Kentucky Power Company

2007 Annual Report

Financial Statements

TABLE OF CONTENTS

GLOSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	Clean Air Act.
CO_2	Carbon Dioxide.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. This agreement was amended in May 2006 to remove TCC and TNC. AEPSC acts as the agent.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 47	FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations."
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48."
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 distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
MISO	Midwest Independent Transmission System Operator.

Term	Meaning
MTM	Mark-to-Market.
MW	Megawatt.
NO_x	Nitrogen oxide.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCT	Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation."
SFAS 109	Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes."
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 143	Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."
SFAS 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements."
SFAS 158	Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."
SFAS 159	Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities."
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying balance sheets of Kentucky Power Company (the "Company") as of December 31, 2007 and 2006, and the related statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2007 and 2006, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2 and 7 to the financial statements, respectively, the Company adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes", effective January 1, 2007, and FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2008

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2007, 2006 and 2005
(in thousands)

	2007	2006	2005
REVENUES			
Electric Generation, Transmission and Distribution	$ 526,754	$ 526,432	$ 458,858
Sales to AEP Affiliates	60,551	58,287	70,803
Other	695	1,148	1,682
TOTAL	588,000	585,867	531,343
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	147,912	152,335	142,672
Purchased Electricity for Resale	17,786	8,724	7,213
Purchased Electricity from AEP Affiliates	185,399	192,080	176,350
Other Operation	66,118	60,674	59,024
Maintenance	36,880	35,430	30,652
Depreciation and Amortization	47,193	46,387	45,110
Taxes Other Than Income Taxes	11,872	8,612	9,491
TOTAL	513,160	504,242	470,512
OPERATING INCOME	74,840	81,625	60,831
Other Income (Expense):			
Interest Income	1,992	656	880
Allowance for Equity Funds Used During Construction	260	241	305
Interest Expense	(28,635)	(28,832)	(29,071)
INCOME BEFORE INCOME TAXES	48,457	53,690	32,945
Income Tax Expense	15,987	18,655	12,136
NET INCOME	$ 32,470	$ 35,035	$ 20,809

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

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2007, 2006 and 2005
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2004	$ 50,450	$ 208,750	$ 70,555	$ (8,775)	$ 320,980
Common Stock Dividends			(2,500)		(2,500)
TOTAL					318,480
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $542				(1,007)	(1,007)
Minimum Pension Liability, Net of Tax of $5,147				9,559	9,559
NET INCOME			20,809		20,809
TOTAL COMPREHENSIVE INCOME					29,361
DECEMBER 31, 2005	50,450	208,750	88,864	(223)	347,841
Common Stock Dividends			(15,000)		(15,000)
TOTAL					332,841
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $940				1,746	1,746
Minimum Pension Liability, Net of Tax of $16				29	29
NET INCOME			35,035		35,035
TOTAL COMPREHENSIVE INCOME					36,810
DECEMBER 31, 2006	50,450	208,750	108,899	1,552	369,651
FIN 48 Adoption, Net of Tax			(786)		(786)
Common Stock Dividends			(12,000)		(12,000)
TOTAL					356,865
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,274				(2,366)	(2,366)
NET INCOME			32,470		32,470
TOTAL COMPREHENSIVE INCOME					30,104
DECEMBER 31, 2007	$ 50,450	$ 208,750	$ 128,583	$ (814)	$ 386,969

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2007 and 2006
(in thousands)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 727	$ 702
Accounts Receivable:		
Customers	20,196	30,112
Affiliated Companies	15,984	10,540
Accrued Unbilled Revenues	2,904	3,602
Miscellaneous	178	327
Allowance for Uncollectible Accounts	(1,071)	(227)
Total Accounts Receivable	38,191	44,354
Fuel	8,338	16,070
Materials and Supplies	11,758	8,726
Risk Management Assets	12,480	25,624
Regulatory Asset for Under-Recovered Fuel Costs	4,426	1,042
Prepayments and Other	4,701	5,327
TOTAL	80,621	101,845
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	482,653	478,955
Transmission	402,259	394,419
Distribution	502,486	481,083
Other	61,665	61,089
Construction Work in Progress	46,439	29,587
Total	1,495,502	1,445,133
Accumulated Depreciation and Amortization	457,028	442,778
TOTAL - NET	1,038,474	1,002,355
OTHER NONCURRENT ASSETS		
Regulatory Assets	124,828	136,139
Long-term Risk Management Assets	15,356	21,282
Deferred Charges and Other	53,708	48,944
TOTAL	193,892	206,365
TOTAL ASSETS	$ 1,312,987	$ 1,310,565

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2007 and 2006

	2007	2006
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 19,153	$ 30,636
Accounts Payable:		
General	32,603	31,490
Affiliated Companies	29,437	23,658
Long-term Debt Due Within One Year – Nonaffiliated	30,000	322,048
Risk Management Liabilities	10,974	20,001
Customer Deposits	15,312	16,095
Accrued Taxes	16,875	18,775
Other	31,909	26,303
TOTAL	186,263	489,006
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	398,373	104,920
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	9,711	15,426
Deferred Income Taxes	240,858	242,133
Regulatory Liabilities and Deferred Investment Tax Credits	46,434	49,109
Deferred Credits and Other	24,379	20,320
TOTAL	739,755	451,908
TOTAL LIABILITIES	926,018	940,914
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – $50 Par Value Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	208,750	208,750
Retained Earnings	128,583	108,899
Accumulated Other Comprehensive Income (Loss)	(814)	1,552
TOTAL	386,969	369,651
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,312,987	$ 1,310,565

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2007, 2006 and 2005
(in thousands)

	2007	2006	2005
OPERATING ACTIVITIES			
Net Income	$ 32,470	$ 35,035	$ 20,809
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	47,193	46,387	45,110
Deferred Income Taxes	5,691	2,596	10,555
Allowance for Equity Funds Used During Construction	(260)	(241)	(305)
Mark-to-Market of Risk Management Contracts	2,479	580	(3,465)
Pension Contributions to Qualified Plan Trusts	-	-	(18,894)
Change in Other Noncurrent Assets	(4,122)	(4,497)	(114)
Change in Other Noncurrent Liabilities	1,001	2,621	3,844
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	2,445	11,903	(3,681)
Fuel, Materials and Supplies	9,015	(6,125)	(2,735)
Accounts Payable	1,806	(3,436)	13,184
Customer Deposits	(783)	(5,548)	9,334
Accrued Taxes, Net	(1,410)	15,547	(7,041)
Other Current Assets	(3,207)	7,867	(9,261)
Other Current Liabilities	1,376	3,953	1,589
Net Cash Flows from Operating Activities	93,694	106,642	58,929
INVESTING ACTIVITIES			
Construction Expenditures	(68,134)	(77,848)	(56,979)
Change in Other Cash Deposits, Net	-	5	(5)
Change in Advances to Affiliates, Net	-	-	16,127
Proceeds from Sales of Assets	695	2,956	300
Net Cash Flows Used for Investing Activities	(67,439)	(74,887)	(40,557)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	321,100	-	-
Change in Advances from Affiliates, Net	(11,483)	24,596	6,040
Retirement of Long-term Debt – Nonaffiliated	(322,964)	-	-
Retirement of Long-term Debt – Affiliated	-	(40,000)	(20,000)
Principal Payments for Capital Lease Obligations	(883)	(1,175)	(1,518)
Dividends Paid on Common Stock	(12,000)	(15,000)	(2,500)
Net Cash Flows Used for Financing Activities	(26,230)	(31,579)	(17,978)
Net Increase in Cash and Cash Equivalents	25	176	394
Cash and Cash Equivalents at Beginning of Period	702	526	132
Cash and Cash Equivalents at End of Period	$ 727	$ 702	$ 526
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 28,864	$ 27,887	$ 27,354
Net Cash Paid for Income Taxes	10,477	11,516	11,655
Noncash Acquisitions Under Capital Leases	826	648	419
Construction Expenditures Included in Accounts Payable at December 31,	12,161	3,357	6,553

See Notes to Financial Statements.

NOTES TO FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 176,000 retail customers in its service territory in eastern Kentucky. As a member of the AEP Power Pool, KPCo shares the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. KPCo also sells power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Under a unit power agreement with AEGCo, an affiliated company that is not a member of the AEP Power Pool, KPCo purchases 15% of the total output of the 2,600 MW Rockport Plant capacity. Therefore, KPCo purchases 390 MW of Rockport Plant capacity. The unit power agreement expires in December 2022. KPCo pays a demand charge for the right to receive the power, which is payable even if the power is not taken.

Prior to April 1, 2006, under the SIA, AEPSC allocated physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded. The capacity-based allocation mechanism was triggered in July 2005, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of each year.

Effective April 1, 2006, under the SIA, AEPSC allocates physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. Accordingly, the 2006 results of operations and cash flows reflect nine months of the SIA change.

