Performance Obligations

The following table represents KPCo's remaining fixed performance obligations satisfied over time as of March 31, 2019. Fixed performance obligations primarily include wholesale transmission services, electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. KPCo's amounts shown in the table below include affiliated and nonaffiliated revenues.

2019	2020-2021	2022-2023	After 2023	Total
		(in thousands)		
$ 16,136	$ 2,870	$ 2,870	$ 1,435	$ 23,311

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 March 31, 2019 and 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 March 31, 2019 and 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 are not material as of March 31, 2019. See "Securitized Accounts Receivable - AEP Credit" section of Note 11 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 $7.8 million and $8.4 million, respectively, as of March 31, 2019 and December 31, 2018.

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GLOSSARY OF TERMS

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

Term	Meaning
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 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.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARAM	Average Rate Assumption Method, an IRS approved method used to calculate the reversal of Excess ADIT for ratemaking purposes.
ASU	Accounting Standards Update.
Excess ADIT	Excess accumulated deferred income taxes.
FASB	Financial Accounting Standards Board.
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.
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.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MWh	Megawatt-hour.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
ROE	Return on Equity.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to a the “Tax Cut 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.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2019 and 2018
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	**2018**	**2019**	**2018**
REVENUES				
Electric Generation, Transmission and Distribution	$ 137,135	$ 148,779	$ 302,671	$ 322,277
Sales to AEP Affiliates	3,760	2,909	7,537	6,147
Other Revenues	198	259	479	539
TOTAL REVENUES	141,093	151,947	310,687	328,963
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	21,653	22,941	51,347	38,846
Purchased Electricity for Resale	6,822	13,330	16,457	32,691
Purchased Electricity from AEP Affiliates	22,021	25,918	47,616	52,231
Other Operation	27,828	22,151	54,507	49,103
Maintenance	17,268	20,245	33,167	37,949
Depreciation and Amortization	21,742	21,232	45,981	49,526
Taxes Other Than Income Taxes	7,513	6,098	14,592	12,170
TOTAL EXPENSES	124,847	131,915	263,667	272,516
OPERATING INCOME	16,246	20,032	47,020	56,447
Other Income (Expense):				
Interest Income	6	8	21	24
Carrying Costs Income	1	5	4	10
Allowance for Equity Funds Used During Construction	588	587	847	988
Non-Service Cost Components of Net Periodic Benefit Cost	954	1,013	1,908	2,026
Interest Expense	(9,739)	(9,519)	(18,605)	(18,893)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	8,056	12,126	31,195	40,602
Income Tax Expense (Benefit)	555	(1,898)	2,933	2,080
NET INCOME	$ 7,501	$ 14,024	$ 28,262	$ 38,522

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

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2019 and 2018
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	**2018**	**2019**	**2018**
Net Income	$ 7,501	$ 14,024	$ 28,262	$ 38,522
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(3) and $(6) for the Three Months Ended June 30, 2019 and 2018, Respectively, and $(5) and $(12) for the Six Months Ended June 30, 2019 and 2018, Respectively	(9)	(22)	(18)	(44)
TOTAL COMPREHENSIVE INCOME	$ 7,492	$ 14,002	$ 28,244	$ 38,478

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2019 and 2018
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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			24,498		24,498
Other Comprehensive Loss				(22)	(22)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2018	50,450	526,135	117,858	296	694,739
Net Income			14,024		14,024
Other Comprehensive Loss				(22)	(22)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2018	$ 50,450	$ 526,135	$ 131,882	$ 274	$ 708,741
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 50,450	$ 526,135	$ 156,506	$ (212)	$ 732,879
Net Income			20,761		20,761
Other Comprehensive Loss				(9)	(9)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2019	50,450	526,135	177,267	(221)	753,631
Common Stock Dividends			(5,000)		(5,000)
Net Income			7,501		7,501
Other Comprehensive Loss				(9)	(9)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2019	$ 50,450	$ 526,135	$ 179,768	$ (230)	$ 756,123

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2019 and December 31, 2018
(in thousands)
(Unaudited)

	June 30, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 591	$ 1,168
Accounts Receivable:		
Customers	17,261	20,242
Affiliated Companies	22,172	29,018
Accrued Unbilled Revenues	9,745	8,931
Miscellaneous	227	57
Allowance for Uncollectible Accounts	(226)	(85)
Total Accounts Receivable	49,179	58,163
Fuel	22,306	10,621
Materials and Supplies	16,575	17,207
Risk Management Assets	14,693	5,722
Accrued Tax Benefits	9,774	2,732
Regulatory Asset for Under-Recovered Fuel Costs	—	2,379
Margin Deposits	898	882
Prepayments and Other Current Assets	3,869	3,203
TOTAL CURRENT ASSETS	117,885	102,077
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,204,790	1,195,701
Transmission	608,799	603,317
Distribution	864,630	845,821
Other Property, Plant and Equipment	98,747	98,280
Construction Work in Progress	116,560	84,748
Total Property, Plant and Equipment	2,893,526	2,827,867
Accumulated Depreciation and Amortization	983,138	961,457
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,910,388	1,866,410
OTHER NONCURRENT ASSETS		
Regulatory Assets	422,193	391,745
Long-term Risk Management Assets	67	159
Employee Benefits and Pension Assets	16,958	15,819
Operating Lease Assets	9,441	—
Deferred Charges and Other Noncurrent Assets	26,429	36,221
TOTAL OTHER NONCURRENT ASSETS	475,088	443,944
TOTAL ASSETS	$ 2,503,361	$ 2,412,431

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2019 and December 31, 2018
(Unaudited)

	June 30, 2019	December 31, 2018
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 71,439	$ 27,871
Accounts Payable:		
General	75,245	51,022
Affiliated Companies	19,516	30,615
Long-term Debt Due Within One Year – Nonaffiliated	65,000	—
Risk Management Liabilities	1,459	95
Customer Deposits	30,691	30,149
Accrued Taxes	21,679	30,479
Accrued Interest	8,251	6,550
Obligations Under Operating Leases	1,822	—
Regulatory Liability for Over-Recovered Fuel Costs	329	—
Asset Retirement Obligations	31,455	20,961
Other Current Liabilities	20,026	24,213
TOTAL CURRENT LIABILITIES	346,912	221,955
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	802,340	867,128
Long-term Risk Management Liabilities	55	44
Deferred Income Taxes	412,509	402,070
Regulatory Liabilities and Deferred Investment Tax Credits	145,638	155,682
Asset Retirement Obligations	20,078	20,720
Employee Benefits and Pension Obligations	5,722	5,989
Obligations Under Operating Leases	7,603	—
Deferred Credits and Other Noncurrent Liabilities	6,381	5,964
TOTAL NONCURRENT LIABILITIES	1,400,326	1,457,597
TOTAL LIABILITIES	1,747,238	1,679,552
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	526,135	526,135
Retained Earnings	179,768	156,506
Accumulated Other Comprehensive Income (Loss)	(230)	(212)
TOTAL COMMON SHAREHOLDER'S EQUITY	756,123	732,879
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,503,361	$ 2,412,431

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2019 and 2018
(in thousands)
(Unaudited)

	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
OPERATING ACTIVITIES		
Net Income	$ 28,262	$ 38,522
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	45,981	49,526
Deferred Income Taxes	2,791	3,765
Allowance for Equity Funds Used During Construction	(847)	(988)
Mark-to-Market of Risk Management Contracts	(7,504)	(4,653)
Property Taxes	9,932	7,224
Deferred Fuel Over/Under-Recovery, Net	2,708	(2,755)
Change in Other Noncurrent Assets	(16,338)	(20,039)
Change in Other Noncurrent Liabilities	(18,797)	(3,100)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	9,304	10,389
Fuel, Materials and Supplies	(10,987)	(2,852)
Accounts Payable	7,227	(7,409)
Accrued Taxes, Net	(15,842)	(7,938)
Other Current Assets	(691)	9,424
Other Current Liabilities	(1,819)	(5,990)
Net Cash Flows from Operating Activities	33,380	63,126
INVESTING ACTIVITIES		
Construction Expenditures	(72,578)	(69,079)
Other Investing Activities	304	523
Net Cash Flows Used for Investing Activities	(72,274)	(68,556)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	43,568	5,794
Principal Payments for Finance Lease Obligations	(327)	(455)
Dividends Paid on Common Stock	(5,000)	—
Other Financing Activities	76	38
Net Cash Flows from Financing Activities	38,317	5,377
Net Decrease in Cash and Cash Equivalents	(577)	(53)
Cash and Cash Equivalents at Beginning of Period	1,168	909
Cash and Cash Equivalents at End of Period	$ 591	$ 856
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 16,541	$ 18,532
Net Cash Paid (Received) for Income Taxes	7,049	(266)
Noncash Acquisitions Under Finance Leases	475	115
Construction Expenditures Included in Current Liabilities as of June 30,	26,896	17,123

See Condensed Notes to Condensed Financial Statements beginning on page 8.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three and six months ended June 30, 2019 is not necessarily indicative of results that may be expected for the year ending December 31, 2019. The condensed financial statements are unaudited and should be read in conjunction with the audited 2018 financial statements and notes thereto, which are included in KPCo's 2018 Annual Report.

Subsequent Events

Management reviewed subsequent events through July 25, 2019, the date that the second quarter 2019 report was available to be issued.

2. NEW ACCOUNTING PRONOUNCEMENTS

During the 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 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, capital leases are known as finance leases going forward. Leases with terms of 12 months or longer are also subject to the new requirements. Fundamentally, the criteria used to determine lease classification remains the same, but is 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. See Note 10 - Leases for additional disclosures required by the new standard.

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 results of operations, financial position or cash flows. Management plans to adopt ASU 2016-13 and related implementation guidance effective January 1, 2020.

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. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 - Benefit Plans for additional details.

Three Months Ended June 30, 2019	**Pension and OPEB**
	(in thousands)
Balance in AOCI as of March 31, 2019	$ (221)
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(56)
Amortization of Actuarial (Gains) Losses	44
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(12)
Income Tax (Expense) Benefit	(3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(9)
Net Current Period Other Comprehensive Income (Loss)	(9)
Balance in AOCI as of June 30, 2019	$ (230)

Three Months Ended June 30, 2018	**Pension and OPEB**
	(in thousands)
Balance in AOCI as of March 31, 2018	$ 296
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(56)
Amortization of Actuarial (Gains) Losses	28
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(28)
Income Tax (Expense) Benefit	(6)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(22)
Net Current Period Other Comprehensive Income (Loss)	(22)
Balance in AOCI as of June 30, 2018	$ 274

Six Months Ended June 30, 2019	**Pension and OPEB**
	(in thousands)
Balance in AOCI as of December 31, 2018	$ (212)
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(112)
Amortization of Actuarial (Gains) Losses	89
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(23)
Income Tax (Expense) Benefit	(5)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(18)
Net Current Period Other Comprehensive Income (Loss)	(18)
Balance in AOCI as of June 30, 2019	$ (230)

Six Months Ended June 30, 2018	**Pension and OPEB**
	(in thousands)
Balance in AOCI as of December 31, 2017	$ 262
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(112)
Amortization of Actuarial (Gains) Losses	56
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(56)
Income Tax (Expense) Benefit	(12)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(44)
Net Current Period Other Comprehensive Income (Loss)	(44)
ASU 2018-02 Adoption	56
Balance in AOCI as of June 30, 2018	$ 274

4. RATE MATTERS

As discussed in KPCo's 2018 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2018 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2019 and updates KPCo's 2018 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	June 30, 2019	December 31, 2018
	(in thousands)	
Regulatory Assets Currently Earning a Return		
Kentucky Deferred Purchased Power Expenses	$ 22,260	$ 14,477
Regulatory Assets Currently Not Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	1,272	1,148
Total Regulatory Assets Pending Final Regulatory Approval	$ 23,532	$ 15,625

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC Transmission Complaint - AEP's PJM Participants

In October 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 March 2018, AEP's transmission owning subsidiaries within PJM and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). The settlement agreement: (a) establishes a base ROE 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 May 2019, the FERC approved the settlement agreement.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation 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. The Commitments, Guarantees and Contingencies note within KPCo's 2018 Annual Report should be read in conjunction with this report.

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 June 30, 2019, 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.

6. BENEFIT 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.

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost (credit) for the plans:

	Pension Plans		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2019	2018	2019	2018
	(in thousands)			
Service Cost	$ 711	$ 703	$ 66	$ 82
Interest Cost	1,823	1,686	464	432
Expected Return on Plan Assets	(2,728)	(2,652)	(910)	(986)
Amortization of Prior Service Credit	—	—	(606)	(606)
Amortization of Net Actuarial Loss	505	755	212	90
Net Periodic Benefit Cost (Credit)	$ 311	$ 492	$ (774)	$ (988)

	Pension Plans		OPEB	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(in thousands)			
Service Cost	$ 1,422	$ 1,406	$ 131	$ 164
Interest Cost	3,646	3,372	928	863
Expected Return on Plan Assets	(5,455)	(5,303)	(1,820)	(1,972)
Amortization of Prior Service Credit	—	—	(1,212)	(1,212)
Amortization of Net Actuarial Loss	1,010	1,510	426	181
Net Periodic Benefit Cost (Credit)	$ 623	$ 985	$ (1,547)	$ (1,976)

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of KPCo.

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

KPCo utilizes power, capacity, 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 may also utilize 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

	Volume		
Primary Risk Exposure	**June 30, 2019**	**December 31, 2018**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	23,722	12,140	MWhs
Natural Gas	—	698	MMBtus
Heating Oil and Gasoline	351	329	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 may utilize a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo may also utilize 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 June 30, 2019 and December 31, 2018 balance sheets, KPCo netted $88 thousand and $227 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $635 thousand and $117 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
June 30, 2019

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	$ 25,732	$ (11,039)	$ 14,693
Long-term Risk Management Assets	1,299	(1,232)	67
Total Assets	27,031	(12,271)	14,760
Current Risk Management Liabilities	13,026	(11,567)	1,459
Long-term Risk Management Liabilities	1,306	(1,251)	55
Total Liabilities	14,332	(12,818)	1,514
Total MTM Derivative Contract Net Assets	$ 12,699	$ 547	$ 13,246

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 (Liabilities)	$ 5,852	$ (110)	$ 5,742

(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)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
		(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 37	$ (123)	$ 44	$ (289)
Purchased Electricity for Resale	23	37	60	96
Other Operation	—	17	(15)	30
Maintenance	(4)	22	(18)	36
Regulatory Assets (a)	(224)	—	(102)	—
Regulatory Liabilities (a)	2,268	3,551	554	7,731
Total Gain on Risk Management Contracts	$ 2,100	$ 3,504	$ 523	$ 7,604

(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 three and six months ended June 30, 2019 and 2018, 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 three and six months ended June 30, 2019 and 2018, KPCo did not apply cash flow hedging to outstanding interest rate derivatives.

There was no impact of cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets as of June 30, 2019 and December 31, 2018.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes. As of June 30, 2019, 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 the 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 June 30, 2019 and December 31, 2018, 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:

	June 30, 2019	December 31, 2018
	(in thousands)	
Liabilities for Contracts with Cross-Default Provisions Prior to Contractual Netting Arrangements	$ 1,114	$ 165
Additional Settlement Liability if Cross-Default Provision is Triggered	100	4

8. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

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 derivatives 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.

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:

	June 30, 2019		December 31, 2018	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 867,340	$ 960,854	$ 867,128	$ 903,690

Fair Value Measurements of Financial Assets and Liabilities

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
June 30, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 11,868	$ 15,093	$ (12,201)	$ 14,760
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 12,450	$ 1,812	$ (12,748)	$ 1,514

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
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

(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 three and six months ended June 30, 2019 and 2018.

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:

Three Months Ended June 30, 2019	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of March 31, 2019	$ 1,367
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	2,689
Settlements	(3,651)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	12,876
Balance as of June 30, 2019	$ 13,281

Three Months Ended June 30, 2018	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of March 31, 2018	$ 1,134
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	1,687
Settlements	(2,466)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	5,723
Balance as of June 30, 2018	$ 6,078

Six Months Ended June 30, 2019	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of December 31, 2018	$ 5,804
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	1,399
Settlements	(6,600)
Transfers out of Level 3 (c)	(120)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	12,798
Balance as of June 30, 2019	$ 13,281

Six Months Ended June 30, 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)	6,790
Settlements	(8,429)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	5,904
Balance as of June 30, 2018	$ 6,078

(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) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(d) 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 or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
June 30, 2019

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 1,820	$ 457	Discounted Cash Flow	Forward Market Price	$ 12.55	$ 45.35	$ 27.56
FTRs	13,273	1,355	Discounted Cash Flow	Forward Market Price	(0.42)	4.16	1.38
Total	$ 15,093	$ 1,812					

Significant Unobservable Inputs
December 31, 2018

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable 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					

(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 June 30, 2019 and December 31, 2018:

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)

9. INCOME TAXES

Effective Tax Rates (ETR)

The interim ETR for KPCo reflects the estimated annual ETR for 2019 and 2018 adjusted for tax expense associated with certain discrete items. The interim ETR differs from the federal statutory tax rate of 21% primarily due to state income taxes, increased amortization of Excess ADIT and other book/tax differences which are accounted for on a flow-through basis. KPCo includes the amortization of Excess ADIT not subject to normalization requirements in the annual estimated ETR when regulatory proceedings instruct KPCo to provide the benefits of Tax Reform to customers over multiple interim periods. Certain regulatory proceedings may instruct KPCo to provide the benefits of Tax Reform to customers in a single period (e.g. by applying the Excess ADIT not subject to normalization requirements against an existing regulatory asset balance) and in these circumstances, KPCo recognizes the tax benefit discretely in the period recorded.

The ETR for KPCo are included in the following table. Significant variances in the ETR are described below.

Three Months Ended June 30,		Six Months Ended June 30,	
2019	**2018**	**2019**	**2018**
6.9%	(15.7)%	9.4%	5.1%

Three Months Ended June 30, 2019 Compared to Three Months Ended June 30, 2018

The increase in ETR was primarily due to $2.7 million of decreased amortization of Excess ADIT not subject to normalization requirements and $346 thousand of Excess ADIT subject to normalization requirements which impacted the ETR by 19.8% and 1.6%, respectively. Amortization of Excess ADIT not subject to normalization requirements for the three months ended June 30, 2018 reflects Tax Reform elements of the June 2018 KPSC Tax Reform order.

Six Months Ended June 30, 2019 Compared to Six Months Ended June 30, 2018

The increase in ETR was primarily due to $892 thousand of decreased amortization of Excess ADIT not subject to normalization requirements, $686 thousand of decreased amortization of Excess ADIT subject to normalization requirements and $478 thousand of increased state income taxes which impacted the ETR by 0.4%, 0.8% and 1.7%, respectively.

Federal and State Income Tax Audit Status

The IRS has completed its examination of KPCo and other AEP subsidiaries for all years through 2016.

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.

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 Sec. 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.

10. LEASES

KPCo leases property, plant and equipment including, but not limited to, fleet, information technology and real estate leases. These leases require payments of non-lease components, including related property taxes, operating and maintenance costs. As of the adoption date of ASU 2016-02, management elected not to separate non-lease components from associated lease components in accordance with the accounting guidance for "Leases." Many of these leases have purchase or renewal options. Leases not renewed are often replaced by other leases. Options to renew or purchase a lease are included in the measurement of lease assets and liabilities if it is reasonably certain that KPCo will exercise the option.

Lease obligations are measured using the discount rate implicit in the lease when that rate is readily determinable. When the implicit rate is not readily determinable, KPCo measures its lease obligation using its estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk free rate and a secured credit spread relative to the lessee on a matched maturity basis.

Lease rentals for both operating and finance leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with finance leases, a finance lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Finance leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs for were as follows:

Lease Rental Costs	Three Months Ended June 30, 2019	Six Months Ended June 30, 2019
	(in thousands)	
Operating Lease Cost	$ 596	$ 1,171
Finance Lease Cost:		
Amortization of Right-of-Use Assets	159	312
Interest on Lease Liabilities	29	58
Total Lease Rental Costs (a)	$ 784	$ 1,541

(a) Excludes variable and short-term lease costs, which were immaterial for the three and six months ended June 30, 2019.

Supplemental information related to leases as of and for the six months ended June 30, 2019 are shown in the tables below.

Lease Type	Weighted-Average Remaining Lease Term (years):	Weighted-Average Discount Rate
Operating Leases	6.43	3.79%
Finance Leases	5.91	4.57%

	Six Months Ended June 30, 2019
	(in thousands)
Cash paid for amounts included in the measurement of lease liabilities:	
Operating Cash Flows from Operating Leases	$ 1,135
Operating Cash Flows from Finance Leases	58
Financing Cash Flows from Finance Leases	327
Non-cash Acquisitions Under Operating Leases	$ 1,368

The following tables show the property, plant and equipment under finance leases and noncurrent assets under operating leases and related obligations recorded on KPCo's balance sheets. Unless shown as a separate line on the balance sheets due to materiality, net operating lease assets are included in Deferred Charges and Other Noncurrent Assets, current finance lease obligations are included in Other Current Liabilities and long-term finance lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets. Lease obligations are not recognized on the balance sheets for lease agreements with a lease term of less than twelve months.

	June 30, 2019 (in thousands)
Property, Plant and Equipment Under Finance Leases	
Generation	$ 1,949
Other Property, Plant and Equipment	2,853
Total Property, Plant and Equipment Under Finance Leases	4,802
Accumulated Amortization	2,123
Net Property, Plant and Equipment Under Finance Leases	$ 2,679
Obligations Under Finance Leases	
Noncurrent Liability	$ 2,077
Liability Due Within One Year	602
Total Obligations Under Finance Leases	$ 2,679

	June 30, 2019 (in thousands)
Operating Lease Assets	$ 9,441
Obligations Under Operating Leases	
Noncurrent Liability	$ 7,603
Liability Due Within One Year	1,822
Total Obligations Under Operating Leases	$ 9,425

Future minimum lease payments as of June 30, 2019 are presented on a rolling 12-month basis as shown in the table below:

Future Minimum Lease Payments	Finance Leases	Operating Leases
	(in thousands)	
Year 1	$ 718	$ 2,193
Year 2	621	2,004
Year 3	513	1,743
Year 4	345	1,425
Year 5	283	1,097
Later Years	668	2,441
Total Future Minimum Lease Payments	3,148	10,903
Less Imputed Interest	469	1,478
Estimated Present Value of Future Minimum Lease Payments	$ 2,679	$ 9,425

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

Future Minimum Lease Payments	Finance Leases	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 Imputed Interest	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 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 amount guaranteed. As of June 30, 2019, the maximum potential loss for these lease agreements was $1.6 million assuming the fair value of the equipment is zero at the end of the lease term.

Lessor Activity

KPCo's lessor activity was immaterial as of and for the three and six months ended June 30, 2019.

11. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first six months of 2019.

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 June 30, 2019, 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 Federal Power Act restriction does not limit the ability of KPCo 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 its agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of June 30, 2019 and December 31, 2018 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limit for the six months ended June 30, 2019 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Average Borrowings from the Utility Money Pool	Borrowings from the Utility Money Pool as of June 30, 2019	Authorized Short-Term Borrowing Limit
	(in thousands)		
$ 71,439	$ 30,383	$ 71,439	$ 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:

Six Months Ended June 30,	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
2019	3.02%	2.68%	—%	—%	2.78%	—%
2018	2.52%	1.83%	2.51%	1.84%	2.33%	1.93%

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 sold under the sale of receivables agreement were $36.5 million and $43.2 million as of June 30, 2019 and December 31, 2018, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended June 30, 2019 and 2018 were $1 million and $899 thousand, respectively, and for the six months ended June 30, 2019 and 2018 were $2.1 million and $1.8 million, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended June 30, 2019 and 2018 were $125.8 million and $145.2 million, respectively, and for the six months ended June 30, 2019 and 2018 were $282.7 million and $312.1 million, respectively.

12. PROPERTY, PLANT AND EQUIPMENT

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.

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

ARO as of December 31, 2018	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of June 30, 2019
		(in thousands)			
$ 41,681	$ 1,212	$ —	$ (12,788)	$ 21,428	$ 51,533

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

13. 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:

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
	(in thousands)			
Retail Revenues:				
Residential Revenues	$ 50,001	$ 58,895	$ 124,233	$ 139,878
Commercial Revenues	36,441	39,809	75,114	80,547
Industrial Revenues	38,476	43,518	77,699	82,490
Other Retail Revenues	480	493	991	996
Total Retail Revenues	125,398	142,715	278,037	303,911
Wholesale Revenues:				
Generation Revenues (a)	5,445	4,740	12,605	10,492
Transmission Revenues (b)	5,051	3,500	9,869	9,870
Total Wholesale Revenues	10,496	8,240	22,474	20,362
Other Revenues from Contracts with Customers (a)	4,069	4,179	8,120	9,196
Total Revenues from Contracts with Customers	139,963	155,134	308,631	333,469
Other Revenues:				
Alternative Revenues	1,130	(3,187)	2,056	(4,506)
Total Other Revenues	1,130	(3,187)	2,056	(4,506)
Total Revenues	$ 141,093	$ 151,947	$ 310,687	$ 328,963

(a) Amounts included affiliated and nonaffiliated revenues.
(b) Amounts included affiliated and nonaffiliated revenues. The affiliated revenues were $2.5 million and $1.3 million for the three months ended June 30, 2019 and June 30, 2018, respectively and $4.8 million and $4.3 million for the six months ended June 30, 2019 and June 30, 2018, respectively.

Fixed Performance Obligations

The following table represents KPCo's remaining fixed performance obligations satisfied over time as of June 30, 2019. 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)		
$ 12,381	$ 4,364	$ 4,153	$ 1,435	$ 22,333

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 June 30, 2019 and 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 June 30, 2019 and 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 June 30, 2019. See "Securitized Accounts Receivable - AEP Credit" section of Note 11 for additional information related to AEP Credit's securitized accounts receivable.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on KPCo's balance sheets were $6 million and $8.4 million, respectively, as of June 30, 2019 and December 31, 2018.

Kentucky Power Company

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GLOSSARY OF TERMS

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

Term	Meaning
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 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.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ASU	Accounting Standards Update.
Excess ADIT	Excess accumulated deferred income taxes.
FASB	Financial Accounting Standards Board.
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.
IRS	Internal Revenue Service.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MWh	Megawatt-hour.
OATT	Open Access Transmission Tariff.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
ROE	Return on Equity.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the “Tax Cut 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.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2019 and 2018
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
REVENUES				
Electric Generation, Transmission and Distribution	$ 156,170	$ 154,341	$ 458,841	$ 476,618
Sales to AEP Affiliates	5,285	3,122	12,822	9,269
Other Revenues	231	308	710	847
TOTAL REVENUES	161,686	157,771	472,373	486,734
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	33,274	41,677	84,621	80,523
Purchased Electricity for Resale	2,211	1,155	18,668	33,846
Purchased Electricity from AEP Affiliates	26,155	25,697	73,771	77,928
Other Operation	27,702	22,489	82,209	71,592
Maintenance	15,150	15,892	48,317	53,841
Depreciation and Amortization	26,762	23,758	72,743	73,284
Taxes Other Than Income Taxes	7,970	6,021	22,562	18,191
TOTAL EXPENSES	139,224	136,689	402,891	409,205
OPERATING INCOME	22,462	21,082	69,482	77,529
Other Income (Expense):				
Other Income	253	638	1,125	1,660
Non-Service Cost Components of Net Periodic Benefit Cost	954	1,013	2,862	3,039
Interest Expense	(9,882)	(9,450)	(28,487)	(28,343)
INCOME BEFORE INCOME TAX EXPENSE	13,787	13,283	44,982	53,885
Income Tax Expense	133	2,232	3,066	4,312
NET INCOME	$ 13,654	$ 11,051	$ 41,916	$ 49,573

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

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2019 and 2018
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	**2018**	**2019**	**2018**
Net Income	$ 13,654	$ 11,051	$ 41,916	$ 49,573
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(2) and $(6) for the Three Months Ended September 30, 2019 and 2018, Respectively, and $(7) and $(18) for the Nine Months Ended September 30, 2019 and 2018, Respectively	(10)	(23)	(28)	(67)
TOTAL COMPREHENSIVE INCOME	$ 13,644	$ 11,028	$ 41,888	$ 49,506

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2019 and 2018
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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			24,498		24,498
Other Comprehensive Loss				(22)	(22)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2018	50,450	526,135	117,858	296	694,739
Net Income			14,024		14,024
Other Comprehensive Loss				(22)	(22)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2018	50,450	526,135	131,882	274	708,741
Net Income			11,051		11,051
Other Comprehensive Loss				(23)	(23)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2018	$ 50,450	$ 526,135	$ 142,933	$ 251	$ 719,769
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 50,450	$ 526,135	$ 156,506	$ (212)	$ 732,879
Net Income			20,761		20,761
Other Comprehensive Loss				(9)	(9)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2019	50,450	526,135	177,267	(221)	753,631
Common Stock Dividends			(5,000)		(5,000)
Net Income			7,501		7,501
Other Comprehensive Loss				(9)	(9)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2019	50,450	526,135	179,768	(230)	756,123
Net Income			13,654		13,654
Other Comprehensive Loss				(10)	(10)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2019	$ 50,450	$ 526,135	$ 193,422	$ (240)	$ 769,767

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2019 and December 31, 2018
(in thousands)
(Unaudited)

	September 30, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 962	$ 1,168
Accounts Receivable:		
Customers	14,403	20,242
Affiliated Companies	20,633	29,018
Accrued Unbilled Revenues	13,393	8,931
Miscellaneous	76	57
Allowance for Uncollectible Accounts	(459)	(85)
Total Accounts Receivable	48,046	58,163
Fuel	22,172	10,621
Materials and Supplies	17,570	17,207
Risk Management Assets	10,090	5,722
Accrued Tax Benefits	10,661	2,732
Regulatory Asset for Under-Recovered Fuel Costs	—	2,379
Margin Deposits	853	882
Prepayments and Other Current Assets	4,535	3,203
TOTAL CURRENT ASSETS	114,889	102,077
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,204,973	1,195,701
Transmission	615,500	603,317
Distribution	879,121	845,821
Other Property, Plant and Equipment	100,125	98,280
Construction Work in Progress	133,193	84,748
Total Property, Plant and Equipment	2,932,912	2,827,867
Accumulated Depreciation and Amortization	995,511	961,457
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,937,401	1,866,410
OTHER NONCURRENT ASSETS		
Regulatory Assets	422,117	391,745
Long-term Risk Management Assets	31	159
Employee Benefits and Pension Assets	17,533	15,819
Operating Lease Assets	10,191	—
Deferred Charges and Other Noncurrent Assets	22,264	36,221
TOTAL OTHER NONCURRENT ASSETS	472,136	443,944
TOTAL ASSETS	$ 2,524,426	$ 2,412,431

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2019 and December 31, 2018
(Unaudited)

	September 30, 2019	December 31, 2018
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 86,863	$ 27,871
Accounts Payable:		
General	67,162	51,022
Affiliated Companies	23,904	30,615
Long-term Debt Due Within One Year – Nonaffiliated	65,000	—
Risk Management Liabilities	1,289	95
Customer Deposits	30,536	30,149
Accrued Taxes	19,360	30,479
Accrued Interest	7,365	6,550
Obligations Under Operating Leases	1,988	—
Regulatory Liability for Over-Recovered Fuel Costs	1,085	—
Asset Retirement Obligations	31,455	20,961
Other Current Liabilities	21,670	24,213
TOTAL CURRENT LIABILITIES	357,677	221,955
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	802,446	867,128
Long-term Risk Management Liabilities	10	44
Deferred Income Taxes	406,870	402,070
Regulatory Liabilities and Deferred Investment Tax Credits	152,663	155,682
Asset Retirement Obligations	14,689	20,720
Employee Benefits and Pension Obligations	5,853	5,989
Obligations Under Operating Leases	8,163	—
Deferred Credits and Other Noncurrent Liabilities	6,288	5,964
TOTAL NONCURRENT LIABILITIES	1,396,982	1,457,597
TOTAL LIABILITIES	1,754,659	1,679,552
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	526,135	526,135
Retained Earnings	193,422	156,506
Accumulated Other Comprehensive Income (Loss)	(240)	(212)
TOTAL COMMON SHAREHOLDER'S EQUITY	769,767	732,879
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,524,426	$ 2,412,431

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2019 and 2018
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2019	2018
OPERATING ACTIVITIES		
Net Income	$ 41,916	$ 49,573
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	72,743	73,284
Deferred Income Taxes	2,000	2,442
Allowance for Equity Funds Used During Construction	(1,104)	(1,607)
Mark-to-Market of Risk Management Contracts	(3,080)	(4,878)
Property Taxes	14,574	10,778
Deferred Fuel Over/Under-Recovery, Net	3,464	(2,468)
Change in Other Noncurrent Assets	(22,959)	(25,930)
Change in Other Noncurrent Liabilities	(25,542)	(12,185)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	10,598	12,548
Fuel, Materials and Supplies	(11,766)	9,744
Accounts Payable	6,840	(8,536)
Accrued Taxes, Net	(19,048)	(5,998)
Other Current Assets	(1,354)	8,294
Other Current Liabilities	(3,177)	(3,696)
Net Cash Flows from Operating Activities	64,105	101,365
INVESTING ACTIVITIES		
Construction Expenditures	(118,363)	(104,412)
Other Investing Activities	411	1,035
Net Cash Flows Used for Investing Activities	(117,952)	(103,377)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	58,992	2,418
Principal Payments for Finance Lease Obligations	(480)	(655)
Dividends Paid on Common Stock	(5,000)	—
Other Financing Activities	129	38
Net Cash Flows from Financing Activities	53,641	1,801
Net Decrease in Cash and Cash Equivalents	(206)	(211)
Cash and Cash Equivalents at Beginning of Period	1,168	909
Cash and Cash Equivalents at End of Period	$ 962	$ 698
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 27,126	$ 26,481
Net Cash Paid (Received) for Income Taxes	8,860	(166)
Noncash Acquisitions Under Finance Leases	761	147
Construction Expenditures Included in Current Liabilities as of September 30,	24,997	13,489

See Condensed Notes to Condensed Financial Statements beginning on page 8.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair statement of the net income, financial position and cash flows for the interim periods. Net income for the three and nine months ended September 30, 2019 is not necessarily indicative of results that may be expected for the year ending December 31, 2019. The condensed financial statements are unaudited and should be read in conjunction with the audited 2018 financial statements and notes thereto, which are included in KPCo's 2018 Annual Report.

Subsequent Events

Management reviewed subsequent events through October 24, 2019, the date that the third quarter 2019 report was available to be issued.

2. NEW ACCOUNTING STANDARDS

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

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, capital leases are known as finance leases going forward. Leases with terms of 12 months or longer are also subject to the new requirements. Fundamentally, the criteria used to determine lease classification remains the same, but is 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. See Note 10 - Leases for additional disclosures required by the new standard.

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

In June 2016, the FASB issued ASU 2016-13 requiring the recognition of an allowance for expected credit losses for financial instruments within its scope. Examples of financial instruments that are in scope include trade receivables, certain financial guarantees, and held-to-maturity debt securities. The allowance for expected credit losses should be based on historical information, current conditions and reasonable and supportable forecasts. The new standard also revises the other-than-temporary impairment model for available-for-sale debt securities.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019, with early adoption permitted for interim and annual periods beginning after December 15, 2018. The amendments will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective.

Management continues to analyze the impact of this new standard. Implementation activities to date include the identification of the population of financial instruments within KPCo that are subject to the new standard, and evaluations to determine whether the new expected loss recognition model will cause any material changes to previously calculated allowance balances and supporting valuation models. Based on the assessments performed to date, Management does not expect the new standard to have a material impact on results of operations, financial position or cash flows.

