Kentucky Power Company

2008 Annual Report

Financial Statements

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GLOSSARY OF TERMS

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

Term	Meaning
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 electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
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.
CWIP	Construction Work in Progress.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EIS	Energy Insurance Services, Inc., a protected cell insurance company that AEP consolidates due to FIN 46.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 06-10	EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements."
ERCOT	Electric Reliability Council of Texas.
ERISA	Employee Retirement Income Security Act of 1974, as amended.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 46R	FIN 46R, "Consolidation of Variable Interest Entities."
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."
FSP	FASB Staff Position.
FSP FIN 39-1	FSP FIN 39-1, "Amendment of FASB Interpretation No. 39."
GAAP	Accounting Principles Generally Accepted in the United States of America.

Term	Meaning
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.
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.
OTC	Over the counter.
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.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
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 107	Statement of Financial Accounting Standards No. 107, “Disclosures about Fair Value of Financial Investments.”
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 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 141R	Statement of Financial Accounting Standards No. 141 (revised 2007), “Business Combinations.”
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
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, 2008 and 2007, 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, 2008. 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, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 9 to the financial statements, the Company adopted FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes,” effective January 1, 2007. As discussed in Note 6 to the financial statements, the Company adopted FASB Statement No. 158, “Accounting for Defined Benefit Pension and Other Postretirement Plans,” effective December 31, 2006.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

	2008	2007	2006
REVENUES			
Electric Generation, Transmission and Distribution	$ 597,699	$ 526,754	$ 526,432
Sales to AEP Affiliates	66,249	60,551	58,287
Other	1,612	695	1,148
TOTAL	665,560	588,000	585,867
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	171,215	147,912	152,335
Purchased Electricity for Resale	26,157	17,786	8,724
Purchased Electricity from AEP Affiliates	234,379	185,399	192,080
Other Operation	64,330	66,118	60,674
Maintenance	47,921	36,880	35,430
Depreciation and Amortization	48,067	47,193	46,387
Taxes Other Than Income Taxes	9,644	11,872	8,612
TOTAL	601,713	513,160	504,242
OPERATING INCOME	63,847	74,840	81,625
Other Income (Expense):			
Interest Income	2,103	1,992	656
Allowance for Equity Funds Used During Construction	1,012	260	241
Interest Expense	(34,535)	(28,635)	(28,832)
INCOME BEFORE INCOME TAX EXPENSE	32,427	48,457	53,690
Income Tax Expense	7,896	15,987	18,655
NET INCOME	$ 24,531	$ 32,470	$ 35,035

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, 2008, 2007 and 2006
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
EITF 06-10 Adoption, Net of Tax of $197			(365)		(365)
Common Stock Dividends			(14,000)		(14,000)
TOTAL					372,604
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $470				873	873
NET INCOME			24,531		24,531
TOTAL COMPREHENSIVE INCOME					25,404
DECEMBER 31, 2008	$ 50,450	$ 208,750	$ 138,749	$ 59	$ 398,008

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2008 and 2007
(in thousands)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 646	$ 727
Accounts Receivable:		
Customers	21,681	20,196
Affiliated Companies	6,721	15,984
Accrued Unbilled Revenues	2,533	2,904
Miscellaneous	83	178
Allowance for Uncollectible Accounts	(1,144)	(1,071)
Total Accounts Receivable	29,874	38,191
Fuel	29,440	8,338
Materials and Supplies	10,630	11,758
Risk Management Assets	13,760	12,121
Regulatory Asset for Under-Recovered Fuel Costs	9,953	4,426
Margin Deposits	5,207	1,940
Prepayments and Other	5,751	2,084
TOTAL	105,261	79,585
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	533,998	482,653
Transmission	431,835	402,259
Distribution	528,711	502,486
Other	65,485	61,665
Construction Work in Progress	46,650	46,439
Total	1,606,679	1,495,502
Accumulated Depreciation and Amortization	476,568	457,028
TOTAL - NET	1,130,111	1,038,474
OTHER NONCURRENT ASSETS		
Regulatory Assets	179,845	124,828
Long-term Risk Management Assets	10,860	14,826
Deferred Charges and Other	41,884	53,708
TOTAL	232,589	193,362
TOTAL ASSETS	$ 1,467,961	$ 1,311,421