AEPSC conducts power, gas, coal and emission allowance risk management activities on KPCo's behalf. KPCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. KPCo shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. KPCo settles the majority of the physical forward contracts by entering into offsetting contracts.

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

KPCo's affiliated transactions are regulated by the FERC under the 2005 Public Utility Holding Company Act (2005 PUHCA) and by the KPSC. The KPSC approves the retail rates KPCo charges and regulates KPCo's retail services and operations for the generation and supply of power, retail transmission and distribution energy delivery services.

The FERC regulates wholesale power markets, wholesale power transactions and wholesale transmission services. KPCo's wholesale power transactions are generally market-based and are not cost-based regulated unless KPCo negotiates and files a cost-based contract with the FERC or the FERC determines that KPCo has "market power" in the region in which the transaction is taking place. KPCo enters into wholesale power supply contracts with various municipalities and cooperatives that are FERC regulated, cost-based contracts.

In addition, the FERC regulates the AEP Power Pool, the Transmission Equalization Agreement, the System Interim Allowance Agreement, and SIA, all of which allocate shared AEP system costs and revenues to the utility subsidiaries that are parties to the agreements, including KPCo.

The KPSC regulates all of the retail public utility operations (generation/power supply, transmission and distribution operations) and retail rates of KPCo, which are cost-based. In 2005, KPCo was subject to regulation by the SEC under the Public Utility Holding Company Act of 1935 (1935 PUHCA). The Energy Policy Act of 2005 repealed the 1935 PUHCA effective February 8, 2006 and replaced it with the 2005 PUHCA. With the repeal of the 1935 PUHCA, the SEC no longer has jurisdiction over the activities of registered holding companies, their respective service corporations and their intercompany transactions, which it regulated since 1935 predominantly at cost. Jurisdiction over holding company-related activities was transferred to the FERC and the required reporting was reduced by the 2005 PUHCA. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets, mergers with another electric utility or holding company, inter-company transactions, accounting and AEPSC intercompany service billings which are generally at cost. The intercompany sale of non-power goods and non-AEPSC services to affiliates cannot exceed market under the 2005 PUHCA.

Both the FERC and the KPSC are permitted to review and audit the books and records of KPCo.

Accounting for the Effects of Cost-Based Regulation

As a cost-based rate-regulated electric public utility company, KPCo's financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for cost-based rate-regulated operations under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. The depreciation rates that are established for the generating plants take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain the plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets." Equity investments are required to be tested for impairment when it is determined there may be an other than temporary loss in value.

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

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant.

Valuation of Nonderivative Financial Instruments

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

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Inventory

Fossil fuel inventories and materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales or delivery when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, KPCo accrues and recognizes, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable for KPCo. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be removed from KPCo's balance sheet (see "Sale of Receivables - AEP Credit" section of Note 12).

Deferred Fuel Costs

The cost of fuel and related chemical and emission allowance consumables is charged to Fuel and Other Consumables Used for Electric Generation Expense when the fuel is burned or the consumable is utilized. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to customers over fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or billed to customers in later months with the regulator's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of regulators. On a routine basis, state regulatory commissions audit fuel cost calculations. When a fuel cost disallowance becomes probable, KPCo adjusts its deferrals and records provisions for estimated refunds to recognize the probable outcomes. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when the fuel clauses have been suspended or terminated.

In general, changes in fuel costs are reflected in rates in a timely manner through the fuel cost adjustment clause. A portion of profits from off-system sales are shared with customers through the fuel clause.

Revenue Recognition

Regulatory Accounting

The financial statements for cost-based rate-regulated operations reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains or losses that occur due to changes in the fair value of physical and/or financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

When regulatory assets are probable of recovery through regulated rates, KPCo records them as assets on the balance sheet. KPCo tests for probability of recovery whenever new events occur, for example, issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, KPCo writes off that regulatory asset as a charge against earnings.

Traditional Electricity Supply and Delivery Activities

KPCo recognizes revenues from retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues in the financial statements upon delivery of the energy to the customer and includes unbilled as well as billed amounts.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory, and the AEP East companies purchase power back from the same RTO to supply power to KPCo's load. These power sales and purchases are reported on a net basis in Revenues in the Statements of Income.

Physical energy purchases, including those from all RTOs that are identified as non-trading, but excluding PJM purchases described in the preceding paragraph, are accounted for on a gross basis in Purchased Electricity for Resale in the Statements of Income.

KPCo records expenses upon receipt of purchased electricity and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting. KPCo, which operates solely in a jurisdiction where the generation /supply business is subject to cost-based regulation, defers the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

KPCo engages in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where the AEP System owns assets. KPCo's activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. KPCo engages in certain energy marketing and risk management transactions with RTOs.

KPCo recognizes revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. KPCo uses MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or as a normal purchase or sale. The realized gains and losses on wholesale marketing and risk management transactions are included in Revenues in the Statements of Income on a net basis. The unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). KPCo initially records the effective portion of the cash flow hedge's gain or loss as a component of Accumulated Other Comprehensive Income (Loss). When the forecasted transaction is realized and affects earnings, KPCo subsequently reclassifies the gain or loss on the hedge from Accumulated Other Comprehensive Income into revenues or expenses on its Statements of Income, within the same financial statement line item as the forecasted transaction. KPCo defers the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains).

Maintenance

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

Income Taxes and Investment Tax Credits

KPCo uses the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits are accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are amortized over the life of the plant investment.

KPCo accounts for uncertain tax positions in accordance with FIN 48. Effective with the adoption of FIN 48, KPCo classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Other Operation.

Excise Taxes

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

Debt

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

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

Emission Allowances

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

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Components of Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in the common shareholder's equity section. AOCI for KPCo as of December 31, 2007 and 2006 is shown in the following table.

	December 31,	
	2007	**2006**
Components	**(in thousands)**	
Cash Flow Hedges	$ (814)	$ 1,552

Earnings Per Share (EPS)

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

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. These revisions had no impact on KPCo's previously reported results of operations or changes in shareholder's equity.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, management thoroughly reviews the new accounting literature to determine the relevance, if any, to KPCo's business. The following represents a summary of final pronouncements that management has determined relate to KPCo's operations.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It establishes how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. SFAS 141R requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period.

SFAS 141R is effective prospectively for business combinations with an acquisition date on or after the beginning of the first annual reporting period after December 15, 2008. Early adoption is prohibited. KPCo will adopt SFAS 141R effective January 1, 2009 and apply it to any business combinations on or after that date.

SFAS 157 "Fair Value Measurements" (SFAS 157)

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholder's equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy level being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level, an entity include its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. The standard also nullifies the consensus reached in EITF Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) that prohibited the recognition of trading gains or losses at the inception of a derivative contract, unless the fair value of such derivative is supported by observable market data.

In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-1 "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13" which amends SFAS 157 to exclude SFAS 13 "Accounting for Leases" and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13.

In February 2008, the FASB issued FSP FAS 157-2 "Effective Date of FASB Statement No. 157" which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

KPCo partially adopted SFAS 157 effective January 1, 2008. KPCo will adopt SFAS 157 effective January 1, 2009 for items within the scope of FSP FAS 157-2. The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF 02-3, b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, amounts for transition adjustment are recorded to beginning retained earnings. The impact of considering AEP's own credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on KPCo's fair value measurements upon adoption.

SFAS 159 "The Fair Value Option for Financial Assets and Financial Liabilities" (SFAS 159)

In February 2007, the FASB issued SFAS 159, permitting entities to choose to measure many financial instruments and certain other items at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. The statement is applied prospectively upon adoption.

KPCo adopted SFAS 159 effective January 1, 2008. At adoption, KPCo did not elect the fair value option for any assets or liabilities.

SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. It requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

SFAS 160 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. The statement is applied prospectively upon adoption. Early adoption is prohibited. Upon adoption, prior period financial statements will be restated for the presentation of the noncontrolling interest for comparability. Although management has not completed its analysis, management expects that the adoption of this standard will have an immaterial impact on the financial statements. KPCo will adopt SFAS 160 effective January 1, 2009.

EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements" (EITF 06-10)

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 "Employers' Accounting for Postretirement Benefits Other Than Pension" or Accounting Principles Board Opinion No. 12 "Omnibus Opinion – 1967" if the employer has agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a change in accounting principle through a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) a change in accounting principle through retrospective application to all prior periods. KPCo adopted EITF 06-10 effective January 1, 2008 with an immaterial effect on the financial statements.

EITF Issue No. 06-11 "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards" (EITF 06-11)

In June 2007, the FASB ratified the EITF consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, "Share-Based Payments." Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital.

KPCo adopted EITF 06-11 effective January 1, 2008. EITF 06-11 is applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years after September 15, 2007. The adoption of this standard will have an immaterial impact on the financial statements.