Management's implementation activities, including an assessment of the new standard's disclosure requirements will continue throughout the fourth quarter of 2019. Management will continue to analyze the related impacts to allowances for credit losses and monitor for any potential industry implementation issues. Additionally, Management does not anticipate any significant changes to current accounting systems because of the adoption of the new standard. Management plans to adopt ASU 2016-13 and its related implementation guidance 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. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 - Benefit Plans for additional details.

Three Months Ended September 30, 2019	Pension and OPEB
	(in thousands)
Balance in AOCI as of June 30, 2019	$ (230)
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(55)
Amortization of Actuarial (Gains) Losses	43
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(12)
Income Tax (Expense) Benefit	(2)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(10)
Net Current Period Other Comprehensive Income (Loss)	(10)
Balance in AOCI as of September 30, 2019	$ (240)

Three Months Ended September 30, 2018	Pension and OPEB
	(in thousands)
Balance in AOCI as of June 30, 2018	$ 274
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(56)
Amortization of Actuarial (Gains) Losses	27
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(29)
Income Tax (Expense) Benefit	(6)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(23)
Net Current Period Other Comprehensive Income (Loss)	(23)
Balance in AOCI as of September 30, 2018	$ 251

Nine Months Ended September 30, 2019	Pension and OPEB
	(in thousands)
Balance in AOCI as of December 31, 2018	$ (212)
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(167)
Amortization of Actuarial (Gains) Losses	132
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(35)
Income Tax (Expense) Benefit	(7)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(28)
Net Current Period Other Comprehensive Income (Loss)	(28)
Balance in AOCI as of September 30, 2019	$ (240)

Nine Months Ended September 30, 2018	Pension and OPEB
	(in thousands)
Balance in AOCI as of December 31, 2017	$ 262
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(168)
Amortization of Actuarial (Gains) Losses	83
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(85)
Income Tax (Expense) Benefit	(18)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(67)
Net Current Period Other Comprehensive Income (Loss)	(67)
ASU 2018-02 Adoption	56
Balance in AOCI as of September 30, 2018	$ 251

4. RATE MATTERS

As discussed in KPCo's 2018 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2018 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2019 and updates KPCo's 2018 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	September 30, 2019	December 31, 2018
	(in thousands)	
Regulatory Assets Currently Earning a Return		
Kentucky Deferred Purchased Power Expenses	$ 26,197	$ 14,477
Regulatory Assets Currently Not Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	1,299	1,148
Total Regulatory Assets Pending Final Regulatory Approval	$ 27,496	$ 15,625

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC Transmission Complaint - AEP's PJM Participants

In October 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 March 2018, AEP's transmission owning subsidiaries within PJM and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). The settlement agreement: (a) established a base ROE 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) required 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) increased 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 rate normalization requirements over a ten-year period through credits to the federal income tax expense component of the revenue requirement. In May 2019, the FERC approved the settlement agreement.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation 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. The Commitments, Guarantees and Contingencies note within KPCo's 2018 Annual Report should be read in conjunction with this report.

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 September 30, 2019, 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.

6. BENEFIT 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.

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost (credit) for the plans:

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Service Cost	$ 711	$ 703	$ 65	$ 82
Interest Cost	1,823	1,687	464	431
Expected Return on Plan Assets	(2,728)	(2,651)	(910)	(985)
Amortization of Prior Service Credit	—	—	(606)	(607)
Amortization of Net Actuarial Loss	506	754	214	91
Net Periodic Benefit Cost (Credit)	$ 312	$ 493	$ (773)	$ (988)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Service Cost	$ 2,133	$ 2,109	$ 196	$ 246
Interest Cost	5,469	5,059	1,392	1,294
Expected Return on Plan Assets	(8,183)	(7,954)	(2,730)	(2,957)
Amortization of Prior Service Credit	—	—	(1,818)	(1,819)
Amortization of Net Actuarial Loss	1,516	2,264	640	272
Net Periodic Benefit Cost (Credit)	$ 935	$ 1,478	$ (2,320)	$ (2,964)

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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 may also utilize 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

	Volume		
Primary Risk Exposure	**September 30, 2019**	**December 31, 2018**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	18,515	12,140	MWhs
Natural Gas	—	698	MMBtus
Heating Oil and Gasoline	374	329	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 may utilize a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo may also utilize 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 September 30, 2019 and December 31, 2018 balance sheets, KPCo netted $0 thousand and $227 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $288 thousand and $117 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
September 30, 2019

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	$ 16,164	$ (6,074)	$ 10,090
Long-term Risk Management Assets	803	(772)	31
Total Assets	16,967	(6,846)	10,121
Current Risk Management Liabilities	7,612	(6,323)	1,289
Long-term Risk Management Liabilities	821	(811)	10
Total Liabilities	8,433	(7,134)	1,299
Total MTM Derivative Contract Net Assets	$ 8,534	$ 288	$ 8,822

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 (Liabilities)	$ 5,852	$ (110)	$ 5,742

(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)	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
		(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 218	$ (114)	$ 262	$ (403)
Purchased Electricity for Resale	37	20	97	116
Other Operation	(5)	18	(20)	48
Maintenance	(6)	26	(24)	62
Regulatory Assets (a)	(579)	—	(681)	—
Regulatory Liabilities (a)	3,226	2,279	3,780	10,010
Total Gain on Risk Management Contracts	$ 2,891	$ 2,229	$ 3,414	$ 9,833

(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 three and nine months ended September 30, 2019 and 2018, 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 three and nine months ended September 30, 2019 and 2018, KPCo did not apply cash flow hedging to outstanding interest rate derivatives.

There was no impact of cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets as of September 30, 2019 and December 31, 2018.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes. As of September 30, 2019, 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 the 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 September 30, 2019 and December 31, 2018, 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:

	September 30, 2019	December 31, 2018
	(in thousands)	
Liabilities for Contracts with Cross-Default Provisions Prior to Contractual Netting Arrangements	$ 714	$ 165
Additional Settlement Liability if Cross-Default Provision is Triggered	38	4

8. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

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 derivatives 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.

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:

	September 30, 2019		December 31, 2018	
	Book Value	**Fair Value**	**Book Value**	**Fair Value**
		(in thousands)		
Long-term Debt	$ 867,446	$ 985,284	$ 867,128	$ 903,690

Fair Value Measurements of Financial Assets and Liabilities

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
September 30, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 6,340	$ 10,297	$ (6,516)	$ 10,121
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 6,399	$ 1,704	$ (6,804)	$ 1,299

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
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

(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 three and nine months ended September 30, 2019 and 2018.

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:

Three Months Ended September 30, 2019	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of June 30, 2019	$ 13,281
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	3,125
Settlements	(7,118)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	(695)
Balance as of September 30, 2019	$ 8,593

Three Months Ended September 30, 2018	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of June 30, 2018	$ 6,078
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	1,685
Settlements	(2,929)
Transfers out of Level 3 (c)	(1)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	2,103
Balance as of September 30, 2018	$ 6,936

Nine Months Ended September 30, 2019	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2018	$ 5,804
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	1,248
Settlements	(6,657)
Transfers out of Level 3 (c)	(120)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	8,318
Balance as of September 30, 2019	$ 8,593

Nine Months Ended September 30, 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)	6,704
Settlements	(8,383)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	6,802
Balance as of September 30, 2018	$ 6,936

(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) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(d) 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 or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
September 30, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 667	$ 205	Discounted Cash Flow	Forward Market Price	$ 12.93	$ 59.25	$ 31.28
FTRs	9,630	1,499	Discounted Cash Flow	Forward Market Price	(1.48)	7.26	1.29
Total	$ 10,297	$ 1,704					

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					

(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 September 30, 2019 and December 31, 2018:

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)

9. INCOME TAXES

Effective Tax Rates (ETR)

The interim ETR for KPCo reflects the estimated annual ETR for 2019 and 2018 adjusted for tax expense associated with certain discrete items. The interim ETR differs from the federal statutory tax rate of 21% primarily due to state income taxes, increased amortization of Excess ADIT and other book/tax differences which are accounted for on a flow-through basis. KPCo includes the amortization of Excess ADIT not subject to normalization requirements in the annual estimated ETR when regulatory proceedings instruct KPCo to provide the benefits of Tax Reform to customers over multiple interim periods. Certain regulatory proceedings may instruct KPCo to provide the benefits of Tax Reform to customers in a single period (e.g. by applying the Excess ADIT not subject to normalization requirements against an existing regulatory asset balance) and in these circumstances, KPCo recognizes the tax benefit discretely in the period recorded.

The ETR for KPCo are included in the following table. Significant variances in the ETR are described below.

Three Months Ended September 30,		Nine Months Ended September 30,	
2019	**2018**	**2019**	**2018**
1.0%	16.8%	6.8%	8.0%

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

The decrease in ETR was primarily due to $1.3 million of increased amortization of Excess ADIT not subject to normalization requirements, $565 thousand of increased amortization of Excess ADIT subject to normalization requirements and $418 thousand of decreased state tax expense which impacted the ETR by (9.2%), (4.0%), and (3.2%), respectively.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

The decrease in ETR was primarily due to $406 thousand of increased amortization of Excess ADIT not subject to normalization requirements which impacted the ETR by (2.4%).

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination by the IRS for all years through 2013. During the IRS examination of years 2011 through 2014, the statute of limitations for these years was extended to coincide with the examination of 2015. During the third quarter of 2019, KPCo and other AEP subsidiaries amended the 2014 and 2015 federal returns. Due to the amendment of these federal returns, the 2014 and 2015 years will remain open for possible IRS examination of the items that were amended on the 2014 and 2015 federal returns. The IRS examination of 2016 began in October 2018 and concluded in March 2019.

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 Sec. 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.

10. LEASES

KPCo leases property, plant and equipment including, but not limited to, fleet, information technology and real estate leases. These leases require payments of non-lease components, including related property taxes, operating and maintenance costs. As of the adoption date of ASU 2016-02, management elected not to separate non-lease components from associated lease components in accordance with the accounting guidance for "Leases." Many of these leases have purchase or renewal options. Leases not renewed are often replaced by other leases. Options to renew or purchase a lease are included in the measurement of lease assets and liabilities if it is reasonably certain that KPCo will exercise the option.

Lease obligations are measured using the discount rate implicit in the lease when that rate is readily determinable. When the implicit rate is not readily determinable, KPCo measures its lease obligation using its estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk free rate and a secured credit spread relative to the lessee on a matched maturity basis.

Lease rentals for both operating and finance leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with finance leases, a finance 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	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2019
	(in thousands)	
Operating Lease Cost	$ 544	$ 1,715
Finance Lease Cost:		
Amortization of Right-of-Use Assets	168	480
Interest on Lease Liabilities	27	85
Total Lease Rental Costs (a)	$ 739	$ 2,280

(a) Excludes variable and short-term lease costs, which were immaterial for the three and nine months ended September 30, 2019.

Supplemental information related to leases as of and for the nine months ended September 30, 2019 are shown in the tables below.

Lease Type	Weighted-Average Remaining Lease Term (years):	Weighted-Average Discount Rate
Operating Leases	6.47	3.76%
Finance Leases	5.83	4.53%

	Nine Months Ended September 30, 2019
	(in thousands)
Cash paid for amounts included in the measurement of lease liabilities:	
Operating Cash Flows Used for Operating Leases	$ 1,686
Operating Cash Flows Used for Finance Leases	85
Financing Cash Flows Used for Finance Leases	480
Non-cash Acquisitions Under Operating Leases	$ 1,426

The following tables show the property, plant and equipment under finance leases and noncurrent assets under operating leases and related obligations recorded on KPCo's balance sheets. Unless shown as a separate line on the balance sheets due to materiality, net operating lease assets are included in Deferred Charges and Other Noncurrent Assets, current finance lease obligations are included in Other Current Liabilities and long-term finance lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets. Lease obligations are not recognized on the balance sheets for lease agreements with a lease term of less than twelve months.

		September 30, 2019 (in thousands)
Property, Plant and Equipment Under Finance Leases		
Generation	$	1,445
Other Property, Plant and Equipment		2,993
Total Property, Plant and Equipment Under Finance Leases		4,438
Accumulated Amortization		1,686
Net Property, Plant and Equipment Under Finance Leases	$	2,752
Obligations Under Finance Leases		
Noncurrent Liability	$	2,176
Liability Due Within One Year		621
Total Obligations Under Finance Leases	$	2,797

		September 30, 2019 (in thousands)
Operating Lease Assets	$	10,191
Obligations Under Operating Leases		
Noncurrent Liability	$	8,163
Liability Due Within One Year		1,988
Total Obligations Under Operating Leases	$	10,151

Future minimum lease payments as of September 30, 2019 are presented on a rolling 12-month basis as shown in the table below:

Future Minimum Lease Payments		Finance Leases		Operating Leases
		(in thousands)		
Year 1	$	728	$	2,377
Year 2		666		2,185
Year 3		535		1,845
Year 4		365		1,493
Year 5		321		1,134
Later Years		643		2,672
Total Future Minimum Lease Payments		3,258		11,706
Less Imputed Interest		461		1,555
Estimated Present Value of Future Minimum Lease Payments	$	2,797	$	10,151

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

Future Minimum Lease Payments	**Finance Leases**	**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 Imputed Interest	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 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 amount guaranteed. As of September 30, 2019, 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.

Lessor Activity

KPCo's lessor activity was immaterial as of and for the three and nine months ended September 30, 2019.

11. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first nine months of 2019.

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 September 30, 2019, 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 Federal Power Act restriction does not limit the ability of KPCo 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 its agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of September 30, 2019 and December 31, 2018 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limit for the nine months ended September 30, 2019 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Average Borrowings from the Utility Money Pool	Borrowings from the Utility Money Pool as of September 30, 2019	Authorized Short-Term Borrowing Limit
	(in thousands)		
$ 93,532	$ 46,885	$ 86,863	$ 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:

Nine Months Ended September 30,	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
2019	3.43%	1.83%	—%	—%	2.60%	—%
2018	2.52%	1.81%	2.51%	1.82%	2.30%	1.96%

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 expires in July 2021.

KPCo's amounts of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement were $37 million and $43.2 million as of September 30, 2019 and December 31, 2018, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended September 30, 2019 and 2018 were $926 thousand and $954 thousand, respectively, and for the nine months ended September 30, 2019 and 2018 were $3 million and $2.8 million, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended September 30, 2019 and 2018 were $141.6 million and $140.6 million, respectively, and for the nine months ended September 30, 2019 and 2018 were $424.3 million and $452.7 million, respectively.

12. PROPERTY, PLANT AND EQUIPMENT

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.

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

ARO as of December 31, 2018	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of September 30, 2019
		(in thousands)			
$ 41,681	$ 1,842	$ —	$ (18,807)	$ 21,428	$ 46,144

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

13. 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:

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(in thousands)			
Retail Revenues:				
Residential Revenues	$ 61,711	$ 57,960	$ 185,944	$ 197,838
Commercial Revenues	39,839	38,746	114,953	119,293
Industrial Revenues	37,998	37,557	115,697	120,047
Other Retail Revenues	481	473	1,472	1,469
Total Retail Revenues	140,029	134,736	418,066	438,647
Wholesale Revenues:				
Generation Revenues (a)	12,635	15,201	25,240	25,693
Transmission Revenues (b)	4,628	5,303	14,497	15,173
Total Wholesale Revenues	17,263	20,504	39,737	40,866
Other Revenues from Contracts with Customers (a)	3,484	4,218	11,604	13,414
Total Revenues from Contracts with Customers	160,776	159,458	469,407	492,927
Other Revenues:				
Alternative Revenues	910	(1,687)	2,966	(6,193)
Total Other Revenues	910	(1,687)	2,966	(6,193)
Total Revenues	$ 161,686	$ 157,771	$ 472,373	$ 486,734

(a) Amounts included affiliated and nonaffiliated revenues.
(b) Amounts included affiliated and nonaffiliated revenues. The affiliated revenues were $2 million and $2.4 million for the three months ended September 30, 2019 and September 30, 2018, respectively, and $6.8 million and $6.7 million for the nine months ended September 30, 2019 and September 30, 2018, respectively.

Fixed Performance Obligations

The following table represents KPCo's remaining fixed performance obligations satisfied over time as of September 30, 2019. 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)		
$ 6,275	$ 4,504	$ 2,870	$ 1,435	$ 15,084

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 material contract assets as of September 30, 2019 and 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 material contract liabilities as of September 30, 2019 and 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 September 30, 2019. See "Securitized Accounts Receivable - AEP Credit" section of Note 11 for additional information related to AEP Credit's securitized accounts receivable.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on KPCo's balance sheets were \$6.5 million and \$8.4 million, respectively, as of September 30, 2019 and December 31, 2018.

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GLOSSARY OF TERMS

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

Term	Meaning
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 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.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ASU	Accounting Standards Update.
COVID-19	Coronavirus 2019, a highly infectious respiratory disease. In March 2020, the World Health Organization declared COVID-19 a worldwide pandemic.
Excess ADIT	Excess accumulated deferred income taxes.
FASB	Financial Accounting Standards Board.
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.
IRS	Internal Revenue Service.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MTM	Mark-to-Market.
MWh	Megawatt-hour.
OPEB	Other Postretirement Benefits.
OTC	Over the counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
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.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2020 and 2019
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2020	2019
REVENUES		
Electric Generation, Transmission and Distribution	$ 143,959	$ 165,536
Sales to AEP Affiliates	3,430	3,777
Other Revenues	244	281
TOTAL REVENUES	147,633	169,594
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	23,980	29,694
Purchased Electricity for Resale	13,267	9,635
Purchased Electricity from AEP Affiliates	15,487	25,595
Other Operation	23,008	26,679
Maintenance	14,953	15,899
Depreciation and Amortization	24,420	24,239
Taxes Other Than Income Taxes	6,927	7,079
TOTAL EXPENSES	122,042	138,820
OPERATING INCOME	25,591	30,774
Other Income (Expense):		
Other Income	31	277
Non-Service Cost Components of Net Periodic Benefit Cost	1,014	954
Interest Expense	(9,916)	(8,866)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	16,720	23,139
Income Tax Expense (Benefit)	(2,115)	2,378
NET INCOME	$ 18,835	$ 20,761

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

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2020 and 2019
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2020	Three Months Ended March 31, 2019
Net Income	$ 18,835	$ 20,761
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(7) and $(2) in 2020 and 2019, Respectively	(27)	(9)
TOTAL COMPREHENSIVE INCOME	$ 18,808	$ 20,752

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2020 and 2019
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 50,450	$ 526,135	$ 156,506	$ (212)	$ 732,879
Net Income			20,761		20,761
Other Comprehensive Loss				(9)	(9)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2019	$ 50,450	$ 526,135	$ 177,267	$ (221)	$ 753,631
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 50,450	$ 526,135	$ 204,806	$ 790	$ 782,181
ASU 2016-13 Adoption			48		48
Net Income			18,835		18,835
Other Comprehensive Loss				(27)	(27)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2020	$ 50,450	$ 526,135	$ 223,689	$ 763	$ 801,037

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2020 and December 31, 2019
(in thousands)
(Unaudited)

	March 31, 2020	December 31, 2019
CURRENT ASSETS		
Cash and Cash Equivalents	$ 629	$ 849
Accounts Receivable:		
Customers	10,813	14,749
Affiliated Companies	21,782	20,663
Accrued Unbilled Revenues	11,543	13,550
Miscellaneous	88	145
Allowance for Uncollectible Accounts	(531)	(346)
Total Accounts Receivable	43,695	48,761
Fuel	23,552	29,855
Materials and Supplies	17,623	18,011
Risk Management Assets	3,457	6,878
Accrued Tax Benefits	3,944	2,205
Margin Deposits	364	600
Prepayments and Other Current Assets	2,251	2,892
TOTAL CURRENT ASSETS	95,515	110,051
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,227,916	1,219,454
Transmission	655,226	651,091
Distribution	919,296	897,247
Other Property, Plant and Equipment	115,733	112,529
Construction Work in Progress	91,925	98,671
Total Property, Plant and Equipment	3,010,096	2,978,992
Accumulated Depreciation and Amortization	1,017,550	1,005,546
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,992,546	1,973,446
OTHER NONCURRENT ASSETS		
Regulatory Assets	431,128	421,621
Long-term Risk Management Assets	22	25
Employee Benefits and Pension Assets	23,900	23,421
Operating Lease Assets	10,838	10,120
Deferred Charges and Other Noncurrent Assets	28,139	33,815
TOTAL OTHER NONCURRENT ASSETS	494,027	489,002
TOTAL ASSETS	$ 2,582,088	$ 2,572,499

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2020 and December 31, 2019
(Unaudited)

	March 31, 2020	December 31, 2019
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 10,685	$ 113,175
Accounts Payable:		
General	43,665	63,350
Affiliated Companies	21,938	23,449
Long-term Debt Due Within One Year – Nonaffiliated	65,000	65,000
Risk Management Liabilities	1,931	1,480
Customer Deposits	31,261	30,954
Accrued Taxes	21,496	33,108
Accrued Interest	6,609	6,365
Obligations Under Operating Leases	2,132	2,005
Regulatory Liability for Over-Recovered Fuel Costs	3,546	223
Asset Retirement Obligations	15,480	15,480
Other Current Liabilities	22,405	25,080
TOTAL CURRENT LIABILITIES	246,148	379,669
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	927,617	802,553
Long-term Risk Management Liabilities	21	1
Deferred Income Taxes	424,669	421,858
Regulatory Liabilities and Deferred Investment Tax Credits	134,670	135,686
Asset Retirement Obligations	25,144	28,108
Employee Benefits and Pension Obligations	7,460	7,496
Obligations Under Operating Leases	8,738	8,154
Deferred Credits and Other Noncurrent Liabilities	6,584	6,793
TOTAL NONCURRENT LIABILITIES	1,534,903	1,410,649
TOTAL LIABILITIES	1,781,051	1,790,318
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	526,135	526,135
Retained Earnings	223,689	204,806
Accumulated Other Comprehensive Income (Loss)	763	790
TOTAL COMMON SHAREHOLDER'S EQUITY	801,037	782,181
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,582,088	$ 2,572,499

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2020 and 2019
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2020	Three Months Ended March 31, 2019
OPERATING ACTIVITIES		
Net Income	$ 18,835	$ 20,761
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	24,420	24,239
Deferred Income Taxes	(377)	(145)
Allowance for Equity Funds Used During Construction	23	(259)
Mark-to-Market of Risk Management Contracts	3,895	4,490
Property Taxes	5,356	5,294
Deferred Fuel Over/Under-Recovery, Net	3,323	2,937
Deferred Rockport Capacity Costs	(2,745)	(3,876)
Change in Other Noncurrent Assets	(9,643)	(3,274)
Change in Other Noncurrent Liabilities	(4,613)	(8,563)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	5,244	6,539
Fuel, Materials and Supplies	6,686	(2,937)
Margin Deposits	236	(2,751)
Accounts Payable	(11,697)	(7,427)
Accrued Taxes, Net	(13,351)	(6,484)
Accrued Interest	244	2,514
Other Current Assets	604	(106)
Other Current Liabilities	(1,338)	(3,864)
Net Cash Flows from Operating Activities	25,102	27,088
INVESTING ACTIVITIES		
Construction Expenditures	(47,962)	(34,519)
Other Investing Activities	269	228
Net Cash Flows Used for Investing Activities	(47,693)	(34,291)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	124,955	—
Change in Advances from Affiliates, Net	(102,490)	6,894
Principal Payments for Finance Lease Obligations	(190)	(165)
Other Financing Activities	96	53
Net Cash Flows from Financing Activities	22,371	6,782
Net Decrease in Cash and Cash Equivalents	(220)	(421)
Cash and Cash Equivalents at Beginning of Period	849	1,168
Cash and Cash Equivalents at End of Period	$ 629	$ 747
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 9,746	$ 6,167
Net Cash Paid for Income Taxes	—	470
Noncash Acquisitions Under Finance Leases	568	358
Construction Expenditures Included in Current Liabilities as of March 31,	20,981	21,129

See Condensed Notes to Condensed Financial Statements beginning on page 8.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair statement of the net income, financial position and cash flows for the interim periods. Net income for the three months ended March 31, 2020 is not necessarily indicative of results that may be expected for the year ending December 31, 2020. The condensed financial statements are unaudited and should be read in conjunction with the audited 2019 financial statements and notes thereto, which are included in KPCo's 2019 Annual Report.

COVID-19

In March 2020, COVID-19 was declared a pandemic by the World Health Organization and the Centers for Disease Control and Prevention. Its rapid spread around the world and throughout the United States prompted many countries, including the United States, to institute restrictions on travel, public gatherings and certain business operations. These restrictions significantly disrupted economic activity in AEP's service territory and could reduce future demand for energy, particularly from commercial and industrial customers. KPCo is taking steps to mitigate the potential risks to customers, suppliers and employees posed by the spread of COVID-19.

As of March 31, 2020 and through the date of this report, KPCo assessed certain accounting matters that require consideration of forecasted financial information, including, but not limited to, the allowance for credit losses and the carrying value of long-lived assets. While there were not any impairments or significant increases in credit allowances resulting from these assessments as of and for the quarter ended March 31, 2020, the ultimate impact of COVID-19 also depends on factors beyond management's knowledge or control, including the duration and severity of this outbreak as well as third-party actions taken to contain its spread and mitigate its public health effects. Therefore, management cannot estimate the potential future impact to financial position, results of operations and cash flows, but the impacts could be material.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense related to receivables purchased from KPCo under a sale of receivables agreement. The assessment is performed separately by each participating AEP subsidiary, which inherently contemplates any differences in geographical risk characteristics for the allowance. 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 based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable, unless specifically identified. In addition to these processes, management contemplates available current information, as well as any reasonable and supportable forecast information, to determine if allowances for uncollectible accounts should be further adjusted in accordance with the accounting guidance for Credit Losses. Management's assessments contemplate expected losses over the life of the accounts receivable.

Subsequent Events

Management reviewed subsequent events through May 6, 2020, the date that the first quarter 2020 report was available to be issued.

2. NEW ACCOUNTING STANDARDS

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

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

In June 2016, the FASB issued ASU 2016-13 requiring the recognition of an allowance for expected credit losses for financial instruments within its scope. Examples of financial instruments that are in scope include trade receivables, certain financial guarantees and held-to-maturity debt securities. The allowance for expected credit losses should be based on historical information, current conditions and reasonable and supportable forecasts. Entities are required to evaluate, and if necessary, recognize expected credit losses at the inception or initial acquisition of a financial instrument (or pool of financial instruments that share similar risk characteristics) subject to ASU 2016-13, and subsequently as of each reporting date. The new standard also revises the other-than-temporary impairment model for available-for-sale debt securities.

New standard implementation activities included: (a) the identification and evaluation of the population of financial instruments within the AEP system that are subject to the new standard, (b) the development of supporting valuation models to also contemplate appropriate metrics for current and supportable forecasted information and (c) the development of disclosures to comply with the requirements of ASU 2016-13. As required by ASU 2016-13, the financial instruments subject to the new standard were evaluated on a pool-basis to the extent such financial instruments shared similar risk characteristics.

Management adopted ASU 2016-13 and its related implementation guidance effective January 1, 2020, by means of an immaterial cumulative-effect adjustment to Retained Earnings on the balance sheets. The adoption of the new standard did not have a material impact to financial position and had no impact on the results of operations or cash flows. Additionally, the adoption of the new standard did not result in any changes to current accounting systems.

ASU 2020-04 "Reference Rate Reform: Facilitation of the Effects of Reference Rate Reform on Financial Reporting" (ASU 2020-04)

In March 2020, the FASB issued ASU 2020-04 providing guidance to ease the potential burden in accounting for Reference Rate Reform on financial reporting. The new standard is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference the London Interbank Offered Rate (LIBOR) or another reference rate expected to be discontinued because of Reference Rate Reform. The new standard establishes a general contract modification principle that entities can apply in other areas that may be affected by Reference Rate Reform and certain elective hedge accounting expedients. Under the new standard, an entity may make a one-time election to sell or to transfer to the available-for-sale or trading classifications (or both sell and transfer), debt securities that both reference an affected rate, and were classified as held to maturity before January 1, 2020.

The new accounting guidance is effective for all entities as of March 12, 2020 through December 31, 2022. The amendments may be applied to contract modifications as of any date from the beginning of an interim period that includes or is subsequent to March 12, 2020, or prospectively from a date within an interim period that includes or is subsequent to March 12, 2020, up to the date that the financial statements are available to be issued. The amendments may be applied to eligible hedging relationships existing as of the beginning of the interim period that includes March 12, 2020 and to new eligible hedging relationships entered into after the beginning of the interim period that includes March 12, 2020. The one-time election to sell, transfer, or both sell and transfer debt securities classified as held to maturity may be made at any time after March 12, 2020 but no later than December 31, 2022. Management has yet to apply the amendments in the new standard to any contract modifications, hedging relationships, or debt securities. 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.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 - Benefit Plans for additional details.

Three Months Ended March 31, 2020	Pension and OPEB
	(in thousands)
Balance in AOCI as of December 31, 2019	$ 790
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(57)
Amortization of Actuarial (Gains) Losses	23
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(34)
Income Tax (Expense) Benefit	(7)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(27)
Net Current Period Other Comprehensive Income (Loss)	(27)
Balance in AOCI as of March 31, 2020	$ 763

Three Months Ended March 31, 2019	Pension and OPEB
	(in thousands)
Balance in AOCI as of December 31, 2018	$ (212)
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(56)
Amortization of Actuarial (Gains) Losses	45
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(11)
Income Tax (Expense) Benefit	(2)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(9)
Net Current Period Other Comprehensive Income (Loss)	(9)
Balance in AOCI as of March 31, 2019	$ (221)

4. RATE MATTERS

As discussed in KPCo's 2019 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2019 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2020 and updates KPCo's 2019 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	March 31, 2020	December 31, 2019
	(in thousands)	
Regulatory Assets Currently Earning a Return		
Kentucky Deferred Purchased Power Expenses	$ 32,910	$ 30,165
Regulatory Assets Currently Not Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	1,478	1,333
Total Regulatory Assets Pending Final Regulatory Approval	$ 34,388	$ 31,498

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

COVID-19 Pandemic

AEP's electric utility operating companies have informed retail customers and state regulators that disconnections for non-payment have been temporarily suspended. These uncertain economic conditions may result in the inability of customers to pay for electric service, which could affect the collectability of revenues and adversely affect financial results. KPCo is currently evaluating and working with the KPSC on potential rate recovery for increased costs as a result of the impacts of COVID-19. If any costs related to COVID-19 are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Storm-Related Costs

In April 2020, major storms impacted KPCo's service territory resulting in customer outages for approximately 62,000 customers and damages to KPCo utility assets. Management currently estimates that KPCo will incur incremental other operation and maintenance expenses, primarily in the second quarter of 2020, related to the April 2020 storms ranging from $3.7 million to $5.8 million. Consistent with prior guidance from the KPSC, KPCo will file with the KPSC seeking recovery of these prudently incurred costs in addition to $502 thousand of previously incurred incremental operation and maintenance expenses related to a major storm in January 2020. Until KPCo receives deferral authority for these incremental storm costs from the KPSC, it will reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation 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. The Commitments, Guarantees and Contingencies note within KPCo's 2019 Annual Report should be read in conjunction with this report.

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 March 31, 2020, 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.

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 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 amount guaranteed. As of March 31, 2020, the maximum potential loss for these lease agreements was $1.8 million assuming the fair value of the equipment is zero at the end of the lease term.

CONTINGENCIES

Claims Challenging Transition of American Electric Power System Retirement Plan to Cash Balance Formula

The American Electric Power System Retirement Plan (the Plan) has received a letter written on behalf of four participants (the Claimants) making a claim for additional plan benefits and purporting to advance such claims on behalf of a class. When the Plan's benefit formula was changed in the year 2000, AEP provided a special provision for employees hired before January 1, 2001, allowing them to continue benefit accruals under the then benefit formula for a full 10 years alongside of the new cash balance benefit formula then being implemented. Employees who were hired on or after January 1, 2001 accrued benefits only under the new cash balance benefit formula. The Claimants have asserted claims that (a) the Plan violates the requirements under the Employee Retirement Income Security Act (ERISA) intended to preclude back-loading the accrual of benefits to the end of a participant's career; (b) the Plan violates the age discrimination prohibitions of ERISA and the Age Discrimination in Employment Act (ADEA); and (c) the company failed to provide required notice regarding the changes to the Plan. AEP has responded to the Claimants providing a reasoned explanation for why each of their claims have been denied, and the denial to those claims have been appealed to the AEP System Retirement Plan Appeal Committee. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

6. BENEFIT PLANS

KPCo participates in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. 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.

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost (credit) for the plans:

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2020	2019	2020	2019
	(in thousands)			
Service Cost	$ 780	$ 711	$ 75	$ 65
Interest Cost	1,493	1,823	373	464
Expected Return on Plan Assets	(2,473)	(2,727)	(941)	(910)
Amortization of Prior Service Credit	—	—	(613)	(606)
Amortization of Net Actuarial Loss	823	505	60	214
Net Periodic Benefit Cost (Credit)	$ 623	$ 312	$ (1,046)	$ (773)

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of KPCo.

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

KPCo utilizes power, capacity, 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 may also utilize 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

	Volume		
Primary Risk Exposure	**March 31, 2020**	**December 31, 2019**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	7,249	11,383	MWhs
Heating Oil and Gasoline	199	273	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 may utilize a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo may also utilize 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 March 31, 2020 and December 31, 2019 balance sheets, KPCo netted $0 and $129 thousand, respectively, of cash collateral received from third-parties against short-term and long-term risk management assets and $1 million and $150 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
March 31, 2020

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	$	13,215	$	(9,758)	$	3,457
Long-term Risk Management Assets		646		(624)		22
Total Assets		13,861		(10,382)		3,479
Current Risk Management Liabilities		12,705		(10,774)		1,931
Long-term Risk Management Liabilities		645		(624)		21
Total Liabilities		13,350		(11,398)		1,952
Total MTM Derivative Contract Net Assets	$	511	$	1,016	$	1,527

Fair Value of Derivative Instruments
December 31, 2019

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	$	21,653	$	(14,775)	$	6,878
Long-term Risk Management Assets		160		(135)		25
Total Assets		21,813		(14,910)		6,903
Current Risk Management Liabilities		16,285		(14,805)		1,480
Long-term Risk Management Liabilities		128		(127)		1
Total Liabilities		16,413		(14,932)		1,481
Total MTM Derivative Contract Net Assets	$	5,400	$	22	$	5,422

(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)		Three Months Ended March 31, 2020		Three Months Ended March 31, 2019
		(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$	132	$	7
Purchased Electricity for Resale		1		37
Other Operation		(8)		(15)
Maintenance		(7)		(14)
Regulatory Assets (a)		(1,394)		122
Regulatory Liabilities (a)		424		(1,714)
Total Loss on Risk Management Contracts	$	(852)	$	(1,577)

(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 three months ended March 31, 2020 and 2019, 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 three months ended March 31, 2020 and 2019, KPCo did not apply cash flow hedging to outstanding interest rate derivatives.

There was no impact of cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets as of March 31, 2020 and December 31, 2019.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes. As of March 31, 2020, 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 the 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 March 31, 2020 and December 31, 2019, 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:

	March 31, 2020	December 31, 2019
	(in thousands)	
Liabilities for Contracts with Cross-Default Provisions Prior to Contractual Netting Arrangements	$ 404	$ 419
Additional Settlement Liability if Cross-Default Provision is Triggered	35	65

8. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

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 derivatives 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.