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2008 and 2007

	2008	2007
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 131,399	$ 19,153
Accounts Payable:		
General	35,584	32,603
Affiliated Companies	45,245	29,437
Long-term Debt Due Within One Year – Nonaffiliated	-	30,000
Risk Management Liabilities	6,316	10,310
Customer Deposits	15,985	14,422
Accrued Taxes	11,903	16,875
Other	29,526	31,909
TOTAL	275,958	184,709
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	398,555	398,373
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	5,630	9,699
Deferred Income Taxes	259,666	240,858
Regulatory Liabilities and Deferred Investment Tax Credits	46,135	46,434
Deferred Credits and Other	64,009	24,379
TOTAL	793,995	739,743
TOTAL LIABILITIES	1,069,953	924,452
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	208,750	208,750
Retained Earnings	138,749	128,583
Accumulated Other Comprehensive Income (Loss)	59	(814)
TOTAL	398,008	386,969
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,467,961	$ 1,311,421

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

	2008	2007	2006
OPERATING ACTIVITIES			
Net Income	$ 24,531	$ 32,470	$ 35,035
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	48,067	47,193	46,387
Deferred Income Taxes	4,097	5,691	2,596
Allowance for Equity Funds Used During Construction	(1,012)	(260)	(241)
Mark-to-Market of Risk Management Contracts	(4,650)	89	(3,917)
Change in Other Noncurrent Assets	(11,298)	(4,122)	(4,497)
Change in Other Noncurrent Liabilities	2,055	1,001	2,621
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	8,317	2,445	11,903
Fuel, Materials and Supplies	(18,866)	9,015	(6,125)
Accounts Payable	21,288	1,806	(3,436)
Accrued Taxes, Net	(4,199)	(1,410)	15,547
Other Current Assets	(9,481)	(2,968)	6,107
Other Current Liabilities	2,473	2,744	4,662
Net Cash Flows from Operating Activities	61,322	93,694	106,642
INVESTING ACTIVITIES			
Construction Expenditures	(129,619)	(68,134)	(77,848)
Change in Other Cash Deposits	-	-	5
Acquisitions of Assets	(314)	-	-
Proceeds from Sales of Assets	947	695	2,956
Net Cash Flows Used for Investing Activities	(128,986)	(67,439)	(74,887)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	-	321,100	-
Change in Advances from Affiliates, Net	112,246	(11,483)	24,596
Retirement of Long-term Debt – Nonaffiliated	(30,000)	(322,964)	-
Retirement of Long-term Debt – Affiliated	-	-	(40,000)
Principal Payments for Capital Lease Obligations	(806)	(883)	(1,175)
Dividends Paid on Common Stock	(14,000)	(12,000)	(15,000)
Other	143	-	-
Net Cash Flows from (Used for) Financing Activities	67,583	(26,230)	(31,579)
Net Increase (Decrease) in Cash and Cash Equivalents	(81)	25	176
Cash and Cash Equivalents at Beginning of Period	727	702	526
Cash and Cash Equivalents at End of Period	$ 646	$ 727	$ 702
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 28,602	$ 28,864	$ 27,887
Net Cash Paid for Income Taxes	3,554	10,477	11,516
Noncash Acquisitions Under Capital Leases	544	826	648
Construction Expenditures Included in Accounts Payable at December 31,	9,662	12,161	3,357
Revenue Refund Included in Accounts Payable at December 31,	18,526	-	-

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.

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 net income 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

The KPSC approves retail rates and regulates the retail services and operations for the generation and supply of power and retail transmission and distribution energy delivery services. KPCo's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, are regulated by the FERC under the 2005 Public Utility Holding Company Act, the Federal Power Act and by the KPSC. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility holding company subsidiaries, such as KPCo, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. A FERC order in 2008 pursuant to the Federal Power Act codified that for non-power goods and services, a non-regulated affiliate can bill a public utility company no more than market while a public utility must bill the higher of cost or market to a non-regulated affiliate.