FIN 48 "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of Settlement in FASB Interpretation No. 48" (FIN 48)

In July 2006, the FASB issued FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" and in May 2007, the FASB issued FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48." FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. KPCo adopted FIN 48 effective January 1, 2007. The impact of this interpretation was an unfavorable adjustment to retained earnings of $786 thousand.

FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1)

In April 2007, the FASB issued FIN 39-1. It amends FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts" by replacing the interpretation's definition of contracts with the definition of derivative instruments per SFAS 133. It also requires entities that offset fair values of derivatives with the same party under a netting agreement to also net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period.

KPCo adopted FIN 39-1 effective January 1, 2008. This standard changed the method of netting certain balance sheet amounts and reduced assets and liabilities by an immaterial amount. It requires retrospective application as a change in accounting principle for all periods presented.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, liabilities and equity, derivatives disclosures, emission allowances, leases, insurance, subsequent events and related tax impacts. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future results of operations and financial position.

3. RATE MATTERS

KPCo is involved in rate and regulatory proceedings at the FERC and their state commission. This note is a discussion of rate matters and industry restructuring related proceedings that could have a material effect on the results of operations and cash flows.

Kentucky Rate Matters

Validity of Nonstatutory Surcharges

In August 2007, the Franklin Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The Kentucky Attorney General (AG) notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include other existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses. The KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable to KPCo, it is possible that the AG or another intervenor could challenge KPCo's existing surcharges, which are also not specifically authorized by statute. These include KPCo's fuel clause surcharge, annual Rockport Plant capacity surcharge, merger surcredit and off-system sales credit rider. These surcharges are currently producing net annual revenues of approximately $10 million. The KPSC has asked interested parties to brief the issue in KPCo's outstanding fuel cost proceeding. The AG has stated that the KPCo fuel clause should be invalidated because the KPSC lacked the authority to implement a fuel clause for KPCo without a full rate case review. The KPSC has issued an order stating that it has the authority to provide for surcharges and surcredits until the Court of Appeals rules. The appeals process could take up to two years to complete. The AG agreed to stay its challenge during that time. KPCo's exposure is indeterminable at this time since it is not known whether a final adverse appeal could result in a refund of prior amounts collected, which could have an adverse effect on future results of operations and cash flows.

FERC Rate Matters

Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving AEP and ultimately its internal load customers to make up the short fall in revenues. Approximately $10 million of SECA revenues billed by PJM and recognized by the AEP East companies were not collected. The AEP East companies filed a motion with the FERC to force payment of these uncollected SECA billings. KPCo's portion of recognized gross SECA revenues is $17 million.

In August 2006, a FERC ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates was not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount. As a result, SECA ratepayers are engaged with AEP in settlement discussions. Management has been advised by external FERC counsel that it is probable that the FERC will reverse the ALJ's decision as it is contrary to two prior FERC decisions and lacks merit.

In 2006, the AEP East companies provided reserves of $37 million for net refunds for current and future SECA settlements. After reviewing existing settlements, the AEP East companies increased their reserves by an additional $5 million in December 2007. KPCo provided reserves of $0.4 million and $3.0 million in 2007 and 2006, respectively. The AEP East companies have reached settlements related to approximately $69 million of the $220 million of SECA revenues for a net refund of $3 million. The AEP East companies are also in the process of completing two settlements-in-principle on an additional $36 million of SECA revenues and expect to make net refunds of $4 million when those settlements are approved. Thus, completed and in-process settlements cover $105 million of SECA revenues and cover about $7 million of the reserve for refund, leaving approximately $115 million of contested SECA revenues and $35 million of refund reserves. However, if the ALJ's initial decision was upheld in its entirety, it could result in a disallowance of approximately $90 million of the AEP East companies' remaining $115 million of unsettled gross SECA revenues. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the remaining reserve of $35 million is adequate to cover all remaining settlements and any uncollectible amounts. KPCo's portion of the reserve is $3 million.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. As directed by the FERC, management is working to settle the remaining $115 million of unsettled revenues within the remaining reserve balance. Although management believes it has meritorious arguments and can settle with the remaining customers within the amount provided, management cannot predict the ultimate outcome of ongoing settlement talks and, if necessary, any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision and/or AEP cannot settle a significant portion of the remaining unsettled claims within the amount provided, it will have an adverse effect on future results of operations and cash flows.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates and the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM will be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them. AEP had requested rehearing of this order which the FERC denied. Management expects to file an appeal. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies' future construction of new transmission facilities, results of operations and cash flows.

The AEP East companies increased their retail rates in Ohio, Virginia, West Virginia and Kentucky to recover lost T&O and SECA revenues. The AEP East companies are presently recovering from retail customers, approximately 85% of the lost T&O/SECA transmission revenues of $128 million a year.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, voted to continue zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argues the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. Management expects to file for rehearing. Should this effort be successful, KPCo would reduce future retail rates in fuel or base rate proceedings. Management is unable to predict the outcome of this case.

PJM Marginal-Loss Pricing

In June 2007, in response to a 2006 FERC order, PJM revised its methodology for considering transmission line losses in generation dispatch and the calculation of locational marginal prices. Marginal-loss dispatch recognizes the varying delivery costs of transmitting electricity from individual generator locations to the places where customers consume the energy. Prior to the implementation of marginal-loss dispatch, PJM used average losses in dispatch and in the calculation of locational marginal prices. Locational marginal prices in PJM now include the real-time impact of transmission losses from individual sources to loads.

Due to the implementation of marginal-loss pricing, for the period June 1, 2007 through December 31, 2007, AEP experienced an increase in the cost of delivering energy from its generating plants to customer load zones, which was partially offset by cost recoveries. Management believes these additional costs should be recoverable through retail and/or cost-based wholesale rates and plans to seek recovery. KPCo's incremental PJM billings for the period June through December 2007 were $7 million. In the interim, the incremental PJM billings will continue to have an adverse effect on results of operations and cash flows. Management is unable to predict whether recovery will ultimately be approved.

AEP has initiated discussions with PJM regarding the impact it is experiencing from the change in methodology and will pursue a modification of such methodology through the appropriate PJM stakeholder processes.

Allocation of Off-system Sales Margins

In August 2007, the OCC issued an order adopting the ALJ's recommendation that the allocation of system sales/trading margins is a FERC jurisdictional issue. In October 2007, the OCC orally directed the OCC staff to explore filing a complaint at FERC alleging the allocation of off-system sales margins to PSO is improper.

In December 2007, some cities served by TNC requested the PUCT to initiate, or order TNC to initiate a proceeding at the FERC to determine if TNC misapplied its tariff. In January 2008, TNC filed a response with the PUCT recommending the cities' request be denied.

To date, no claim has been asserted at the FERC. Although management cannot predict if a complaint will be filed at the FERC, management believes the allocations were in accordance with the then-existing FERC-approved allocation agreement and additional off-system sales margins should not be retroactively reallocated to the AEP West companies. A reallocation of off-system sales margins from the AEP East companies to the AEP West companies could result in an adverse effect on future results of operations and cash flows for KPCo.

4. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2007	December 31, 2006	Notes
Regulatory Assets:	(in thousands)		
Total Current Regulatory Assets –			
Under-recovered Fuel Costs (g)	$ 4,426	$ 1,042	(a) (f)
SFAS 109 Regulatory Asset, Net	$ 101,340	$ 100,439	(a) (d)
SFAS 158 Regulatory Asset (Note 7)	13,573	24,375	(a) (d)
Other	9,915	11,325	(b) (d)
Total Noncurrent Regulatory Assets	$ 124,828	$ 136,139	
Regulatory Liabilities:			
Asset Removal Costs	$ 33,106	$ 31,165	(c)
Deferred Investment Tax Credits	3,395	4,356	(a) (e)
Other	9,933	13,588	(a) (d)
Total Noncurrent Regulatory Liabilities	$ 46,434	$ 49,109	

(a) Amount does not earn a return.
(b) Includes items both earning and not earning a return.
(c) The liability for removal costs, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
(d) Recovery/refund period – various periods.
(e) Recovery/refund period – up to 12 years.
(f) Recovery/refund period – 1 year.
(g) Current Regulatory Asset – Under-recovered Fuel Costs are recorded in Prepayments and Other on KPCo's Balance Sheets.

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. The key provision of the merger rate agreement was a rate reduction starting the third quarter 2000 through 2007 of $3.5 million per year in Kentucky. Rates will remain in effect until KPCo changes base rates. KPCo will file for new base rates in Kentucky when appropriate.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements.