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:

	March 31, 2020		December 31, 2019	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 992,617	$ 1,056,633	$ 867,553	$ 970,437

Fair Value Measurements of Financial Assets and Liabilities

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
March 31, 2020

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Assets:					
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 10,061	$ 3,338	$ (9,920)	$ 3,479
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 10,800	$ 2,088	$ (10,936)	$ 1,952

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Assets:					
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 14,758	$ 7,054	$ (14,909)	$ 6,903
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 15,059	$ 1,352	$ (14,930)	$ 1,481

(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.

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:

Three Months Ended March 31, 2020	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2019	$ 5,702
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(338)
Settlements	(4,094)
Transfers out of Level 3 (c)	129
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	(149)
Balance as of March 31, 2020	$ 1,250

Three Months Ended March 31, 2019	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2018	$ 5,804
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(1,852)
Settlements	(2,631)
Transfers out of Level 3 (c)	(120)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	166
Balance as of March 31, 2019	$ 1,367

(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) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(d) 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 or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
March 31, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in thousands)						
Energy Contracts	$ 984	$ 410	Discounted Cash Flow	Forward Market Price	$ 9.95	$ 42.15	$ 21.81
FTRs	2,354	1,678	Discounted Cash Flow	Forward Market Price	(0.07)	3.27	0.43
Total	$ 3,338	$ 2,088					

December 31, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in thousands)						
Energy Contracts	$ 1,049	$ 475	Discounted Cash Flow	Forward Market Price	$ 12.70	$ 41.20	$ 25.92
FTRs	6,005	877	Discounted Cash Flow	Forward Market Price	(0.47)	4.07	1.30
Total	$ 7,054	$ 1,352					

(a) Represents market prices in dollars per MWh.
(b) The weighted average is the product of the forward market price of the underlying commodity and volume weighted by term.

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of March 31, 2020 and December 31, 2019:

Uncertainty 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)

9. INCOME TAXES

Federal Legislation

In March 2020, the "Coronavirus Aid, Relief, and Economic Security Act" (CARES Act) was signed into law. The CARES Act includes several significant changes to the Internal Revenue Code that will have an impact on KPCo. The CARES Act includes certain tax relief provisions applicable to KPCo including a) the immediate refund of the corporate Alternative Minimum Tax credit, b) the ability to carryback net operating losses five years for tax years 2018 through 2020 and c) delayed payment of employer payroll taxes. KPCo and other AEP subsidiaries were most recently a tax payer in 2014 and management is currently evaluating the ability to recover cash taxes paid in 2014 under the 5-year net operating loss carryback provision.

Effective Tax Rates (ETR)

The interim ETR for KPCo reflects the estimated annual ETR for 2020 and 2019 adjusted for tax expense associated with certain discrete items. The interim ETR differs from the federal statutory tax rate of 21% primarily due to state income taxes, amortization of Excess ADIT and other book/tax differences which are accounted for on a flow-through basis. KPCo includes the amortization of Excess ADIT not subject to normalization requirements in the annual estimated ETR when regulatory proceedings instruct KPCo to provide the benefits of Tax Reform to customers over multiple interim periods. Certain regulatory proceedings may instruct KPCo to provide the benefits of Tax Reform to customers in a single period (e.g. by applying the Excess ADIT not subject to normalization requirements against an existing regulatory asset balance) and in these circumstances, KPCo recognizes the tax benefit discretely in the period recorded.

The ETR for KPCo are included in the following table:

	Three Months Ended March 31,	
	2020	**2019**
U.S. Federal Statutory Rate	21.0 %	21.0 %
Increase (decrease) due to:		
State Income Tax, net of Federal benefit	(3.8)%	2.2 %
Tax Reform Excess ADIT Reversal	(25.8)%	(11.7)%
Flow Through	0.3 %	(3.3)%
AFUDC Equity	(1.8)%	(0.9)%
Parent Company Loss Benefit	— %	(1.2)%
Discrete Tax Adjustments	(2.7)%	4.0 %
Other	0.2 %	0.2 %
Effective Income Tax Rate	(12.6)%	10.3 %

Federal and State Income Tax Audit Status

KPCo and other AEP and subsidiaries are no longer subject to U.S. federal examination by the IRS for all years through 2015. During the third quarter of 2019, AEP and subsidiaries elected to amend the 2014 and 2015 federal returns and as such the IRS may examine only the amended items on the 2014 and 2015 federal returns.

10. FINANCING ACTIVITIES

Long-term Debt

Long-term debt issued during the first three months of 2020 are shown in the following table:

Type of Issuance	Principal Amount (a)	Interest Rate	Due Date
	(in thousands)	(%)	
Other Long-term Debt	$ 125,000	Variable	2022

(a) Amounts indicated on the statements of cash flows are net of issuance costs and premium or discount and will not tie to the issuance amounts.

KPCo did not have any long-term debt retirements during the first three months of 2020.

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 March 31, 2020, 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 Federal Power Act restriction does not limit the ability of KPCo 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 its agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of March 31, 2020 and December 31, 2019 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limit for the three months ended March 31, 2020 are described in the following table:

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 March 31, 2020	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 126,742	$ 6,572	$ 86,867	$ 5,020	$ 10,685	$ 180,000

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

Three Months Ended March 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
2020	2.24%	1.76%	2.08%	1.80%	1.91%	1.81%
2019	3.02%	2.73%	—%	—%	2.86%	—%

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 expires in July 2021.

KPCo's amounts of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement were $42 million and $41.6 million as of March 31, 2020 and December 31, 2019, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended March 31, 2020 and 2019 were $1 million and $1.1 million, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended March 31, 2020 and 2019 were $142.6 million and $156.9 million, respectively.

11. 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:

	Three Months Ended March 31, 2020	Three Months Ended March 31, 2019
	(in thousands)	
Retail Revenues:		
Residential Revenues	$ 65,273	$ 74,232
Commercial Revenues	35,246	38,673
Industrial Revenues	32,783	39,223
Other Retail Revenues	498	511
Total Retail Revenues	133,800	152,639
Wholesale Revenues:		
Generation Revenues (a)	3,267	7,160
Transmission Revenues (b)	5,725	4,818
Total Wholesale Revenues	8,992	11,978
Other Revenues from Contracts with Customers (a)	5,264	4,051
Total Revenues from Contracts with Customers	148,056	168,668
Other Revenues:		
Alternative Revenues	(423)	926
Total Other Revenues	(423)	926
Total Revenues	$ 147,633	$ 169,594

(a) Amounts included affiliated and nonaffiliated revenues.
(b) Amounts included affiliated and nonaffiliated revenues. The affiliated revenues were $2.6 million and $2.3 million for the three months ended March 31, 2020 and 2019, respectively.

Fixed Performance Obligations

The following table represents KPCo's remaining fixed performance obligations satisfied over time as of March 31, 2020. Fixed performance obligations primarily include wholesale transmission services, electricity sales for fixed amounts of energy and stand ready services into PJM's Reliability Pricing Model market. The amounts shown in the table below include affiliated and nonaffiliated revenues.

2020	2021-2022	2023-2024	After 2024	Total
(in thousands)				
$ 17,735	$ 2,870	$ 2,870	$ 1,435	$ 24,910

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 material contract assets as of March 31, 2020 and December 31, 2019.

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 material contract liabilities as of March 31, 2020 and December 31, 2019.

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 March 31, 2020 and December 31, 2019. See "Securitized Accounts Receivable - AEP Credit" section of Note 10 for additional information related to AEP Credit's securitized accounts receivable.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on KPCo's balance sheets were $9.1 million and $7 million, respectively, as of March 31, 2020 and December 31, 2019.

Kentucky Power Company
AEPSC Charges by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2017,2018,2019 and Test Year Ended March 2020

American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of AEP and is the Centralized Service Company for the AEP System. AEPSC's activities are authorized by the FERC under the Public Utilities Holding Company Act of 2005. AEPSC performs, at cost, various corporate support services for subsidiaries of AEP, including Kentucky Power.

AEPSC transactions are accounted for through a work order system as required by the FERC. Costs for support services are accumulated in work orders and are billed to the company or companies benefiting from the service. Accounting within each work order is in accordance with the FERC Uniform System of Accounts. The costs for services benefiting only one company are directly assigned and are billed 100% to that company. Where services benefit more than one company, the costs for those services are allocated to the benefiting companies using an approved allocation factor. The allocation factor for any given allocation of costs is selected for use because it best reflects the cost driver associated with the service provided.

The FERC monitors the factors used for allocations, through required annual reporting, and can audit the validity of each factor. All services are billed at cost, with no profit charged, as required by the FERC's "at cost" rules

			2017					2018					2019					TEST YEAR 12 MONTHS ENDED MARCH 2020				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
Cost of Service	5000 - Oper Supervision & Engineering	08 - Number of Electric Retail Cust		2	2				603	603				1,772	1,772				3,705	3,705		
		09 - Number of Employees		(12,993)	(12,993)				(20,699)	(20,699)				38,929	38,929				25,237	25,237		
		17 - Number of Purchase Orders		72	72				235	235				31	31				257	257		
		26 - Number of Stores Transactions		831	831				21	21												
		28 - Number of Trans Pole Miles		47	47				(13)	(13)				129	129				127	127		
		31 - Number of Vehicles												80	80				80	80		
		33 - Number of Workstations		8,310	8,310				4,497	4,497				10,378	10,378				10,940	10,940		
		39 - 100% to One Company	2,053,522		2,053,522			1,775,154		1,775,154			1,757,703		1,757,703			1,608,836		1,608,836		
		40 - Equal Share Ratio		(7,309)	(7,309)									34,267	34,267				29,257	29,257		
		48 - MW Generating Capability		3,204,538	3,204,538				3,634,620	3,634,620				4,382,608	4,382,608				3,734,120	3,734,120		
		49 - MWH's Generation		152,490	152,490				197,055	197,055				223,782	223,782				219,736	219,736		
		52 - Past 3 Mo MMBTU Burned (Coal)		3,644	3,644				9,569	9,569				120	120				120	120		
		57 - Tons of Fuel Acquired		3,889	3,889				4,111	4,111				5,125	5,125				3,906	3,906		
		58 - Total Assets		39,547	39,547				56,938	56,938				75,515	75,515				85,355	85,355		
		60 - AEPSC Bill less Indir and Int		3,935	3,935				1,353	1,353				(228)	(228)				975	975		
		61 - Total Fixed Assets	6,308	4,326	10,634				2,190	2,190				98,936	98,936				105,214	105,214		
		63 - Total Gross Utility Plant		7,129	7,129				942	942				20,927	20,927				19,107	19,107		
		64 - Member/Peak Load		217	217																	
	5000 - Oper Supervision & Engineering Total		2,059,829	3,408,677	5,468,507	(1,951,119)	3,517,388	1,775,154	3,891,422	5,666,577	(2,169,401)	3,497,175	1,757,703	4,892,370	6,650,073	(2,643,225)	4,006,849	1,608,836	4,238,137	5,846,974	(2,305,111)	3,541,863
	5010 - Fuel	09 - Number of Employees		11,199	11,199									374	374				374	374		
		28 - Number of Trans Pole Miles		0	0				0	0				(0)	(0)				(7)	(7)		
		33 - Number of Workstations							25	25												
		39 - 100% to One Company	353,522		353,522			350,258		350,258			463,740		463,740			486,076		486,076		
		48 - MW Generating Capability		18,154	18,154				27,377	27,377				30,805	30,805				33,774	33,774		
		52 - Past 3 Mo MMBTU Burned (Coal)							31	31				82	82				52	52		
		53 - Past 3 Mo MMBTU (Gas)		297	297				310	310				2,497	2,497				10,273	10,273		
		57 - Tons of Fuel Acquired												350	350				350	350		
		58 - Total Assets		121	121				344	344				193	193				9	9		
		60 - AEPSC Bill less Indir and Int		183	183				(18)	(18)				(117)	(117)				(63)	(63)		
		63 - Total Gross Utility Plant												75	75				75	75		
	5010 - Fuel Total		353,522	29,956	383,478	(18,563)	364,915	350,258	28,070	378,328	(23,129)	355,199	463,740	34,259	497,999	(28,767)	469,232	486,076	44,837	530,913	(35,808)	495,105
	5020 - Steam Expenses	39 - 100% to One Company	52,143		52,143			81,062		81,062			83,147		83,147			95,032		95,032		
		48 - MW Generating Capability		6	6				57	57				(32)	(32)				(3)	(3)		
	5020 - Steam Expenses Total		52,143	6	52,149	(26,074)	26,075	81,062	57	81,119	(39,805)	41,314	83,147	(32)	83,115	(40,743)	42,373	95,032	(3)	95,028	(41,482)	53,546
	5050 - Electric Expenses	39 - 100% to One Company						1,093		1,093			5,657		5,657			3,232		3,232		
		48 - MW Generating Capability		0	0				328	328				(328)	(328)				(371)	(371)		
		60 - AEPSC Bill less Indir and Int												(0)	(0)				(0)	(0)		
	5050 - Electric Expenses Total			0	0	(0)	(0)	1,093	328	1,420	(139)	1,281	5,657	(328)	5,330	139	5,469	3,232	(371)	2,861	157	3,019
	5060 - Misc Steam Power Expenses	08 - Number of Electric Retail Cust		(0)	(0)				1	1				4	4				19	19		
		09 - Number of Employees		1,496	1,496				3,006	3,006				4,186	4,186				3,954	3,954		
		28 - Number of Trans Pole Miles		(5)	(5)									3	3				577	577		
		39 - 100% to One Company	4,537		4,537			383,471		383,471			(502,302)		(502,302)			(350,097)		(350,097)		
		40 - Equal Share Ratio		1,335	1,335				2,029	2,029				2,886	2,886				2,079	2,079		
		48 - MW Generating Capability		(17,848)	(17,848)				4,091	4,091				98,628	98,628				3,108	3,108		
		49 - MWH's Generation												60	60				25	25		
		57 - Tons of Fuel Acquired												4	4				4	4		
		58 - Total Assets		36,317	36,317				22,141	22,141				22,072	22,072				22,821	22,821		
		60 - AEPSC Bill less Indir and Int		(223)	(223)				(11)	(11)				900	900				1,169	1,169		
		61 - Total Fixed Assets												95,953	95,953				167,871	167,871		
		63 - Total Gross Utility Plant												504	504				504	504		
	5060 - Misc Steam Power Expenses Total		4,537	21,071	25,608	(181,210)	(155,602)	383,471	31,257	414,728	(66,576)	348,152	(502,302)	225,200	(277,101)	(104,579)	(381,680)	(350,097)	202,132	(147,966)	(53,105)	(201,071)
	5070 - Rents	28 - Number of Trans Pole Miles												0	0							
		39 - 100% to One Company											1		1							
	5070 - Rents Total					0	0				0	0	1	0	1	0	1				0	0
	5100 - Maint Supv & Engineering	17 - Number of Purchase Orders							0	0				(0)	(0)				(0)	(0)		
		28 - Number of Trans Pole Miles		0	0																	
		39 - 100% to One Company	268,846		268,846			246,464		246,464			225,756		225,756			207,432		207,432		
		40 - Equal Share Ratio		2,291	2,291				1,765	1,765												
		48 - MW Generating Capability		298,475	298,475				320,695	320,695				265,571	265,571				206,342	206,342		
		49 - MWH's Generation		247	247				172	172									316	316		
		58 - Total Assets		13,625	13,625				866	866				310	310				384	384		
		60 - AEPSC Bill less Indir and Int		905	905				717	717				(1,622)	(1,622)				(622)	(622)		
		63 - Total Gross Utility Plant							261	261				3,515	3,515				3,399	3,399		
	5100 - Maint Supv & Engineering Total		268,846	315,544	584,390	(219,282)	365,108	246,464	324,476	570,940	(224,992)	345,948	225,756	267,774	493,530	(164,524)	329,005	207,432	209,819	417,251	(115,716)	301,535
	5110 - Maintenance of Structures	28 - Number of Trans Pole Miles		0	0				0	0				0	0				48	48		
		39 - 100% to One Company	406,515		406,515			329,121		329,121			517,180		517,180			376,095		376,095		
		48 - MW Generating Capability		(218)	(218)				(18)	(18)				450	450				(171)	(171)		
		60 - AEPSC Bill less Indir and Int							10	10				(10)	(10)				0	0		
	5110 - Maintenance of Structures Total		406,515	(218)	406,297	(132,825)	273,472	329,121	(7)	329,114	(110,264)	218,849	517,180	440	517,620	(123,082)	394,539	376,095	(122)	375,973	(83,096)	292,877
	5120 - Maintenance of Boiler Plant	28 - Number of Trans Pole Miles		24	24				(27)	(27)				(2)	(2)				96	96		
		39 - 100% to One Company	496,358		496,358			950,644		950,644			1,212,786		1,212,786			1,206,004		1,206,004		
		48 - MW Generating Capability		(3,001)	(3,001)				11,838	11,838				7,657	7,657				2,348	2,348		
		60 - AEPSC Bill less Indir and Int		(1)	(1)									14	14				27	27		
		63 - Total Gross Utility Plant												39	39				39	39		
	5120 - Maintenance of Boiler Plant Total		496,358	(2,979)	493,380	(208,259)	285,121	950,644	11,811	962,455	(399,178)	563,276	1,212,786	7,708	1,220,494	(535,369)	685,125	1,206,004	2,510	1,208,513	(562,119)	646,395
	5130 - Maintenance of Electric Plant	08 - Number of Electric Retail Cust												(0)	(0)				(0)	(0)		
		28 - Number of Trans Pole Miles		19	19				31	31				(54)	(54)				(30)	(30)		
		39 - 100% to One Company	1,149,774		1,149,774			1,832,145		1,832,145			1,746,138		1,746,138			1,489,642		1,489,642		
		48 - MW Generating Capability		(3,521)	(3,521)				14,691	14,691				(12,842)	(12,842)				(2,224)	(2,224)		
		60 - AEPSC Bill less Indir and Int		(0)	(0)				4	4				(4)	(4)				(2)	(2)		
	5130 - Maintenance of Electric Plant Total		1,149,774	(3,502)	1,146,272	(517,388)	628,885	1,832,145	14,725	1,846,871	(813,462)	1,033,409	1,746,138	(12,899)	1,733,239	(782,171)	951,069	1,489,642	(2,256)	1,487,386	(624,683)	862,703
	5140 - Maintenance of Misc Steam Plt	08 - Number of Electric Retail Cust		0	0									0	0				0	0		
		28 - Number of Trans Pole Miles		0	0				0	0				3	3				(44)	(44)		
		39 - 100% to One Company	132,902		132,902			170,671		170,671			396,280		396,280			518,231		518,231		
		48 - MW Generating Capability		(811)	(811)				1,262	1,262				773	773				1,349	1,349		
		60 - AEPSC Bill less Indir and Int		30	30				(15)	(15)				17	17				(12)	(12)		
	5140 - Maintenance of Misc Steam Plt Total		132,902	(781)	132,121	(58,325)	73,796	170,671	1,247	171,918	(69,937)	101,981	396,280	793	397,074	(113,796)	283,278	518,231	1,293	519,523	(162,407)	357,116
	5170 - Oper Supervision & Engineering	48 - MW Generating Capability		(48)	(48)				29	29				(46)	(46)				(7)	(7)		
		60 - AEPSC Bill less Indir and Int							(0)	(0)				0	0				0	0		
	5170 - Oper Supervision & Engineering Total			(48)	(48)	0	(48)		29	29	0	29		(46)	(46)	0	(46)		(7)	(7)	0	(7)
	5200 - Steam Expenses	09 - Number of Employees		232	232				(0)	(0)				29	29				17	17		
		28 - Number of Trans Pole Miles		0	0																	
		48 - MW Generating Capability		0	0																	
		58 - Total Assets		89	89																	
	5200 - Steam Expenses Total			322	322	0	322		(0)	(0)	0	(0)		29	29	0	29		17	17	0	17
	5240 - Misc Nuclear Power Expenses	08 - Number of Electric Retail Cust		0	0				(0)	(0)				0	0				0	0		
		28 - Number of Trans Pole Miles		0	0																	
		48 - MW Generating Capability		(13)	(13)				0	0				0	0				(45)	(45)		
		60 - AEPSC Bill less Indir and Int		0	0				(0)	(0)				48	48				22	22		
		63 - Total Gross Utility Plant		433	433				34	34				722	722				720	720		
	5240 - Misc Nuclear Power Expenses Total			420	420	0	420		34	34	0	34		770	770	0	770		698	698	0	698
	5280 - Maint Supv & Engineering	48 - MW Generating Capability		10,562	10,562				2,485	2,485				2,987	2,987				2,200	2,200		
		60 - AEPSC Bill less Indir and Int		(0)	(0)				(0)	(0)				(0)	(0)				(75)	(75)		
	5280 - Maint Supv & Engineering Total			10,562	10,562	0	10,562		2,485	2,485	0	2,485		2,987	2,987	0	2,987		2,126	2,126	0	2,126
	5290 - Maintenance of Structures	63 - Total Gross Utility Plant												149	149				149	149		
	5290 - Maintenance of Structures Total					0	0				0	0		149	149	0	149		149	149	0	149
	5300 - Maint of Reactor Plant Equip	09 - Number of Employees							19	19				15	15				15	15		
		28 - Number of Trans Pole Miles		(29)	(29)				(0)	(0)												
		48 - MW Generating Capability		(1,013)	(1,013)				(0)	(0)				(0)	(0)				(8,143)	(8,143)		

Kentucky Power Company
AEPSC Charges by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2017,2018,2019 and Test Year Ended March 2020

American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of AEP and is the Centralized Service Company for the AEP System. AEPSC's activities are authorized by the FERC under the Public Utilities Holding Company Act of 2005. AEPSC performs, at cost, various corporate support services for subsidiaries of AEP, including Kentucky Power.

AEPSC transactions are accounted for through a work order system as required by the FERC. Costs for support services are accumulated in work orders and are billed to the company or companies benefiting from the service. Accounting within each work order is in accordance with the FERC Uniform System of Accounts. The costs for services benefiting only one company are directly assigned and are billed 100% to that company. Where services benefit more than one company, the costs for those services are allocated to the benefiting companies using an approved allocation factor. The allocation factor for any given allocation of costs is selected for use because it best reflects the cost driver associated with the service provided.

The FERC monitors the factors used for allocations, through required annual reporting, and can audit the validity of each factor. All services are billed at cost, with no profit charged, as required by the FERC's "at cost" rules

			2017					2018					2019					TEST YEAR 12 MONTHS ENDED MARCH 2020				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
	5300 - Maint of Reactor Plant Equip Total			(1,043)	(1,043)	0	(1,043)		19	19	0	19		15	15	0	15		(8,128)	(8,128)	0	(8,128)
	5310 - Maintenance of Electric Plant	28 - Number of Trans Pole Miles							0	0												
		48 - MW Generating Capability		16,242	16,242				14,995	14,995				15,938	15,938				13,685	13,685		
		63 - Total Gross Utility Plant												5	5				5	5		
	5310 - Maintenance of Electric Plant Total			16,242	16,242	0	16,242		14,995	14,995	0	14,995		15,943	15,943	0	15,943		13,690	13,690	0	13,690
	5320 - Maint of Misc Nuclear Plant	09 - Number of Employees												197	197				197	197		
		33 - Number of Workstations		0	0																	
		48 - MW Generating Capability		(40)	(40)																	
		58 - Total Assets		0	0																	
	5320 - Maint of Misc Nuclear Plant Total			(39)	(39)	0	(39)				0	0		197	197	0	197		197	197	0	197
	5350 - Oper Supervision & Engineering	39 - 100% to One Company	21		21																	
		48 - MW Generating Capability		1,510	1,510				610	610				962	962				889	889		
		63 - Total Gross Utility Plant												297	297				297	297		
	5350 - Oper Supervision & Engineering Total		21	1,510	1,531	0	1,531		610	610	0	610		1,259	1,259	0	1,259		1,186	1,186	0	1,186
	5360 - Water for Power	48 - MW Generating Capability												(0)	(0)				(0)	(0)		
	5360 - Water for Power Total					0	0				0	0		(0)	(0)	0	(0)		(0)	(0)	0	(0)
	5370 - Hydraulic Expenses	48 - MW Generating Capability							(0)	(0)				325	325				155	155		
	5370 - Hydraulic Expenses Total					0	0		(0)	(0)	0	(0)		325	325	0	325		155	155	0	155
	5380 - Electric Expenses	28 - Number of Trans Pole Miles		(0)	(0)									0	0							
	5380 - Electric Expenses Total			(0)	(0)	0	(0)				0	0		0	0	0	0				0	0
	5390 - Misc Hydr Power Generation Exp	09 - Number of Employees												0	0				0	0		
		28 - Number of Trans Pole Miles		(0)	(0)									3	3				(2)	(2)		
		48 - MW Generating Capability		106	106				(87)	(87)				(0)	(0)				(3)	(3)		
		60 - AEPSC Bill less Indir and Int							21	21				(18)	(18)				(8)	(8)		
		63 - Total Gross Utility Plant												2,446	2,446				2,446	2,446		
	5390 - Misc Hydr Power Generation Exp Total			106	106	0	106		(66)	(66)	0	(66)		2,431	2,431	0	2,431		2,433	2,433	0	2,433
	5410 - Maint Supv & Engineering	48 - MW Generating Capability												67	67				48	48		
	5410 - Maint Supv & Engineering Total					0	0				0	0		67	67	0	67		48	48	0	48
	5420 - Maintenance of Structures	48 - MW Generating Capability		(36)	(36)				11	11				118	118				96	96		
		60 - AEPSC Bill less Indir and Int		(14)	(14)				(9)	(9)				(0)	(0)				(0)	(0)		
	5420 - Maintenance of Structures Total			(49)	(49)	0	(49)		2	2	0	2		118	118	0	118		96	96	0	96
	5430 - Maint Rsrvoirs,Dams&Wtrways	48 - MW Generating Capability		(290)	(290)				(13)	(13)				285	285				988	988		
	5430 - Maint Rsrvoirs,Dams&Wtrways Total			(290)	(290)	0	(290)		(13)	(13)	0	(13)		285	285	0	285		988	988	0	988
	5440 - Maintenance of Electric Plant	28 - Number of Trans Pole Miles		(0)	(0)				(0)	(0)				(0)	(0)				0	0		
		48 - MW Generating Capability		266	266				(96)	(96)				1,991	1,991				276	276		
		58 - Total Assets		7	7																	
		60 - AEPSC Bill less Indir and Int												3	3				0	0		
	5440 - Maintenance of Electric Plant Total			273	273	0	273		(96)	(96)	0	(96)		1,994	1,994	0	1,994		276	276	0	276
	5450 - Maint of Misc Hydraulic Plant	28 - Number of Trans Pole Miles		(0)	(0)				(0)	(0)												
		48 - MW Generating Capability							(0)	(0)				(0)	(0)				(49)	(49)		
		60 - AEPSC Bill less Indir and Int																	28	28		
	5450 - Maint of Misc Hydraulic Plant Total			(0)	(0)	0	(0)		(0)	(0)	0	(0)		(0)	(0)	0	(0)		(20)	(20)	0	(20)
	5460 - Oper Supervision & Engineering	48 - MW Generating Capability		(110)	(110)				(105)	(105)				(76)	(76)				(191)	(191)		
	5460 - Oper Supervision & Engineering Total			(110)	(110)	0	(110)		(105)	(105)	0	(105)		(76)	(76)	0	(76)		(191)	(191)	0	(191)
	5470 - Fuel	48 - MW Generating Capability		21	21				11	11				(43)	(43)				(34)	(34)		
		60 - AEPSC Bill less Indir and Int		22	22				(7)	(7)				(21)	(21)							
	5470 - Fuel Total			42	42	0	42		4	4	0	4		(63)	(63)	0	(63)		(34)	(34)	0	(34)
	5480 - Generation Expenses	28 - Number of Trans Pole Miles		0	0																	
		48 - MW Generating Capability		4	4																	
	5480 - Generation Expenses Total			4	4	0	4				0	0				0	0				0	0
	5490 - Misc Other Pwer Generation Exp	48 - MW Generating Capability		12	12				254	254				(246)	(246)				56	56		
		60 - AEPSC Bill less Indir and Int		0	0																	
	5490 - Misc Other Pwer Generation Exp Total			12	12	0	12		254	254	0	254		(246)	(246)	0	(246)		56	56	0	56
	5510 - Maint Supv & Engineering	48 - MW Generating Capability												(0)	(0)				(0)	(0)		
	5510 - Maint Supv & Engineering Total					0	0				0	0		(0)	(0)	0	(0)		(0)	(0)	0	(0)
	5530 - Maintenance of Generating Plt	28 - Number of Trans Pole Miles							0	0				0	0				0	0		
		48 - MW Generating Capability		(173)	(173)				(11)	(11)				160	160				(0)	(0)		
		60 - AEPSC Bill less Indir and Int		14	14				12	12				(25)	(25)				(22)	(22)		
	5530 - Maintenance of Generating Plt Total			(159)	(159)	0	(159)		1	1	0	1		135	135	0	135		(22)	(22)	0	(22)
	5550 - Purchased Power	48 - MW Generating Capability		(7)	(7)				(4)	(4)				(0)	(0)				(1)	(1)		
	5550 - Purchased Power Total			(7)	(7)	0	(7)		(4)	(4)	0	(4)		(0)	(0)	0	(0)		(1)	(1)	0	(1)
	5560 - Sys Control & Load Dispatching	28 - Number of Trans Pole Miles		(2)	(2)														8	8		
		48 - MW Generating Capability		2,445	2,445				(1,653)	(1,653)				1,223	1,223				14,017	14,017		
		49 - MWH's Generation		558,472	558,472				573,987	573,987				549,911	549,911				500,722	500,722		
		58 - Total Assets		1	1									31	31				10	10		
		60 - AEPSC Bill less Indir and Int		(8)	(8)				4	4				(4)	(4)							
		61 - Total Fixed Assets							1,367	1,367												
		63 - Total Gross Utility Plant		49	49																	
		64 - Member/Peak Load		13,383	13,383				26,232	26,232				19,968	19,968				13,745	13,745		
	5560 - Sys Control & Load Dispatching Total			574,339	574,339	0	574,339		599,937	599,937	0	599,937		571,130	571,130	0	571,130		528,502	528,502	0	528,502
	5570 - Other Expenses	09 - Number of Employees		61	61				29	29				312	312				559	559		
		28 - Number of Trans Pole Miles							0	0				4	4				9	9		
		32 - Number of Vendor Invoice Pay												3,936	3,936				4,006	4,006		
		33 - Number of Workstations							864	864				279	279				3,856	3,856		
		39 - 100% to One Company	2,576		2,576			1,773		1,773			2,255		2,255			2,094		2,094		
		40 - Equal Share Ratio												288	288				259	259		
		48 - MW Generating Capability		60,736	60,736				53,853	53,853				75,812	75,812				93,193	93,193		
		49 - MWH's Generation		19,435	19,435				3,189	3,189				2,498	2,498				2,367	2,367		
		52 - Past 3 Mo MMBTU Burned (Coal)		32,057	32,057				32,218	32,218				9,883	9,883				3,587	3,587		
		58 - Total Assets		20,846	20,846				20,512	20,512				17,146	17,146				17,531	17,531		
		60 - AEPSC Bill less Indir and Int		178	178				992	992				(22)	(22)				558	558		
		61 - Total Fixed Assets							1,319	1,319				9,998	9,998				8,766	8,766		
		64 - Member/Peak Load		1,006,362	1,006,362				1,095,047	1,095,047				929,595	929,595				871,945	871,945		
	5570 - Other Expenses Total		2,576	1,139,675	1,142,251	0	1,142,251	1,773	1,208,024	1,209,797	0	1,209,797	2,255	1,049,729	1,051,984	(441,895)	610,089	2,094	1,006,637	1,008,731	(421,873)	586,858
	5600 - Oper Supervision & Engineering	08 - Number of Electric Retail Cust		(14)	(14)				14	14				8,517	8,517				15,218	15,218		
		09 - Number of Employees		4,686	4,686				3,198	3,198				3,026	3,026				3,031	3,031		
		11 - Number of GL Transactions												693	693				693	693		
		28 - Number of Trans Pole Miles		84,302	84,302				84,880	84,880				142,567	142,567				145,576	145,576		
		32 - Number of Vendor Invoice Pay		8	8																	
		33 - Number of Workstations		538	538				1,839	1,839				83	83				53	53		
		39 - 100% to One Company	112,528		112,528			204,002		204,002			292,070		292,070			296,737		296,737		
		40 - Equal Share Ratio							43	43												
		44 - Level of Const-Distribution																	0	0		
		46 - Level of Const-Transmission		5	5									9,797	9,797				11,979	11,979		
		48 - MW Generating Capability		10,303	10,303				5,760	5,760				1,633	1,633				1,536	1,536		
		58 - Total Assets		1,672,682	1,672,682				1,997,760	1,997,760				2,436,340	2,436,340				2,304,877	2,304,877		
		60 - AEPSC Bill less Indir and Int		127	127				287	287				5,811	5,811				5,454	5,454		
		61 - Total Fixed Assets		10,713	10,713				6,935	6,935				39,955	39,955				52,800	52,800		
		63 - Total Gross Utility Plant		548	548				48	48				12,441	12,441				11,624	11,624		
	5600 - Oper Supervision & Engineering Total		112,528	1,783,898	1,896,427	0	1,896,427	204,002	2,100,763	2,304,766	0	2,304,766	292,070	2,660,863	2,952,933	0	2,952,933	296,737	2,552,842	2,849,579	0	2,849,579
	5611 - Load Dispatch - Reliability	28 - Number of Trans Pole Miles		398	398				(0)	(0)												
		58 - Total Assets		1,533	1,533				19	19												
	5611 - Load Dispatch - Reliability Total			1,930	1,930	0	1,930		19	19	0	19				0	0				0	0
	5612 - Load Dispatch-Mntr&Op TransSys	09 - Number of Employees		360	360				21	21												
		28 - Number of Trans Pole Miles		22,377	22,377				19,112	19,112				8,107	8,107				4,477	4,477		
		39 - 100% to One Company	258		258			208		208			37		37			0		0		
		58 - Total Assets		357,660	357,660				313,473	313,473				367,890	367,890				359,126	359,126		
		61 - Total Fixed Assets		21,947	21,947				24,011	24,011				20,806	20,806				20,876	20,876		
	5612 - Load Dispatch-Mntr&Op TransSys Total		258	402,345	402,602	0	402,602	208	356,617	356,825	0	356,825	37	396,803	396,840	0	396,840	0	384,479	384,479	0	384,479

Kentucky Power Company
AEPSC Charges by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2017,2018,2019 and Test Year Ended March 2020

American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of AEP and is the Centralized Service Company for the AEP System. AEPSC's activities are authorized by the FERC under the Public Utilities Holding Company Act of 2005. AEPSC performs, at cost, various corporate support services for subsidiaries of AEP, including Kentucky Power.

AEPSC transactions are accounted for through a work order system as required by the FERC. Costs for support services are accumulated in work orders and are billed to the company or companies benefiting from the service. Accounting within each work order is in accordance with the FERC Uniform System of Accounts. The costs for services benefiting only one company are directly assigned and are billed 100% to that company. Where services benefit more than one company, the costs for those services are allocated to the benefiting companies using an approved allocation factor. The allocation factor for any given allocation of costs is selected for use because it best reflects the cost driver associated with the service provided.