The FERC regulates wholesale power markets, wholesale power transactions and wholesale transmission services. KPCo's wholesale power transactions are generally market-based. They are cost-based regulated when KPCo negotiates and files a cost-based contract with the FERC or the FERC determines that KPCo has "market power" in the region where the transaction occurs. KPCo enters into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the System Transmission Integration Agreement, the Transmission Equalization Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the AEP subsidiaries that are parties to each agreement, including KPCo.

The KPSC regulates all of the retail public utility services/operations (generation/power supply, transmission and distribution operations) and rates for KPCo, which are cost-based. 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 (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, 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 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 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 11).

Concentrations of Credit Risk and Significant Customers

KPCo does not have any significant customers that comprise 10% or more of its Operating Revenues as of December 31, 2008.

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

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. In Kentucky, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or when 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, the KPSC audits fuel cost calculations and deferrals. When a fuel cost disallowance becomes probable, KPCo adjusts its deferrals and records provisions for estimated refunds to recognize the probable outcomes. 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) and regulatory liabilities (deferred 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 at each balance sheet date or whenever new events occur. Examples include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, KPCo writes off that regulatory asset as a charge against income.

Traditional Electricity Supply and Delivery Activities

KPCo recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues 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. The AEP East companies purchase power from PJM to supply power to customers. 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

AEPSC, on behalf of the AEP East companies, 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 and adjacent markets. These 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. Certain energy marketing and risk management transactions are with RTOs.

KPCo recognizes revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. KPCo uses MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. The realized gains and losses on wholesale marketing and risk management transactions are included in Revenues 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 AOCI. When the forecasted transaction is realized and affects net income, KPCo subsequently reclassifies the gain or loss on the hedge from Accumulated Other Comprehensive Income into revenues or expenses within the same financial statement line item as the forecasted transaction on its Statements of Income. KPCo defers the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Cash Flow Hedging Strategies" section of Note 8.

Maintenance

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

Income Taxes and Investment Tax Credits

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

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 beginning January 1, 2007, 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 and the State of Kentucky, respectively. KPCo follows the inventory model for these allowances. Allowances expected to be consumed within one year are reported in Materials and Supplies. Allowances with expected consumption beyond one year are included in 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, 2008 and 2007 is shown in the following table:

	December 31,	
	2008	2007
Components	(in thousands)	
Cash Flow Hedges	$ 59	$ (814)

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. See "FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" section of Note 2 for discussion of changes in netting certain balance sheet amounts. These reclassifications had no impact on KPCo's previously reported net income or changes in shareholder's equity.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management 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.

Pronouncements Adopted in 2008

The following standards were effective during 2008. Consequently, the financial statements and footnotes reflect their impact.

SFAS 157 "Fair Value Measurements" (SFAS 157)

KPCo partially adopted SFAS 157 effective January 1, 2008. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures.

In February 2008, the FASB issued FSP SFAS 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" (SFAS 157-1) 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. SFAS 157-1 was effective upon issuance and had an immaterial impact on the financial statements.

In February 2008, the FASB issued FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2) 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 fully adopted SFAS 157 effective January 1, 2009 for items within the scope of SFAS 157-2. The adoption of SFAS 157-2 had an immaterial impact on the financial statements.

In October 2008, the FASB issued FSP SFAS 157-3 "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active" which clarifies application of SFAS 157 in markets that are not active and provides an illustrative example. The FSP was effective upon issuance. The adoption of this standard had no impact on the financial statements.

See "SFAS 157 Fair Value Measurements" Section of Note 8 for further information.

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

The FASB permitted entities to choose to measure many financial instruments and certain other items at fair value. The standard also established 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 162 "The Hierarchy of Generally Accepted Accounting Principles" (SFAS 162)

In May 2008, the FASB issued SFAS 162, clarifying the sources of generally accepted accounting principles in descending order of authority. The statement specifies that the reporting entity, not its auditors, is responsible for its compliance with GAAP.

KPCo adopted SFAS 162 in the fourth quarter of 2008. The adoption of this standard had no impact on the financial statements.

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 if the employer 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 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) retrospective application to all prior periods. KPCo adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $562 thousand, ($365 thousand, net of tax) to beginning retained earnings.

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 addressed the recognition of income tax benefits of dividends on employee share-based compensation. 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. The adoption of this standard will have an immaterial impact on the financial statements.