Insurance and Potential Losses

KPCo maintains insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. The insurance includes coverage for all risks of physical loss or damage to assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. KPCo's insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of KPCo's retentions. Coverage is generally provided by a combination of a South Carolina domiciled protected-cell captive insurance company together with and/or in addition to various industry mutual and commercial insurance carriers.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

COMMITMENTS

KPCo has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, KPCo contractually commits to third-party construction vendors for certain material purchases and other construction services. Aggregate construction expenditures for 2008 through 2010 are estimated at approximately $360.4 million. The amounts for 2008, 2009 and 2010 are $126.8 million, $104.6 million and $129 million, respectively. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital.

KPCo enters into long-term contracts to acquire fuel for electric generation and transport it to its facilities. The longest contract extends to the year 2013. The contracts provide for periodic price adjustments and contain various clauses that would release KPCo from its obligations under certain conditions.

KPCo purchases materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination. KPCo does not expect to incur penalty payments under these provisions that would materially affect results of operations, cash flows or financial condition.

GUARANTEES

There are certain immaterial liabilities recorded for guarantees in accordance with FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

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. Prior to December 31, 2007 KPCo entered into sale agreements including indemnifications with a maximum exposure that was not significant. There are no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

Master Operating Lease

KPCo leases certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance. Assuming the fair market value of the equipment is zero at the end of the lease term, the maximum potential loss for these lease agreements was approximately $2 million as of December 31, 2007.

CONTINGENCIES

Environmental Settlement

In 1999, the Federal EPA, a number of states and certain special interest groups filed complaints alleging that certain of KPCo's affiliates including APCo, CSPCo, I&M and OPCo modified units at certain of their coal-fired generating plants in violation of the New Source Review (NSR) requirements of the CAA. The alleged modifications occurred at the AEP System's generating units over a 20-year period.

As part of a global consent decree covering all coal-fired units in the five eastern states of the AEP System to resolve all past NSR allegations and secure a covenant not to sue for future claims from the Federal EPA, KPCo agreed to complete previously announced flue gas desulfurization emissions control equipment (scrubbers) on Unit 2 of the Big Sandy Plant by December 2015. The obligation to pay a $15 million civil penalty and provide $36 million for environmental mitigation projects coordinated with the federal government and $24 million to the states for environmental mitigation was shared by members of the AEP Power Pool. Under the consent decree, KPCo recorded its share of the costs of $5.2 million in Other Operation during the third quarter of 2007.

Management believes KPCo can recover any capital and operating costs of additional pollution control equipment that may be required as a result of the consent decree through regulated rates or market prices of electricity. If KPCo is unable to recover such costs, it would adversely affect KPCo's future results of operations, cash flows and possibly financial condition.

Carbon Dioxide (CO_2) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The defendants' motion to dismiss the lawsuits was granted in September 2005. The dismissal was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. On April 2, 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case. Management believes the actions are without merit and intends to defend against the claims.

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

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

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2007, there is one site for which KPCo has received an information request which could lead to a Potentially Responsible Party designation. In the instance where KPCo has been named a defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on results of operations.

KPCo evaluates the potential liability for each Superfund site separately, but several general statements can be made regarding potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named for each site and several of the parties are financially sound enterprises. At present, management's estimates do not anticipate material cleanup costs for identified sites.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that KPCo and certain other AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed and the U.S. Supreme Court decided that it will review the Ninth Circuit's decision in 2008. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. Management asserted claims against certain companies that sold power to KPCo and certain other AEP subsidiaries, which was resold to the Nevada utilities, seeking to recover a portion of any amounts that may be owed to the Nevada utilities.

6. COMPANY-WIDE STAFFING AND BUDGET REVIEW

KPCo recorded $1.1 million of severance benefits expense in 2005 (primarily in Other Operation and Maintenance) resulting from a company-wide staffing and budget review, including the allocation of approximately $19.2 million of severance benefits expense associated with AEPSC employees. Payments and accrual adjustments recorded during 2006 were immaterial and were settled by June 30, 2006.

7. BENEFIT PLANS

KPCo participates in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. KPCo participates in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

KPCo adopted SFAS 158 as of December 31, 2006. It requires employers to fully recognize the obligations associated with defined benefit pension plans and OPEB plans, which include retiree healthcare, in their balance sheets. Previous standards required an employer to disclose the complete funded status of its plan only in the notes to the financial statements and provided that an employer delay recognition of certain changes in plan assets and obligations that affected the costs of providing benefits resulting in an asset or liability that often differed from the plan's funded status. SFAS 158 requires a defined benefit pension or postretirement plan sponsor to (a) recognize in its statement of financial position an asset for a plan's overfunded status or a liability for the plan's underfunded status, (b) measure the plan's assets and obligations that determine its funded status as of the end of the employer's fiscal year and (c) recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year but are not recognized as a component of net periodic benefit cost pursuant to previous standards. It also requires an employer to disclose additional information on how delayed recognition of certain changes in the funded status of a defined benefit pension or OPEB plan affects net periodic benefit costs for the next fiscal year. KPCo recorded a SFAS 71 regulatory asset of $24.4 million for qualifying SFAS 158 costs of regulated operations that for ratemaking purposes will be deferred for future recovery. The effect of this standard on the 2006 financial statements was a pretax AOCI adjustment that was fully offset by a SFAS 71 regulatory asset.

SFAS 158 requires adjustment of pretax AOCI at the end of each year, for both underfunded and overfunded defined benefit pension and OPEB plans, to an amount equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction and deferred gains result in an AOCI equity addition. The year-end AOCI measure can be volatile based on fluctuating investment returns and discount rates.

The following tables provide a reconciliation of the changes in projected benefit obligations and fair value of assets for AEP's plans over the two-year period ending at the plan's measurement date of December 31, 2007, and their funded status as of December 31 for each year:

Projected Pension Obligations, Plan Assets, Funded Status as of December 31, 2007 and 2006

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
	(in millions)			
Change in Projected Benefit Obligation				
Projected Obligation at January 1	$ 4,108	$ 4,347	$ 1,818	$ 1,831
Service Cost	96	97	42	39
Interest Cost	235	231	104	102
Actuarial Gain	(64)	(293)	(91)	(55)
Plan Amendments	18	2	-	-
Benefit Payments	(284)	(276)	(130)	(112)
Participant Contributions	-	-	22	21
Medicare Subsidy	-	-	8	(8)
Projected Obligation at December 31	$ 4,109	$ 4,108	$ 1,773	$ 1,818
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 4,346	$ 4,143	$ 1,302	$ 1,172
Actual Return on Plan Assets	435	470	115	127
Company Contributions	7	9	91	94
Participant Contributions	-	-	22	21
Benefit Payments	(284)	(276)	(130)	(112)
Fair Value of Plan Assets at December 31	$ 4,504	$ 4,346	$ 1,400	$ 1,302
Funded (Underfunded) Status at December 31	$ 395	$ 238	$ (373)	$ (516)

Amounts Recognized on AEP's Balance Sheets as of December 31, 2007 and 2006

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 482	$ 320	$ -	$ -
Other Current Liabilities – Accrued Short-term Benefit Liability	(8)	(8)	(4)	(5)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(79)	(74)	(369)	(511)
Funded (Underfunded) Status	$ 395	$ 238	$ (373)	$ (516)

SFAS 158 Amounts Recognized in AEP's Accumulated Other Comprehensive Income (AOCI) as of December 31, 2007 and 2006

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
Components	(in millions)			
Net Actuarial Loss	$ 534	$ 759	$ 231	$ 354
Prior Service Cost (Credit)	14	(5)	4	4
Transition Obligation	-	-	97	124
Pretax AOCI	$ 548	$ 754	$ 332	$ 482
Recorded as				
Regulatory Assets	$ 453	$ 582	$ 204	$ 293
Deferred Income Taxes	33	60	45	66
Net of Tax AOCI	62	112	83	123
Pretax AOCI	$ 548	$ 754	$ 332	$ 482

Components of the Change in AEP's Plan Assets and Benefit Obligations Recognized in Pretax AOCI during the year ended December 31, 2007 are as follows:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
2007 Actuarial Gain	$ (166)	$ (111)
Amortization of Actuarial Loss	(59)	(12)
2007 Prior Service Cost	19	-
Amortization of Transition Obligation	-	(27)
Total 2007 Pretax AOCI Change	$ (206)	$ (150)

Pension and Other Postretirement Plans' Assets

The asset allocations for AEP's pension plans at the end of 2007 and 2006, and the target allocation for 2008, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
Asset Category	2008	2007	2006
Equity Securities	55%	57%	63%
Real Estate	5%	6%	6%
Debt Securities	39%	36%	26%
Cash and Cash Equivalents	1%	1%	5%
Total	100%	100%	100%

The asset allocations for AEP's other postretirement benefit plans at the end of 2007 and 2006, and target allocation for 2008, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
Asset Category	**2008**	**2007**	**2006**
Equity Securities	66%	62%	66%
Debt Securities	33%	35%	32%
Cash and Cash Equivalents	1%	3%	2%
Total	100%	100%	100%

AEP's investment strategy for the employee benefit trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the plans' assets relative to the plans' liabilities. To minimize investment risk, AEP's employee benefit trust funds are broadly diversified among classes of assets, investment strategies and investment managers. AEP regularly reviews the actual asset allocation and periodically rebalances the investments to AEP's targeted allocation when considered appropriate. AEP's investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investment policies prohibit investment in AEP securities, with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies.