The FERC monitors the factors used for allocations, through required annual reporting, and can audit the validity of each factor. All services are billed at cost, with no profit charged, as required by the FERC's "at cost" rules

			2017					2018					2019					TEST YEAR 12 MONTHS ENDED MARCH 2020				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
	5615 - Reliability,Plng&Stds Develop	28 - Number of Trans Pole Miles		168	168				374	374				1,989	1,989				1,056	1,056		
		33 - Number of Workstations		2	2																	
		39 - 100% to One Company	27		27			28		28			7		7			7		7		
		58 - Total Assets		63,356	63,356				60,711	60,711				79,551	79,551				83,194	83,194		
		60 - AEPSC Bill less Indir and Int		0	0				(0)	(0)				9	9				(5)	(5)		
		61 - Total Fixed Assets		13,702	13,702				14,618	14,618				22,259	22,259				25,222	25,222		
	5615 - Reliability,Plng&Stds Develop Total		27	77,227	77,254	0	77,254	28	75,703	75,731	0	75,731	7	103,808	103,815	0	103,815	7	109,467	109,474	0	109,474
	5616 - Transmission service studies	28 - Number of Trans Pole Miles							0	0												
		58 - Total Assets		4	4																	
		61 - Total Fixed Assets							16	16												
	5616 - Transmission service studies Total			4	4	0	4		16	16	0	16				0	0				0	0
	5620 - Station Expenses	28 - Number of Trans Pole Miles		389	389				172	172				351	351				98	98		
		39 - 100% to One Company	64,112		64,112			53,522		53,522			38,343		38,343			43,168		43,168		
		48 - MW Generating Capability							0	0				0	0				0	0		
		58 - Total Assets		120,221	120,221				91,541	91,541				88,818	88,818				96,226	96,226		
		60 - AEPSC Bill less Indir and Int		0	0				0	0				6	6				6	6		
		63 - Total Gross Utility Plant												123	123				123	123		
	5620 - Station Expenses Total		64,112	120,610	184,722	0	184,722	53,522	91,713	145,235	0	145,235	38,343	89,297	127,640	0	127,640	43,168	96,453	139,621	0	139,621
	5630 - Overhead Line Expenses	08 - Number of Electric Retail Cust							0	0												
		09 - Number of Employees		72	72				20	20				2	2				2	2		
		28 - Number of Trans Pole Miles		(82)	(82)				54	54				77	77				92	92		
		39 - 100% to One Company	62		62			(22)		(22)			3		3			2		2		
		48 - MW Generating Capability												52	52				52	52		
		58 - Total Assets		47,876	47,876				5,427	5,427				13,299	13,299				12,614	12,614		
		60 - AEPSC Bill less Indir and Int							4	4				11	11				3	3		
	5630 - Overhead Line Expenses Total		62	47,867	47,928	0	47,928	(22)	5,504	5,482	0	5,482	3	13,441	13,444	0	13,444	2	12,762	12,765	0	12,765
	5640 - Underground Line Expenses	28 - Number of Trans Pole Miles												0	0				(6)	(6)		
	5640 - Underground Line Expenses Total					0	0				0	0		0	0	0	0		(6)	(6)	0	(6)
	5660 - Misc Transmission Expenses	08 - Number of Electric Retail Cust		23	23				37	37				(31)	(31)				53	53		
		09 - Number of Employees		7,231	7,231				6,091	6,091				4,665	4,665				3,826	3,826		
		17 - Number of Purchase Orders		5	5									10,997	10,997				10,997	10,997		
		26 - Number of Stores Transactions		10	10																	
		28 - Number of Trans Pole Miles		6,528	6,528				34,958	34,958				157,662	157,662				221,778	221,778		
		31 - Number of Vehicles												0	0				0	0		
		33 - Number of Workstations		165	165				0	0												
		39 - 100% to One Company	22,711		22,711			125,962		125,962			(196,107)		(196,107)			(279,172)		(279,172)		
		40 - Equal Share Ratio		8	8																	
		46 - Level of Const-Transmission																	22	22		
		48 - MW Generating Capability		262	262				76	76				717	717				488	488		
		58 - Total Assets		511,581	511,581				701,165	701,165				650,428	650,428				563,832	563,832		
		60 - AEPSC Bill less Indir and Int		(320)	(320)				109	109				3,070	3,070				3,492	3,492		
		61 - Total Fixed Assets		18,038	18,038				10,763	10,763				27,707	27,707				38,787	38,787		
		63 - Total Gross Utility Plant		25	25				44	44				5,957	5,957				5,883	5,883		
	5660 - Misc Transmission Expenses Total		22,711	543,554	566,265	0	566,265	125,962	753,245	879,207	0	879,207	(196,107)	861,171	665,064	0	665,064	(279,172)	849,157	569,985	0	569,985
	5670 - Rents	28 - Number of Trans Pole Miles												0	0				0	0		
		39 - 100% to One Company	250		250								0		0			0		0		
		63 - Total Gross Utility Plant												55	55				55	55		
	5670 - Rents Total		250		250	0	250				0	0	0	55	55	0	55	0	55	55	0	55
	5680 - Maint Supv & Engineering	08 - Number of Electric Retail Cust		(8)	(8)									27	27				42	42		
		28 - Number of Trans Pole Miles		(164)	(164)				240	240				(343)	(343)				3	3		
		39 - 100% to One Company	169		169			22		22			1,363		1,363			2,688		2,688		
		48 - MW Generating Capability							29	29				(29)	(29)				(4)	(4)		
		58 - Total Assets		13,488	13,488				24,636	24,636				33,181	33,181				15,276	15,276		
		60 - AEPSC Bill less Indir and Int		5	5				9	9				(9)	(9)				3	3		
		61 - Total Fixed Assets							216	216												
	5680 - Maint Supv & Engineering Total		169	13,320	13,489	0	13,489	22	25,128	25,150	0	25,150	1,363	32,827	34,190	0	34,190	2,688	15,320	18,009	0	18,009
	5690 - Maintenance of Structures	28 - Number of Trans Pole Miles		27	27				(25)	(25)				13	13				14	14		
		39 - 100% to One Company						110		110			86		86			86		86		
		58 - Total Assets		4,667	4,667				5,642	5,642				7,655	7,655				4,825	4,825		
	5690 - Maintenance of Structures Total			4,695	4,695	0	4,695	110	5,617	5,727	0	5,727	86	7,669	7,755	0	7,755	86	4,839	4,925	0	4,925
	5691 - Maint of Computer Hardware	28 - Number of Trans Pole Miles		68	68				185	185				(3)	(3)				57	57		
		33 - Number of Workstations		161	161																	
		39 - 100% to One Company	0		0																	
		58 - Total Assets		5,355	5,355				6,215	6,215				6,287	6,287				6,289	6,289		
		60 - AEPSC Bill less Indir and Int		75	75				15	15				92	92				(42)	(42)		
	5691 - Maint of Computer Hardware Tota		0	5,659	5,659	0	5,659		6,414	6,414	0	6,414		6,377	6,377	0	6,377		6,305	6,305	0	6,305
	5692 - Maint of Computer Software	06 - Number of Commercial Customers												17	17				17	17		
		08 - Number of Electric Retail Cust		37	37																	
		09 - Number of Employees		16	16				22	22												
		28 - Number of Trans Pole Miles		4,912	4,912				6,843	6,843				151	151				2,512	2,512		
		33 - Number of Workstations		268	268				1,453	1,453				2,488	2,488				1,662	1,662		
		39 - 100% to One Company	15		15			(3,044)		(3,044)			3,295		3,295			12		12		
		48 - MW Generating Capability		20	20																	
		58 - Total Assets		67,048	67,048				71,136	71,136				67,952	67,952				67,653	67,653		
		60 - AEPSC Bill less Indir and Int		(4)	(4)				(0)	(0)				137	137				75	75		
		61 - Total Fixed Assets							617	617				1,867	1,867				1,612	1,612		
		63 - Total Gross Utility Plant		1,521	1,521				425	425				12,209	12,209				19,468	19,468		
	5692 - Maint of Computer Software Total		15	73,818	73,833	0	73,833	(3,044)	80,496	77,451	0	77,451	3,295	84,821	88,116	0	88,116	12	93,000	93,012	0	93,012
	5693 - Maint of Communication Equip	28 - Number of Trans Pole Miles		(23)	(23)				8	8				6	6				20	20		
		33 - Number of Workstations		136	136																	
		58 - Total Assets		2,101	2,101				2,300	2,300				2,428	2,428				2,457	2,457		
	5693 - Maint of Communication Equip Total			2,213	2,213	0	2,213		2,308	2,308	0	2,308		2,435	2,435	0	2,435		2,476	2,476	0	2,476
	5700 - Maint of Station Equipment	08 - Number of Electric Retail Cust		0	0																	
		09 - Number of Employees		21	21				8	8												
		17 - Number of Purchase Orders		(2)	(2)																	
		28 - Number of Trans Pole Miles		(424)	(424)				936	936				1,704	1,704				4,568	4,568		
		39 - 100% to One Company	374,695		374,695			395,406		395,406			272,351		272,351			346,314		346,314		
		48 - MW Generating Capability												36	36				(0)	(0)		
		58 - Total Assets		133,627	133,627				152,952	152,952				138,260	138,260				146,964	146,964		
		60 - AEPSC Bill less Indir and Int		(0)	(0)				(0)	(0)				3	3				2	2		
		63 - Total Gross Utility Plant												58	58				58	58		
	5700 - Maint of Station Equipment Total		374,695	133,222	507,917	0	507,917	395,406	153,896	549,302	0	549,302	272,351	140,061	412,413	0	412,413	346,314	151,593	497,907	0	497,907
	5710 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust		(51)	(51)				(360)	(360)				(25)	(25)				(23)	(23)		
		28 - Number of Trans Pole Miles		12,943	12,943				12,616	12,616				17	17				745	745		
		39 - 100% to One Company	721,306		721,306			768,636		768,636			946,516		946,516			1,060,507		1,060,507		
		44 - Level of Const-Distribution		65	65																	
		48 - MW Generating Capability		(1)	(1)				(0)	(0)				13	13				17	17		
		58 - Total Assets		1,404	1,404				3,885	3,885				3,835	3,835				4,037	4,037		
		60 - AEPSC Bill less Indir and Int		(16)	(16)				17	17				226	226				133	133		
		61 - Total Fixed Assets												400	400				805	805		
	5710 - Maintenance of Overhead Lines Total		721,306	14,343	735,649	0	735,649	768,636	16,158	784,794	0	784,794	946,516	4,465	950,982	0	950,982	1,060,507	5,715	1,066,221	0	1,066,221
	5720 - Maint of Underground Lines	28 - Number of Trans Pole Miles		25	25				85	85				(86)	(86)				(38)	(38)		
		39 - 100% to One Company	0		0			0		0			0		0							
		58 - Total Assets		192	192				205	205				8	8							
	5720 - Maint of Underground Lines Total		0	217	218	0	218	0	290	291	0	291	0	(78)	(78)	0	(78)		(38)	(38)	0	(38)
	5730 - Maint of Misc Trnsmssion Plt	08 - Number of Electric Retail Cust		0	0																	
		09 - Number of Employees		274	274				45	45				112	112				152	152		
		28 - Number of Trans Pole Miles		1,475	1,475				281	281				1,762	1,762				1,860	1,860		
		39 - 100% to One Company	83,103		83,103			2		2			1		1			0		0		

Kentucky Power Company
AEPSC Charges by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2017,2018,2019 and Test Year Ended March 2020

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The FERC monitors the factors used for allocations, through required annual reporting, and can audit the validity of each factor. All services are billed at cost, with no profit charged, as required by the FERC's "at cost" rules

			2017					2018					2019					TEST YEAR 12 MONTHS ENDED MARCH 2020				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
		48 - MW Generating Capability		(1)	(1)									77	77				77	77		
		58 - Total Assets		71,386	71,386				66,219	66,219				99,266	99,266				92,456	92,456		
		60 - AEPSC Bill less Indir and Int		(0)	(0)																	
	5730 - Maint of Misc Trnsmssion Plt Total		83,103	73,134	156,237	0	156,237	2	66,545	66,547	0	66,547	1	101,216	101,217	0	101,217	0	94,545	94,546	0	94,546
	5800 - Oper Supervision & Engineering	08 - Number of Electric Retail Cust		180,334	180,334				208,915	208,915				227,631	227,631				217,499	217,499		
		09 - Number of Employees		20,933	20,933				25,890	25,890				35,895	35,895				38,867	38,867		
		17 - Number of Purchase Orders		126	126				193	193				336	336				284	284		
		27 - Number of Telephones		49	49				45	45				7	7				(0)	(0)		
		28 - Number of Trans Pole Miles		(22)	(22)				126	126				(139)	(139)				78	78		
		31 - Number of Vehicles												9	9				9	9		
		33 - Number of Workstations		657	657				6,319	6,319				13,016	13,016				13,296	13,296		
		39 - 100% to One Company	142,420		142,420			156,940		156,940			107,760		107,760			80,191		80,191		
		44 - Level of Const-Distribution		7,737	7,737				7,954	7,954				15,361	15,361				14,644	14,644		
		48 - MW Generating Capability		628	628				370	370				1,462	1,462				1,735	1,735		
		58 - Total Assets		9,551	9,551				11,408	11,408				13,066	13,066				13,017	13,017		
		60 - AEPSC Bill less Indir and Int		280	280				598	598				(143)	(143)				216	216		
		61 - Total Fixed Assets		128,686	128,686				32,738	32,738				27,858	27,858				29,650	29,650		
		63 - Total Gross Utility Plant		6,087	6,087				1,617	1,617												
	5800 - Oper Supervision & Engineering Total		142,420	355,049	497,469	0	497,469	156,940	296,173	453,113	0	453,113	107,760	334,360	442,120	0	442,120	80,191	329,296	409,487	0	409,487
	5810 - Load Dispatching	08 - Number of Electric Retail Cust		0	0																	
		28 - Number of Trans Pole Miles		(0)	(0)									0	0							
		33 - Number of Workstations		1	1																	
	5810 - Load Dispatching Total			1	1	0	1				0	0		0	0	0	0				0	0
	5820 - Station Expenses	08 - Number of Electric Retail Cust		43	43																	
		28 - Number of Trans Pole Miles		575	575				(97)	(97)				807	807				691	691		
		33 - Number of Workstations		28	28																	
		39 - 100% to One Company	137,367		137,367			138,987		138,987			153,044		153,044			149,416		149,416		
		46 - Level of Const-Transmission		13,209	13,209				26,488	26,488				40,846	40,846				42,752	42,752		
		48 - MW Generating Capability		63	63				(63)	(63)												
		58 - Total Assets		194	194				348	348				103	103				35	35		
		60 - AEPSC Bill less Indir and Int							0	0				63	63				56	56		
	5820 - Station Expenses Total		137,367	14,112	151,479	0	151,479	138,987	26,675	165,663	0	165,663	153,044	41,819	194,864	0	194,864	149,416	43,533	192,949	0	192,949
	5830 - Overhead Line Expenses	08 - Number of Electric Retail Cust		(6)	(6)				(0)	(0)				(0)	(0)				(0)	(0)		
		28 - Number of Trans Pole Miles		(25)	(25)				(9)	(9)				(4)	(4)				(11)	(11)		
		39 - 100% to One Company	638		638			906		906			39		39			39		39		
		48 - MW Generating Capability							0	0				66	66				66	66		
		60 - AEPSC Bill less Indir and Int		0	0				2	2				(2)	(2)				(4)	(4)		
	5830 - Overhead Line Expenses Total		638	(31)	607	0	607	906	(8)	899	0	899	39	60	99	0	99	39	52	91	0	91
	5840 - Underground Line Expenses	08 - Number of Electric Retail Cust		3,755	3,755				8	8				6	6				(28)	(28)		
		39 - 100% to One Company						391		391			474		474			474		474		
		60 - AEPSC Bill less Indir and Int												0	0							
	5840 - Underground Line Expenses Total			3,755	3,755	0	3,755	391	8	398	0	398	474	6	480	0	480	474	(28)	446	0	446
	5860 - Meter Expenses	08 - Number of Electric Retail Cust		49,321	49,321				47,296	47,296				55,325	55,325				52,318	52,318		
		09 - Number of Employees		5,346	5,346				5,356	5,356				12,086	12,086				12,928	12,928		
		26 - Number of Stores Transactions		308	308				257	257				6	6				79	79		
		27 - Number of Telephones												1	1				1	1		
		28 - Number of Trans Pole Miles		103	103				(4)	(4)				1	1				(7)	(7)		
		33 - Number of Workstations		89	89																	
		39 - 100% to One Company	6,004		6,004			11,212		11,212			19,207		19,207			20,473		20,473		
		48 - MW Generating Capability		(0)	(0)																	
		58 - Total Assets		2,348	2,348				1,752	1,752				2,392	2,392				2,218	2,218		
		60 - AEPSC Bill less Indir and Int		45	45				(43)	(43)				94	94				59	59		
		61 - Total Fixed Assets		164	164																	
		63 - Total Gross Utility Plant												400	400				378	378		
	5860 - Meter Expenses Total		6,004	57,723	63,727	0	63,727	11,212	54,614	65,826	0	65,826	19,207	70,305	89,512	0	89,512	20,473	67,973	88,446	0	88,446
	5870 - Customer Installations Exp	28 - Number of Trans Pole Miles		0	0																	
		48 - MW Generating Capability							0	0												
	5870 - Customer Installations Exp Total			0	0	0	0		0	0	0	0				0	0				0	0
	5880 - Miscellaneous Distribution Exp	05 - Number of CIS Customers Mail							5,230	5,230												
		06 - Number of Commercial Customers												34	34				34	34		
		08 - Number of Electric Retail Cust		148,965	148,965				164,998	164,998				196,754	196,754				177,483	177,483		
		09 - Number of Employees		43,089	43,089				43,075	43,075				47,519	47,519				48,818	48,818		
		16 - Number of Phone Center Calls		7,941	7,941				7,759	7,759				7,713	7,713				8,129	8,129		
		17 - Number of Purchase Orders		3,603	3,603				833	833				13,017	13,017				13,161	13,161		
		27 - Number of Telephones		45,734	45,734				52,739	52,739				49,765	49,765				48,037	48,037		
		28 - Number of Trans Pole Miles		(7)	(7)				43	43				44	44				3	3		
		31 - Number of Vehicles		700	700				207	207				226	226				371	371		
		32 - Number of Vendor Invoice Pay		256	256				383	383				466	466				522	522		
		33 - Number of Workstations		7,748	7,748				3,212	3,212				4,573	4,573				4,774	4,774		
		39 - 100% to One Company	156,636		156,636			308,970		308,970			271,519		271,519			34,247		34,247		
		44 - Level of Const-Distribution		146	146				1,572	1,572				1,039	1,039				1,123	1,123		
		46 - Level of Const-Transmission												23	23				23	23		
		48 - MW Generating Capability		91	91				141	141				951	951				354	354		
		58 - Total Assets	737	98,190	98,926			2,099	84,833	86,931			2,163	76,141	78,305			2,296	84,036	86,331		
		60 - AEPSC Bill less Indir and Int		(5,133)	(5,133)				4,286	4,286				3,075	3,075				(1,647)	(1,647)		
		61 - Total Fixed Assets	129	6,210	6,339				2,825	2,825				12,999	12,999				11,988	11,988		
		63 - Total Gross Utility Plant												90	90				90	90		
	5880 - Miscellaneous Distribution Exp Total		157,502	357,532	515,034	0	515,034	311,069	372,136	683,205	0	683,205	273,682	414,429	688,111	0	688,111	36,543	397,300	433,843	0	433,843
	5890 - Rents	08 - Number of Electric Retail Cust		4	4				(4)	(4)												
	5890 - Rents Total			4	4	0	4		(4)	(4)	0	(4)				0	0				0	0
	5900 - Maint Supv & Engineering	08 - Number of Electric Retail Cust		2,513	2,513				2,616	2,616				3,147	3,147				2,946	2,946		
		28 - Number of Trans Pole Miles		20	20				(19)	(19)				(11)	(11)				(7)	(7)		
		39 - 100% to One Company	1,190		1,190								570		570			570		570		
		58 - Total Assets		23	23																	
	5900 - Maint Supv & Engineering Total		1,190	2,557	3,747	0	3,747		2,597	2,597	0	2,597	570	3,136	3,706	0	3,706	570	2,938	3,508	0	3,508
	5910 - Maintenance of Structures	28 - Number of Trans Pole Miles		(23)	(23)				(0)	(0)				(6)	(6)				8	8		
		33 - Number of Workstations		98	98																	
		39 - 100% to One Company	5,173		5,173			217		217			4,673		4,673			3,313		3,313		
		58 - Total Assets												240	240				240	240		
	5910 - Maintenance of Structures Total		5,173	76	5,248	0	5,248	217	(0)	217	0	217	4,673	234	4,907	0	4,907	3,313	248	3,561	0	3,561
	5920 - Maint of Station Equipment	28 - Number of Trans Pole Miles		(505)	(505)				105	105				442	442				3,554	3,554		
		39 - 100% to One Company	385,186		385,186			332,223		332,223			445,907		445,907			448,395		448,395		
		46 - Level of Const-Transmission		28,802	28,802				22,535	22,535				17,675	17,675				17,957	17,957		
		58 - Total Assets		629	629				574	574				512	512				399	399		
		60 - AEPSC Bill less Indir and Int		6	6				33	33				38	38				20	20		
	5920 - Maint of Station Equipment Total		385,186	28,932	414,118	0	414,118	332,223	23,247	355,469	0	355,469	445,907	18,667	464,574	0	464,574	448,395	21,929	470,324	0	470,324
	5930 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust		12,315	12,315				10,685	10,685				14,353	14,353				13,237	13,237		
		09 - Number of Employees		58	58																	
		28 - Number of Trans Pole Miles		66	66				126	126				36	36				(250)	(250)		
		39 - 100% to One Company	7,801		7,801			5,238		5,238			8,124		8,124			3,445		3,445		
		48 - MW Generating Capability		14	14				9	9				15	15				8	8		
		58 - Total Assets		84	84				31	31												
		60 - AEPSC Bill less Indir and Int		(0)	(0)				(0)	(0)				263	263				150	150		
	5930 - Maintenance of Overhead Lines Total		7,801	12,537	20,339	0	20,339	5,238	10,851	16,090	0	16,090	8,124	14,667	22,791	0	22,791	3,445	13,145	16,591	0	16,591
	5940 - Maint of Underground Lines	08 - Number of Electric Retail Cust							(0)	(0)												
		09 - Number of Employees		10	10																	
		28 - Number of Trans Pole Miles		0	0				(0)	(0)				0	0				(1)	(1)		
		48 - MW Generating Capability		32	32				(32)	(32)				0	0				161	161		
		60 - AEPSC Bill less Indir and Int							(0)	(0)												

Kentucky Power Company
AEPSC Charges by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2017,2018,2019 and Test Year Ended March 2020

American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of AEP and is the Centralized Service Company for the AEP System. AEPSC's activities are authorized by the FERC under the Public Utilities Holding Company Act of 2005. AEPSC performs, at cost, various corporate support services for subsidiaries of AEP, including Kentucky Power.

AEPSC transactions are accounted for through a work order system as required by the FERC. Costs for support services are accumulated in work orders and are billed to the company or companies benefiting from the service. Accounting within each work order is in accordance with the FERC Uniform System of Accounts. The costs for services benefiting only one company are directly assigned and are billed 100% to that company. Where services benefit more than one company, the costs for those services are allocated to the benefiting companies using an approved allocation factor. The allocation factor for any given allocation of costs is selected for use because it best reflects the cost driver associated with the service provided.

The FERC monitors the factors used for allocations, through required annual reporting, and can audit the validity of each factor. All services are billed at cost, with no profit charged, as required by the FERC's "at cost" rules

			2017					2018					2019					TEST YEAR 12 MONTHS ENDED MARCH 2020				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
	5940 - Maint of Underground Lines Total			42	42	0	42		(32)	(32)	0	(32)		0	0	0	0		160	160	0	160
	5950 - Maint of Lne Trnf,Rglators&Dvi	08 - Number of Electric Retail Cust		(34)	(34)																	
		28 - Number of Trans Pole Miles		(0)	(0)																	
		48 - MW Generating Capability							0	0												
		58 - Total Assets																	5,748	5,748		
		60 - AEPSC Bill less Indir and Int							(0)	(0)												
	5950 - Maint of Lne Trnf,Rglators&Dvi Total			(34)	(34)	0	(34)		0	0	0	0				0	0		5,748	5,748	0	5,748
	5960 - Maint of Strt Lghtng & Sgnal S	28 - Number of Trans Pole Miles		0	0				(0)	(0)				0	0				(0)	(0)		
	5960 - Maint of Strt Lghtng & Sgnal S Total			0	0	0	0		(0)	(0)	0	(0)		0	0	0	0		(0)	(0)	0	(0)
	5970 - Maintenance of Meters	08 - Number of Electric Retail Cust		193	193				184	184				120	120				121	121		
		28 - Number of Trans Pole Miles		(27)	(27)																	
		39 - 100% to One Company	592		592																	
	5970 - Maintenance of Meters Total		592	166	759	0	759		184	184	0	184		120	120	0	120		121	121	0	121
	5980 - Maint of Misc Distribution Plt	08 - Number of Electric Retail Cust							132	132												
		28 - Number of Trans Pole Miles		(51)	(51)				(2)	(2)				7	7				10	10		
		39 - 100% to One Company	1,083		1,083			2,403		2,403			652		652			1,266		1,266		
		58 - Total Assets		11	11				1	1												
		60 - AEPSC Bill less Indir and Int												0	0							
	5980 - Maint of Misc Distribution Plt Total		1,083	(40)	1,043	0	1,043	2,403	131	2,534	0	2,534	652	7	659	0	659	1,266	10	1,277	0	1,277
	9010 - Supervision - Customer Accts	05 - Number of CIS Customers Mail		8,068	8,068				4,910	4,910												
		08 - Number of Electric Retail Cust		17,992	17,992				11,258	11,258				15,792	15,792				15,309	15,309		
		09 - Number of Employees		261	261				13	13				670	670				1,104	1,104		
		58 - Total Assets		110	110				17	17				98	98				82	82		
		63 - Total Gross Utility Plant		71	71																	
	9010 - Supervision - Customer Accts Total			26,501	26,501	0	26,501		16,198	16,198	0	16,198		16,559	16,559	0	16,559		16,496	16,496	0	16,496
	9020 - Meter Reading Expenses	05 - Number of CIS Customers Mail		14	14				45	45				100	100				73	73		
		08 - Number of Electric Retail Cust		58,636	58,636				36,773	36,773				21,330	21,330				21,711	21,711		
		09 - Number of Employees		2,030	2,030				1,401	1,401				77	77				90	90		
		11 - Number of GL Transactions							25	25												
		16 - Number of Phone Center Calls		1,473	1,473				708	708												
		20 - Number of Remittance Items							1	1												
		28 - Number of Trans Pole Miles		0	0																	
		39 - 100% to One Company						12,275		12,275			29,667		29,667			34,209		34,209		
		58 - Total Assets		848	848				1,996	1,996				11,665	11,665				11,519	11,519		
		60 - AEPSC Bill less Indir and Int							182	182				55	55				55	55		
	9020 - Meter Reading Expenses Total			63,001	63,001	0	63,001	12,275	41,131	53,406	0	53,406	29,667	33,226	62,893	0	62,893	34,209	33,448	67,657	0	67,657
	9030 - Cust Records & Collection Exp	05 - Number of CIS Customers Mail		163,255	163,255				250,175	250,175				261,937	261,937				247,513	247,513		
		08 - Number of Electric Retail Cust		726,037	726,037				730,038	730,038				745,239	745,239				730,135	730,135		
		09 - Number of Employees		84,962	84,962				67,681	67,681				75,040	75,040				76,239	76,239		
		11 - Number of GL Transactions												1,422	1,422				3,322	3,322		
		16 - Number of Phone Center Calls		853,953	853,953				658,043	658,043				746,731	746,731				742,618	742,618		
		17 - Number of Purchase Orders		215	215				329	329				345	345				329	329		
		20 - Number of Remittance Items		179,683	179,683				91,185	91,185				67,759	67,759				67,560	67,560		
		28 - Number of Trans Pole Miles												(0)	(0)				(17)	(17)		
		31 - Number of Vehicles		1	1																	
		33 - Number of Workstations		4,533	4,533				4,843	4,843									105	105		
		39 - 100% to One Company	1,082,460		1,082,460			1,115,058		1,115,058			1,356,479		1,356,479			1,363,789		1,363,789		
		48 - MW Generating Capability		10	10				65	65				(6)	(6)				64	64		
		58 - Total Assets		22,356	22,356				10,301	10,301				11,272	11,272				11,502	11,502		
		60 - AEPSC Bill less Indir and Int		(284)	(284)				(1,859)	(1,859)				37	37				87	87		
		61 - Total Fixed Assets												232	232				232	232		
		70 - No Nonelectric OAR Invoices		15,217	15,217				16,759	16,759				20,210	20,210				20,777	20,777		
	9030 - Cust Records & Collection Exp Total		1,082,460	2,049,937	3,132,397	0	3,132,397	1,115,058	1,827,558	2,942,616	0	2,942,616	1,356,479	1,930,218	3,286,697	0	3,286,697	1,363,789	1,900,466	3,264,255	0	3,264,255
	9050 - Misc Customer Accounts Exp	08 - Number of Electric Retail Cust		893	893				541	541				218	218				140	140		
		09 - Number of Employees		343	343				19	19												
		20 - Number of Remittance Items		396	396				138	138				36	36				36	36		
		33 - Number of Workstations		8,729	8,729				8,372	8,372				8,024	8,024				8,390	8,390		
		58 - Total Assets		468	468				460	460				894	894				1,150	1,150		
	9050 - Misc Customer Accounts Exp Total			10,829	10,829	0	10,829		9,528	9,528	0	9,528		9,172	9,172	0	9,172		9,716	9,716	0	9,716
	9070 - Supervision - Customer Service	08 - Number of Electric Retail Cust		35,897	35,897				40,963	40,963				38,025	38,025				36,051	36,051		
		09 - Number of Employees		3,652	3,652				2,805	2,805				2,650	2,650				2,437	2,437		
		20 - Number of Remittance Items												5	5				5	5		
		28 - Number of Trans Pole Miles												6	6				0	0		
		33 - Number of Workstations																	34	34		
		39 - 100% to One Company	5,778		5,778			7,948		7,948			6,932		6,932			6,384		6,384		
		48 - MW Generating Capability																	0	0		
		58 - Total Assets		730	730				1,450	1,450				116	116				114	114		
		60 - AEPSC Bill less Indir and Int		0	0				(0)	(0)				1	1				0	0		
	9070 - Supervision - Customer Service Total		5,778	40,279	46,057	0	46,057	7,948	45,218	53,166	0	53,166	6,932	40,801	47,734	0	47,734	6,384	38,641	45,025	0	45,025
	9080 - Customer Assistance Expenses	08 - Number of Electric Retail Cust		14,332	14,332				17,979	17,979				18,765	18,765				18,306	18,306		
		09 - Number of Employees		1,759	1,759				203	203				149	149				93	93		
		16 - Number of Phone Center Calls		3,514	3,514				5,387	5,387				3,098	3,098				2,908	2,908		
		32 - Number of Vendor Invoice Pay		57	57				145	145				31	31				27	27		
		39 - 100% to One Company	3		3			6,783		6,783			276		276			276		276		
		48 - MW Generating Capability		149	149				(149)	(149)												
		58 - Total Assets		659	659				1,081	1,081				832	832				897	897		
		60 - AEPSC Bill less Indir and Int		(117)	(117)				23	23				(24)	(24)				0	0		
	9080 - Customer Assistance Expenses Total		3	20,354	20,357	0	20,357	6,783	24,670	31,453	0	31,453	276	22,851	23,127	0	23,127	276	22,232	22,508	0	22,508
	9090 - Information & Instruct Advrtis	08 - Number of Electric Retail Cust												0	0				0	0		
		33 - Number of Workstations							63	63												
		58 - Total Assets											1,312		1,312			1,312		1,312		
	9090 - Information & Instruct Advrtis Total					0	0		63	63	0	63	1,312	0	1,312	0	1,312	1,312	0	1,312	0	1,312
	9100 - Misc Cust Svc&Informational Ex	06 - Number of Commercial Customers						10,231		10,231												
		08 - Number of Electric Retail Cust		36,222	36,222				47	47				0	0				0	0		
		09 - Number of Employees		2,637	2,637				2,497	2,497				4,108	4,108				3,696	3,696		
		32 - Number of Vendor Invoice Pay																	403	403		
		33 - Number of Workstations												100	100				26	26		
		48 - MW Generating Capability												144	144				378	378		
		58 - Total Assets		463	463				755	755				1,848	1,848				5,841	5,841		
		60 - AEPSC Bill less Indir and Int		7	7				133	133				267	267				375	375		
		61 - Total Fixed Assets												60	60							
		63 - Total Gross Utility Plant							64	64				4	4							
	9100 - Misc Cust Svc&Informational Ex Total			39,329	39,329	0	39,329	10,231	3,497	13,728	0	13,728		6,530	6,530	0	6,530		10,718	10,718	0	10,718
	9110 - Supervision - Sales Expenses	08 - Number of Electric Retail Cust							3	3				(3)	(3)				(1)	(1)		
		33 - Number of Workstations												651	651				699	699		
	9110 - Supervision - Sales Expenses Total					0	0		3	3	0	3		648	648	0	648		698	698	0	698
	9120 - Demonstrating & Selling Exp	06 - Number of Commercial Customers		5,218	5,218				6,132	6,132				7,532	7,532				7,740	7,740		
		08 - Number of Electric Retail Cust		43,207	43,207				41,456	41,456				28,212	28,212				30,105	30,105		
		09 - Number of Employees		28	28				10	10				47	47				47	47		
		17 - Number of Purchase Orders							1	1												
		58 - Total Assets		57	57				6	6				4,571	4,571				5,178	5,178		
		60 - AEPSC Bill less Indir and Int							(0)	(0)												
		61 - Total Fixed Assets							12,828	12,828												
	9120 - Demonstrating & Selling Exp Total			48,509	48,509	0	48,509		60,433	60,433	0	60,433		40,363	40,363	0	40,363		43,070	43,070	0	43,070
	9200 - Administrative & Gen Salaries	05 - Number of CIS Customers Mail		7,333	7,333				4,671	4,671												
		06 - Number of Commercial Customers		12,938	12,938				12,451	12,451				11,758	11,758				11,727	11,727		
		08 - Number of Electric Retail Cust	29,208	340,194	369,403			20,672	379,827	400,499			49,943	435,560	485,502			23,970	442,425	466,394		
		09 - Number of Employees	310	1,239,591	1,239,901			15,375	1,224,800	1,240,175			9,410	1,283,694	1,293,103			2,284	1,261,081	1,263,365		
		11 - Number of GL Transactions	203,522	190,671	394,194			187,534	519,092	706,626			33,341	350,751	384,092			19,015	304,180	323,195		

Kentucky Power Company
AEPSC Charges by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2017,2018,2019 and Test Year Ended March 2020