FSP SFAS 133-1 and FIN 45-4 "Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161" (FSP SFAS 133-1 and FIN 45-4)

In September 2008, the FASB issued FSP SFAS 133-1 and FIN 45-4 amending SFAS 133 and FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." Under the SFAS 133 requirements, the seller of a credit derivative shall disclose the following information for each derivative, including credit derivatives embedded in a hybrid instrument, even if the likelihood of payment is remote:

(a) The nature of the credit derivative.
(b) The maximum potential amount of future payments.
(c) The fair value of the credit derivative.
(d) The nature of any recourse provisions and any assets held as collateral or by third parties.

Further, the standard requires the disclosure of current payment status/performance risk of all FIN 45 guarantees. In the event an entity uses internal groupings, the entity shall disclose how those groupings are determined and used for managing risk.

KPCo adopted the standard effective December 31, 2008. The adoption of this standard had no impact on the financial statements and footnote disclosures.

FSP SFAS 140-4 and FIN 46R-8 "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities" (FSP SFAS 140-4 and FIN 46R-8)

In December 2008, the FASB issued FSP SFAS 140-4 and FIN 46R-8 amending SFAS 140 "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities" and FIN 46R "Consolidation of Variable Interest Entities." Under the requirements, the transferor of financial assets in the securitization or asset-backed financing arrangement must disclose the following:

(a) Nature of any restrictions on assets reported by an entity in its balance sheet that relate to a transferred financial asset, including the carrying amounts of such assets.
(b) Method of reporting servicing assets and servicing liabilities.
(c) If reported as sales and the transferor has continuing involvement with the transferred financial assets and the transfers are accounted for as secured borrowings, how the transfer of financial assets affects the transferors' balance sheet, net income and cash flows.

The FIN 46R amendments contain disclosure requirements for a public enterprise that (a) is the primary beneficiary of a variable interest entity (VIE), (b) holds a significant variable interest in a VIE but is not the primary beneficiary or (c) is a sponsor that holds a variable interest in a VIE. The principle objectives of the disclosures required by this standard are to provide financial statement users an understanding of:

(a) Significant judgments and assumptions made to determine whether to consolidate a variable interest entity and/or disclose information about involvement with a variable interest entity.
(b) Nature of the restrictions on a consolidated variable interest entity's assets reported in the balance sheet, including the carrying amounts of such assets.
(c) Nature of, and changes in, risks associated with a company's involvement with a variable interest entity.
(d) A variable interest entity's effect on the balance sheet, net income and cash flows.
(e) The nature, purpose, size and activities of any variable interest equity, including how it is financed.

KPCo adopted the standard effective December 31, 2008. The adoption of this standard had no impact on the financial statements but increased the footnote disclosures for variable interest entities. See "Variable Interest Entities" section of Note 12.

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

In April 2007, the FASB issued FSP FIN 39-1 amending FIN 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. The amendment requires entities that offset fair values of derivatives with the same party under a netting agreement to 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 the standard effective January 1, 2008. This standard changed the method of netting certain balance sheet amounts and reduced assets and liabilities. It requires retrospective application as a change in accounting principle. Consequently, KPCo reclassified the following amounts on its December 31, 2007 balance sheet as shown:

December 2007 10-K Balance Sheet Line Description	**FSP FIN 39-1 Reclassification**
Current Assets:	**(in thousands)**
Risk Management Assets	$ (359)
Prepayments and Other	(677)
Long-term Risk Management Assets	(530)
Current Liabilities:	
Risk Management Liabilities	(664)
Customer Deposits	(890)
Long-term Risk Management Liabilities	(12)

For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2008 balance sheet, KPCo netted $468 thousand of cash collateral received from third parties against short-term and long-term risk management assets and $1.2 million of cash collateral paid to third parties against short-term and long-term risk management liabilities.

Pronouncements Adopted During The First Quarter of 2009

The following standards are effective during the first quarter of 2009. Consequently, their impact will be reflected in the first quarter of 2009 financial statements when filed. The following paragraphs discuss their expected impact on future financial statement and footnote disclosures.

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 established 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. The standard 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 can affect tax positions on previous acquisitions. KPCo does not have any such tax positions that result in adjustments.