The value of the pension plans' assets increased to $4.5 billion at December 31, 2007 from $4.3 billion at December 31, 2006. The qualified plans paid $277 million in benefits to plan participants during 2007 (nonqualified plans paid $7 million in benefits). The value of AEP's Postretirement Plans' assets increased to $1.4 billion in December 31, 2007 from $1.3 billion at December 31, 2006. The Postretirement Plans paid $130 million in benefits to plan participants during 2007.

AEP bases the determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

	December 31, 2007	December 31, 2006
Accumulated Benefit Obligation	(in millions)	
Qualified Pension Plans	$ 3,914	$ 3,861
Nonqualified Pension Plans	77	78
Total	$ 3,991	$ 3,939

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets of these plans at December 31, 2007 and 2006 were as follows:

	Underfunded Pension Plans December 31, 2007	Underfunded Pension Plans December 31, 2006
	(in millions)	
Projected Benefit Obligation	$ 81	$ 82
Accumulated Benefit Obligation	$ 77	$ 78
Fair Value of Plan Assets	-	-
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	$ 77	$ 78

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31, used in the measurement of AEP's benefit obligations are shown in the following tables:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2007**	**2006**	**2007**	**2006**
Discount Rate	6.00%	5.75%	6.20%	5.85%
Rate of Compensation Increase	5.90%(a)	5.90%(a)	N/A	N/A

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

N/A = Not Applicable

To determine a discount rate, AEP uses a duration-based method by constructing a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2007, the rate of compensation increase assumed varies with the age of the employee, ranging from 5% per year to 11.5% per year, with an average increase of 5.9%.

Estimated Future Benefit Payments and Contributions

Information about the 2008 expected cash flows for the pension (qualified and nonqualified) and other postretirement benefit plans is as follows:

Employer Contributions	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Required Contributions (a)	$ 8	$ 4
Additional Discretionary Contributions	-	73

(a) Contribution required to meet minimum funding requirement per the U.S. Department of Labor plus direct payments for unfunded benefits.

The contribution to the pension plans is based on the minimum amount required by the U.S. Department of Labor and the amount to pay unfunded nonqualified benefits. The contribution to the other postretirement benefit plans is generally based on the amount of the other postretirement benefit plans' periodic benefit cost for accounting purposes as provided for in agreements with state regulatory authorities, plus the additional discretionary contribution of AEP's Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from the employer's assets, including both the employer's share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates, and variances in actuarial results. The estimated payments for AEP's pension benefits and other postretirement benefits are as follows:

	Pension Plans	**Other Postretirement Benefit Plans**	
	Pension Payments	**Benefit Payments**	**Medicare Subsidy Receipts**
		(in millions)	
2008	$ 356	$ 111	$ (10)
2009	362	121	(11)
2010	363	131	(11)
2011	363	141	(12)
2012	368	149	(13)
Years 2013 to 2017, in Total	1,861	864	(82)

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost for the plans for fiscal years 2007, 2006 and 2005:

	Pension Plans			**Other Postretirement Benefit Plans**		
	Years Ended December 31,					
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
			(in millions)			
Service Cost	$ 96	$ 97	$ 93	$ 42	$ 39	$ 42
Interest Cost	235	231	228	104	102	107
Expected Return on Plan Assets	(340)	(335)	(314)	(104)	(94)	(92)
Amortization of Transition Obligation	-	-	-	27	27	27
Amortization of Prior Service Cost (Credit)	-	(1)	(1)	-	-	-
Amortization of Net Actuarial Loss	59	79	55	12	22	25
Net Periodic Benefit Cost	50	71	61	81	96	109
Capitalized Portion	(14)	(21)	(17)	(25)	(27)	(33)
Net Periodic Benefit Cost Recognized as Expense	$ 36	$ 50	$ 44	$ 56	$ 69	$ 76

Estimated amounts expected to be amortized to net periodic benefit costs from AEP's pretax accumulated other comprehensive income during 2008 are shown in the following table:

	Pension Plans	**Other Postretirement Benefit Plans**
	(in millions)	
Net Actuarial Loss	$ 26	$ 5
Prior Service Cost	1	1
Transition Obligation	-	27
Total Estimated 2008 Pretax AOCI Amortization	$ 27	$ 33

The following table provides KPCo's net periodic benefit cost for the plans for the years ended December 31, 2007, 2006 and 2005:

	Pension Plans			**Other Postretirement Benefit Plans**		
	Years Ended December 31,					
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
			(in thousands)			
Benefit Costs	$ 1,018	$ 1,435	$ 1,506	$ 1,706	$ 2,050	$ 2,204

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1, used in the measurement of AEP's benefit costs are shown in the following tables:

	Pension Plans			Other Postretirement Benefit Plans		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
Discount Rate	5.75%	5.50%	5.50%	5.85%	5.65%	5.80%
Expected Return on Plan Assets	8.50%	8.50%	8.75%	8.00%	8.00%	8.37%
Rate of Compensation Increase	5.90%	5.90%	3.70%	N/A	N/A	N/A

N/A = Not Applicable

The expected return on plan assets for 2007 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, and current prospects for economic growth.

The health care trend rate assumptions as of January 1, used for other postretirement benefit plans measurement purposes are shown below:

Health Care Trend Rates	2007	2006
Initial	7.5%	8.0%
Ultimate	5.0%	5.0%
Year Ultimate Reached	2012	2009

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

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 19	$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	185	(154)

AEP Savings Plan

KPCo participates in an AEP sponsored defined contribution retirement savings plans for substantially all employees. These plans offer participants an opportunity to contribute a portion of their pay, include features under Section 401(k) of the Internal Revenue Code and provide for company matching contributions. The matching contributions to the plan are 75% of the first 6% of eligible compensation contributed by the employee. The cost for contributions to these plans totaled $1.4 million in 2007, $1.3 million in 2006 and $1.2 million in 2005.

8. BUSINESS SEGMENTS

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

9. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the statement of financial position 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 and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the influence that imperfections in marketplace transparency may cause pricing to be less than or more than what the price should be based purely on supply and demand. Because energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with the approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in the Statements of Income on an accrual basis.

KPCo's accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, KPCo designates a hedging instrument as a fair value hedge or cash flow hedge. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), KPCo recognizes the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in earnings. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), KPCo initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) until the period the hedged item affects earnings. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

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. Realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in KPCo's Statements of Income. Realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the Statements of Income depending on the relevant facts and circumstances. Unrealized MTM gains and losses are recorded as regulatory assets (for losses) and regulatory liabilities (for gains).

Fair Value Hedging Strategies

At certain times, KPCo enters into interest rate derivative transactions in order to manage interest rate risk exposure. These interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. KPCo records gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as offsetting changes in the fair value of the debt being hedged, in Interest Expense on the statements of income. During 2007, 2006 and 2005, KPCo recognized no hedge ineffectiveness related to these derivative transactions.

Cash Flow Hedging Strategies

KPCo enters into, and designates as cash flow hedges, certain derivative transactions for the purchase and sale of electricity and natural gas in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. At various times during 2007, 2006 and 2005, KPCo designated cash flow hedge relationships using these commodities. Management closely monitors the potential impacts of commodity price changes, and where appropriate, enters into derivative transactions to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues or fuel expense, depending on the specific nature of the risk being hedged. KPCo does not hedge all variable price risk exposure related to energy commodities. During 2007, 2006 and 2005, KPCo recognized immaterial amounts related to hedge ineffectiveness. However, there was no earnings impact because KPCo operates in a regulated jurisdiction.

KPCo enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo enters into various derivative instruments to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated debt offerings have a high probability of occurrence because the proceeds will be used to fund existing debt maturities as well as fund projected capital expenditures. At various times during 2007, 2006 and 2005, KPCo designated interest rate derivatives as cash flow hedges. KPCo reclassifies gains and losses on the hedges from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which the interest payments being hedged occur. During 2007, 2006 and 2005, KPCo recognized immaterial amounts related to hedge ineffectiveness. However, there was no earnings impact because KPCo operates in a regulated jurisdiction.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges for the years 2005, 2006 and 2007:

	(in thousands)
Balance at December 31, 2004	$ 813
Effective portion of changes in fair value	81
Reclasses from AOCI to Net Income	(1,088)
Balance at December 31, 2005	(194)
Effective portion of changes in fair value	1,496
Impact Due to Changes in SIA	(106)
Reclasses from AOCI to Net Income	356
Balance at December 31, 2006	1,552
Effective portion of changes in fair value	(1,061)
Reclasses from AOCI to Net Income	(1,305)
Balance at December 31, 2007	$ (814)

The following table approximates net loss (gain) from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2007 that are expected to be reclassified to net income in the next twelve months as the items being hedged settle. In addition, the following table summarizes the maximum length of time that the variability of future cash flows is being hedged. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes.