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			2017					2018					2019					TEST YEAR 12 MONTHS ENDED MARCH 2020				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
		16 - Number of Phone Center Calls		1,377	1,377				1,282	1,282				1,562	1,562				1,586	1,586		
		17 - Number of Purchase Orders		46,976	46,976				50,148	50,148				67,199	67,199				62,997	62,997		
		26 - Number of Stores Transactions		31,630	31,630				34,533	34,533				30,026	30,026				27,147	27,147		
		27 - Number of Telephones		10	10																	
		28 - Number of Trans Pole Miles		146,808	146,808				198,488	198,488				173,734	173,734				122,507	122,507		
		31 - Number of Vehicles		226	226				1,027	1,027				10,813	10,813				14,086	14,086		
		32 - Number of Vendor Invoice Pay		59,824	59,824				57,822	57,822				32,335	32,335				28,554	28,554		
		33 - Number of Workstations		156,854	156,854				242,755	242,755				261,738	261,738				270,406	270,406		
		39 - 100% to One Company	619,287		619,287			585,941		585,941			884,532		884,532			716,063		716,063		
		40 - Equal Share Ratio		6,520	6,520				10,710	10,710				4,462	4,462				4,473	4,473		
		44 - Level of Const-Distribution		346	346				11	11				5	5				5	5		
		46 - Level of Const-Transmission		181	181				111	111				324	324				304	304		
		48 - MW Generating Capability		329,014	329,014				362,587	362,587				385,806	385,806				361,297	361,297		
		49 - MWH's Generation		135,767	135,767				132,813	132,813				189,498	189,498				204,608	204,608		
		51 - Past 3 Mo MMBTU's Burned (Tot)		130,932	130,932				175,091	175,091				188,297	188,297				222,339	222,339		
		52 - Past 3 Mo MMBTU Burned (Coal)							29,252	29,252				54,282	54,282				45,240	45,240		
		57 - Tons of Fuel Acquired		155	155																	
		58 - Total Assets	685,063	4,673,850	5,358,913			606,875	4,594,918	5,201,793			535,143	4,994,525	5,529,668			562,951	5,228,882	5,791,833		
		60 - AEPSC Bill less Indir and Int	(3,865)	(64,760)	(68,625)				52,427	52,427				55,456	55,456				76,591	76,591		
		61 - Total Fixed Assets	88,120	557,772	645,892			46,106	484,705	530,811			5,368	425,328	430,695			1,602	399,214	400,816		
		63 - Total Gross Utility Plant	32,260	35,801	68,061			4,113	28,808	32,921			21,162	60,806	81,968			6,784	89,873	96,657		
		64 - Member/Peak Load		111,458	111,458				100,969	100,969				103,997	103,997				110,821	110,821		
		67 - Number of Banking Transactions		29,786	29,786				26,240	26,240				29,790	29,790				28,669	28,669		
		70 - No Nonelectric OAR Invoices		16,086	16,086				13,175	13,175				4,278	4,278				2,800	2,800		
		77 - Power Transactions							129	129				304	304				278	278		
	9200 - Administrative & Gen Salaries Total		1,653,906	8,197,344	9,851,251	(2,323,034)	7,528,217	1,466,615	8,738,842	10,205,458	(2,404,776)	7,800,682	1,538,898	9,156,326	10,695,224	(2,441,348)	8,253,876	1,332,669	9,322,091	10,654,760	(2,426,205)	8,228,555
	9210 - Office Supplies and Expenses	05 - Number of CIS Customers Mail		72	72				193	193				42	42				24	24		
		06 - Number of Commercial Customers		35	35				40	40				36	36				37	37		
		08 - Number of Electric Retail Cust	14	7,425	7,439			23	10,372	10,396			8,225	7,232	15,457			11	6,454	6,465		
		09 - Number of Employees	0	55,439	55,439			1,265	59,838	61,103			136	43,465	43,601			12	38,113	38,125		
		11 - Number of GL Transactions	1	2,566	2,566			1	46,948	46,949				62,757	62,757				19,151	19,151		
		16 - Number of Phone Center Calls		201	201				280	280				282	282				254	254		
		17 - Number of Purchase Orders		1,214	1,214				2,628	2,628				3,707	3,707				1,955	1,955		
		20 - Number of Remittance Items							29,271	29,271				65,394	65,394				64,164	64,164		
		26 - Number of Stores Transactions		61	61				58	58				32	32				30	30		
		27 - Number of Telephones		61,395	61,395				71,967	71,967				70,298	70,298				75,751	75,751		
		28 - Number of Trans Pole Miles		1,552	1,552				1,880	1,880				1,606	1,606				1,264	1,264		
		31 - Number of Vehicles		0	0				1	1				16	16				23	23		
		32 - Number of Vendor Invoice Pay		(91,502)	(91,502)				(102,865)	(102,865)				(79,705)	(79,705)				(128,678)	(128,678)		
		33 - Number of Workstations		2,874	2,874				13,317	13,317				20,454	20,454				14,719	14,719		
		39 - 100% to One Company	40,290		40,290			30,819		30,819			30,810		30,810			30,299		30,299		
		40 - Equal Share Ratio		333	333				1,119	1,119				364	364				602	602		
		44 - Level of Const-Distribution		0	0																	
		46 - Level of Const-Transmission		8	8				12	12				1	1				1	1		
		48 - MW Generating Capability		17,299	17,299				11,138	11,138				21,893	21,893				24,354	24,354		
		49 - MWH's Generation		2,873	2,873				(4,361)	(4,361)				219	219				247	247		
		51 - Past 3 Mo MMBTU's Burned (Tot)		154	154				470	470				235	235				254	254		
		52 - Past 3 Mo MMBTU Burned (Coal)							594	594				527	527				922	922		
		53 - Past 3 Mo MMBTU (Gas)							5	5												
		57 - Tons of Fuel Acquired		0	0									196	196				325	325		
		58 - Total Assets	70,717	350,585	421,301			26,618	405,653	432,271			1,725	369,019	370,744			1,997	374,406	376,403		
		60 - AEPSC Bill less Indir and Int		475	475				(825)	(825)				265	265				229	229		
		61 - Total Fixed Assets	331	3,383	3,714			34	4,173	4,208			5	4,205	4,209			2	3,741	3,743		
		63 - Total Gross Utility Plant	614	1,274	1,888			34	613	647			211	7,320	7,531			52	7,471	7,523		
		64 - Member/Peak Load		521	521				467	467				304	304				217	217		
		67 - Number of Banking Transactions		151	151				93	93				148	148				134	134		
		70 - No Nonelectric OAR Invoices		54	54				49	49				21	21				23	23		
		77 - Power Transactions							8	8				0	0				0	0		
	9210 - Office Supplies and Expenses Total		111,966	418,441	530,407	(125,334)	405,073	58,796	553,136	611,932	(140,248)	471,684	41,111	600,333	641,444	(138,754)	502,690	32,373	506,185	538,558	(117,040)	421,518
	9220 - Administrative Exp Trnsf - Cr	08 - Number of Electric Retail Cust												0	0							
		09 - Number of Employees		0	0				0	0												
		28 - Number of Trans Pole Miles		0	0				0	0												
		58 - Total Assets												0	0				0	0		
		60 - AEPSC Bill less Indir and Int		0	0				(0)	(0)												
	9220 - Administrative Exp Trnsf - Cr Total			0	0	0	0		(0)	(0)	0	(0)		0	0	0	0		0	0	0	0
	9230 - Outside Services Employed	05 - Number of CIS Customers Mail							34	34				16	16				16	16		
		08 - Number of Electric Retail Cust		70,606	70,606				93,947	93,947				161,370	161,370				171,655	171,655		
		09 - Number of Employees		116,346	116,346			30	244,807	244,837				95,673	95,673				112,519	112,519		
		11 - Number of GL Transactions		4,981	4,981			17,865	198,390	216,255			70,926	249,344	320,270			50,034	242,783	292,817		
		16 - Number of Phone Center Calls		(262)	(262)				(108)	(108)				(79)	(79)				(78)	(78)		
		17 - Number of Purchase Orders		16,863	16,863				17,239	17,239				25,568	25,568				26,431	26,431		
		20 - Number of Remittance Items		622	622				(606)	(606)												
		26 - Number of Stores Transactions		21,294	21,294				18,498	18,498				12,081	12,081				9,805	9,805		
		27 - Number of Telephones												(0)	(0)				1	1		
		28 - Number of Trans Pole Miles		14,954	14,954				6,618	6,618				11,245	11,245				9,802	9,802		
		31 - Number of Vehicles												9,846	9,846				12,321	12,321		
		32 - Number of Vendor Invoice Pay		12,453	12,453				14,644	14,644				15,336	15,336				15,908	15,908		
		33 - Number of Workstations		204,301	204,301				137,656	137,656				111,978	111,978				120,191	120,191		
		37 - AEPSC Past 3 Months Total Bill		(237,790)	(237,790)				692,594	692,594				(754,938)	(754,938)				1,574	1,574		
		39 - 100% to One Company	82,857		82,857			(112,899)		(112,899)			(435,978)		(435,978)			194,579		194,579		
		40 - Equal Share Ratio							11,872	11,872				35,124	35,124				36,118	36,118		
		44 - Level of Const-Distribution												135	135				135	135		
		46 - Level of Const-Transmission		3,699	3,699				13,470	13,470				22,241	22,241				24,572	24,572		
		48 - MW Generating Capability		21,406	21,406				32,323	32,323				25,507	25,507				23,265	23,265		
		49 - MWH's Generation		9,792	9,792				5,557	5,557				4,585	4,585				4,710	4,710		
		51 - Past 3 Mo MMBTU's Burned (Tot)		3,065	3,065				1,982	1,982				2,206	2,206				2,508	2,508		
		52 - Past 3 Mo MMBTU Burned (Coal)							360,198	360,198				1,218,138	1,218,138				1,116,071	1,116,071		
		58 - Total Assets	152,889	572,161	725,050			1,696	516,037	517,733			37	697,391	697,429			25	769,694	769,720		
		60 - AEPSC Bill less Indir and Int		13,242	13,242				6,605	6,605				21,715	21,715				75,911	75,911		
		61 - Total Fixed Assets		10,289	10,289				93,778	93,778				110,769	110,769				82,149	82,149		
		63 - Total Gross Utility Plant		136,853	136,853				139,593	139,593				173,041	173,041				204,695	204,695		
		64 - Member/Peak Load		5,966	5,966				3,708	3,708				11,029	11,029				7,123	7,123		
		67 - Number of Banking Transactions		490	490				690	690				668	668				670	670		
		70 - No Nonelectric OAR Invoices		220	220				244	244				(173)	(173)				(161)	(161)		
		77 - Power Transactions							95	95				2,000	2,000				1,741	1,741		
	9230 - Outside Services Employed Total		235,746	1,001,551	1,237,297	(226,792)	1,010,505	(93,308)	2,609,865	2,516,557	(669,997)	1,846,561	(365,015)	2,261,817	1,896,801	(628,726)	1,268,075	244,639	3,072,129	3,316,768	(859,845)	2,456,923
	9240 - Property Insurance	61 - Total Fixed Assets							317	317				662	662				662	662		
	9240 - Property Insurance Total					0	0		317	317	(78)	239		662	662	(157)	505		662	662	(157)	505
	9250 - Injuries and Damages	09 - Number of Employees		5,732	5,732				5,449	5,449				8,140	8,140				6,040	6,040		
		28 - Number of Trans Pole Miles		0	0																	
		58 - Total Assets		38	38									1	1				1	1		
		60 - AEPSC Bill less Indir and Int		5	5				(54)	(54)				60	60				(158)	(158)		
		61 - Total Fixed Assets							100	100												
	9250 - Injuries and Damages Total			5,775	5,775	(1,312)	4,463		5,496	5,496	(1,216)	4,280		8,202	8,202	(1,700)	6,501		5,884	5,884	(1,200)	4,683
	9260 - Employee Pensions & Benefits	05 - Number of CIS Customers Mail							7	7												
		08 - Number of Electric Retail Cust		221	221				109	109				23	23				26	26		
		09 - Number of Employees		8,875	8,875				3,945	3,945				5,497	5,497				4,760	4,760		
		11 - Number of GL Transactions							11	11				25	25				10	10		
		17 - Number of Purchase Orders		8	8									9	9				9	9		

Kentucky Power Company
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For 2017,2018,2019 and Test Year Ended March 2020

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Account Type	FERC Account	Allocation Factor	2017 Direct	2017 Allocated	2017 AEPSC Billed to Kentucky Power	2017 Share Billed to Co-Owner	2017 AEPSC Billed to Kentucky Power, Net	2018 Direct	2018 Allocated	2018 AEPSC Billed to Kentucky Power	2018 Share Billed to Co-Owner	2018 AEPSC Billed to Kentucky Power, Net	2019 Direct	2019 Allocated	2019 AEPSC Billed to Kentucky Power	2019 Share Billed to Co-Owner	2019 AEPSC Billed to Kentucky Power, Net	TEST YEAR 12 MONTHS ENDED MARCH 2020 Direct	Test Year Allocated	Test Year AEPSC Billed to Kentucky Power	Test Year Share Billed to Co-Owner	Test Year AEPSC Billed to Kentucky Power, Net
		20 - Number of Remittance Items		0	0																	
		26 - Number of Stores Transactions																	263	263		
		28 - Number of Trans Pole Miles		(18)	(18)				16	16				24	24				(22)	(22)		
		31 - Number of Vehicles							7	7				7	7				7	7		
		32 - Number of Vendor Invoice Pay		6	6																	
		33 - Number of Workstations		60	60				926	926				54	54				2	2		
		39 - 100% to One Company	1		1			0		0			0		0							
		48 - MW Generating Capability		383	383				188	188				1,481	1,481				1,267	1,267		
		49 - MWH's Generation												574	574				915	915		
		58 - Total Assets		25,057	25,057				27,166	27,166				13,228	13,228				11,265	11,265		
		60 - AEPSC Bill less Indir and Int		(54)	(54)				(94)	(94)				(229)	(229)				(35)	(35)		
		61 - Total Fixed Assets		24	24									6	6				4	4		
		63 - Total Gross Utility Plant												5	5				5	5		
		64 - Member/Peak Load		8	8																	
	9260 - Employee Pensions & Benefits Total		1	34,571	34,571	(8,395)	26,177	0	32,279	32,279	(8,034)	24,245	0	20,705	20,705	(5,314)	15,391		18,475	18,475	(4,728)	13,747
	9280 - Regulatory Commission Exp	08 - Number of Electric Retail Cust		0	0				11	11				6	6				(1)	(1)		
		09 - Number of Employees		27	27									61	61				64	64		
		28 - Number of Trans Pole Miles		208	208				182	182				578	578				145	145		
		39 - 100% to One Company	14,352		14,352			10,429		10,429			67,567		67,567			85,826		85,826		
		48 - MW Generating Capability		(877)	(877)				799	799				1,188	1,188				650	650		
		58 - Total Assets	143	19,872	20,015			668	10,682	11,351			1,292	15,204	16,496			17,057	16,010	33,067		
		60 - AEPSC Bill less Indir and Int		47	47				2,253	2,253				(2,503)	(2,503)				119	119		
		61 - Total Fixed Assets	1,598,828	6,935	1,605,763			90,951	4,167	95,118			377,066	3,378	380,445			395,400	5,089	400,489		
	9280 - Regulatory Commission Exp Total		1,613,323	26,214	1,639,537	(189)	1,639,348	102,048	18,093	120,141	(422)	119,719	445,926	17,913	463,839	(164)	463,675	498,283	22,077	520,360	(210)	520,151
	9301 - General Advertising Expenses	06 - Number of Commercial Customers		3	3																	
		08 - Number of Electric Retail Cust		8,729	8,729				8,681	8,681				2,366	2,366				934	934		
		09 - Number of Employees		163	163				101	101				63	63				54	54		
		28 - Number of Trans Pole Miles												72	72				72	72		
		58 - Total Assets		5,711	5,711				5,785	5,785				7,899	7,899				8,027	8,027		
	9301 - General Advertising Expenses Total			14,606	14,606	0	14,606		14,568	14,568	0	14,568		10,400	10,400	0	10,400		9,087	9,087	0	9,087
	9302 - Misc General Expenses	06 - Number of Commercial Customers		7,734	7,734				8,470	8,470				9,242	9,242				9,077	9,077		
		08 - Number of Electric Retail Cust		345	345				894	894				4,088	4,088				4,298	4,298		
		09 - Number of Employees		4,541	4,541				11,278	11,278				11,714	11,714				10,153	10,153		
		11 - Number of GL Transactions		23	23				76	76				2,131	2,131				187	187		
		16 - Number of Phone Center Calls												24	24				24	24		
		20 - Number of Remittance Items		22	22																	
		27 - Number of Telephones												812	812				1,067	1,067		
		28 - Number of Trans Pole Miles		2,980	2,980				3,341	3,341				3,308	3,308				3,437	3,437		
		32 - Number of Vendor Invoice Pay		138	138				24	24				12	12				7	7		
		33 - Number of Workstations		(4,431)	(4,431)																	
		39 - 100% to One Company	18,218		18,218			11,644		11,644			3,829		3,829			7,751		7,751		
		46 - Level of Const-Transmission		0	0																	
		48 - MW Generating Capability		(6)	(6)				116	116				701	701				72	72		
		57 - Tons of Fuel Acquired												1,181	1,181				1,181	1,181		
		58 - Total Assets		87,598	87,598				113,518	113,518				145,384	145,384				153,668	153,668		
		60 - AEPSC Bill less Indir and Int		89	89				231	231				298	298				181	181		
		61 - Total Fixed Assets		84	84				1	1												
		63 - Total Gross Utility Plant							16	16				136	136				132	132		
		64 - Member/Peak Load		4	4				9	9												
		70 - No Nonelectric OAR Invoices		21	21				35	35				32	32				49	49		
	9302 - Misc General Expenses Total		18,218	99,140	117,358	(19,995)	97,363	11,644	138,008	149,653	(29,569)	120,084	3,829	179,063	182,892	(39,499)	143,393	7,751	183,533	191,283	(39,880)	151,403
	9310 - Rents	08 - Number of Electric Retail Cust												223	223				223	223		
		09 - Number of Employees		16	16									0	0				63	63		
		11 - Number of GL Transactions																1	237	238		
		17 - Number of Purchase Orders												91	91				91	91		
		27 - Number of Telephones												8,553	8,553				10,659	10,659		
		28 - Number of Trans Pole Miles												61	61				126	126		
		31 - Number of Vehicles												17	17				17	17		
		32 - Number of Vendor Invoice Pay		58	58									13	13				16	16		
		33 - Number of Workstations		(50,586)	(50,586)														1	1		
		39 - 100% to One Company																10,179		10,179		
		40 - Equal Share Ratio																	1	1		
		48 - MW Generating Capability							1	1				10,973	10,973				13,733	13,733		
		49 - MWH's Generation																	19	19		
		58 - Total Assets		21,216	21,216				10,302	10,302				7,879	7,879				12,279	12,279		
		60 - AEPSC Bill less Indir and Int																	4	4		
		61 - Total Fixed Assets												90	90				122	122		
		63 - Total Gross Utility Plant																	0	0		
	9310 - Rents Total			(29,297)	(29,297)	3,147	(26,150)		10,303	10,303	(2,721)	7,582		27,901	27,901	(8,326)	19,575	10,181	37,590	47,770	(10,742)	37,028
	9350 - Maintenance of General Plant	05 - Number of CIS Customers Mail		608	608				500	500				605	605							
		08 - Number of Electric Retail Cust		87,480	87,480				89,000	89,000				60,148	60,148				67,108	67,108		
		09 - Number of Employees	402	56,523	56,925				63,711	63,711				59,383	59,383				52,025	52,025		
		11 - Number of GL Transactions												5,202	5,202				5,202	5,202		
		27 - Number of Telephones		47,911	47,911				42,139	42,139				40,491	40,491				42,403	42,403		
		28 - Number of Trans Pole Miles		4,823	4,823				459	459				885	885				958	958		
		31 - Number of Vehicles		10	10																	
		33 - Number of Workstations	505	448,993	449,498			456	387,228	387,684			265	300,379	300,643			265	366,703	366,968		
		39 - 100% to One Company	255,297		255,297			593		593			822,442		822,442			537,506		537,506		
		40 - Equal Share Ratio		177	177																	
		46 - Level of Const-Transmission		1,577	1,577																	
		48 - MW Generating Capability		107,387	107,387				197,781	197,781				195,828	195,828				179,894	179,894		
		49 - MWH's Generation		2,784	2,784																	
		51 - Past 3 Mo MMBTU's Burned (Tot)		17,632	17,632				24,959	24,959				0	0				4,252	4,252		
		58 - Total Assets		139,450	139,450				123,894	123,894				91,284	91,284				86,898	86,898		
		60 - AEPSC Bill less Indir and Int		(357)	(357)				1,976	1,976				12,974	12,974				14,616	14,616		
		61 - Total Fixed Assets	4,814	7,398	12,211			453,618	2,420	456,037			(270,239)		(270,239)			203,078		203,078		
		63 - Total Gross Utility Plant		62,797	62,797				98,193	98,193				199,796	199,796				207,707	207,707		
		64 - Member/Peak Load		93,238	93,238				50,250	50,250				39,221	39,221				43,340	43,340		
	9350 - Maintenance of General Plant Total		261,019	1,078,429	1,339,447	(248,334)	1,091,113	454,667	1,082,511	1,537,178	(260,455)	1,276,723	552,467	1,006,195	1,558,663	(247,586)	1,311,076	740,848	1,071,106	1,811,955	(247,707)	1,564,248
Cost of Service Total			12,133,637	22,785,484	34,919,121	(6,263,282)	28,655,838	11,779,033	25,888,215	37,667,248	(7,434,397)	30,232,851	11,892,323	27,855,343	39,747,666	(8,489,587)	31,258,079	12,129,766	27,830,517	39,960,282	(8,112,957)	31,847,325
Non-Cost of Service	1070 - Construction Work In Progress	06 - Number of Commercial Customers		179	179				81,212	81,212				13,786	13,786				9,980	9,980		
		08 - Number of Electric Retail Cust		840,260	840,260				1,021,533	1,021,533				1,822,294	1,822,294				2,478,805	2,478,805		
		09 - Number of Employees		56,565	56,565				85,091	85,091				52,552	52,552				60,275	60,275		
		11 - Number of GL Transactions		513	513				1,536	1,536				30,752	30,752				48,370	48,370		
		16 - Number of Phone Center Calls		3,052	3,052				5,974	5,974				(165)	(165)				314	314		
		17 - Number of Purchase Orders		5,534	5,534				108,834	108,834				19,988	19,988				13,425	13,425		
		20 - Number of Remittance Items		635	635				18,486	18,486				413	413							
		26 - Number of Stores Transactions		2,944	2,944				76	76				82,326	82,326				111,791	111,791		
		27 - Number of Telephones		1,747	1,747				223	223												
		28 - Number of Trans Pole Miles		113,102	113,102				50,756	50,756				23,224	23,224				21,187	21,187		
		31 - Number of Vehicles		7,066	7,066				260,015	260,015				94,355	94,355				90,445	90,445		
		33 - Number of Workstations		3,807,812	3,807,812				2,272,609	2,272,609				1,785,739	1,785,739				1,856,360	1,856,360		
		37 - AEPSC Past 3 Months Total Bill																	33,257	33,257		
		39 - 100% to One Company	8,645,655		8,645,655			10,662,381		10,662,381			12,972,215		12,972,215			12,981,632		12,981,632		
		40 - Equal Share Ratio		7,816	7,816				105	105												
		44 - Level of Const-Distribution		170,229	170,229				176,408	176,408				315,161	315,161				300,286	300,286		
		45 - Level of Const-Production		1,045,319	1,045,319				1,137,741	1,137,741				1,918,299	1,918,299				1,626,544	1,626,544		
		46 - Level of Const-Transmission		738,600	738,600				1,792,847	1,792,847				2,790,836	2,790,836				3,082,071	3,082,071		
		48 - MW Generating Capability		507,596	507,596				766,175	766,175				406,841	406,841				573,583	573,583		

Kentucky Power Company
AEPSC Charges by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2017,2018,2019 and Test Year Ended March 2020

American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of AEP and is the Centralized Service Company for the AEP System. AEPSC's activities are authorized by the FERC under the Public Utilities Holding Company Act of 2005. AEPSC performs, at cost, various corporate support services for subsidiaries of AEP, including Kentucky Power.

AEPSC transactions are accounted for through a work order system as required by the FERC. Costs for support services are accumulated in work orders and are billed to the company or companies benefiting from the service. Accounting within each work order is in accordance with the FERC Uniform System of Accounts. The costs for services benefiting only one company are directly assigned and are billed 100% to that company. Where services benefit more than one company, the costs for those services are allocated to the benefiting companies using an approved allocation factor. The allocation factor for any given allocation of costs is selected for use because it best reflects the cost driver associated with the service provided.

The FERC monitors the factors used for allocations, through required annual reporting, and can audit the validity of each factor. All services are billed at cost, with no profit charged, as required by the FERC's "at cost" rules

			2017					2018					2019					TEST YEAR 12 MONTHS ENDED MARCH 2020				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
		49 - MWH's Generation		62,515	62,515				85,218	85,218				153,323	153,323				79,502	79,502		
		51 - Past 3 Mo MMBTU's Burned (Tot)		3,076	3,076				991	991				6,554	6,554				5,588	5,588		
		52 - Past 3 Mo MMBTU Burned (Coal)		71,479	71,479				4,500	4,500				234	234				230	230		
		53 - Past 3 Mo MMBTU (Gas)							110,184	110,184				83,654	83,654				54,676	54,676		
		57 - Tons of Fuel Acquired		4,484	4,484				28	28												
		58 - Total Assets		556,708	556,708				820,145	820,145				1,021,468	1,021,468				924,094	924,094		
		60 - AEPSC Bill less Indir and Int		3,291,845	3,291,845				2,381,019	2,381,019				1,792,136	1,792,136				1,889,265	1,889,265		
		61 - Total Fixed Assets		72,755	72,755				122,274	122,274				112,925	112,925				104,676	104,676		
		63 - Total Gross Utility Plant		2,966,812	2,966,812				3,857,123	3,857,123				4,034,970	4,034,970				3,896,313	3,896,313		
		67 - Number of Banking Transactions							143	143				1	1				720	720		
	1070 - Construction Work In Progress Total		8,645,655	14,338,643	22,984,298	(931,172)	22,053,126	10,662,381	15,161,246	25,823,627	(716,671)	25,106,956	12,972,215	16,561,665	29,533,880	(817,745)	28,716,135	12,981,632	17,261,758	30,243,389	(767,460)	29,475,929
	1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	1,579,252		1,579,252			1,581,518		1,581,518			1,416,980		1,416,980			1,544,339		1,544,339		
		45 - Level of Const-Production		18	18				34	34				56	56				131	131		
		46 - Level of Const-Transmission		5,598	5,598				4,075	4,075				2,387	2,387				2,445	2,445		
		60 - AEPSC Bill less Indir and Int		(116)	(116)				3,012	3,012				1,078	1,078				9,194	9,194		
	1080 - Accum Prov for Deprec of Plant Total		1,579,252	5,500	1,584,753	(282,388)	1,302,364	1,581,518	7,120	1,588,639	(67,768)	1,520,871	1,416,980	3,521	1,420,501	(80,028)	1,340,472	1,544,339	11,771	1,556,109	(60,450)	1,495,660
	1220 - Depr & Amort of Nonutil Prop	39 - 100% to One Company						8,342		8,342			15,025		15,025			16,090		16,090		
	1220 - Depr & Amort of Nonutil Prop Total					0	0	8,342		8,342	0	8,342	15,025		15,025	0	15,025	16,090		16,090	0	16,090
	1240 - Other Investments	39 - 100% to One Company						4,574		4,574			7,283		7,283			7,351		7,351		
	1240 - Other Investments Total					0	0	4,574		4,574	0	4,574	7,283		7,283	0	7,283	7,351		7,351	0	7,351
	1520 - Fuel Stock Exp Undistributed	09 - Number of Employees		3,561	3,561				1,778	1,778				2,435	2,435				1,514	1,514		
		11 - Number of GL Transactions							116	116				4,951	4,951				1,901	1,901		
		33 - Number of Workstations							10	10												
		39 - 100% to One Company	396,230		396,230			396,925		396,925			446,712		446,712			378,654		378,654		
		48 - MW Generating Capability		14,122	14,122				15,629	15,629				17,291	17,291				14,455	14,455		
		49 - MWH's Generation		4,899	4,899				74	74												
		51 - Past 3 Mo MMBTU's Burned (Tot)		5,971	5,971				4,550	4,550				1,887	1,887				1,198	1,198		
		52 - Past 3 Mo MMBTU Burned (Coal)		33,134	33,134				29,394	29,394				28,055	28,055				31,651	31,651		
		53 - Past 3 Mo MMBTU (Gas)												2	2							
		55 - Past 3 MMBTU Burned (Solid)												36,332	36,332				59,187	59,187		
		57 - Tons of Fuel Acquired		387,654	387,654				432,866	432,866				331,616	331,616				351,656	351,656		
		58 - Total Assets		21,520	21,520				4,911	4,911				14,878	14,878				18,850	18,850		
		60 - AEPSC Bill less Indir and Int		25	25				474	474				296	296				583	583		
		61 - Total Fixed Assets		95	95				12	12												
		64 - Member/Peak Load		46	46				256	256												
	1520 - Fuel Stock Exp Undistributed Total		396,230	471,026	867,256	0	867,256	396,925	490,070	886,995	0	886,995	446,712	437,743	884,455	0	884,455	378,654	480,994	859,649	0	859,649
	1630 - Stores Expense Undistributed	05 - Number of CIS Customers Mail		2	2																	
		08 - Number of Electric Retail Cust		1,063	1,063				20	20				1	1				97	97		
		09 - Number of Employees		32,032	32,032				22,930	22,930			55	33,254	33,309			55	35,564	35,619		
		11 - Number of GL Transactions							58	58				578	578				578	578		
		17 - Number of Purchase Orders		1,047,204	1,047,204				1,270,239	1,270,239				1,295,552	1,295,552				1,373,767	1,373,767		
		20 - Number of Remittance Items							22	22												
		26 - Number of Stores Transactions		145,973	145,973				156,612	156,612				162,380	162,380				190,695	190,695		
		27 - Number of Telephones		51	51				(15)	(15)				0	0				0	0		
		28 - Number of Trans Pole Miles		10,014	10,014				7,318	7,318				7,278	7,278				7,076	7,076		
		31 - Number of Vehicles		137	137				215	215				14	14				20	20		
		32 - Number of Vendor Invoice Pay		1,074	1,074				2,285	2,285				1,466	1,466				1,783	1,783		
		33 - Number of Workstations		2,202	2,202				4,598	4,598				2,988	2,988				95	95		
		39 - 100% to One Company	435,237		435,237			511,406		511,406			537,306		537,306			579,975		579,975		
		44 - Level of Const-Distribution		527	527				10	10				0	0				0	0		
		48 - MW Generating Capability		330,394	330,394				157,860	157,860				212,336	212,336				214,908	214,908		
		51 - Past 3 Mo MMBTU's Burned (Tot)												65	65				73	73		
		58 - Total Assets		206,582	206,582				157,013	157,013				186,743	186,743				216,690	216,690		
		60 - AEPSC Bill less Indir and Int		778	778				2,608	2,608				9,029	9,029				14,433	14,433		
		61 - Total Fixed Assets		136,313	136,313				344,589	344,589				349,075	349,075				378,698	378,698		
		63 - Total Gross Utility Plant		10	10				15	15				14,119	14,119				25,771	25,771		
		70 - No Nonelectric OAR Invoices												(5)	(5)				(5)	(5)		
	1630 - Stores Expense Undistributed Total		435,237	1,914,355	2,349,592	0	2,349,592	511,406	2,126,378	2,637,783	0	2,637,783	537,361	2,274,873	2,812,234	0	2,812,234	580,030	2,460,244	3,040,274	0	3,040,274
	1830 - Prelimin Surv&Investgtn Chrgs	28 - Number of Trans Pole Miles		(845)	(845)				68	68				30	30				(466)	(466)		
		39 - 100% to One Company	353,903		353,903			395,959		395,959			133,604		133,604			(236,071)		(236,071)		
		48 - MW Generating Capability		1,236	1,236				541	541				1,221	1,221				(13)	(13)		
		58 - Total Assets												0	0				0	0		
		60 - AEPSC Bill less Indir and Int		(64)	(64)				587	587				1,183	1,183				963	963		
	1830 - Prelimin Surv&Investgtn Chrgs Total		353,903	327	354,230	0	354,230	395,959	1,196	397,155	0	397,155	133,604	2,434	136,038	0	136,038	(236,071)	484	(235,587)	0	(235,587)
	1840 - Clearing Accounts	09 - Number of Employees		1	1																	
	1840 - Clearing Accounts Total			1	1	0	1				0	0				0	0				0	0
	1860 - MDD-Internal Billing Only	28 - Number of Trans Pole Miles							0	0												
		39 - 100% to One Company	1,015,804		1,015,804			1,075,486		1,075,486			1,384,293		1,384,293			1,219,980		1,219,980		
		48 - MW Generating Capability							0	0												
		60 - AEPSC Bill less Indir and Int							0	0												
	1860 - MDD-Internal Billing Only Total		1,015,804		1,015,804	0	1,015,804	1,075,486	0	1,075,486	0	1,075,486	1,384,293		1,384,293	0	1,384,293	1,219,980		1,219,980	0	1,219,980
	1880 - R&D Expenses	28 - Number of Trans Pole Miles		73,915	73,915				67,022	67,022				72,608	72,608				72,767	72,767		
		33 - Number of Workstations		13,623	13,623				17,162	17,162				17,647	17,647				18,151	18,151		
		48 - MW Generating Capability		61,984	61,984				63,758	63,758				66,352	66,352				59,158	59,158		
		51 - Past 3 Mo MMBTU's Burned (Tot)		503,947	503,947				526,216	526,216				429,466	429,466				419,080	419,080		
		52 - Past 3 Mo MMBTU Burned (Coal)		71,528	71,528				14,128	14,128				23,836	23,836				13,739	13,739		
		55 - Past 3 MMBTU Burned (Solid)		14,650	14,650				429	429				1,036	1,036				948	948		
		58 - Total Assets		6,308	6,308				4,841	4,841				5,761	5,761				6,742	6,742		
		60 - AEPSC Bill less Indir and Int		(17)	(17)				281	281				305	305				58	58		
		61 - Total Fixed Assets		62,850	62,850				85,733	85,733				64,386	64,386				103,430	103,430		
	1880 - R&D Expenses Total			808,789	808,789	0	808,789		779,570	779,570	0	779,570		681,398	681,398	0	681,398		694,072	694,072	0	694,072
	4010 - Operation Expense	48 - MW Generating Capability																	0	0		
	4010 - Operation Expense Total					0	0				0	0				0	0		0	0	0	0
	4020 - Maintenance Expense	63 - Total Gross Utility Plant												3	3				3	3		
	4020 - Maintenance Expense Total					0	0				0	0		3	3	246	249		3	3	246	249
	4171 - Expenses of Non-Utility Oper	39 - 100% to One Company											(0)		(0)			(115)		(115)		
	4171 - Expenses of Non-Utility Oper Total					0	0				0	0	(0)		(0)	0	(0)	(115)		(115)	0	(115)
	4180 - Non-Operatng Rental Income	39 - 100% to One Company	4,050		4,050			1,478		1,478												
	4180 - Non-Operatng Rental Income Total		4,050		4,050	0	4,050	1,478		1,478	0	1,478				0	0				0	0
	4210 - Misc Non-Operating Income	08 - Number of Electric Retail Cust		0	0				0	0				0	0				0	0		
		09 - Number of Employees							0	0												
		58 - Total Assets		528	528				6,798	6,798				(131)	(131)				(608)	(608)		
		60 - AEPSC Bill less Indir and Int		(291)	(291)				240	240				197	197				109	109		
	4210 - Misc Non-Operating Income Total			237	237	43	281		7,038	7,038	(2,364)	4,674		66	66	(195)	(129)		(499)	(499)	(15)	(514)
	4261 - Donations	60 - AEPSC Bill less Indir and Int		11,999	11,999				19,546	19,546				64,592	64,592				68,792	68,792		
	4261 - Donations Total			11,999	11,999	0	11,999		19,546	19,546	0	19,546		64,592	64,592	0	64,592		68,792	68,792	0	68,792
	4263 - Penalties	09 - Number of Employees		512	512				(4)	(4)												
		11 - Number of GL Transactions		16	16																	
		33 - Number of Workstations		13	13																	
		39 - 100% to One Company	6,470		6,470																	
		58 - Total Assets		200	200				432	432				198	198				433	433		
	4263 - Penalties Total		6,470	741	7,211	(171)	7,041		428	428	(112)	316		198	198	(51)	147		433	433	(108)	325
	4264 - Civic & Political Activities	09 - Number of Employees		0	0																	
		28 - Number of Trans Pole Miles		10	10				(10)	(10)				0	0				0	0		
		48 - MW Generating Capability		7	7				173	173				102	102				4	4		
		58 - Total Assets		185,574	185,574				267,942	267,942				226,853	226,853				203,855	203,855		
		60 - AEPSC Bill less Indir and Int		(293)	(293)				486	486				675	675				503	503		
	4264 - Civic & Political Activities Total			185,299	185,299	(1,829)	183,469		268,591	268,591	(684)	267,907		227,630	227,630	(9,109)	218,521		204,361	204,361	(9,783)	194,578
	4265 - Other Deductions	09 - Number of Employees							38	38												

Kentucky Power Company
AEPSC Charges by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2017,2018,2019 and Test Year Ended March 2020

American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of AEP and is the Centralized Service Company for the AEP System. AEPSC's activities are authorized by the FERC under the Public Utilities Holding Company Act of 2005. AEPSC performs, at cost, various corporate support services for subsidiaries of AEP, including Kentucky Power.