KPCo adopted SFAS 141R effective January 1, 2009. It is effective prospectively for business combinations with an acquisition date on or after January 1, 2009. KPCo will apply it to any future business combinations.

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. The statement 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.

KPCo adopted SFAS 160 effective January 1, 2009. The adoption of this standard had no impact.

SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how an entity accounts for derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation.

KPCo adopted SFAS 161 effective January 1, 2009. This standard will increase the disclosure requirements related to derivative instruments and hedging activities in future reports.

EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5)

In September 2008, the FASB ratified the consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer's credit standing without the support of the credit enhancement affect the fair value measurement of the issuer's liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application.

KPCo adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability in the period of adoption. The adoption of this standard will impact the financial statements in the 2009 Annual Report as KPCo reports fair value of long-term debt annually.

EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6)

In November 2008, the FASB ratified the consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. It requires initial carrying value be determined using the SFAS 141R cost allocation method. When an investee issues shares, the equity method investor should treat the transaction as if the investor sold part of its interest.

KPCo adopted EITF 08-6 effective January 1, 2009 with no impact on the financial statements. It was applied prospectively.

FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

KPCo adopted SFAS 142-3 effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard's disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on the financial statements.

Pronouncements Effective in the Future

The following standards will be effective in the future and their impacts disclosed at that time.

FSP SFAS 132R-1 "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP SFAS 132R-1)

In December 2008, the FASB issued FSP SFAS 132R-1 providing additional disclosure guidance for pension and OPEB plan assets. The rule requires disclosure of investment policy including target allocations by investment class, investment goals, risk management policies and permitted or prohibited investments. It specifies a minimum of investment classes by further dividing equity and debt securities by issuer grouping. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk.

This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to AEP's benefit plans. KPCo will adopt the standard effective for the 2009 Annual Report.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, 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, contingencies, liabilities and equity, emission allowances, leases, insurance, hedge accounting, trading inventory 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 net income and financial position.

3. RATE MATTERS

KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. This note is a discussion of rate matters and industry restructuring related proceedings that could have a material effect on net income and cash flows.

For discussion of the FERC's November 2008 order on AEP's allocation of off-system sales, see "Allocation of Off-system Sales Margins" section within "FERC Rate Matters".

Validity of Nonstatutory Surcharges

In August 2007, the Franklin County 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. Both the KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable, KPCo has existing surcharges which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, the annual Rockport Plant capacity surcharge, the merger surcredit and the off-system sales credit rider. On an annual basis these surcharges recently ranged from revenues of approximately $10 million to a reduction of revenues of $2 million due to the volatility of these surcharges. The KPSC asked interested parties to brief the issue in KPCo's fuel cost proceeding. The AG responded 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 issued an order stating that it has the authority to provide for surcharges and surcredits until the court of appeals rules otherwise.

In November 2008, the Kentucky Court of Appeals concluded that Duke Energy's surcharge was illegal. However, the order stated that the "decision was premised on the nature of the long-term capital improvements proposed by Duke Energy as distinguished from the fuel increases that are fluctuating and unanticipated. The latter have been approved by the Kentucky Supreme Court and remain the law". In February 2009, the Kentucky Court of Appeals denied the KPSC request for appeal of the Franklin County Circuit Court decision. Management believes that all of KPCo's variable rate mechanisms are valid and would be upheld if ever challenged.

2008 Fuel Cost Reconciliation

In January 2008, KPCo filed its semi-annual fuel cost reconciliation covering the period May 2007 through October 2007. As part of this filing, KPCo sought recovery of incremental costs associated with transmission line losses billed by PJM since June 2007 due to PJM's implementation of PJM transmission marginal line loss pricing. KPCo expensed these incremental PJM costs associated with transmission line losses pending a determination that they are recoverable through the Kentucky fuel clause. In June 2008, the KPSC issued an order approving KPCo's semi-annual fuel cost reconciliation filing and recovery of incremental costs associated with transmission line losses billed by PJM. For the year ended December 31, 2008, KPCo recorded $20 million of income and the related Regulatory Asset for Under-Recovered Fuel Costs for transmission line losses incurred from June 2007 through December 2008 of which $7 million related to 2007.