Company	Portion Expected to be Reclassified to Earnings During the Next Twelve Months (in thousands)	Maximum Term for Exposure to Variability of Future Cash Flow (in months)
KPCo	$ (302)	$ 17

FINANCIAL INSTRUMENTS

The fair values of Long-term Debt are based on quoted market prices for the same or similar issues and the current interest rates offered for instruments with similar maturities. 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 significant financial instruments for KPCo at December 31, 2007 and 2006 are summarized in the following table.

	December 31,			
	2007		2006	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 448,373	$ 442,090	$ 446,968	$ 440,839

10. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31,		
	2007	2006	2005
	(in thousands)		
Income Tax Expense (Credit):			
Current	$ 11,258	$ 17,203	$ 2,803
Deferred	5,691	2,596	10,555
Deferred Investment Tax Credits	(962)	(1,144)	(1,222)
Total Income Tax	$ 15,987	$ 18,655	$ 12,136

Shown below is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory rate and the amount of income taxes reported.

	Years Ended December 31,		
	2007	2006	2005
	(in thousands)		
Net Income	$ 32,470	$ 35,035	$ 20,809
Income Taxes	15,987	18,655	12,136
Pretax Income	$ 48,457	$ 53,690	$ 32,945
Income Tax on Pretax Income at Statutory Rate (35%)	$ 16,960	$ 18,791	$ 11,531
Increase (Decrease) in Income Tax resulting from the following items:			
Depreciation	1,223	1,669	1,644
Allowance for Funds Used During Construction	(661)	(606)	(614)
Removal Costs	(1,766)	(1,361)	(995)
Investment Tax Credits, Net	(962)	(1,144)	(1,222)
State and Local Income Taxes	736	1,070	778
Other	457	236	1,014
Total Income Taxes	$ 15,987	$ 18,655	$ 12,136
Effective Income Tax Rate	33.0%	34.7%	36.8%

The following table shows the elements of the net deferred tax liability and the significant temporary differences:

	December 31, 2007	December 31, 2006
	(in thousands)	
Deferred Tax Assets	$ 35,037	$ 38,454
Deferred Tax Liabilities	(280,667)	(280,587)
Net Deferred Tax Liabilities	$ (245,630)	$ (242,133)
Property Related Temporary Differences	$ (188,213)	$ (180,662)
Amounts Due From Customers For Future Federal Income Taxes	(25,794)	(24,888)
Deferred State Income Taxes	(27,325)	(29,331)
Deferred Income Taxes on Other Comprehensive Loss	438	(836)
Deferred Fuel and Purchased Power	(1,617)	(410)
Accrued Pensions	(3,521)	(1,665)
All Other, Net	402	(4,341)
Net Deferred Tax Liabilities	$ (245,630)	$ (242,133)

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

KPCo and other AEP Subsidiaries are no longer subject to U.S. federal examination for years before 2000. However, KPCo and other AEP Subsidiaries have filed refund claims with the IRS for years 1997 through 2000 for the CSW pre-merger tax period, which are currently being reviewed. KPCo and other AEP Subsidiaries have completed the exam for the years 2001 through 2003 and have issues that will be pursued at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

KPCo, along with other AEP Subsidiaries, files income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and KPCo and other AEP Subsidiaries are currently under examination in several state and local jurisdictions. Management believes that KPCo and other AEP Subsidiaries have filed tax returns with positions that may be challenged by these tax authorities. However, management does not believe that the ultimate resolution of these audits will materially impact results of operations. With few exceptions, KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2000.

Prior to the adoption of FIN 48, KPCo recorded interest and penalty expense related to uncertain tax positions in tax expense accounts. With the adoption of FIN 48, KPCo began recognizing interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation. In 2007, KPCo reported $300 thousand of interest expense and reversed $900 thousand of prior period interest expense. KPCo had approximately $1.3 million and $1.4 million for the payment of interest and penalties accrued at December 31, 2007 and 2006, respectively.

As a result of the implementation of FIN 48 on January 1, 2007, KPCo recognized a $786 thousand increase in the liabilities for unrecognized tax benefits, as well as related interest expense and penalties, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings.

As of December 31, 2007, the reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

		(in millions)
Balance at January 1, 2007	$	3.4
Increase - Tax Positions Taken During a Prior Period		-
Decrease - Tax Positions Taken During a Prior Period		(1.8)
Increase - Tax Positions Taken During the Current Year		0.6
Decrease - Settlements with Taxing Authorities		-
Decrease - Lapse of the Applicable Statute of Limitations		-
Balance at December 31, 2007	$	2.2

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $900 thousand. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

In 2005, the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of IGCC plants. The credit is 20% of the eligible property in the construction of new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC plant, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. AEP announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. AEP filed applications for the Mountaineer and Great Bend projects with the DOE and the IRS. Both projects were certified by the DOE and qualified by the IRS. However, neither project was awarded credits during this round of credit awards. AEP will continue to pursue credits for the next round of available credits.

The Tax Increase Prevention and Reconciliation Act of 2005 (TIPRA 2005) was passed May 17, 2006. The majority of the provisions in TIPRA 2005 were directed toward individual income tax relief including the extension of reduced tax rates for dividends and capital gains through 2010. Management believes the application of this act will not materially affect KPCo's results of operations, cash flow or financial condition.

The President signed the Pension Protection Act of 2006 (PPA 2006) into law on August 17, 2006. This law is directed toward strengthening qualified retirement plans and adding new restrictions on charitable contributions. Specifically, PPA 2006 concentrates on the funding of defined benefit plans and the health of the Pension Benefit Guaranty Corporation. PPA 2006 imposes new minimum funding rules for multiemployer plans as well as increasing the deduction limitation for contributions to multiemployer defined benefit plans. Due to the significant funding of the AEP pension plans in 2005, the Act will not materially affect KPCo's results of operations, cash flows or financial condition.

On December 20, 2006, the Tax Relief and Health Care Act of 2006 (TRHCA 2006) was signed into law. The primary purpose of the bill was to extend expiring tax provisions for individuals and business taxpayers and provide increased tax flexibility around medical benefits. In addition to extending the lower capital gains and dividend tax rates for individuals, TRHCA 2006 extended the research credit and for 2007 provided a new alternative formula for determining the research credit. The application of TRHCA 2006 is not expected to materially affect KPCo's results of operations, cash flows or financial condition.

Several tax bills and other legislation with tax-related sections were enacted in 2007, including the Tax Technical Corrections Act of 2007, the Tax Increase Prevention Act of 2007 and the Energy Independence and Security Act of 2007. The tax law changes enacted in 2007 are not expected to materially affect KPCo's results of operations, cash flows or financial condition.

State Tax Legislation

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, KPCo reversed $3.6 million of SFAS 109 Regulatory Assets and deferred state income tax liabilities that are not expected to reverse during the phase-out.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax is being phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate.

On July 12, 2007, the Governor of Michigan signed Michigan Senate Bill 0094 (MBT Act) and related companion bills into law providing a comprehensive restructuring of Michigan's principal business tax. The new law is effective January 1, 2008 and replaces the Michigan Single Business Tax that expired at the end of 2007. The MBT Act is composed of a new tax which will be calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The new law also includes significant credits for engaging in Michigan-based activity.

On September 30, 2007, the Governor of Michigan signed House Bill 5198 which amends the MBT Act to provide for a new deduction on the BIT and GRT tax returns equal to the book-tax basis difference triggered as a result of the enactment of the MBT Act. This new state-only temporary difference will be deducted over a 15 year period on the MBT Act tax returns starting in 2015. The purpose of the new MBT Act state deduction was to provide companies relief from the recordation of the SFAS 109 Income Tax Liability. KPCo has evaluated the impact of the MBT Act and the application of the MBT Act will not materially affect its results of operations, cash flows or financial condition.