AEPSC transactions are accounted for through a work order system as required by the FERC. Costs for support services are accumulated in work orders and are billed to the company or companies benefiting from the service. Accounting within each work order is in accordance with the FERC Uniform System of Accounts. The costs for services benefiting only one company are directly assigned and are billed 100% to that company. Where services benefit more than one company, the costs for those services are allocated to the benefiting companies using an approved allocation factor. The allocation factor for any given allocation of costs is selected for use because it best reflects the cost driver associated with the service provided.

The FERC monitors the factors used for allocations, through required annual reporting, and can audit the validity of each factor. All services are billed at cost, with no profit charged, as required by the FERC's "at cost" rules

			2017					2018				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
		11 - Number of GL Transactions							(0)	(0)		
		17 - Number of Purchase Orders							4	4		
		33 - Number of Workstations		92	92				154	154		
		39 - 100% to One Company										
		48 - MW Generating Capability		123	123				68	68		
		58 - Total Assets		17,186	17,186				24,507	24,507		
		60 - AEPSC Bill less Indir and Int							0	0		
	4265 - Other Deductions Total			17,401	17,401	(1,621)	15,779		24,770	24,770	(2,683)	22,086
Non-Cost of Service Total			12,436,602	17,754,318	30,190,920	(1,217,138)	28,973,781	14,638,069	18,885,954	33,524,023	(790,282)	32,733,741
Grand Total			24,570,238	40,539,802	65,110,041	(7,480,421)	57,629,620	26,417,102	44,774,170	71,191,271	(8,224,679)	62,966,592

			2019					TEST YEAR 12 MONTHS ENDED MARCH 2020				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
		11 - Number of GL Transactions		0	0				0	0		
		17 - Number of Purchase Orders										
		33 - Number of Workstations		215	215				92	92		
		39 - 100% to One Company	115		115			2,014		2,014		
		48 - MW Generating Capability							26	26		
		58 - Total Assets	418	39,621	40,039			418	46,639	47,056		
		60 - AEPSC Bill less Indir and Int		0	0				21	21		
	4265 - Other Deductions Total		532	39,836	40,369	(6,893)	33,476	2,432	46,778	49,210	(6,694)	42,517
Non-Cost of Service Total			16,914,006	20,293,958	37,207,964	(913,776)	36,294,188	16,494,322	21,229,192	37,723,514	(844,264)	36,879,250
Grand Total			28,806,329	48,149,301	76,955,630	(9,403,363)	67,552,267	28,624,088	49,059,708	77,683,796	(8,957,221)	68,726,575

Kentucky Power Company
Other Affiliates Charges by FERC Account, Allocation Factor and Allocation Type
For 2017,2018,2019 and Test Year Ended March 2020

Kentucky Power has a variety of transactions with affiliates on a normal basis. Transactions with affiliates generally fall into two categories. The first category, service payments, is a billing made when an affiliate provides a service to Kentucky Power, such as Appalachian Power providing assistance in distribution maintenance, generation engineering, or other affiliates providing assistance during storm recovery efforts. The second category, convenience payments, occurs when an affiliate company receives an invoice and the cost of that invoice should be borne by multiple AEP companies. For example, a legal invoice for a system-wide issue may be paid by one affiliate company, and that company then bills the other affiliates who benefit from the service.

Charges from affiliates are accumulated using a work order system. All affiliate services and convenience payments are billed to Kentucky Power at cost, per FERC affiliate requirements.

				2017			2018			2019			TEST YEAR 12 MONTHS ENDED MARCH 2020		
Account Type	Affiliate	FERC Account	Allocation Factor	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total
Cost of Service	AEP Energy Partners, Inc.	5570 - Other Expenses	58 - Total Assets		46,568	46,568		10,613	10,613						
		9200 - Administrative & Gen Salaries	09 - Number of Employees		12	12		646	646		887	887		887	887
			58 - Total Assets		8,535	8,535		6,521	6,521		28,350	28,350		51,436	51,436
		9210 - Office Supplies and Expenses	09 - Number of Employees		0	0		0	0						
			58 - Total Assets		409	409		4	4		116	116		116	116
		9230 - Outside Services Employed	58 - Total Assets								10	10		8	8
	AEP Energy Partners, Inc. Total				55,524	55,524		17,784	17,784		29,363	29,363		52,447	52,447
	AEP Generation Resources	5000 - Oper Supervision & Engineering	39 - 100% to One Company	7,215		7,215	1,576		1,576						
			48 - MW Generating Capability		2,304	2,304		8,961	8,961						
		5010 - Fuel	39 - 100% to One Company	5,354		5,354	12,080		12,080						
		5060 - Misc Steam Power Expenses	39 - 100% to One Company	0		0	49		49						
		5100 - Maint Supv & Engineering	48 - MW Generating Capability								67	67		67	67
		5140 - Maintenance of Misc Steam Plt	39 - 100% to One Company	123		123									
		5570 - Other Expenses	58 - Total Assets		647	647		1,422	1,422		1,076	1,076		1,329	1,329
		9040 - Uncollectible Accounts	26 - Number of Stores Transactions		(13)	(13)									
		9200 - Administrative & Gen Salaries	58 - Total Assets		1,606	1,606					1,760	1,760		6,367	6,367
		9210 - Office Supplies and Expenses	09 - Number of Employees		0	0									
			48 - MW Generating Capability		64	64		59	59		59	59		59	59
			58 - Total Assets		131	131					95	95		114	114
		9230 - Outside Services Employed	09 - Number of Employees		10	10					1	1		1	1
			58 - Total Assets		30,638	30,638		19,388	19,388		21,930	21,930		20,868	20,868
			61 - Total Fixed Assets		25,769	25,769		20,354	20,354		14,148	14,148		8,127	8,127
		9250 - Injuries and Damages	39 - 100% to One Company	356		356	272		272						
			61 - Total Fixed Assets		12,243	12,243		592	592		681	681		107	107
	AEP Generation Resources Total			13,048	73,399	86,447	13,977	50,775	64,752		39,817	39,817		37,040	37,040
	Appalachian Power Company	5000 - Oper Supervision & Engineering	39 - 100% to One Company	898		898									
			48 - MW Generating Capability		9,066	9,066		21,970	21,970		5,762	5,762		983	983
		5010 - Fuel	39 - 100% to One Company	6,155		6,155									
		5060 - Misc Steam Power Expenses	39 - 100% to One Company	4,233		4,233									
			40 - Equal Share Ratio		539	539		457	457		1,314	1,314		1,314	1,314
			58 - Total Assets					3,386	3,386		24	24			
		5100 - Maint Supv & Engineering	39 - 100% to One Company	43,138		43,138	17,161		17,161	8,334		8,334	6,448		6,448
			48 - MW Generating Capability		474	474					588	588		588	588
		5120 - Maintenance of Boiler Plant	39 - 100% to One Company	11,984		11,984	2,696		2,696	10,788		10,788	17,840		17,840
		5130 - Maintenance of Electric Plant	39 - 100% to One Company	257		257				0		0	0		0
		5390 - Misc Hydr Power Generation Exp	39 - 100% to One Company							69		69	69		69
		5430 - Maint Rsrvoirs,Dams&Wtrways	48 - MW Generating Capability								4	4		4	4
		5440 - Maintenance of Electric Plant	48 - MW Generating Capability								11	11		11	11
		5600 - Oper Supervision & Engineering	09 - Number of Employees		(0)	(0)									
			28 - Number of Trans Pole Miles		(1)	(1)									
			39 - 100% to One Company	10,720		10,720	12,699		12,699	15,850		15,850	14,626		14,626
			58 - Total Assets		3,571	3,571		14,926	14,926		3,769	3,769		977	977
		5630 - Overhead Line Expenses	58 - Total Assets		362	362									
		5660 - Misc Transmission Expenses	28 - Number of Trans Pole Miles		1,410	1,410									
			31 - Number of Vehicles					17	17						
			58 - Total Assets		297	297		(0)	(0)		430	430		460	460
		5700 - Maint of Station Equipment	08 - Number of Electric Retail Cust		30	30		38	38						
			39 - 100% to One Company				4,463		4,463						
		5710 - Maintenance of Overhead Lines	39 - 100% to One Company							2,834		2,834			
		5730 - Maint of Misc Trnsmssion Plt	28 - Number of Trans Pole Miles		12	12									
			39 - 100% to One Company	4,260		4,260	1,041		1,041	2,189		2,189	2,124		2,124
			58 - Total Assets		(19)	(19)									
		5800 - Oper Supervision & Engineering	08 - Number of Electric Retail Cust		1,579	1,579		1,486	1,486		2,245	2,245		2,664	2,664
			09 - Number of Employees		912	912		672	672		688	688		578	578
			16 - Number of Phone Center Calls		20	20		19	19		76	76		63	63
			17 - Number of Purchase Orders		(0)	(0)									
			39 - 100% to One Company	18,710		18,710	32,811		32,811	36,608		36,608	37,913		37,913
			44 - Level of Const-Distribution		296	296									
			58 - Total Assets		377	377		303	303		366	366		375	375
			63 - Total Gross Utility Plant								12	12		8	8
		5830 - Overhead Line Expenses	39 - 100% to One Company	(10)		(10)				(23)		(23)	(23)		(23)
		5860 - Meter Expenses	39 - 100% to One Company	57,181		57,181	56,002		56,002	58,950		58,950	56,428		56,428
		5870 - Customer Installations Exp	39 - 100% to One Company	266		266				127		127	127		127
		5880 - Miscellaneous Distribution Exp	08 - Number of Electric Retail Cust		10	10		136	136		(577)	(577)		(577)	(577)
			09 - Number of Employees					42	42		29	29		29	29
			39 - 100% to One Company	16,101		16,101	52,972		52,972	83,812		83,812	83,398		83,398
			58 - Total Assets		35	35		(615)	(615)		6	6		6	6
		5920 - Maint of Station Equipment	39 - 100% to One Company	117		117									
		5930 - Maintenance of Overhead Lines	39 - 100% to One Company	54,728		54,728	56,203		56,203	51,986		51,986	60,840		60,840
		5940 - Maint of Underground Lines	39 - 100% to One Company	40		40	(109)		(109)	(3)		(3)	(3)		(3)
		5950 - Maint of Lne Trnf,Rglators&Dvi	39 - 100% to One Company	129		129	109		109	100		100	163		163
		5970 - Maintenance of Meters	39 - 100% to One Company	1,085		1,085	243		243						
		5980 - Maint of Misc Distribution Plt	09 - Number of Employees					127	127						
			39 - 100% to One Company	(5)		(5)	302		302	658		658	852		852
		9010 - Supervision - Customer Accts	08 - Number of Electric Retail Cust					16	16		458	458		7	7
		9030 - Cust Records & Collection Exp	39 - 100% to One Company	140		140							0		0
		9100 - Misc Cust Svc&Informational Ex	39 - 100% to One Company				626		626						
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust		16,814	16,814		10,077	10,077		311	311		105	105
			33 - Number of Workstations		10	10									
			39 - 100% to One Company	7,495		7,495				1,477		1,477	1,477		1,477
			58 - Total Assets		1,182	1,182		1,134	1,134		6,195	6,195		23,164	23,164
			63 - Total Gross Utility Plant								297	297		243	243
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust		745	745		198	198		7	7		2	2
			09 - Number of Employees		24	24									
			33 - Number of Workstations		447	447									
			39 - 100% to One Company	328		328	40		40	2		2	187,483		187,483
			58 - Total Assets		1,280	1,280		305	305		459	459		2,201	2,201
		9220 - Administrative Exp Trnsf - Cr	58 - Total Assets								658	658		972	972
		9230 - Outside Services Employed	08 - Number of Electric Retail Cust		2,780	2,780		3,064	3,064		2,731	2,731		3,713	3,713
			09 - Number of Employees		5,161	5,161		8,719	8,719		9,183	9,183		7,897	7,897
			17 - Number of Purchase Orders		56	56									
			33 - Number of Workstations		73	73		266	266		148	148		79	79
			58 - Total Assets		13,466	13,466		23,561	23,561		45,380	45,380		43,026	43,026
			61 - Total Fixed Assets		30,183	30,183		51,872	51,872		23,450	23,450		12,038	12,038
		9250 - Injuries and Damages	61 - Total Fixed Assets		19,401	19,401		2,520	2,520		3,184	3,184		3,994	3,994
		9280 - Regulatory Commission Exp	58 - Total Assets					3,661	3,661		145	145		90	90
			61 - Total Fixed Assets		1,572	1,572		14	14						
		9302 - Misc General Expenses	06 - Number of Commercial Customers		7	7		7	7						
			39 - 100% to One Company	0		0				0		0	0		0
		9310 - Rents	11 - Number of GL Transactions											1	1
			39 - 100% to One Company	6,052		6,052							33		33
			48 - MW Generating Capability											0	0
		9350 - Maintenance of General Plant	27 - Number of Telephones		121	121									
			39 - 100% to One Company	164,559		164,559	157,534		157,534	115,035		115,035	112,144		112,144
	Appalachian Power Company Total			408,563	112,291	520,854	394,794	148,379	543,173	388,791	107,353	496,144	581,938	105,014	686,952
	Indiana Michigan Power Company	5000 - Oper Supervision & Engineering	39 - 100% to One Company							16,686		16,686	16,686		16,686
			48 - MW Generating Capability		3,384	3,384		2,000	2,000		5,008	5,008		5,008	5,008
		5060 - Misc Steam Power Expenses	39 - 100% to One Company							2,741		2,741	2,741		2,741
			40 - Equal Share Ratio		555	555		1,480	1,480		169	169		188	188
			58 - Total Assets					30	30		21	21		21	21
		5100 - Maint Supv & Engineering	48 - MW Generating Capability								433	433		433	433
		5120 - Maintenance of Boiler Plant	39 - 100% to One Company				472		472	4,964		4,964	4,964		4,964
			48 - MW Generating Capability								70	70		70	70
		5130 - Maintenance of Electric Plant	39 - 100% to One Company							279		279			
		5240 - Misc Nuclear Power Expenses	63 - Total Gross Utility Plant		10,862	10,862		10,136	10,136		1,054	1,054		59	59
		5570 - Other Expenses	39 - 100% to One Company	78		78	26		26	7,251		7,251			
		5600 - Oper Supervision & Engineering	09 - Number of Employees		(2)	(2)									
			58 - Total Assets		499	499		7,611	7,611		2,546	2,546		2,315	2,315
		5660 - Misc Transmission Expenses	09 - Number of Employees		5	5									
			31 - Number of Vehicles					17	17						
			39 - 100% to One Company					515	515						
			58 - Total Assets		685	685		1,625	1,625		1,429	1,429		1,437	1,437
		5700 - Maint of Station Equipment	58 - Total Assets								7	7		7	7
		5730 - Maint of Misc Trnsmssion Plt	28 - Number of Trans Pole Miles		17	17					371	371		371	371
			39 - 100% to One Company		17	17									
			58 - Total Assets		135	135					1	1		1	1
		5800 - Oper Supervision & Engineering	09 - Number of Employees		52	52		266	266						
		5830 - Overhead Line Expenses	39 - 100% to One Company	4		4									
		5860 - Meter Expenses	09 - Number of Employees								1	1		1	1
			39 - 100% to One Company	2		2	2,070		2,070						
		5880 - Miscellaneous Distribution Exp	08 - Number of Electric Retail Cust					9	9					3	3
			09 - Number of Employees					340	340		61	61		80	80
			39 - 100% to One Company	70		70									
			58 - Total Assets		97	97		1	1					38	38
		5910 - Maintenance of Structures	39 - 100% to One Company	248		248									
		5920 - Maint of Station Equipment	39 - 100% to One Company				267		267	3,034		3,034	6,805		6,805
		5930 - Maintenance of Overhead Lines	39 - 100% to One Company	155,366		155,366	74		74				28		28
		5940 - Maint of Underground Lines	39 - 100% to One Company				(1)		(1)						
		5950 - Maint of Lne Trnf,Rglators&Dvi	39 - 100% to One Company	(4)		(4)	1		1				0		0
		9010 - Supervision - Customer Accts	08 - Number of Electric Retail Cust								11	11		11	11
		9030 - Cust Records & Collection Exp	08 - Number of Electric Retail Cust					690	690						
			09 - Number of Employees					987	987						
			16 - Number of Phone Center Calls					3	3						
			39 - 100% to One Company				1,348		1,348						
			58 - Total Assets					128	128						
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust		139	139									
			09 - Number of Employees		795	795		302	302		535	535		353	353
			58 - Total Assets		1,639	1,639		1,894	1,894		10,080	10,080		36,805	36,805
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust		51	51									
			09 - Number of Employees		29	29		39	39		68	68		51	51
			17 - Number of Purchase Orders		95	95		1,604	1,604		107	107			
			39 - 100% to One Company	0		0									
			58 - Total Assets		2,865	2,865		72	72		790	790		2,161	2,161
		9230 - Outside Services Employed	08 - Number of Electric Retail Cust					14	14						
			09 - Number of Employees		121	121		204	204		62	62		62	62
			58 - Total Assets		43	43		61	61		157	157		405	405
		9250 - Injuries and Damages	09 - Number of Employees		6	6									
		9260 - Employee Pensions & Benefits	58 - Total Assets								1	1		1	1
		9302 - Misc General Expenses	39 - 100% to One Company	1,021		1,021	332		332						

Kentucky Power Company
Other Affiliates Charges by FERC Account, Allocation Factor and Allocation Type
For 2017,2018,2019 and Test Year Ended March 2020

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Charges from affiliates are accumulated using a work order system. All affiliate services and convenience payments are billed to Kentucky Power at cost, per FERC affiliate requirements.

				2017			2018			2019			TEST YEAR 12 MONTHS ENDED MARCH 2020		
Account Type	Affiliate	FERC Account	Allocation Factor	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total
		9310 - Rents	11 - Number of GL Transactions											0	0
			39 - 100% to One Company										1		1
			58 - Total Assets											3	3
		9350 - Maintenance of General Plant	39 - 100% to One Company	162		162	294		294				9		9
	Indiana Michigan Power Company Total			156,946	22,089	179,036	4,883	30,029	34,911	34,954	22,983	57,936	31,234	49,883	81,117
	Kentucky Power Company	5060 - Misc Steam Power Expenses	39 - 100% to One Company				6,779		6,779	(4)		(4)			
		5120 - Maintenance of Boiler Plant	39 - 100% to One Company							1,229		1,229	449		449
		5600 - Oper Supervision & Engineering	58 - Total Assets		1,841	1,841		3,314	3,314						
		5660 - Misc Transmission Expenses	58 - Total Assets		80	80		82	82						
		5670 - Rents	39 - 100% to One Company				3,273		3,273						
		5690 - Maintenance of Structures	39 - 100% to One Company										850		850
		5700 - Maint of Station Equipment	39 - 100% to One Company	0		0	442		442	1,692		1,692	1,692		1,692
			39 - 100% to One Company					187	187		99	99		99	99
		5710 - Maintenance of Overhead Lines	39 - 100% to One Company	1,630,374		1,630,374	3,741,516		3,741,516	4,187,314		4,187,314	4,415,668		4,415,668
		5800 - Oper Supervision & Engineering	39 - 100% to One Company										40		40
		5880 - Miscellaneous Distribution Exp	39 - 100% to One Company	1,024		1,024	986		986	8,830		8,830	20,459		20,459
			58 - Total Assets								20	20		20	20
		5920 - Maint of Station Equipment	39 - 100% to One Company	243		243	0		0						
		5930 - Maintenance of Overhead Lines	39 - 100% to One Company	20,815		20,815				0		0	0		0
		9010 - Supervision - Customer Accts	39 - 100% to One Company							11,976		11,976	1,411		1,411
		9040 - Uncollectible Accounts	39 - 100% to One Company	4,551		4,551									
		9080 - Customer Assistance Expenses	39 - 100% to One Company				479		479						
		9090 - Information & Instruct Advrtis	39 - 100% to One Company	103,592		103,592	55,384		55,384	123,963		123,963	123,963		123,963
		9100 - Misc Cust Svc&Informational Ex	39 - 100% to One Company	22,107		22,107	37,836		37,836	48,408		48,408	48,238		48,238
		9120 - Demonstrating & Selling Exp	39 - 100% to One Company				9		9						
		9130 - Advertising Expenses	39 - 100% to One Company	917		917	1,710		1,710	400		400	400		400
		9200 - Administrative & Gen Salaries	33 - Number of Workstations		67	67									
			39 - 100% to One Company	660,475		660,475	1,058,727		1,058,727	1,008,373		1,008,373	959,721		959,721
			58 - Total Assets								2,414	2,414		10,003	10,003
		9210 - Office Supplies and Expenses	09 - Number of Employees		0	0									
			39 - 100% to One Company	58,540		58,540	21,658		21,658	43,623		43,623	28,136		28,136
			58 - Total Assets		144	144		5	5		219	219		615	615
		9230 - Outside Services Employed	39 - 100% to One Company	77,123		77,123	272,563		272,563	147,854		147,854	162,573		162,573
			58 - Total Assets		28	28								3	3
		9250 - Injuries and Damages	39 - 100% to One Company	19		19									
		9280 - Regulatory Commission Exp	39 - 100% to One Company	1,944,423		1,944,423	(504,948)		(504,948)	357,287		357,287	365,861		365,861
		9301 - General Advertising Expenses	39 - 100% to One Company	294,859		294,859	27,525		27,525	78,381		78,381	73,691		73,691
		9302 - Misc General Expenses	39 - 100% to One Company	66,010		66,010	96,556		96,556	102,582		102,582	94,252		94,252
		9310 - Rents	39 - 100% to One Company	95		95							27		27
		9350 - Maintenance of General Plant	39 - 100% to One Company	53,271		53,271	74,918		74,918	97,200		97,200	83,303		83,303
	Kentucky Power Company Total			4,938,439	2,160	4,940,599	4,895,413	3,587	4,899,000	6,219,109	2,752	6,221,860	6,380,733	10,740	6,391,473
	Ohio Power Company	5000 - Oper Supervision & Engineering	48 - MW Generating Capability					262	262						
		5120 - Maintenance of Boiler Plant	39 - 100% to One Company							974		974			
		5600 - Oper Supervision & Engineering	09 - Number of Employees		0	0		5	5						
			39 - 100% to One Company				17,825		17,825	32,680		32,680	31,433		31,433
			58 - Total Assets		712	712		438	438		421	421		414	414
			61 - Total Fixed Assets					54	54						
		5630 - Overhead Line Expenses	58 - Total Assets					26	26		13	13			
		5660 - Misc Transmission Expenses	09 - Number of Employees		30	30		0	0						
			31 - Number of Vehicles					18	18						
			58 - Total Assets		124	124		2,899	2,899		(183)	(183)		(168)	(168)
		5700 - Maint of Station Equipment	39 - 100% to One Company	12,827		12,827	7,394		7,394	7,431		7,431	6,409		6,409
			58 - Total Assets								2	2		2	2
		5710 - Maintenance of Overhead Lines	09 - Number of Employees		86	86									
			58 - Total Assets					11	11						
		5730 - Maint of Misc Trnsmssion Plt	58 - Total Assets		(3)	(3)									
		5800 - Oper Supervision & Engineering	08 - Number of Electric Retail Cust		248	248		470	470		629	629		2,568	2,568
			09 - Number of Employees		369	369		413	413		823	823		1,785	1,785
			33 - Number of Workstations		79	79		30	30		44	44		48	48
			39 - 100% to One Company	22,341		22,341	45,053		45,053	39,112		39,112	39,268		39,268
			44 - Level of Const-Distribution		6	6		233	233		627	627		541	541
			58 - Total Assets		185	185		351	351		214	214		222	222
		5830 - Overhead Line Expenses	39 - 100% to One Company	853		853									
		5840 - Underground Line Expenses	08 - Number of Electric Retail Cust		5	5									
			39 - 100% to One Company	2,349		2,349	2,039		2,039	1,826		1,826	1,595		1,595
		5860 - Meter Expenses	08 - Number of Electric Retail Cust		222	222		53	53		120	120		127	127
			09 - Number of Employees		12	12		13	13		23	23		23	23
			17 - Number of Purchase Orders					14	14						
			39 - 100% to One Company	10,285		10,285	8,510		8,510	14,271		14,271	16,147		16,147
			58 - Total Assets					16	16						
		5880 - Miscellaneous Distribution Exp	08 - Number of Electric Retail Cust		909	909		142	142		495	495		471	471
			09 - Number of Employees		3,676	3,676		2,755	2,755		1,462	1,462		1,804	1,804
			39 - 100% to One Company	16,146		16,146	18,304		18,304	42,996		42,996	47,264		47,264
			44 - Level of Const-Distribution		0	0		18	18		123	123		132	132
			58 - Total Assets		23	23		47	47		545	545		675	675
		5890 - Rents	39 - 100% to One Company							25		25	25		25
			44 - Level of Const-Distribution		67	67		82	82		205	205		180	180
		5920 - Maint of Station Equipment	39 - 100% to One Company	1,606		1,606	1,729		1,729	539		539	(4)		(4)
		5930 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust					33	33						
			39 - 100% to One Company	39,461		39,461	14,547		14,547	1,457		1,457	98		98
		5940 - Maint of Underground Lines	39 - 100% to One Company							1,876		1,876	373		373
		5950 - Maint of Lne Trnf,Rglators&Dvi	39 - 100% to One Company	3		3				4		4	1		1
		5960 - Maint of Strt Lghtng & Sgnal S	39 - 100% to One Company				202		202						
		5970 - Maintenance of Meters	08 - Number of Electric Retail Cust		77	77									
			39 - 100% to One Company	341		341									
		5980 - Maint of Misc Distribution Plt	39 - 100% to One Company				(3)		(3)						
		9010 - Supervision - Customer Accts	09 - Number of Employees		24	24									
		9030 - Cust Records & Collection Exp	05 - Number of CIS Customers Mail		30,138	30,138		1,038	1,038		299	299		198	198
			16 - Number of Phone Center Calls					8	8						
			20 - Number of Remittance Items					512	512		(475)	(475)			
			39 - 100% to One Company	42,336		42,336	657		657	2,006		2,006	3,489		3,489
		9070 - Supervision - Customer Service	09 - Number of Employees		36	36		44	44						
		9080 - Customer Assistance Expenses	08 - Number of Electric Retail Cust					31	31		32	32			
			09 - Number of Employees		62	62		105	105		29	29		66	66
		9110 - Supervision - Sales Expenses	08 - Number of Electric Retail Cust		366	366		1	1		12	12		12	12
		9120 - Demonstrating & Selling Exp	08 - Number of Electric Retail Cust		399	399		(53)	(53)						
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust		2,433	2,433		1,010	1,010		546	546		512	512
			09 - Number of Employees		189	189		547	547		3,348	3,348		2,946	2,946
			11 - Number of GL Transactions		173	173					222	222			
			33 - Number of Workstations											17	17
			39 - 100% to One Company				943		943						
			58 - Total Assets		2,366	2,366		1,576	1,576		4,463	4,463		19,111	19,111
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust		8	8					0	0		0	0
			09 - Number of Employees		0	0		3	3		15	15		13	13
			11 - Number of GL Transactions		0	0					13	13			
			17 - Number of Purchase Orders		5	5					168	168		168	168
			39 - 100% to One Company				9		9						
			58 - Total Assets		1,856	1,856		134	134		115	115		129	129
		9230 - Outside Services Employed	08 - Number of Electric Retail Cust		391	391					89	89		54	54
			09 - Number of Employees		2	2		4	4		36	36		35	35
			58 - Total Assets		995	995		735	735		562	562		3,301	3,301
		9240 - Property Insurance	61 - Total Fixed Assets								5	5		5	5
		9310 - Rents	11 - Number of GL Transactions											1	1
			39 - 100% to One Company										56		56
		9350 - Maintenance of General Plant	27 - Number of Telephones		103	103									
			39 - 100% to One Company	5,472		5,472	4,479		4,479	6,472		6,472	4,251		4,251
	Ohio Power Company Total			154,019	46,373	200,393	121,689	14,081	135,770	151,668	15,041	166,709	150,404	35,395	185,798
	Public Service Company of Oklahoma	5000 - Oper Supervision & Engineering	48 - MW Generating Capability		14,634	14,634		19,400	19,400		2,704	2,704		2,949	2,949
		5020 - Steam Expenses	39 - 100% to One Company										132		132
		5060 - Misc Steam Power Expenses	39 - 100% to One Company							6,269		6,269	6,269		6,269
			40 - Equal Share Ratio		723	723		904	904		1,967	1,967		1,967	1,967
			48 - MW Generating Capability					136	136						
		5100 - Maint Supv & Engineering	48 - MW Generating Capability								2,614	2,614		2,614	2,614
		5120 - Maintenance of Boiler Plant	39 - 100% to One Company	640		640	20		20	587		587	765		765
		5130 - Maintenance of Electric Plant	39 - 100% to One Company							(1,646)		(1,646)	(1,646)		(1,646)
		5600 - Oper Supervision & Engineering	09 - Number of Employees		3	3		4	4						
			58 - Total Assets		394	394		311	311		992	992		988	988
		5612 - Load Dispatch-Mntr&Op TransSys	58 - Total Assets					86	86		36	36		36	36
		5660 - Misc Transmission Expenses	09 - Number of Employees		5	5									
			31 - Number of Vehicles					17	17						
			39 - 100% to One Company				276		276						
			40 - Equal Share Ratio								12	12			
			58 - Total Assets		450	450		1,107	1,107		853	853		1,271	1,271
		5730 - Maint of Misc Trnsmssion Plt	58 - Total Assets		(5)	(5)									
		5800 - Oper Supervision & Engineering	08 - Number of Electric Retail Cust		976	976									
			09 - Number of Employees					307	307						
		5840 - Underground Line Expenses	39 - 100% to One Company							2,177		2,177	2,177		2,177
		5860 - Meter Expenses	08 - Number of Electric Retail Cust					1,541	1,541		8,413	8,413		6,246	6,246
			39 - 100% to One Company							1,078		1,078	1,121		1,121
		5880 - Miscellaneous Distribution Exp	09 - Number of Employees		814	814		1,125	1,125		1,415	1,415		1,252	1,252
			58 - Total Assets											174	174
		5930 - Maintenance of Overhead Lines	39 - 100% to One Company				1,150		1,150	0		0	0		0
		5940 - Maint of Underground Lines	39 - 100% to One Company				(13)		(13)						
		5960 - Maint of Strt Lghtng & Sgnal S	39 - 100% to One Company							476		476	476		476
		5980 - Maint of Misc Distribution Plt	39 - 100% to One Company							60		60	60		60
		9030 - Cust Records & Collection Exp	39 - 100% to One Company				25		25						
		9040 - Uncollectible Accounts	26 - Number of Stores Transactions		0	0									
		9120 - Demonstrating & Selling Exp	06 - Number of Commercial Customers								882	882		882	882
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust		5,102	5,102									
			09 - Number of Employees		119	119									
			39 - 100% to One Company										718		718
			58 - Total Assets		593	593		115	115		5,337	5,337		19,946	19,946
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust		326	326									
			09 - Number of Employees		63	63					3,879	3,879		16	16
			39 - 100% to One Company										1		1
			48 - MW Generating Capability								12	12		12	12
			58 - Total Assets		94	94		16	16		690	690		1,797	1,797
			61 - Total Fixed Assets								0	0		0	0
		9230 - Outside Services Employed	09 - Number of Employees					1	1						

Kentucky Power Company
Other Affiliates Charges by FERC Account, Allocation Factor and Allocation Type
For 2017,2018,2019 and Test Year Ended March 2020

Kentucky Power has a variety of transactions with affiliates on a normal basis. Transactions with affiliates generally fall into two categories. The first category, service payments, is a billing made when an affiliate provides a service to Kentucky Power, such as Appalachian Power providing assistance in distribution maintenance, generation engineering, or other affiliates providing assistance during storm recovery efforts. The second category, convenience payments, occurs when an affiliate company receives an invoice and the cost of that invoice should be borne by multiple AEP companies. For example, a legal invoice for a system-wide issue may be paid by one affiliate company, and that company then bills the other affiliates who benefit from the service.

Charges from affiliates are accumulated using a work order system. All affiliate services and convenience payments are billed to Kentucky Power at cost, per FERC affiliate requirements.