FERC Rate Matters

Regional 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 at FERC's direction 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 the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues. KPCo's portion of recognized gross SECA revenues was $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 should not have been 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.

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, based on advice of legal counsel, 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. AEP and SECA ratepayers have engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a disallowance of a large portion on any unsettled SECA revenues.

Based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $39 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. KPCo provided reserves of $2.9 million and $400 thousand in 2006 and 2007, respectively.

In December 2008, an additional settlement agreement was approved by the FERC resulting in the completion of a $2 million settlement applicable to $17 million of SECA revenue. Including this most recent settlement, AEP has completed settlements totaling $9 million applicable to $92 million of SECA revenues. The balance in the reserve for future settlements as of December 2008 was $35 million. KPCo's reserve balance at December 31, 2008 was $2.6 million. In-process settlements total $1 million applicable to $20 million of SECA revenues. In February 2009, the FERC approved the in-process settlements resulting in the completion of a $1 million settlement application to $20 million of SECA revenues.

If the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it will have an adverse effect on future net income and cash flows. 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 available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if any.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the 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 would 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 by PJM. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. 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, net income and cash flows.

The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. AEP has also sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. As a result, AEP is now recovering approximately 80% of the lost T&O transmission revenues. The remaining 20% is being incurred by AEP until it can revise its rates in Indiana and Michigan to recover these lost revenues. AEP received net SECA transmission revenues of $128 million in 2005. I&M requested recovery of its portion of these lost revenues in its Indiana rate filing in January 2008 but does not expect to commence recovering the new rates until early 2009. Future net income and cash flows will continue to be adversely affected in Indiana and Michigan until the remaining 20% of the lost T&O transmission revenues are recovered in retail rates.

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 to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of 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 argued 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. AEP filed a rehearing request with the FERC in March 2008. In December 2008, the FERC denied AEP's request for rehearing. In February 2009, AEP filed an appeal in the U.S. Court of Appeals. If the court appeal is successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings. Management is unable to predict the outcome of this case.

PJM Transmission Formula Rate Filing

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM by $63 million annually. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in AEP's cost of service. The requested increase would result in a combined increase in annual revenues for the AEP East companies of approximately $9 million from nonaffiliated customers within PJM. The remaining $54 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of AEP's transmission facilities so that retail rates are not affected. AEP requested an effective date of October 1, 2008. In September 2008, the FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, suspended the effective date until March 1, 2009 and established a settlement proceeding with an ALJ. In October 2008, AEP began settlement discussions and filed the required compliance filing. Management is unable to predict the outcome of this filing.

Allocation of Off-system Sales Margins

In August 2008, the OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the AEP SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the AEP SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating

Agreement, the FERC determined the allocation methodology to be reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. In December 2008, AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. The motion for rehearing is still pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies. The AEP West companies were required to share a portion of such revenues with their wholesale and retail customers during this period. In December 2008, the AEP West companies recorded a provision for refund which had a $97 million unfavorable effect on AEP net income.

The table below lists the respective amounts the AEP East companies and the AEP West companies recorded in December 2008 including the net increase (decrease) to net income for the year ended December 31, 2008:

	Amounts to be (Transferred)/ Received Including Interest	Increase/ (Decrease) to Net Income
AEP East Companies	**(in millions)**	
APCo	$ (77)	$ (50)
I&M	(48)	(32)
OPCo	(62)	(40)
CSPCo	(44)	(28)
KPCo	(19)	(12)
Total – AEP East Companies	(250)	(162)
AEP West Companies		
PSO	72	12
SWEPCo	85	20
TCC	68	23
TNC	25	10
Total – AEP West Companies	250	65
Total – AEP Consolidated	$ -	$ (97)

The table below shows the vintage year of the associated AEP SIA refunds:

	For the Twelve Months Ended December 31,			
	2006 and Prior	2007	2008	Total
AEP East Companies	**(in millions)**			
APCo	$ (66)	$ (6)	$ (5)	$ (77)
I&M	(41)	(4)	(3)	(48)
OPCo	(53)	(5)	(4)	(62)
CSPCo	(40)	(3)	(1)	(44)
KPCo	(17)	(1)	(1)	(19)
Total – AEP East Companies	(217)	(19)	(14)	(250)
AEP West Companies				
PSO	62	6	4	72
SWEPCo	74	6	5	85
TCC	59	5	4	68
TNC	22	2	1	25
Total – AEP West Companies	217	19	14	250
Total – AEP Consolidated	$ -	$ -	$ -	$ -

Management cannot predict the outcome of the requested FERC rehearing proceeding or any future regulatory proceedings but believes the provision regarding future regulatory proceedings is adequate.