11. LEASES

Leases of property, plant and equipment are for periods up to 20 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. The components of rental costs are as follows:

	Years Ended December 31,		
	2007	2006	2005
Lease Rental Costs		(in thousands)	
Net Lease Expense on Operating Leases	$ 2,405	$ 2,079	$ 1,735
Amortization of Capital Leases	1,141	1,207	1,519
Interest on Capital Leases	140	116	34
Total Lease Rental Costs	$ 3,686	$ 3,402	$ 3,288

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

	December 31, 2007	December 31, 2006
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 22	$ 436
Other	5,261	6,723
Total Property, Plant and Equipment Under Capital Leases	5,283	7,159
Accumulated Amortization	3,039	4,512
Net Property, Plant and Equipment Under Capital Leases	**$ 2,244**	**$ 2,647**
Obligations Under Capital Leases		
Noncurrent Liability	$ 1,272	$ 1,493
Liability Due Within One Year	972	1,154
Total Obligations Under Capital Leases	**$ 2,244**	**$ 2,647**

Future minimum lease payments consisted of the following at December 31, 2007:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2008	$ 1,056	$ 2,463
2009	647	2,218
2010	407	2,069
2011	180	1,667
2012	85	1,223
Later Years	58	2,933
Total Future Minimum Lease Payments	**$ 2,433**	**$ 12,573**
Less Estimated Interest Element	189	
Estimated Present Value of Future Minimum Lease Payments	**$ 2,244**	

12. FINANCING ACTIVITIES

Long-term Debt

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

The following details long-term debt outstanding as of December 31, 2007 and 2006:

Type of Debt	Maturity	Interest Rates at December 31, 2007	Interest Rates at December 31, 2006	December 31, 2007	December 31, 2006
				(in thousands)	
Senior Unsecured Notes, Series B	2007	-	4.3148%	-	80,400
Senior Unsecured Notes, Series C	2007	-	4.368%	-	69,564
Senior Unsecured Notes, Series A	2007	-	5.50%	-	125,000
Senior Unsecured Medium Term Notes, Series A	2007	-	6.91%	-	48,000
Senior Unsecured Medium Term Notes, Series A	2008	6.45%	6.45%	30,000	30,000
Senior Unsecured Notes, Series E	2017	6.00%	-	325,000	-
Senior Unsecured Notes, Series D	2032	5.625%	5.625%	75,000	75,000
MTM of Fair Value Hedge				-	(916)
Unamortized Premium (Discount)				(1,627)	(80)
Total Senior Unsecured Notes				428,373	426,968
Notes Payable – Affiliated	2015	5.25%	5.25%	20,000	20,000
Total Notes Payable – Affiliated				20,000	20,000
Total Long-term Debt				448,373	446,968
Less: Long-term Debt Due Within One Year				30,000	322,048
Long-term Debt				$ 418,373	$ 124,920

At December 31, 2007 future annual long-term debt payments are as follows:

	2008	2009	2010	2011	2012	After 2012	Total
				(in thousands)			
Principal Amount	$ 30,000	$ -	$ -	$ -	$ -	$ 420,000	$ 450,000
Unamortized Discount							(1,627)
Total Long-term Debt							$ 448,373

Lines of Credit – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of December 31, 2007 and 2006 are included in Advances to/from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2007 and 2006 are described in the following table:

Year	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
				(in thousands)		
2007	$ 164,913	$ 181,970	$ 59,104	$ 115,727	$ 19,153	$ 250,000
2006	46,156	11,993	25,994	4,384	30,636	200,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the years ended December 31, 2007, 2006 and 2005 are summarized in the following table:

Year Ended December 31,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rates for Funds Borrowed from the Utility Money Pool	Average Interest Rates for Funds Loaned to the Utility Money Pool
2007	5.92%	5.29%	5.94%	5.16%	5.50%	5.58 %
2006	5.41%	3.32%	5.12%	4.19%	4.74%	4.97 %
2005	4.49%	2.68%	4.45%	1.63%	3.70%	2.70 %

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest Income, respectively, in KPCo's Statements of Income. For amounts borrowed from and advanced to the Utility Money Pool, KPCo incurred the following amounts of interest expense and earned the following amounts of interest income, respectively, for the years ended December 31, 2007, 2006 and 2005:

	Years Ended December 31,		
	2007	2006	2005
		(in thousands)	
Interest Expense	$ 2,494	$ 1,065	$ 18
Interest Income	1,614	30	287

Dividend Restrictions

Under the Federal Power Act, KPCo is restricted from paying dividends out of stated capital.

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities," allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and is not required to consolidate these entities in accordance with GAAP. AEP Credit continues to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate AEP Credit's cash collections.

In October 2007, AEP renewed AEP Credit's sale of receivables agreement. The sale of receivables agreement provides a commitment of $650 million from banks and commercial paper conduits to purchase receivables from AEP Credit. Under the agreement, the commitment will increase to $700 million for the months of August and September to accommodate seasonal demand. This agreement will expire in October 2008. AEP intends to extend or replace the sale of receivables agreement. The previous sale of receivables agreement, which expired in August 2007 and was extended until October 2007, provided a commitment of $600 million from a bank conduit to purchase receivables from AEP Credit. At December 31, 2007, $507 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts. AEP Credit purchases accounts receivable through a purchase agreement with KPCo.

Comparative accounts receivable information for AEP Credit is as follows:

	Years Ended December 31, 2007	2006	2005
	($ in millions)		
Proceeds from Sale of Accounts Receivable	$ 6,970	$ 6,849	$ 5,925
Loss on Sale of Accounts Receivable	$ 33	$ 31	$ 18
Average Variable Discount Rate	5.39%	5.02%	3.23%

	December 31, 2007	2006
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 71	$ 87
Deferred Revenue from Servicing Accounts Receivable	1	1
Retained Interest if 10% Adverse Change in Uncollectible Accounts	68	85
Retained Interest if 20% Adverse Change in Uncollectible Accounts	66	83

Historical loss and delinquency amounts for the AEP System's customer accounts receivable managed portfolio is as follows:

	December 31, 2007	2006
	(in millions)	
Customer Accounts Receivable Retained	$ 730	$ 676
Accrued Unbilled Revenues Retained	379	350
Miscellaneous Accounts Receivable Retained	60	44
Allowance for Uncollectible Accounts Retained	(52)	(30)
Total Net Balance Sheet Accounts Receivable	1,117	1,040
Customer Accounts Receivable Securitized	507	536
Total Accounts Receivable Managed	$ 1,624	$ 1,576
Net Uncollectible Accounts Written Off	$ 24	$ 31

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were $30 million and $29 million at December 31, 2007 and 2006, respectively. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

Under the factoring 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 financing costs, its uncollectible accounts experience receivables and administrative costs. The costs of factoring customer accounts receivable are reported in Other Operation of the KPCo's Statements of Income.

KPCo's factored accounts receivable and accrued unbilled revenues were $41.4 million and $44 million as of December 31, 2007 and 2006, respectively.

KPCo paid fees to AEP Credit for factoring customer accounts receivable of $3.8 million, $3.4 million and $2.9 million for the years ended December 31, 2007, 2006 and 2005, respectively.

13. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Lines of Credit – AEP System" and "Sale of Receivables-AEP Credit" sections of Note 12.

AEP System Power Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio," which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement, which provides, among other things, for the transfer of SO_2 allowances associated with the transactions under the Interconnection Agreement.

Power, gas and risk management activities are conducted by the AEP Power Pool and profits/losses are shared among the parties under the System Integration Agreement. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices. In addition, the risk management of electricity, and to a lesser extent gas contracts, includes exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

System Integration Agreement (SIA)

AEP's System Integration Agreement, which has been approved by the FERC, provides for the integration and coordination of AEP's East companies and West companies zones. This includes joint dispatch of generation within the AEP System, and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). It is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within each zone.

In November 2005, AEP filed with the FERC a proposed amendment to the SIA to change the method of allocating profits from off-system electricity sales between the East and West zones. The proposed method causes such profits to be allocated generally on the basis of the zone in which the underlying transactions occur or originate. The filing was made in accordance with a provision of the agreement that called for a re-evaluation of the allocation method effective January 1, 2006 and was approved as filed effective April 1, 2006.

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

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

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales to the pools, direct sales to affiliates, natural gas contracts with AEPES, and other revenues for the years ended December 31, 2007, 2006 and 2005:

	Years Ended December 31,		
	2007	2006	2005
Related Party Revenues		(in thousands)	
Sales to East System Pool	$ 56,708	$ 57,921	$ 49,791
Direct Sales to West Affiliates	3,738	4,801	6,122
Natural Gas Contracts with AEPES	(197)	(4,698)	14,586
Other	302	263	304
Total Revenues	$ 60,551	$ 58,287	$ 70,803

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2007, 2006 and 2005:

	Years Ended December 31,		
	2007	2006	2005
Related Party Purchases	(in thousands)		
Purchases from East System Pool	$ 96,997	$ 99,166	$ 95,187
Direct Purchases from East Affiliates	88,051	92,881	81,163
Direct Purchases from West Affiliates	351	33	-
Total Purchases	$ 185,399	$ 192,080	$ 176,350

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

AEP System Transmission Pool

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

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

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

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TEA, dated April 1, 1984, as amended, defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company's "member-load-ratio."