				2017			2018			2019			TEST YEAR 12 MONTHS ENDED MARCH 2020		
Account Type	Affiliate	FERC Account	Allocation Factor	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total
			58 - Total Assets		3,469	3,469					12	12		1,510	1,510
		9260 - Employee Pensions & Benefits	58 - Total Assets		(4)	(4)									
		9302 - Misc General Expenses	06 - Number of Commercial Customers								212	212		212	212
		9310 - Rents	11 - Number of GL Transactions											0	0
			39 - 100% to One Company										1		1
			48 - MW Generating Capability											0	0
			58 - Total Assets											15	15
	Public Service Company of Oklahoma Total			640	27,756	28,396	1,458	25,071	26,528	9,001	30,031	39,032	10,073	41,888	51,961
	Southwestern Electric Power Company	5000 - Oper Supervision & Engineering	39 - 100% to One Company							435		435	435		435
			48 - MW Generating Capability		16,298	16,298		14,578	14,578		8,995	8,995		7,848	7,848
		5060 - Misc Steam Power Expenses	39 - 100% to One Company	72		72				188		188	188		188
			40 - Equal Share Ratio		164	164		78	78		344	344		344	344
			48 - MW Generating Capability								354	354		354	354
		5100 - Maint Supv & Engineering	48 - MW Generating Capability								2,765	2,765		2,821	2,821
		5110 - Maintenance of Structures	39 - 100% to One Company	96		96									
		5120 - Maintenance of Boiler Plant	39 - 100% to One Company	371		371	81		81	1,000		1,000	1,750		1,750
		5130 - Maintenance of Electric Plant	39 - 100% to One Company							3,324		3,324	3,974		3,974
		5140 - Maintenance of Misc Steam Plt	48 - MW Generating Capability								66	66		66	66
		5600 - Oper Supervision & Engineering	09 - Number of Employees		(2)	(2)									
			58 - Total Assets		559	559		345	345		2,258	2,258		2,421	2,421
			61 - Total Fixed Assets		0	0		3	3		0	0		(3)	(3)
		5612 - Load Dispatch-Mntr&Op TransSys	58 - Total Assets					68	68		25	25		25	25
		5630 - Overhead Line Expenses	58 - Total Assets		11	11									
		5660 - Misc Transmission Expenses	09 - Number of Employees		0	0									
			31 - Number of Vehicles					17	17						
			39 - 100% to One Company	(0)		(0)									
			39 - 100% to One Company					964	964		84	84		84	84
			58 - Total Assets		15	15		900	900		1,053	1,053		1,074	1,074
		5700 - Maint of Station Equipment	39 - 100% to One Company										676		676
			58 - Total Assets		(3)	(3)									
		5730 - Maint of Misc Trnsmssion Plt	58 - Total Assets		(9)	(9)					2	2		2	2
		5800 - Oper Supervision & Engineering	08 - Number of Electric Retail Cust								3	3		3	3
			20 - Number of Remittance Items					82	82						
			58 - Total Assets								2	2		2	2
			61 - Total Fixed Assets		0	0		2	2		0	0		(0)	(0)
		5830 - Overhead Line Expenses	39 - 100% to One Company	(1)		(1)									
		5860 - Meter Expenses	39 - 100% to One Company	46		46				143		143	31		31
		5880 - Miscellaneous Distribution Exp	08 - Number of Electric Retail Cust		62	62					66	66		66	66
			09 - Number of Employees		342	342					4,130	4,130		6,395	6,395
			39 - 100% to One Company	14,713		14,713									
			44 - Level of Const-Distribution		4	4									
		5920 - Maint of Station Equipment	39 - 100% to One Company	327		327									
		5930 - Maintenance of Overhead Lines	09 - Number of Employees		57	57									
			39 - 100% to One Company	1,705		1,705	308		308	846		846	759		759
		5940 - Maint of Underground Lines	39 - 100% to One Company	(3)		(3)									
		5950 - Maint of Lne Trnf,Rglators&Dvi	39 - 100% to One Company	3		3									
		5960 - Maint of Strt Lghtng & Sgnal S	39 - 100% to One Company				11		11	1		1			
		9030 - Cust Records & Collection Exp	39 - 100% to One Company	135		135	125		125	2,091		2,091	2,010		2,010
			58 - Total Assets		6	6									
		9070 - Supervision - Customer Service	61 - Total Fixed Assets		3,244	3,244									
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust		3,503	3,503		36	36						
			09 - Number of Employees		115	115									
			33 - Number of Workstations											57	57
			48 - MW Generating Capability		102	102									
			58 - Total Assets		1,221	1,221		702	702		2,157	2,157		11,442	11,442
			63 - Total Gross Utility Plant								219	219			
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust		630	630					665	665		980	980
			09 - Number of Employees		25	25					1,890	1,890		1,695	1,695
			48 - MW Generating Capability		0	0									
			58 - Total Assets		222	222		150	150		255	255		1,621	1,621
		9230 - Outside Services Employed	09 - Number of Employees		2,827	2,827		2,140	2,140		217	217		28	28
			58 - Total Assets		8,232	8,232		18,376	18,376		16,869	16,869		15,711	15,711
			61 - Total Fixed Assets								21,967	21,967		21,967	21,967
		9260 - Employee Pensions & Benefits	09 - Number of Employees		0	0									
			48 - MW Generating Capability								11	11		11	11
		9302 - Misc General Expenses	39 - 100% to One Company				(0)		(0)						
		9310 - Rents	39 - 100% to One Company										2		2
			48 - MW Generating Capability											0	0
			58 - Total Assets											1	1
	Southwestern Electric Power Company Total			17,462	37,625	55,087	526	38,442	38,968	8,029	64,399	72,428	9,826	75,015	84,841
	Wheeling Power Company	5010 - Fuel	39 - 100% to One Company				32,259		32,259	416,435		416,435	416,435		416,435
		5020 - Steam Expenses	39 - 100% to One Company							343,486		343,486	343,486		343,486
		5130 - Maintenance of Electric Plant	39 - 100% to One Company				150		150	3,134		3,134	854		854
		5600 - Oper Supervision & Engineering	58 - Total Assets		1	1		541	541						
		5660 - Misc Transmission Expenses	31 - Number of Vehicles					17	17						
			58 - Total Assets		(1)	(1)		0	0						
		5730 - Maint of Misc Trnsmssion Plt	58 - Total Assets		(1)	(1)									
		5930 - Maintenance of Overhead Lines	39 - 100% to One Company				390		390	4		4	1		1
		5950 - Maint of Lne Trnf,Rglators&Dvi	39 - 100% to One Company							0		0			
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust		489	489		21	21						
			58 - Total Assets								82	82		82	82
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust		36	36									
			58 - Total Assets								1	1		16	16
	Wheeling Power Company Total				524	524	32,799	578	33,378	763,059	84	763,143	760,776	98	760,874
	Other - Affiliates Grand Toatal Billings less than $100K	5000 - Oper Supervision & Engineering	09 - Number of Employees		3	3									
			48 - MW Generating Capability		2,218	2,218		10,121	10,121		146	146		767	767
		5060 - Misc Steam Power Expenses	39 - 100% to One Company	26		26				90		90	90		90
		5100 - Maint Supv & Engineering	48 - MW Generating Capability								454	454		454	454
		5110 - Maintenance of Structures	39 - 100% to One Company				47		47	271		271	271		271
		5120 - Maintenance of Boiler Plant	39 - 100% to One Company							118		118	118		118
		5130 - Maintenance of Electric Plant	39 - 100% to One Company				70		70						
		5140 - Maintenance of Misc Steam Plt	39 - 100% to One Company							43		43	43		43
		5390 - Misc Hydr Power Generation Exp	48 - MW Generating Capability								87	87		193	193
		5600 - Oper Supervision & Engineering	09 - Number of Employees		1	1		1	1						
			28 - Number of Trans Pole Miles								101	101		126	126
			58 - Total Assets		2,243	2,243		2,339	2,339		53,086	53,086		53,735	53,735
		5612 - Load Dispatch-Mntr&Op TransSys	58 - Total Assets								37	37		37	37
		5630 - Overhead Line Expenses	58 - Total Assets		18	18					11	11			
		5660 - Misc Transmission Expenses	09 - Number of Employees		2	2									
			28 - Number of Trans Pole Miles		17	17									
			31 - Number of Vehicles					51	51						
			39 - 100% to One Company	24,137		24,137	631		631						
			58 - Total Assets		195	195		2,940	2,940		2,541	2,541		2,709	2,709
		5680 - Maint Supv & Engineering	58 - Total Assets					22	22						
		5700 - Maint of Station Equipment	58 - Total Assets					1,251	1,251		6,009	6,009		2,566	2,566
		5710 - Maintenance of Overhead Lines	39 - 100% to One Company	1,192		1,192									
			58 - Total Assets											4	4
		5730 - Maint of Misc Trnsmssion Plt	58 - Total Assets		(187)	(187)									
		5800 - Oper Supervision & Engineering	08 - Number of Electric Retail Cust		0	0									
			09 - Number of Employees								3	3			
		5830 - Overhead Line Expenses	39 - 100% to One Company							(1)		(1)	(1)		(1)
		5860 - Meter Expenses	08 - Number of Electric Retail Cust								0	0		0	0
			39 - 100% to One Company	51		51	494		494	749		749	763		763
		5870 - Customer Installations Exp	39 - 100% to One Company							1,185		1,185	1,185		1,185
		5880 - Miscellaneous Distribution Exp	08 - Number of Electric Retail Cust					7	7						
			09 - Number of Employees		210	210		929	929		58	58		58	58
			39 - 100% to One Company	994		994	(396)		(396)	207		207	320		320
			44 - Level of Const-Distribution								21	21		21	21
			58 - Total Assets		14	14		(6)	(6)		14	14		18	18
		5920 - Maint of Station Equipment	39 - 100% to One Company				138		138						
			58 - Total Assets								5	5		5	5
		5930 - Maintenance of Overhead Lines	39 - 100% to One Company	257		257	113		113	1,496		1,496	1,384		1,384
		5940 - Maint of Underground Lines	39 - 100% to One Company							(0)		(0)	1		1
		5950 - Maint of Lne Trnf,Rglators&Dvi	39 - 100% to One Company							8		8	5		5
		5960 - Maint of Strt Lghtng & Sgnal S	39 - 100% to One Company										1		1
		9030 - Cust Records & Collection Exp	08 - Number of Electric Retail Cust		446	446		655	655		784	784		553	553
			39 - 100% to One Company	412		412				1,604		1,604	1,626		1,626
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust		8,461	8,461		25	25						
			09 - Number of Employees					59	59		48	48		91	91
			40 - Equal Share Ratio		21	21									
			58 - Total Assets		2,205	2,205		1,229	1,229		5,991	5,991		24,803	24,803
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust		768	768									
			09 - Number of Employees		0	0		52	52		20	20			
			11 - Number of GL Transactions					4	4						
			33 - Number of Workstations		16	16									
			58 - Total Assets		506	506		36	36		921	921		1,777	1,777
		9230 - Outside Services Employed	08 - Number of Electric Retail Cust		29	29									
			09 - Number of Employees					15	15		14	14		14	14
			39 - 100% to One Company				(97,000)		(97,000)						
			58 - Total Assets		817	817		362	362		258	258		3,056	3,056
		9260 - Employee Pensions & Benefits	09 - Number of Employees		1	1									
			58 - Total Assets		(9)	(9)					329	329		330	330
		9302 - Misc General Expenses	48 - MW Generating Capability								106	106		106	106
			58 - Total Assets					1,184	1,184		(0)	(0)		(235)	(235)
		9310 - Rents	58 - Total Assets											3	3
		9350 - Maintenance of General Plant	39 - 100% to One Company	1,268		1,268	380		380				1,097		1,097
	Other - Affiliates Grand Toatal Billings less than $100K Total			28,337	17,997	46,334	(95,522)	21,276	(74,245)	5,771	71,044	76,815	6,903	91,193	98,096
Cost of Service Total				5,717,454	395,740	6,113,194	5,370,017	350,002	5,720,019	7,580,381	382,865	7,963,247	7,931,887	498,713	8,430,600
Non Cost of Servicet of Service	AEP Energy Partners, Inc.	1060 - Completed Const Not Classifd	09 - Number of Employees		0	0									
		1630 - Stores Expense Undistributed	09 - Number of Employees		84	84									
	AEP Energy Partners, Inc. Total				84	84									
	AEP Generation Resources	1060 - Completed Const Not Classifd	09 - Number of Employees		0	0									
		1070 - Construction Work In Progress	39 - 100% to One Company	855		855	52		52						
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company							442		442			
		1630 - Stores Expense Undistributed	26 - Number of Stores Transactions		118	118		7	7						
		1840 - Clearing Accounts	09 - Number of Employees		(0)	(0)									
		1860 - MDD-Internal Billing Only	39 - 100% to One Company							213		213			
		4261 - Donations	58 - Total Assets					179	179						
	AEP Generation Resources Total			855	118	973	52	187	239	656		656			

Kentucky Power Company
Other Affiliates Charges by FERC Account, Allocation Factor and Allocation Type
For 2017,2018,2019 and Test Year Ended March 2020

Kentucky Power has a variety of transactions with affiliates on a normal basis. Transactions with affiliates generally fall into two categories. The first category, service payments, is a billing made when an affiliate provides a service to Kentucky Power, such as Appalachian Power providing assistance in distribution maintenance, generation engineering, or other affiliates providing assistance during storm recovery efforts. The second category, convenience payments, occurs when an affiliate company receives an invoice and the cost of that invoice should be borne by multiple AEP companies. For example, a legal invoice for a system-wide issue may be paid by one affiliate company, and that company then bills the other affiliates who benefit from the service.

Charges from affiliates are accumulated using a work order system. All affiliate services and convenience payments are billed to Kentucky Power at cost, per FERC affiliate requirements.

				2017			2018			2019			TEST YEAR 12 MONTHS ENDED MARCH 2020		
Account Type	Affiliate	FERC Account	Allocation Factor	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total
	American Electric Power Company	1650 - Prepayments	61 - Total Fixed Assets					820	820						
		1830 - Prelimin Surv&Investgtn Chrgs	39 - 100% to One Company				34		34						
		1840 - Clearing Accounts	58 - Total Assets								114,573	114,573		112,226	112,226
			61 - Total Fixed Assets		297	297									
		1880 - R&D Expenses	28 - Number of Trans Pole Miles		(2,621)	(2,621)									
	American Electric Power Company Total				(2,324)	(2,324)	34	820	853		114,573	114,573		112,226	112,226
	Appalachian Power Company	1060 - Completed Const Not Classifd	09 - Number of Employees		0	0									
		1070 - Construction Work In Progress	39 - 100% to One Company	231,364		231,364	269,991		269,991	384,698		384,698	334,683		334,683
			58 - Total Assets								204	204		204	204
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	8,104		8,104	32,731		32,731	54,045		54,045	51,383		51,383
		1520 - Fuel Stock Exp Undistributed	61 - Total Fixed Assets		61	61									
		1630 - Stores Expense Undistributed	09 - Number of Employees		331	331					38	38		38	38
			26 - Number of Stores Transactions		59,412	59,412		69,254	69,254		73,253	73,253		70,487	70,487
			39 - 100% to One Company	386,746		386,746	391,209		391,209	368,416		368,416	378,060		378,060
			48 - MW Generating Capability		12,756	12,756		35,863	35,863		25,644	25,644		21,720	21,720
			58 - Total Assets		15	15					214	214		357	357
			61 - Total Fixed Assets		8,903	8,903		10,031	10,031		9,719	9,719		9,811	9,811
		1840 - Clearing Accounts	08 - Number of Electric Retail Cust					39	39		359	359		839	839
			09 - Number of Employees		374	374		95	95					3	3
			26 - Number of Stores Transactions		6,493	6,493		915	915						
			31 - Number of Vehicles		508	508		455	455		466	466		1,409	1,409
			39 - 100% to One Company	4,153		4,153	9,167		9,167	2,221		2,221	3,776		3,776
			48 - MW Generating Capability								186	186		121	121
			52 - Past 3 Mo MMBTU Burned (Coal)		404	404									
			63 - Total Gross Utility Plant		207	207					2,892	2,892		2,892	2,892
		1860 - MDD-Internal Billing Only	39 - 100% to One Company	4,585		4,585	11,470		11,470	1,797		1,797	1,797		1,797
		1880 - R&D Expenses	60 - AEPSC Bill less Indir and Int		0	0		(0)	(0)		(0)	(0)		(0)	(0)
			61 - Total Fixed Assets		8	8		4	4		19	19		21	21
		4261 - Donations	58 - Total Assets		948	948		496	496		484	484		484	484
		4265 - Other Deductions	58 - Total Assets					348	348						
		4560 - Other Electric Revenues	39 - 100% to One Company	(87,237)		(87,237)	(84,328)		(84,328)	(97,688)		(97,688)	(92,071)		(92,071)
	Appalachian Power Company Total			547,716	90,421	638,136	630,240	117,500	747,740	713,489	113,478	826,968	677,628	108,387	786,016
	Indiana Michigan Power Company	1060 - Completed Const Not Classifd	09 - Number of Employees		1	1									
		1070 - Construction Work In Progress	39 - 100% to One Company	42,207		42,207	7,765		7,765	15,119		15,119	15,132		15,132
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	10,452		10,452	1,383		1,383				1		1
		1540 - Materials & Oper Supplies	58 - Total Assets		243	243									
		1630 - Stores Expense Undistributed	09 - Number of Employees		14,819	14,819		18,275	18,275		19,072	19,072		15,100	15,100
			26 - Number of Stores Transactions		32	32		282	282						
			39 - 100% to One Company							522		522			
			44 - Level of Const-Distribution											4	4
			58 - Total Assets		150	150		9	9						
		1840 - Clearing Accounts	08 - Number of Electric Retail Cust								94	94		795	795
			09 - Number of Employees		18	18					12	12		12	12
			31 - Number of Vehicles		448	448		442	442		306	306		280	280
			33 - Number of Workstations								19	19		19	19
			39 - 100% to One Company	7,730		7,730									
			52 - Past 3 Mo MMBTU Burned (Coal)		212	212									
			63 - Total Gross Utility Plant		85,224	85,224		93,487	93,487		(33,237)	(33,237)		6,146	6,146
		1880 - R&D Expenses	33 - Number of Workstations								13,601	13,601		13,601	13,601
		1903 - Accum Deferred Income Taxes	09 - Number of Employees								3	3		3	3
		4261 - Donations	58 - Total Assets					(197)	(197)						
	Indiana Michigan Power Company Total			60,389	101,147	161,536	9,148	112,297	121,445	15,641	(130)	15,511	15,132	35,961	51,094
	Kentucky Power Company	1060 - Completed Const Not Classifd	09 - Number of Employees		0	0									
		1070 - Construction Work In Progress	39 - 100% to One Company	848,944		848,944	784,800		784,800	4,180,009		4,180,009	4,143,752		4,143,752
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	1,375		1,375	1,037		1,037	583		583	52		52
		1630 - Stores Expense Undistributed	09 - Number of Employees		48	48									
			26 - Number of Stores Transactions		200	200		0	0						
			39 - 100% to One Company	53,980		53,980	45,724		45,724	40,756		40,756	29,818		29,818
			58 - Total Assets											8	8
		1830 - Prelimin Surv&Investgtn Chrgs	39 - 100% to One Company							14,000		14,000	14,000		14,000
		1840 - Clearing Accounts	09 - Number of Employees		0	0		1	1						
			31 - Number of Vehicles		19	19		17	17		24	24		24	24
			58 - Total Assets		200	200									
			63 - Total Gross Utility Plant		226	226		709	709		1,140	1,140		730	730
		1860 - MDD-Internal Billing Only	39 - 100% to One Company	18,894		18,894	(2,576)		(2,576)	801		801	801		801
		2420 - Misc Current & Accrued Liab	39 - 100% to One Company	255,000		255,000									
		2530 - Other Deferred Credits	39 - 100% to One Company										(2,020)		(2,020)
		4261 - Donations	39 - 100% to One Company	12,782		12,782	38,001		38,001	28,535		28,535	27,738		27,738
		4264 - Civic & Political Activities	39 - 100% to One Company	229,513		229,513	156,464		156,464	77,720		77,720	78,771		78,771
		4265 - Other Deductions	39 - 100% to One Company	89,817		89,817	36,415		36,415	22,300		22,300	11,697		11,697
		4310 - Other Interest Expense	39 - 100% to One Company	253,672		253,672	97,194		97,194	195,919		195,919	196,296		196,296
		4540 - Rent From Electric Property	39 - 100% to One Company										(1,261)		(1,261)
	Kentucky Power Company Total			1,763,976	694	1,764,670	1,157,060	727	1,157,787	4,560,622	1,164	4,561,786	4,499,645	761	4,500,407
	Ohio Power Company	1060 - Completed Const Not Classifd	09 - Number of Employees		0	0									
		1070 - Construction Work In Progress	39 - 100% to One Company	10,463		10,463	24,123		24,123	22,683		22,683	31,453		31,453
			58 - Total Assets					4	4						
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	2,550		2,550	340		340	49		49	34		34
		1420 - Customer Accounts Receivable	39 - 100% to One Company				70		70						
		1540 - Materials & Oper Supplies	17 - Number of Purchase Orders											252	252
		1630 - Stores Expense Undistributed	09 - Number of Employees		800	800		71	71		1,069	1,069		955	955
			26 - Number of Stores Transactions		660	660		421	421		105	105		95	95
			39 - 100% to One Company	29,033		29,033									
			48 - MW Generating Capability		43	43									
			58 - Total Assets		63	63		18	18						
		1650 - Prepayments	61 - Total Fixed Assets								34	34		34	34
		1840 - Clearing Accounts	08 - Number of Electric Retail Cust								210	210		659	659
			09 - Number of Employees		(0)	(0)									
			31 - Number of Vehicles		1,550	1,550		1,776	1,776		1,825	1,825		1,897	1,897
			33 - Number of Workstations								135	135		184	184
			58 - Total Assets								0	0		0	0
			63 - Total Gross Utility Plant		8	8		102	102		1,273	1,273		1,381	1,381
		1860 - MDD-Internal Billing Only	39 - 100% to One Company				1,077		1,077	10,840		10,840	13,704		13,704
		1880 - R&D Expenses	60 - AEPSC Bill less Indir and Int					0	0		(0)	(0)		(2)	(2)
			61 - Total Fixed Assets					826	826		18	18		5	5
		4170 - Revenues from Non-Util Oper	39 - 100% to One Company							(244)		(244)	(465)		(465)
		4540 - Rent From Electric Property	39 - 100% to One Company				(27,465)		(27,465)	(14,092)		(14,092)	(14,092)		(14,092)
		4560 - Other Electric Revenues	39 - 100% to One Company	(10,009)		(10,009)	(9,218)		(9,218)	(8,427)		(8,427)	(8,427)		(8,427)
	Ohio Power Company Total			32,037	3,123	35,160	(11,073)	3,218	(7,855)	10,809	4,668	15,477	22,206	5,460	27,666
	Public Service Company of Oklahoma	1060 - Completed Const Not Classifd	09 - Number of Employees		0	0									
		1070 - Construction Work In Progress	39 - 100% to One Company	286		286	728		728	155		155	155		155
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company				52		52	7		7	7		7
		1630 - Stores Expense Undistributed	09 - Number of Employees					19	19						
			17 - Number of Purchase Orders		7	7									
			26 - Number of Stores Transactions		(11)	(11)									
			48 - MW Generating Capability					2,383	2,383		15,096	15,096		12,375	12,375
			58 - Total Assets					61	61		14	14		51	51
		1840 - Clearing Accounts	08 - Number of Electric Retail Cust					371	371					415	415
			09 - Number of Employees		35	35									
			31 - Number of Vehicles		174	174		169	169		187	187		187	187
			33 - Number of Workstations								87	87		87	87
			63 - Total Gross Utility Plant		446	446					2,811	2,811		2,811	2,811
		1860 - MDD-Internal Billing Only	39 - 100% to One Company	65,458		65,458	129,431		129,431	86,272		86,272	57,545		57,545
		1880 - R&D Expenses	51 - Past 3 Mo MMBTU's Burned (Tot)								64	64			
			60 - AEPSC Bill less Indir and Int		(0)	(0)		(0)	(0)		(0)	(0)		(34)	(34)
			61 - Total Fixed Assets		765	765		697	697		943	943		1,004	1,004
		4261 - Donations	06 - Number of Commercial Customers								135	135		135	135
		4265 - Other Deductions	06 - Number of Commercial Customers								126	126		126	126
	Public Service Company of Oklahoma Total			65,745	1,417	67,161	130,210	3,700	133,910	86,434	19,463	105,896	57,707	17,156	74,863
	Southwestern Electric Power Company	1060 - Completed Const Not Classifd	09 - Number of Employees		0	0									
		1070 - Construction Work In Progress	39 - 100% to One Company	1,651		1,651	261		261	778		778	1,546		1,546
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	234		234	54		54	415		415	355		355
		1630 - Stores Expense Undistributed	08 - Number of Electric Retail Cust		3	3									
			09 - Number of Employees		196	196		51	51		24	24		52	52
			39 - 100% to One Company							13		13	13		13
			48 - MW Generating Capability					4,138	4,138		31,177	31,177		23,867	23,867
			58 - Total Assets											36	36
		1840 - Clearing Accounts	08 - Number of Electric Retail Cust								483	483		725	725
			09 - Number of Employees		726	726		139	139						
			31 - Number of Vehicles		211	211		205	205		234	234		234	234
			33 - Number of Workstations								8	8		8	8
			52 - Past 3 Mo MMBTU Burned (Coal)		54	54									
			63 - Total Gross Utility Plant		12,035	12,035		11,728	11,728		11,606	11,606		9,906	9,906
		1860 - MDD-Internal Billing Only	39 - 100% to One Company				112		112						
		4261 - Donations	58 - Total Assets		135	135		50	50						
	Southwestern Electric Power Company Total			1,885	13,361	15,246	427	16,310	16,737	1,206	43,531	44,737	1,914	34,828	36,742
	Wheeling Power Company	1060 - Completed Const Not Classifd	09 - Number of Employees		0	0									
		1070 - Construction Work In Progress	39 - 100% to One Company				43,015		43,015	280		280	0		0
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company				5		5	0		0			
		1510 - Fuel Stock	39 - 100% to One Company				(126,469)		(126,469)						
		1840 - Clearing Accounts	31 - Number of Vehicles		63	63		2	2						
			39 - 100% to One Company				3,828		3,828						
		4081 - Taxes Other Than Inc Tax, UOI	39 - 100% to One Company				8,247		8,247						
		4210 - Misc Non-Operating Income	39 - 100% to One Company	(8,078)		(8,078)									
		4540 - Rent From Electric Property	39 - 100% to One Company							(39,316)		(39,316)	(39,316)		(39,316)
		4560 - Other Electric Revenues	39 - 100% to One Company							(31,938)		(31,938)	(31,938)		(31,938)
	Wheeling Power Company Total			(8,078)	63	(8,015)	(71,375)	2	(71,373)	(70,974)		(70,974)	(71,253)		(71,253)
	Other - Affiliates Grand Toatal Billings less than $100K	1060 - Completed Const Not Classifd	09 - Number of Employees		1	1									
		1070 - Construction Work In Progress	39 - 100% to One Company	533		533	(12,730)		(12,730)	(38,407)		(38,407)	(37,250)		(37,250)
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	277		277	17		17	546		546	1,065		1,065
		1430 - Other Accounts Receivable	39 - 100% to One Company	0		0									
		1630 - Stores Expense Undistributed	09 - Number of Employees		58	58									
			26 - Number of Stores Transactions		369	369		484	484		272	272		6	6
			39 - 100% to One Company							2,557		2,557	2,557		2,557
			58 - Total Assets		272	272		437	437		196	196		10	10
			63 - Total Gross Utility Plant								1	1		1	1
		1840 - Clearing Accounts	08 - Number of Electric Retail Cust								114	114		937	937
			09 - Number of Employees		0	0									
			31 - Number of Vehicles		276	276		300	300		262	262		266	266
			58 - Total Assets		11	11									

Kentucky Power Company
Other Affiliates Charges by FERC Account, Allocation Factor and Allocation Type
For 2017,2018,2019 and Test Year Ended March 2020

Kentucky Power has a variety of transactions with affiliates on a normal basis. Transactions with affiliates generally fall into two categories. The first category, service payments, is a billing made when an affiliate provides a service to Kentucky Power, such as Appalachian Power providing assistance in distribution maintenance, generation engineering, or other affiliates providing assistance during storm recovery efforts. The second category, convenience payments, occurs when an affiliate company receives an invoice and the cost of that invoice should be borne by multiple AEP companies. For example, a legal invoice for a system-wide issue may be paid by one affiliate company, and that company then bills the other affiliates who benefit from the service.

Charges from affiliates are accumulated using a work order system. All affiliate services and convenience payments are billed to Kentucky Power at cost, per FERC affiliate requirements.

				2017			2018			2019			TEST YEAR 12 MONTHS ENDED MARCH 2020		
Account Type	Affiliate	FERC Account	Allocation Factor	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total
			63 - Total Gross Utility Plant					19	19		270	270		270	270
		1860 - MDD-Internal Billing Only	39 - 100% to One Company							52		52			
			58 - Total Assets					2	2						
		1880 - R&D Expenses	61 - Total Fixed Assets		726	726					9	9		9	9
		4010 - Operation Expense	48 - MW Generating Capability								284	284		284	284
		4180 - Non-Operatng Rental Income	39 - 100% to One Company	11,525		11,525	3,260		3,260						
		4261 - Donations	58 - Total Assets		29	29									
	Other - Affiliates Grand Toatal Billings less than $100K Total			12,335	1,742	14,078	(9,452)	1,241	(8,211)	(35,252)	1,408	(33,844)	(33,628)	1,783	(31,846)
Non Cost of Servicet of Service Total				2,476,860	209,847	2,686,707	1,835,271	256,002	2,091,273	5,282,631	298,156	5,580,787	5,169,352	316,562	5,485,914
Grand Total				8,194,314	605,587	8,799,901	7,205,288	606,004	7,811,292	12,863,012	681,021	13,544,034	13,101,239	815,275	13,916,514

Kentucky Power Company
Other Affiliate Charges Billed to Co-Owner by Kentucky Power
For 2017,2018,2019 and Test Year Ended March 2020

		2017			2018			2019			TEST YEAR 12 MONTHS ENDED MARCH 2020		
Account Type	FERC Account	Other Affiliates Billed to Kentucky Power	Share Billed to Co-Owner	Total	Other Affiliates Billed to Kentucky Power	Share Billed to Co-Owner	Total	Other Affiliates Billed to Kentucky Power	Share Billed to Co-Owner	Total	Other Affiliates Billed to Kentucky Power	Share Billed to Co-Owner	Total
Cost of Service	5000 - Oper Supervision & Engineering	56,021	(8,662)	47,359	78,867	15,358	94,225	39,735	(4,478)	35,257	34,676	(2,619)	32,057
	5010 - Fuel	11,509	0	11,509	44,339	(2,486)	41,853	416,435	0	416,435	416,435	0	416,435
	5020 - Steam Expenses		0	0		0	0	343,486	(171,743)	171,743	343,618	(171,743)	171,875
	5060 - Misc Steam Power Expenses	6,311	522	6,833	13,302	669	13,971	13,477	(3,152)	10,324	13,476	(3,149)	10,327
	5100 - Maint Supv & Engineering	43,613	(201)	43,411	17,161	163	17,325	15,255	75	15,330	13,425	51	13,476
	5110 - Maintenance of Structures	96	(48)	48	47	0	47	271	0	271	271	0	271
	5120 - Maintenance of Boiler Plant	12,995	(3,977)	9,018	3,269	(1,233)	2,035	19,730	(8,927)	10,803	25,956	(12,430)	13,526
	5130 - Maintenance of Electric Plant	257	0	257	220	(75)	145	5,090	(914)	4,176	3,182	40	3,222
	5140 - Maintenance of Misc Steam Plt	123	(61)	61		0	0	109	112	220	109	112	220
	5240 - Misc Nuclear Power Expenses	10,862	0	10,862	10,136	0	10,136	1,054	0	1,054	59	0	59
	5390 - Misc Hydr Power Generation Exp		0	0		0	0	156	0	156	262	0	262
	5430 - Maint Rsrvoirs,Dams&Wtrways		0	0		0	0	4	0	4	4	0	4
	5440 - Maintenance of Electric Plant		0	0		0	0	11	0	11	11	0	11
	5570 - Other Expenses	47,293	0	47,293	12,061	0	12,061	8,327	(4,082)	4,245	1,329	(563)	766
	5600 - Oper Supervision & Engineering	20,540	0	20,540	60,416	0	60,416	111,703	0	111,703	107,033	0	107,033
	5612 - Load Dispatch-Mntr&Op TransSys		0	0	154	0	154	98	0	98	98	0	98
	5630 - Overhead Line Expenses	391	0	391	26	0	26	24	0	24		0	0
	5660 - Misc Transmission Expenses	27,452	0	27,452	12,093	0	12,093	6,220	0	6,220	6,868	0	6,868
	5670 - Rents		0	0	3,273	0	3,273		0	0		0	0
	5680 - Maint Supv & Engineering		0	0	22	0	22		0	0		0	0
	5690 - Maintenance of Structures		0	0		0	0		0	0	850	0	850
	5700 - Maint of Station Equipment	12,853	0	12,853	13,776	0	13,776	15,240	0	15,240	11,452	0	11,452
	5710 - Maintenance of Overhead Lines	1,631,651	0	1,631,651	3,741,527	0	3,741,527	4,190,148	0	4,190,148	4,415,672	0	4,415,672
	5730 - Maint of Misc Trnsmssion Plt	4,217	0	4,217	1,041	0	1,041	2,563	0	2,563	2,498	0	2,498
	5800 - Oper Supervision & Engineering	46,149	0	46,149	82,499	0	82,499	81,451	0	81,451	86,079	0	86,079
	5830 - Overhead Line Expenses	845	0	845		0	0	(24)	0	(24)	(24)	0	(24)
	5840 - Underground Line Expenses	2,354	0	2,354	2,039	0	2,039	4,003	0	4,003	3,772	0	3,772
	5860 - Meter Expenses	67,799	0	67,799	68,714	0	68,714	83,748	0	83,748	80,886	0	80,886
	5870 - Customer Installations Exp	266	0	266		0	0	1,313	0	1,313	1,313	0	1,313
	5880 - Miscellaneous Distribution Exp	55,244	0	55,244	76,796	0	76,796	143,710	0	143,710	162,105	0	162,105
	5890 - Rents	67	0	67	82	0	82	230	0	230	206	0	206
	5910 - Maintenance of Structures	248	0	248		0	0		0	0		0	0
	5920 - Maint of Station Equipment	2,292	0	2,292	2,134	0	2,134	3,578	0	3,578	6,805	0	6,805
	5930 - Maintenance of Overhead Lines	272,390	0	272,390	72,820	0	72,820	55,789	0	55,789	63,109	0	63,109
	5940 - Maint of Underground Lines	36	0	36	(122)	0	(122)	1,872	0	1,872	371	0	371
	5950 - Maint of Lne Trnf,Rglators&Dvi	131	0	131	110	0	110	113	0	113	169	0	169
	5960 - Maint of Strt Lghtng & Sgnal S		0	0	213	0	213	477	0	477	477	0	477
	5970 - Maintenance of Meters	1,503	0	1,503	243	0	243		0	0		0	0
	5980 - Maint of Misc Distribution Plt	(5)	0	(5)	427	0	427	718	0	718	912	0	912
	9010 - Supervision - Customer Accts	24	0	24	16	0	16	12,444	0	12,444	1,429	0	1,429
	9030 - Cust Records & Collection Exp	73,614	0	73,614	6,175	0	6,175	6,310	0	6,310	7,876	0	7,876
	9040 - Uncollectible Accounts	4,539	0	4,539		0	0		0	0		0	0
	9070 - Supervision - Customer Service	3,280	0	3,280	44	0	44		0	0		0	0
	9080 - Customer Assistance Expenses	62	0	62	614	0	614	61	0	61	66	0	66
	9090 - Information & Instruct Advrtis	103,592	0	103,592	55,384	0	55,384	123,963	0	123,963	123,963	0	123,963
	9100 - Misc Cust Svc&Informational Ex	22,107	0	22,107	38,462	0	38,462	48,408	0	48,408	48,238	0	48,238
	9110 - Supervision - Sales Expenses	366	0	366	1	0	1	12	0	12	12	0	12
	9120 - Demonstrating & Selling Exp	399	0	399	(44)	0	(44)	882	0	882	882	0	882
	9130 - Advertising Expenses	917	0	917	1,710	0	1,710	400	0	400	400	0	400
	9200 - Administrative & Gen Salaries	725,863	(220,734)	505,129	1,085,564	(360,763)	724,801	1,083,091	(354,494)	728,598	1,170,285	(371,609)	798,676
	9210 - Office Supplies and Expenses	69,708	(24,182)	45,525	24,389	26,953	51,341	54,192	(19,360)	34,832	229,164	(12,884)	216,280
	9220 - Administrative Exp Trnsf - Cr		0	0		0	0	658	0	658	972	0	972
	9230 - Outside Services Employed	202,213	(41,759)	160,454	324,702	41,667	366,369	305,079	(44,487)	260,592	304,475	(35,896)	268,579
	9240 - Property Insurance		0	0		0	0	5	(1)	4	5	(1)	4
	9250 - Injuries and Damages	32,025	(13,585)	18,439	3,383	(1,310)	2,073	3,864	(1,155)	2,709	4,102	(1,275)	2,827
	9260 - Employee Pensions & Benefits	(12)	0	(12)		0	0	342	(5)	337	343	(5)	338
	9280 - Regulatory Commission Exp	1,945,995	0	1,945,995	(501,273)	0	(501,273)	357,432	0	357,432	365,951	0	365,951
	9301 - General Advertising Expenses	294,859	0	294,859	27,525	0	27,525	78,381	0	78,381	73,691	0	73,691
	9302 - Misc General Expenses	67,038	(22,641)	44,397	98,080	(33,578)	64,502	102,899	(34,883)	68,016	94,335	(31,610)	62,724
	9310 - Rents	6,147	(33)	6,114		0	0		0	0	144	(14)	130
	9350 - Maintenance of General Plant	224,956	(23,744)	201,212	237,605	(33,702)	203,902	218,708	(43,637)	175,071	200,804	(36,456)	164,347
Cost of Service Total		**6,113,194**	**(359,106)**	**5,754,088**	**5,720,019**	**(348,337)**	**5,371,682**	**7,963,247**	**(691,131)**	**7,272,116**	**8,430,600**	**(680,052)**	**7,750,548**
Non Cost of Servicet of Service	1060 - Completed Const Not Classifd	3	0	3		0	0		0	0		0	0
	1070 - Construction Work In Progress	1,136,305	(91,327)	1,044,978	1,118,010	(76,422)	1,041,588	4,565,519	(24,121)	4,541,398	4,489,675	(6,961)	4,482,714
	1080 - Accum Prov for Deprec of Plant	22,992	(75)	22,917	35,619	(1,604)	34,015	56,087	(207)	55,880	52,896	(207)	52,689
	1420 - Customer Accounts Receivable		0	0	70	0	70		0	0		0	0
	1430 - Other Accounts Receivable	0	0	0		0	0		0	0		0	0
	1510 - Fuel Stock		0	0	(126,469)	0	(126,469)		0	0		0	0
	1520 - Fuel Stock Exp Undistributed	61	0	61		0	0		0	0		0	0
	1540 - Materials & Oper Supplies	243	0	243		0	0		0	0	252	0	252
	1630 - Stores Expense Undistributed	569,088	0	569,088	578,737	0	578,737	588,159	0	588,159	565,422	0	565,422
	1650 - Prepayments		0	0	820	0	820	34	0	34	34	0	34
	1830 - Prelimin Surv&Investgtn Chrgs		0	0	34	0	34	14,000	0	14,000	14,000	0	14,000
	1840 - Clearing Accounts	122,103	0	122,103	123,963	0	123,963	108,557	0	108,557	149,237	0	149,237
	1860 - MDD-Internal Billing Only	88,937	0	88,937	139,516	0	139,516	99,975	0	99,975	73,847	0	73,847
	1880 - R&D Expenses	(1,122)	0	(1,122)	1,528	0	1,528	14,654	0	14,654	14,604	0	14,604
	1903 - Accum Deferred Income Taxes		0	0		0	0	3	0	3	3	0	3
	2420 - Misc Current & Accrued Liab	255,000	0	255,000		0	0		0	0		0	0
	2530 - Other Deferred Credits		0	0		0	0		0	0	(2,020)	0	(2,020)
	4010 - Operation Expense		0	0		0	0	284	(121)	164	284	(121)	164
	4081 - Taxes Other Than Inc Tax, UOI		0	0	8,247	0	8,247		0	0		0	0
	4170 - Revenues from Non-Util Oper		0	0		0	0	(244)	0	(244)	(465)	0	(465)
	4180 - Non-Operatng Rental Income	11,525	0	11,525	3,260	0	3,260		0	0		0	0
	4210 - Misc Non-Operating Income	(8,078)	4,039	(4,039)		0	0		0	0		0	0
	4261 - Donations	13,894	0	13,894	38,530	0	38,530	29,154	0	29,154	28,358	0	28,358
	4264 - Civic & Political Activities	229,513	0	229,513	156,464	0	156,464	77,720	0	77,720	78,771	0	78,771
	4265 - Other Deductions	89,817	(30,980)	58,837	36,763	(12,712)	24,051	22,426	(7,624)	14,803	11,824	(3,991)	7,833
	4310 - Other Interest Expense	253,672	0	253,672	97,194	0	97,194	195,919	0	195,919	196,296	0	196,296
	4540 - Rent From Electric Property		0	0	(27,465)	0	(27,465)	(53,409)	0	(53,409)	(54,670)	0	(54,670)
	4560 - Other Electric Revenues	(97,246)	0	(97,246)	(93,546)	0	(93,546)	(138,052)	15,969	(122,083)	(132,435)	15,969	(116,466)
Non Cost of Servicet of Service Total		**2,686,707**	**(118,342)**	**2,568,364**	**2,091,273**	**(90,738)**	**2,000,535**	**5,580,787**	**(16,104)**	**5,564,683**	**5,485,914**	**4,688**	**5,490,602**
Grand Total		**8,799,901**	**(477,449)**	**8,322,452**	**7,811,292**	**(439,075)**	**7,372,217**	**13,544,034**	**(707,235)**	**12,836,799**	**13,916,514**	**(675,364)**	**13,241,150**