Transmission Equalization Agreement

Certain transmission equipment placed in service in 1998 in KPCo's service territory was inadvertently excluded from the AEP East companies' TEA calculation. As a result, KPCo did not receive a TEA credit from the other TEA member companies to equalize its investment in this equipment. Management believes that it is not probable that a material retroactive adjustment will result from the omission. However, if a retroactive adjustment is required, it could have an effect on future net income, cash flows and financial condition.

4. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

	December 31,		
Regulatory Assets:	**2008**	**2007**	**Notes**
Current Regulatory Asset	**(in thousands)**		
Under-recovered Fuel Costs	$ 9,953	$ 4,426	(a) (f)
Noncurrent Regulatory Assets			
SFAS 109 Regulatory Asset, Net (See Note 9)	$ 107,953	$ 101,340	(a) (d)
SFAS 158 Regulatory Asset (See Note 6)	61,439	13,573	(a) (d)
Other	10,453	9,915	(b) (d)
Total Noncurrent Regulatory Assets	$ 179,845	$ 124,828	
Regulatory Liabilities:			
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Asset Removal Costs	$ 31,874	$ 33,106	(c)
Unrealized Gain on Forward Commitments	11,697	9,592	(a) (d)
Deferred Investment Tax Credits	2,519	3,395	(a) (e)
Other	45	341	(a) (d)
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 46,135	$ 46,434	

(a) Amount does not earn a return.
(b) A portion of this amount earns 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 11 years.
(f) Recovery/refund period – 1 year.

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. The insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of KPCo's retentions. Coverage is generally provided by a combination of a South Carolina domiciled insurance company, EIS, 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 net income, 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. Budgeted construction expenditures for 2009 are $61.9 million. Budgeted 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 purchases fuel, materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination. Management does not expect to incur penalty payments under these provisions that would materially affect net income, cash flows or financial condition.

The following table summarizes KPCo's actual contractual commitments at December 31, 2008:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 164.4	$ 218.7	$ 58.8	$ -	$ 441.9
Energy and Capacity Purchase Contracts (b)	0.6	1.8	0.3	-	2.7
Construction Contracts for Capital Assets (c)	0.3	5.3	9.3	-	14.9
Total	$ 165.3	$ 225.8	$ 68.4	$ -	$ 459.5

(a) Represents contractual commitments to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel. The longest contract extends to the year 2012. The contracts provide for periodic price adjustments and contain various clauses that would release KPCo from its commitments under certain conditions.
(b) Represents contractual commitments for energy and capacity purchase contracts.
(c) Represents only capital assets that are contractual commitments.

GUARANTEES

There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

<u>Contracts</u>

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, 2008, 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 purchase power and sale activity conducted pursuant to the SIA.

<u>Lease Obligations</u>

KPCo leases certain equipment under master lease agreements. See “Master Lease Agreements” section of Note 10 for disclosure of lease residual value guarantees.

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.

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 net income, cash flows and possibly financial condition.

Carbon Dioxide 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 dismissal of the lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument concluded in 2006. In April 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 which were provided in 2007. Management believes the actions are without merit and intends to defend against the claims.

Alaskan Villages' Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in federal court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company, and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. The defendants filed motions to dismiss the action. The motions are pending before the court. Management believes the action is 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, 2008, there is one site for which KPCo has received an information request which could lead to a Potentially Responsible Party designation. In the instance where KPCo has been named a defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each 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 to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. Management believes a provision recorded in 2008 should be sufficient. 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. Management is unable to predict the ultimate outcome of these proceedings or their impact on future net income and cash flows.