KPCo's net credits as allocated under the TEA during the years ended December 31, 2007, 2006 and 2005 were $800 thousand, $2 million and $3.5 million, respectively, and were recorded in Other Operation on KPCo's income statements.

PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA, originally dated January 1, 1997. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the AEP West companies.

Natural Gas Contracts with DETM

Effective October 31, 2003, AEPES assigned to AEPSC, as agent for the AEP East companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. Beginning in 2007, PSO and SWEPCo were allocated a portion of the DETM assignment based on the SIA methodology of sharing trading and marketing margins between the AEP East companies and PSO and SWEPCo. Concurrently, in order to ensure that there would be no financial impact to the AEP East companies, PSO or SWEPCo as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. There is no impact to the AEP consolidated financial statements. KPCo's risk management liabilities related to DETM at December 31, 2007 and 2006 were $1.9 million and $2.7 million, respectively.

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with those two parties to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East companies, who have an agreement to purchase 100% of the available generating capacity from the plant through May 2012. KPCo's related purchases of gas managed by AEPES were $930 thousand, $398 thousand and $924 thousand for the years ended December 31, 2007, 2006 and 2005, respectively.

These purchases are reflected in Purchased Electricity for Resale on KPCo's income statements.

Unit Power Agreements (UPA)

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

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo unit power agreement ends in December 2022. See Affiliated Revenues and Purchases section of this note.

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. KPCo recorded costs of $80 thousand, $68 thousand and $133 thousand in 2007, 2006 and 2005, respectively, for urea transloading provided by I&M. These costs were recorded as fuel expense or operation expense.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers on its balance sheet the cost of performing the services, then transfers the cost to the affiliate for reimbursement. KPCo recorded these billings as capital or maintenance expense depending on the nature of the services received. These billings are recoverable from customers. KPCo's billed amounts were $167 thousands, $181 thousand and $285 thousand for the years ended December 31, 2007, 2006 and 2005, respectively.

Affiliate Railcar Agreement

KPCo has an agreement providing for the use of affiliate's leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. KPCo records these costs or reimbursements as costs or reduction of costs, respectively, in Fuel on the balance sheets and such costs are recoverable from customers. The following table shows the net effect of the railcar agreement on KPCo's 2007 and 2006 balance sheets:

	December 31,	
	2007	2006
Billing Company	(in thousands)	
APCo	$ 90	$ 384
OPCo	183	233

I&M Urea Transloading

I&M provides urea transloading services to KPCo. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. KPCo recorded costs paid to I&M for barging services as Fuel and Other Consumables Used for Electric Generation in the amount of $80 thousand, $68 thousand and $133 thousand for the years ended December 31, 2007, 2006 and 2005, respectively.

AEP Power Pool Purchases from OVEC

Beginning in 2006, the AEP Power Pool began purchasing power from OVEC as part of wholesale marketing and risk management activity. These purchases are reflected in Electric Generation, Transmission and Distribution revenues in KPCo's Statements of Income. The current agreement will expire in May 2008. KPCo recorded $2 million and $2.7 million for the years ended December 31, 2007 and 2006, respectively.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, for the years ended December 31, 2007, 2006 and 2005 as shown in the following table:

	Years Ended December 31,		
	2007	2006	2005
Companies		(in thousands)	
OPCo to KPCo	$ 133	$ -	$ -
KPCo to APCo	-	191	-
KPCo to OPCo	-	-	101

In addition, KPCo had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2007, 2006 and 2005 as shown in the following table:

	APCO	CSPCo	I&M	KGPCo	OPCo	PSO	SWEPCo	TCC	WPCo	TOTAL
Sales					(in thousands)					
2007	$ 345	$ 38	$ 21	$ 10	$ 124	$ 85	$ 7	$ -	$ 66	$ 696
2006	2,178	75	40	11	254	28	-	3	9	2,598
2005	381	1	-	1	135	-	-	-	-	518
Purchases										
2007	$ 518	6	$ 4	$ 1	$ 197	$ -	$ -	$ -	$ 5	$ 731
2006	3,206	1	18	-	504	-	-	-	3	3,732
2005	1,577	8	22	-	304	-	-	-	-	1,911

The amounts above are recorded in Property, Plant and Equipment. Transfers are performed at cost.

Global Borrowing Notes

AEP issued long-term debt, a portion of which was loaned to KPCo. The debt is reflected in Long-term Debt – Affiliated on KPCo's balance sheets. AEP pays the interest on the global notes, but KPCo accrues interest for its share of the global borrowing and remits the interest to AEP. The accrued interest is reflected in Other in the Current Liabilities section of KPCo's balance sheets. KPCo participated in the global borrowing arrangement during the reporting periods.

AEPSC

AEPSC provides certain managerial and professional services to AEP System companies. The costs of the services are billed to KPCo by AEPSC on a direct-charge basis, whenever possible, and on reasonable bases of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital, which is furnished to AEPSC by AEP. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered and are recoverable from customers. During 2005, AEPSC and its billings were subject to regulation by the SEC under the PUHCA of 1935. Effective February 8, 2006, the PUHCA of 2005 was enacted, which repealed the PUHCA of 1935 and transferred the regulatory responsibility from the SEC to the FERC.

Intercompany Billings

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

14. PROPERTY, PLANT AND EQUIPMENT

Depreciation

KPCo provides for depreciation of Property, Plant and Equipment on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides the annual composite depreciation rates by functional class:

2007	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 482,653	$ 168,806	3.8%	40-50	$ -	$ -	-%	-
Transmission	402,259	131,115	1.7%	25-75	-	-	-	-
Distribution	502,486	136,528	3.4%	11-75	-	-	-	-
CWIP	46,439	(1,463)	N.M.	N.M.	-	-	-	-
Other	56,173	21,867	8.7%	N.M.	5,492	175	N.M.	N.M.
Total	$ 1,490,010	$ 456,853			$ 5,492	$ 175		

2006	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ 478,955	$ 161,172	3.8%	40-50	$ -	$ -	-%	-
Transmission	394,419	124,709	1.7%	25-75	-	-	-	-
Distribution	481,083	138,578	3.4%	11-75	-	-	-	-
CWIP	29,587	(1,785)	N.M.	N.M.	-	-	-	-
Other	55,544	19,918	9.6%	N.M.	5,545	186	N.M.	N.M.
Total	$ 1,439,588	$ 442,592			$ 5,545	$ 186		

2005	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	3.8%	40-50	-%	-
Transmission	1.7%	25-75	-	-
Distribution	3.5%	11-75	-	-
Other	9.4%	N.M.	2.0	N.M.

N.M. = Not Meaningful

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

Asset Retirement Obligations (ARO)

KPCo implemented SFAS 143 effective January 1, 2003. SFAS 143 requires entities to record a liability at fair value for any legal obligations for future asset retirements when the related assets are acquired or constructed. Upon establishment of a legal liability, SFAS 143 requires a corresponding ARO asset to be established, which will be depreciated over its useful life. Upon settlement of an ARO, KPCo recognizes any difference between the ARO liability and actual costs as income or expense.

KPCo adopted FIN 47 during the fourth quarter of 2005. FIN 47 interprets the application of SFAS 143. It clarifies that conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO.

KPCo completed a review of its FIN 47 conditional ARO and concluded that legal liabilities exist for asbestos removal and disposal in general buildings and generating plants. In 2005, KPCo recorded a liability for conditional ARO of $1.2 million in accordance with FIN 47.

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

The following is a reconciliation of the 2007 and 2006 aggregate carrying amounts of ARO for KPCo:

Year	ARO at January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in thousands)			
2007	$ 1,175	$ 63	$ -	$ (294)	$ -	$ 944
2006	1,190	74	-	(89)	-	1,175

KPCo's aggregate carrying amounts include ARO related to ash ponds and asbestos removal.

Allowance for Funds Used During Construction (AFUDC)

The amounts of AFUDC included in Allowance For Equity Funds Used During Construction on KPCo's Statements of Income was $0.2 million, $0.2 million and $0.3 million for December 31, 2007, 2006 and 2005, respectively.

The amounts of allowance for borrowed funds used during construction included in Interest Expense on KPCo's Statements of Income was $0.6 million, $0.7 million and $0.3 million for December 31, 2007, 2006 and 2005, respectively.

15. UNAUDITED QUARTERLY FINANCIAL INFORMATION

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

	2007 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
		(in thousands)		
Operating Revenues	$ 154,096	$ 134,530	$ 152,200	$ 147,174
Operating Income	30,535	7,702	16,815	19,788
Net Income	15,211	1,230	6,485	9,544

	2006 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
		(in thousands)		
Operating Revenues	$ 151,847	$ 135,303	$ 152,319	$ 146,398
Operating Income	22,524	13,554	21,846	23,701
Net Income	9,830	5,051	9,869	10,285

There were no significant events in the fourth quarter of 2007 or 2006.