RATE SCHEDULE NO. 303

MITCHELL PLANT OPERATING AGREEMENT

KENTUCKY POWER COMPANY

WHEELING POWER COMPANY

and

AMERICAN ELECTRIC POWER SERVICE CORPORATION, AS AGENT

Tariff Submitter: **Kentucky Power Company**
FERC Program Name: **FERC FPA Electric Tariff**
Tariff Title: **KPCo Rate Schedules and Service Agreement Tariffs**
Tariff Proposed Effective Date: **12/31/2014**
Tariff Record Title: **Mitchell Plant Operating Agreement**
Option Code: **A**
Record Content Description: **Rate Schedule No. 303**

THIS MITCHELL PLANT OPERATING AGREEMENT ("Agreement"), with an effective date of December 31, 2014 ("Effective Date"), is by and among Kentucky Power Company, a Kentucky corporation qualified as a foreign corporation in West Virginia ("KPCo"), and Wheeling Power Company, a West Virginia corporation ("WPCo") (such two parties hereinafter sometimes referred to as the "Owners"); and American Electric Power Service Corporation, a New York corporation qualified as a foreign corporation in West Virginia ("Agent"). KPCo, WPCo and Agent may hereinafter be referred to as a "Party" or collectively as the "Parties".

WITNESSETH:

WHEREAS, KPCo acquired a fifty percent (50%) undivided ownership interest in the Mitchell Power Generation Facility consisting of two 800MW generating units and associated plant, equipment and real estate, located in Moundsville, West Virginia (the "Mitchell Facility") on December 31, 2013; and

WHEREAS, AEP Generation Resources Inc. ("AEPGR"), an affiliate of the Parties, acquired a fifty percent (50%) undivided ownership interest in the Mitchell Facility, also on December 31, 2013; and

WHEREAS, pursuant to an Asset Contribution Agreement between AEPGR and Newco Wheeling Inc., a West Virginia corporation merged or to be merged into WPCo upon the closing of the transactions (the "Transfer Date") set forth in such Asset Contribution Agreement (the "ACA"), AEPGR transferred its fifty percent (50%) undivided interest in the Mitchell Facility to Newco Wheeling Inc., exclusive of its interest in the Conner Run Fly Ash Impoundment and Dam ("Conner Run"), which interest in Conner Run was retained on the Transfer Date by AEPGR; and

WHEREAS, this Agreement shall be effective upon the Effective Date but the rights and obligations set forth herein shall not commence until 12:01 AM on the day following the Transfer Date; and

WHEREAS, the Owners desire that KPCo shall operate and maintain the Mitchell Facility, exclusive of Conner Run (the "Mitchell Plant"), in accordance with the provisions set forth herein; and

WHEREAS, the Owners are subsidiaries of American Electric Power Company, Inc. ("AEP"), the parent company in an integrated public utility holding company system, and use the services of Agent (an affiliated company engaged solely in the business of furnishing essential services to the Owners and to other affiliated companies), as outlined in the service agreements between Agent and KPCo and between Agent and WPCo.

NOW THEREFORE, in consideration of the premises and for the purposes hereinabove recited, and in consideration of the mutual covenants hereinafter contained, the signatories agree as follows:

ARTICLE ONE

FUNCTIONS OF KPCO AND AGENT

1.1 KPCo shall operate and maintain the Mitchell Plant in accordance with good utility practice consistent with procedures employed by KPCo at its other generating stations, and in conformity with the terms and conditions of this Agreement.

1.2 KPCo shall keep all necessary books of record, books of account and memoranda of all transactions involving the Mitchell Plant, and shall make computations and allocations on behalf of the Owners, as required under this Agreement. The books of record, books of account and memoranda shall be kept in such manner as to conform, where so required, to the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission ("FERC") for Public Utilities and Licensees ("Uniform System of Accounts"), and to the rules and regulations of other regulatory bodies having jurisdiction as they may from time to time be in effect.

1.3 The Owners shall establish such bank accounts as may from time to time be required or appropriate.

1.4 As soon as practicable after the end of the month, KPCo shall furnish to WPCo a statement setting forth the dollar amounts associated with the operation and maintenance of the Mitchell Plant as allocated hereunder to KPCo and WPCo for such month. The Owners shall, on a timely basis, deposit sufficient dollar amounts in the appropriate bank accounts to cover their respective allocations of such costs.

1.5 KPCo shall be responsible for the day to day operation and maintenance of the Mitchell Plant. KPCo shall obtain such materials, labor and other services as it considers necessary in connection with the performance of the functions to be performed by it hereunder from such sources or through such persons as it may designate.

1.6 Agent, as directed by the Operating Committee and consistent with Agent's service agreements with KPCo and WPCo, shall provide services necessary for the safe and efficient operation and maintenance of the Mitchell Plant.

ARTICLE TWO

APPORTIONMENT OF CAPACITY AND ENERGY

2.1 The Total Net Capability of the Mitchell Plant at the Mitchell Unit 1 and Unit 2 low-voltage busses, after taking into account auxiliary load demand, is 1,560,000 kilowatts. The Owners may from time to time modify the Total Net Capability of the Mitchell Plant as they may mutually agree.

2.2 The Total Net Generation of the Mitchell Plant during a given period, as determined by the requirements of KPCo and WPCo, shall mean the electrical output of the Mitchell Plant generators during such period, measured in kilowatt hours by suitable instruments, reduced by the energy used by auxiliaries for the Mitchell Unit 1 and Unit 2 during such period.

2.3 Except as set forth in Section 7.6 (including Section 7.6 Subsections), in any hour, KPCo and WPCo shall share the minimum load responsibility of Mitchell Unit 1 and Unit 2 in respective amounts proportionate to their ownership interests in the Mitchell Plant at such time. Each Owner may independently dispatch its share of the generating capacity between minimum and full load.

2.4 In any hour during which the Mitchell Units are out of service, the energy used by the out-of-service Units' auxiliaries during such hour shall be provided by KPCo and WPCo in respective amounts proportionate to their ownership interests in the Mitchell Plant at such time.

ARTICLE THREE

REPLACEMENTS, ADDITIONS, AND RETIREMENTS

3.1 KPCo shall from time to time make or cause to be made any additions to, replacements of, and retirements of, capitalizable facilities associated with the Mitchell Plant in accordance with the approved annual budget.

3.2 The dollar amounts associated with any additions to, replacements of, or retirements of, capitalizable facilities associated with the Mitchell Plant shall be allocated to KPCo and WPCo in respective amounts proportionate to their ownership interests in the Mitchell Plant at the time such additions, replacements, or retirements are made.

ARTICLE FOUR

WORKING CAPITAL REQUIREMENTS

4.1 KPCo and WPCo shall periodically mutually determine the amount of funds required for use as working capital in meeting payrolls and other expenses incurred in the operation and maintenance of the Mitchell Plant, and in buying materials and supplies (exclusive of fuel) for the Mitchell Plant.

4.2 KPCo and WPCo shall from time to time provide their share of working capital requirements in respective amounts proportionate to their ownership interests at such time in the Mitchell Plant.

ARTICLE FIVE

INVESTMENT IN FUEL

5.1 KPCo and Agent shall establish and maintain reserves of coal in stock piles for the Mitchell Plant of such quality and in such quantities as the Operating Committee shall determine to be required to provide adequate fuel reserves against interruptions of normal fuel supply, provided each Owner, subject to the approval of the Operating Committee and subject to no adverse impact on the operation of the Mitchell Plant, will have the right, but not the obligation, to directly purchase coal, transportation and consumables for its ownership interest. For the purposes of this Agreement, "consumables" shall be as defined in FERC account 502.

5.2 Except as provided in Section 5.1 for an Owner to elect to procure coal for its own interest, the Owners shall make such monthly investments in the common coal stock piles associated with the Mitchell Plant as are necessary to maintain the number of tons in such coal stock piles, after taking into account the coal consumption from the common coal stock piles by Mitchell Unit 1 and Unit 2 during such month.

5.3 At any time, KPCo's and WPCo's respective shares of the investment in the common coal stock piles shall be proportionate to their ownership interests in the Mitchell Plant, unless an Owner elects to procure its own coal as provided in Section 5.1, in which case inventories will be separately maintained for accounting purposes.

5.4 Fuel oil and consumables charged to operation for the Mitchell Plant shall be owned and accounted for between the Owners in the same manner as coal.

ARTICLE SIX

APPORTIONMENT OF STATION COSTS

6.1 Except in the case where an Owner has elected to purchase coal for its own interest as provided for in Section 5.1 (in which case the allocation to the Owners of fuel expense shall be in accordance with procedures and processes approved by the Operating Committee), the allocation to the Owners of fuel expense associated with Mitchell Unit 1 and Unit 2 shall be determined by KPCo and Agent as follows:

(a) In any calendar month, the average unit cost of coal available for consumption from the Mitchell Plant common coal stock piles shall be determined based on the prior month's ending inventory dollar and ton balances plus current month receipts delivered to the Mitchell Plant common coal stock piles. Each Owner's average unit cost will be the same, and receipts and inventory available for consumption amounts will be allocated to each Owner based on monthly usage.

(b) The number of tons of coal consumed by the Mitchell Plant in each calendar month from the Mitchell Plant common coal stock piles shall be determined and shall be converted into a dollar amount equal to the product of (i) the average cost per ton of coal associated with the Mitchell Plant in the Mitchell Plant common coal stock pile at the close of such month, and (ii) the number of tons of coal consumed by the Mitchell Plant from the Mitchell Plant common coal stock piles during such month. Such dollar amount shall be credited to the

Mitchell Plant fuel in stock pile and charged to Mitchell Plant fuel consumed.

(c) In each calendar month, KPCo's and WPCo's respective shares of the Mitchell Plant fuel consumed expense as determined by the provisions of Section 6.1(b) shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

(d) Fuel oil reserves will be owned and accounted for in the same manner as coal stock piles, and fuel oil consumed will be allocated to the Owners in the same manner as coal consumed.

6.2 For purposes of this Agreement, KPCo's Assigned Capacity in the Mitchell Plant shall be equal to 50% of the Total Net Capability, and WPCo's Assigned Capacity shall be equal to 50% of the Total Net Capability.

6.3 For each calendar month, KPCo and Agent will, to the extent practicable, determine all Mitchell Plant operations expenses and associated overheads, as accounted for under the FERC Uniform System of Accounts.

6.4 For each calendar month, KPCo and Agent will, to the extent practicable, determine all Mitchell Plant maintenance expenses and associated overheads, as accounted for under the FERC Uniform System of Accounts.

6.5 In each calendar month, KPCo's and WPCo's respective shares of operations and maintenance expenses associated with the Mitchell Plant, as determined in accordance with Sections 6.3 and 6.4, shall be allocated as follows:

(a) In each calendar month, KPCo's and WPCo's respective shares of the Mitchell Plant steam expenses as recorded in FERC Account 502, and emission tons, with allowance expenses as recorded in FERC Account 509, shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

(b) In each calendar month, the maintenance of boiler plant expenses as recorded in FERC Account 512, and maintenance of electric plant expenses as recorded in FERC Account 513, shall be directly assigned to Mitchell Unit 1 or Unit 2 or designated as a common expense attributable to both units. In each calendar month, KPCo's and WPCo's respective shares of these expenses shall be proportionate to each Owner's dispatch of the applicable unit, or both units in the case of common expenses, over the previous sixty (60) calendar months. Dispatch is assumed to have been allocated fifty percent (50%) to each Owner for months that are prior to this Agreement.

(c) In each calendar month, KPCo's and WPCo's respective shares of all other operations, maintenance, administrative and general expenses shall be proportionate to their respective ownership interests.

6.6 Each Owner shall bear the cost of all taxes attributable to its respective ownership interest in the Mitchell Plant.

ARTICLE SEVEN

OPERATING COMMITTEE AND OPERATIONS

7.1 By written notice to each other, the Owners and Agent each shall name one representative ("Operating Representative") and one alternate to act for it in matters pertaining to operating arrangements under this Agreement. Any Party may change its Operating Representative or alternate at any time by written notice to the other

Parties. The Operating Representatives for the respective Parties, or their alternates, shall comprise the Operating Committee. All decisions, directives, or other actions by the Operating Committee must be by unanimous agreement of the Operating Representatives of the Owners. The Operating Representative of Agent, or of any third party that provides services in replacement of Agent, shall be free to express the views of Agent or such third party on any matter, but shall not have a vote on the Operating Committee. Except as otherwise provided in Sections 11.1, 11.2 and 11.3 with respect to a dispute referred to the Operating Committee by an Owner, the failure of the Owners' respective Operating Representatives to unanimously agree with respect to a matter pending before the Operating Committee shall not be considered to be a dispute that would be subject to resolution under Article Eleven.

7.2 The Operating Committee shall have the following responsibilities:

(a) Review and approval of an annual budget and annual operating plan, including determination of the emission allowances required to be acquired by KPCo and WPCo. If the Operating Committee fails to approve an annual budget, the approved annual budget from the previous year will continue to apply until such time as the new annual budget is approved.

(b) Establishment and review of procedures and systems for dispatch, notification of dispatch, and unit commitment under this Agreement, including any commitment of Called Capacity pursuant to Section 7.6.2.

(c) Establishment and monitoring of procedures for communication and coordination with respect to the Mitchell Plant capacity availability, fuel-firing options, and scheduling of outages for maintenance, repairs, equipment replacements, scheduled inspections, and other foreseeable cause of outages, as well as the return to availability following an unplanned outage.

(d) Decisions on capital expenditures, including unit upgrades and re-powering.

(e) Determinations as to changes in the unit capability and decisions on unit retirement.

(f) Establishment and modification of billing procedures under this Agreement.

(g) Approval of material contracts for fuel, transportation or consumable supply. Establishment of specification of fuels, oversight of fuel inspection and certification procedures, management of fuel inventories, and allocation of rights under fuel supply, transportation and consumable contracts. Establishment of an Owner's procurement rights and procedures if the Owner elects to purchase coal, transportation or consumables for its own interest.

(h) Establishment of, termination of, and approval of any change or amendment to the operating arrangements between KPCo and Agent or any replacement third party with respect to the Mitchell Plant generating units; provided, however, that Agent or any replacement third party shall participate in discussions pursuant to this subsection 7.2(h) only if and to the extent requested to do so by both Owners.

(i) Review and approval of plans and procedures designed to ensure compliance with any environmental law, regulation, ordinance or permit, including procedures for allocating and using emission allowances or for any programs that permit averaging at more than one unit for compliance.

(j) Other duties as assigned by agreement of the Owners.

7.3 The Operating Committee shall meet at least annually, and at such other times as any Party may reasonably request.

7.4 The Parties shall cooperate in providing to the Operating Committee the information it reasonably needs to carry out its duties, and to supplement or correct such information on a timely basis.

7.5 The Owners will each make an initial unit commitment one business day ahead of real-time dispatch.

7.6 Application of this Section 7.6 (including subsections) is subject to (i) the receipt of any necessary regulatory approvals or waivers expressly granted for this Section 7.6; and (ii) the Operating Committee establishing and approving procedures and systems for dispatch. As used in this Section and subsections of this Section, the terms "Party" or "Parties" refers only to KPCo and WPCo, or both of them, as the case may be.

7.6.1 If Mitchell Unit 1 or Unit 2 is designated to be committed by both Parties, such unit will be brought on line or kept on line. If neither Party designates Mitchell Unit 1 or Unit 2 to be committed, such unit will remain off line or be taken offline.

7.6.2 When a Mitchell Unit is designated to be committed by one Party, but designated not to be committed by the other Party, the unit will be brought on line or kept on line if the Party designating the unit for commitment undertakes to pay any applicable start-up costs for the unit, as well as any applicable minimum running costs for the unit thereafter, in which event the unit shall be brought on line or kept on line, as the case may be. The Party so designating the unit to be committed shall have the right to schedule and dispatch up to all of the Available Capacity of the unit. Available Capacity means that portion of the Owners' aggregate Assigned Capacity that is currently capable of being dispatched. The Party exercising this right shall be referred to as the "Calling Party," and the capacity called by that Party in excess of its Assigned Capacity Percentage of the Available Capacity of that unit shall be referred to as its "Called Capacity." The other Party shall be referred to as the "Non-Calling Party". The Calling Party shall provide reasonable notice to the Non-Calling Party of its call, including any start-up or shut-down time for the Unit. For purposes of this Agreement, KPCo's Assigned Capacity Percentage shall be 50%, and WPCo's Assigned Capacity Percentage shall be 50%.

7.6.3 The Non-Calling Party can reclaim any Called Capacity attributable to its Assigned Capacity share by giving the Calling Party notice equal to the normal cold start-up time for the unit. At the end of the notice period, the Non-Calling Party shall have the right to schedule and dispatch the recalled capacity. At that point, the Non-

Calling Party shall resume its responsibility for its share of any applicable start-up costs for the unit and prospectively shall bear its responsibility for the costs associated with its Assigned Capacity from the unit.

7.6.4 If any capacity remains available but is not dispatched from a Party's Available Capacity committed as a result of the initial unit commitment, the other Party may only schedule and dispatch such capacity pursuant to agreement with the non-dispatching Party.

7.7 KPCo and WPCo shall be individually responsible for any fees charged by FERC on the basis of the sales or transmission by each of capacity or energy at wholesale in interstate commerce.

7.8 Emission Allowances. On the Transfer Date pursuant to the ACA, AEPGR, the previous owner of WPCo's interest in the Mitchell Plant, will assign to WPCo all Emission Allowances allocated to AEPGR for the Mitchell Plant for each vintage year after 2014, issued by the U.S. Environmental Protection Agency ("USEPA") pursuant to Title IV of the Clean Air Act Amendments of 1990 and any regulations thereunder, and any other emission allowance trading program created under the Clean Air Act and administered by USEPA or the State of West Virginia, including but not limited to the Clean Air Interstate Rule 40 CFR Parts 96 and 97, and any amendments thereto ("Emission Allowances"), and all Emission Allowances for 2014 and any vintage year prior to 2014 that were allocated to the Mitchell Plant and that have not been expended as of the date of assignment. To the extent that additional Emission Allowances are required for operation of the Mitchell Plant, KPCo and WPCo will each be responsible for acquiring sufficient Emission

Allowances to satisfy the Emission Allowances required because of its dispatch of energy from the Mitchell Plant, and the Emission Allowances required to satisfy the Emission Allowance surrender obligations attributable to the Mitchell Plant imposed under the Consent Decree between USEPA and Ohio Power Company entered on December 10, 2007, in Civil Action No. C2-99-1182 and consolidated cases by the U.S. District Court in the Southern District of Ohio. On or before January 10 of each year, Agent shall determine and notify KPCo and WPCo of the number of additional annual Emission Allowances consumed by each of them through December 31 of the previous year, and KPCo and WPCo shall each transfer into the Mitchell Plant U.S. EPA Allowance Transfer System account that number of Emission Allowances with a small compliance margin by January 31 of that year. For seasonal Emission Allowance programs, Agent shall determine and notify KPCo and WPCo of the number of additional seasonal Emission Allowances consumed by each of them during the applicable compliance period by the 10th day of the first month following the end of the compliance period, and KPCo and WPCo shall each transfer into the appropriate Mitchell Plant U.S. EPA Allowance Transfer System Account that number of Emission Allowances with a small compliance margin by the last day of the first month following the end of the compliance period. In the event that KPCo or WPCo fails to surrender the required number of Emission Allowances by January 31 or the last day of the first month following any seasonal compliance period, Agent shall purchase the required number of Emission Allowances, and KPCo or WPCo, as the case may be, shall reimburse Agent for such purchases, with interest at the Federal Funds Rate (as published by the Board of

Governors of the Federal Reserve System as from time to time in effect) running from the date of such purchases to the date of payment. The Operating Committee will develop procedures to be implemented after the end of each calendar year to account for the Emission Allowances required by the use of the Mitchell Plant by KPCo and WPCo and to correct any imbalance between Emission Allowances supplied and Emission Allowances used through the end of the preceding year by settlement or payment.

7.9 Capital repairs and improvements to the Mitchell Plant will be determined by the Operating Committee pursuant to the annual budgeting process set forth in Section 7.10. Expenditures that the Operating Committee determines have been or will be incurred exclusively for one Owner shall be assigned exclusively to that Owner.

7.10 At least 90 days before the start of each operating year, KPCo and Agent shall submit to the Operating Committee a proposed annual budget with respect to the Mitchell Plant, a proposed annual operating plan, and an estimate and schedule of costs to be incurred for major maintenance or replacement items during the next six-year period. The annual budget shall be presented on a month-by-month basis for each month during the next operating year, and shall include an operating budget, a capital budget, an estimate of the cost of any major repairs that are anticipated will occur during such operating year with respect to the Mitchell Plant, and an itemized estimate of all projected non-fuel variable operating expenses relating to the operation of the Mitchell Plant during that operating year. The members of the Operating Committee will meet and work in good faith to agree upon the final annual budget and final annual operating plan. Once approved, the annual budget and annual operating plan shall remain in effect throughout the applicable operating year, subject to such changes, revisions, amendments, and updating as the Operating Committee may determine.

ARTICLE EIGHT

EFFECTIVE DATE AND TERM

8.1 Subject to FERC approval or acceptance for filing, the Effective Date of this Agreement shall be December 31, 2014.

8.2 Subject to FERC approval or acceptance, if necessary, this Agreement shall remain in force until such time as (i) KPCo or WPCo has divested itself of all or any portion of its ownership interest in the Mitchell Plant, other than assignment or other transfer of such ownership interests to another AEP affiliate; or (ii) either KPCo or WPCo is no longer a direct or indirect wholly owned subsidiary of AEP; or (iii) KPCo and WPCo may mutually agree to terminate this Agreement.

ARTICLE NINE

GENERAL

9.1 This Agreement shall inure to the benefit of and be binding upon the signatories hereto and their respective successors and assigns, but this Agreement may not be assigned by any signatory without the written consent of the others, which consent shall not be unreasonably withheld.

9.2 This Agreement is subject to the regulatory authority of any State or Federal agency having jurisdiction.

9.3 The interpretation and performance of this Agreement shall be in accordance with the laws of the State of Ohio, excluding conflict of laws principles that would require the application of the laws of a different jurisdiction.

9.4 This Agreement supersedes all previous representations, understandings, negotiations, and agreements, either written or oral between the signatories or their representatives with respect to operation of the Mitchell Plant, and constitutes the entire agreement of the signatories with respect to the operation of the Plant. Notwithstanding the foregoing, this Agreement does not supersede any previous agreements among any of the signatories allocating or transferring rights to capacity and associated energy, or ownership, of the Mitchell Plant.

9.5 Each Party shall designate in writing a representative to receive any and all notices required under this Agreement. Notices shall be in writing and shall be given to the representative designated to receive them, either by personal delivery, certified mail, facsimile, e-mail or any similar means, properly addressed to such representative at the address specified below:

KENTUCKY POWER COMPANY
Gregory G. Pauley
President & COO

Attn:

Phone: (502) 696-7007

Facsimile:(502) 696-7006

Email: ggpauley@aep.com

WHEELING POWER COMPANY
Charles R. Patton
President

Attn:

Phone: (304) 348-4152

Facsimile: (304) 348-4198

Email: crpatton@aep.com

AMERICAN ELECTRIC POWER SERVICE CORPORATION
Mark C. McCullough
Executive Vice President – Generation

Attn:

Phone: (614) 716-2400

Facsimile: (614) 716-1331

Email: mcmccullough@aep.com

All notices shall be effective upon receipt, or upon such later date following receipt as set forth in the notice. Any Party may, by written notice to the other Parties, change the representative or the address to which such notices are to be sent.

ARTICLE TEN

LIMITATION OF LIABILITY

10.1 Notwithstanding anything in this Agreement to the contrary, neither of the Owners or Agent shall be liable under this Agreement for special, consequential, indirect, punitive or exemplary damages, or for lost profits or business interruption damages, whether arising by statute, in tort or contract or otherwise.

ARTICLE ELEVEN

DISPUTE RESOLUTION

11.1 If either Owner believes that a dispute has arisen as to the meaning or application of this Agreement, it shall present that matter to the Operating Committee in writing, and shall provide a copy of that writing to the other Owner.

11.2 If the Operating Committee is unable to reach agreement on a dispute submitted to the Operating Committee pursuant to Section 11.1within thirty (30) days after the dispute is presented to it, the matter shall be referred to the chief operating officers of the Owners for resolution in the manner that such individuals shall agree is appropriate; provided, however, that either Owner involved in the dispute may invoke the arbitration provisions set forth in Section 11.3 at any time after the end of the thirty (30) day period provided for the Operating Committee to reach agreement if the Operating Committee has not reached agreement.

11.3 If the Owners are unable to resolve a dispute through the Operating Committee within thirty (30) days after the dispute is presented to the Operating Committee pursuant to Section 11.1, or through reference of the matter to the chief operating officers of the Owners pursuant to Section 11.2, either Owner may commence arbitration proceedings by providing written notice to the other Owner, detailing the nature of the dispute, designating the issue(s) to be arbitrated, identifying the provisions of this Agreement under which the dispute arose, and setting forth such Owner's proposed resolution of such dispute.

11.3.1 Within ten (10) days of the date of the notice of arbitration, a representative of each Owner shall meet for the purpose of selecting an arbitrator. If the Owners' representatives are unable to agree on an arbitrator within fifteen (15) days of the date of the notice of arbitration, then an arbitrator shall be selected in accordance with the procedures of the American Arbitration Association ("AAA"). Whether the arbitrator is selected by the Owners' representatives or in accordance with the procedures of the AAA, the arbitrator shall have the qualifications and experience in the occupation, profession, or discipline relevant to the subject matter of the dispute.

11.3.2 Any arbitration proceeding shall be subject to the Federal Arbitration Act, 9 U.S.C. §§ 1 *et seq.* (1994), as it may be amended, or any successor enactment thereto, and shall be conducted in accordance with the commercial arbitration rules of the AAA in effect on the date of the notice to the extent not inconsistent with the provisions of this Article.

11.3.3 The arbitrator shall be bound by the provisions of this Agreement where applicable, and shall have no authority to modify any terms and conditions of this Agreement in any manner. The arbitrator shall render a decision resolving the dispute in an equitable manner, and may determine that monetary damages are due to an Owner or may issue a directive that an Owner take certain actions or refrain from taking certain actions, but shall not be authorized to order any other form of relief; provided, however, that nothing in this Article shall preclude the arbitrator from rendering a decision that adopts the resolution of the dispute proposed by an Owner. Unless otherwise agreed to by the Owners, the arbitrator shall render a decision within one hundred twenty (120) days of appointment, and shall notify the Owners in writing of such decision and the reasons supporting such decision. The decision of the arbitrator shall be final and binding upon the Owners, and any award may be enforced in any court of competent jurisdiction.

11.3.4 The fees and expenses of the arbitrator shall be shared equally by the Owners, unless the arbitrator specifies a different allocation. All other expenses and costs of the arbitration proceeding shall be the responsibility of the Owner incurring such expenses and costs.

11.3.5 Unless otherwise agreed by the Owners, any arbitration proceedings shall be conducted in Columbus, Ohio.

11.3.6 Except as provided in this Article, the existence, contents, or results of any arbitration proceeding under this Article may not be disclosed without the prior written consent of the Owners, provided, however, that either Owner may make disclosures as may be required to fulfill regulatory obligations to any agencies having jurisdiction, and may inform its lenders, affiliates, auditors, and insurers, as necessary, under pledge of confidentiality, and may consult with expert consultants as required in connection with an arbitration proceeding under pledge of confidentiality.

11.3.7 Nothing in this Agreement shall be construed to preclude either Owner from filing a petition or complaint with FERC with respect to any claim over which FERC has jurisdiction. In such case, the other Owner may request that FERC reject the petition or complaint or otherwise decline to exercise its jurisdiction. If FERC declines to act with respect to all or part of a claim, the portion of the claim not so accepted by FERC may be resolved through arbitration, as provided in this Article. To the extent that FERC asserts or accepts jurisdiction over all or part of a claim, the decisions, findings of fact, or orders of FERC shall be final and binding, subject to judicial review under the Federal Power Act, 16 U.S.C. § 791a *et seq.,* as amended from time to time, and any arbitration proceedings that may have commenced prior to the assertion or acceptance of jurisdiction by FERC shall be stayed, pending the outcome of the FERC proceedings. The arbitrator shall have no authority to modify, and shall be conclusively bound by, any decisions, findings of fact, or orders of FERC; provided, however, that to the extent that any decisions, findings of fact, or orders of FERC do not provide a final or complete remedy to an Owner seeking relief, such Owner may proceed to arbitration under this Article to secure such a remedy, subject to any FERC decisions, findings, or orders.

11.4 The procedures set forth in this Article shall be the exclusive means for resolving disputes arising under this Agreement and shall survive this Agreement to the extent necessary to resolve any disputes pertaining to this Agreement. Except as provided in Sections 11.3 and 11.3.7, neither Owner shall have the right to bring any dispute for resolution before a court, agency, or other entity having jurisdiction over this Agreement, unless both Owners agree in writing to such procedure.

11.5 To the extent that a dispute involves the actions, inactions or responsibilities of Agent under this Agreement, the provisions of this Article shall be applicable to such dispute. For such purposes, Agent shall be treated as an Owner in applying the provisions of this Article.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their officers thereunto duly authorized as of the date first above written.

KENTUCKY POWER COMPANY

By: Greg G. Pauley
Gregory G. Pauley

Title: President & COO

WHEELING POWER COMPANY

By:____________________________
Charles R. Patton

Title: President

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By:____________________________
Mark C. McCullough

Title: Executive Vice President - Generation

11.5 To the extent that a dispute involves the actions, inactions or responsibilities of Agent under this Agreement, the provisions of this Article shall be applicable to such dispute. For such purposes, Agent shall be treated as an Owner in applying the provisions of this Article.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their officers thereunto duly authorized as of the date first above written.

KENTUCKY POWER COMPANY

By:____________________________
Gregory G. Pauley

Title: President & COO

WHEELING POWER COMPANY

By: Charles R. Patton
Charles R. Patton

Title: President

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By:____________________________
Mark C. McCullough

Title: Executive Vice President - Generation

11.5 To the extent that a dispute involves the actions, inactions or responsibilities of Agent under this Agreement, the provisions of this Article shall be applicable to such dispute. For such purposes, Agent shall be treated as an Owner in applying the provisions of this Article.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their officers thereunto duly authorized as of the date first above written.

KENTUCKY POWER COMPANY

By:______________________________
Gregory G. Pauley

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By: ______________________________
Mark C. McCullough

Title: Executive Vice President - Generation

Kentucky Power Company
Capital Construction Budget
Years 2020-2022

Category ($000s)	2020	2021	2022
Environmental Generation	10,500	14,059	16,849
Other Generation	11,021	15,237	17,971
Transmission	90,931	64,087	72,432
Distribution	60,358	65,425	46,202
Corporate/Other	27,346	25,526	16,185
	200,156	**184,334**	**169,638**