6. BENEFIT PLANS

KPCo participates in AEP sponsored qualified pension plans (merged at December 31, 2008) and unfunded 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 OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

KPCo adopted SFAS 158 in December 2006 and recognized the obligations associated with defined benefit pension plans and OPEB plans in its balance sheets. KPCo recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status and recognizes as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. KPCo records a SFAS 71 regulatory asset for qualifying SFAS 158 costs of regulated operations that for ratemaking purposes are 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 market conditions, 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, 2008, and their funded status as of December 31 for each year:

Projected Plan Obligations, Plan Assets, Funded Status as of December 31, 2008 and 2007

	Pension Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
	(in millions)			
Change in Projected Benefit Obligation				
Projected Obligation at January 1	$ 4,109	$ 4,108	$ 1,773	$ 1,818
Service Cost	100	96	42	42
Interest Cost	249	235	113	104
Actuarial Loss (Gain)	139	(64)	2	(91)
Plan Amendments	-	18	-	-
Benefit Payments	(296)	(284)	(120)	(130)
Participant Contributions	-	-	24	22
Medicare Subsidy	-	-	9	8
Projected Obligation at December 31	$ 4,301	$ 4,109	$ 1,843	$ 1,773
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 4,504	$ 4,346	$ 1,400	$ 1,302
Actual Gain (Loss) on Plan Assets	(1,054)	435	(368)	115
Company Contributions	7	7	82	91
Participant Contributions	-	-	24	22
Benefit Payments	(296)	(284)	(120)	(130)
Fair Value of Plan Assets at December 31	$ 3,161	$ 4,504	$ 1,018	$ 1,400
Funded (Underfunded) Status at December 31	$ (1,140)	$ 395	$ (825)	$ (373)

AEP has significant investments in several trust funds to provide for future pension and OPEB payments. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The value of the investments in these trusts declined substantially in 2008 due to decreases in domestic and international equity markets. Although the asset values are lower, this decline has not affected the funds' ability to make their required payments.

Amounts Recognized on AEP's Balance Sheets as of December 31, 2008 and 2007

	Pension Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ -	$ 482	$ -	$ -
Other Current Liabilities – Accrued Short-term Benefit Liability	(9)	(8)	(4)	(4)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(1,131)	(79)	(821)	(369)
Funded (Underfunded) Status	$ (1,140)	$ 395	$ (825)	$ (373)

SFAS 158 Amounts Recognized in AEP's Accumulated Other Comprehensive Income (AOCI) as of December 31, 2008, 2007 and 2006

	Pension Plans			Other Postretirement Benefit Plans		
	2008	2007	2006	2008	2007	2006
Components	(in millions)					
Net Actuarial Loss	$ 2,024	$ 534	$ 759	$ 715	$ 231	$ 354
Prior Service Cost (Credit)	13	14	(5)	3	4	4
Transition Obligation	-	-	-	70	97	124
Pretax AOCI	$ 2,037	$ 548	$ 754	$ 788	$ 332	$ 482
Recorded as						
Regulatory Assets	$ 1,660	$ 453	$ 582	$ 502	$ 204	$ 293
Deferred Income Taxes	132	33	60	100	45	66
Net of Tax AOCI	245	62	112	186	83	123
Pretax AOCI	$ 2,037	$ 548	$ 754	$ 788	$ 332	$ 482

Components of the Change in AEP's Plan Assets and Benefit Obligations Recognized in Pretax AOCI during the years ended December 31, 2008 and 2007 are as follows:

	Pensions Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
Components	(in millions)			
Actuarial Loss (Gain) During the Year	$ 1,527	$ (166)	$ 492	$ (111)
Amortization of Actuarial Loss	(37)	(59)	(9)	(12)
Prior Service Cost (Credit)	(1)	19	-	-
Amortization of Transition Obligation	-	-	(27)	(27)
Total Pretax AOCI Change for the Year	$ 1,489	$ (206)	$ 456	$ (150)

Pension and Other Postretirement Plans' Assets

The asset allocations for AEP's pension plans at the end of 2008 and 2007, and the target allocation for 2009, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2009	2008	2007
Asset Category			
Equity Securities	55%	47%	57%
Real Estate	5%	6%	6%
Debt Securities	39%	42%	36%
Cash and Cash Equivalents	1%	5%	1%
Total	100%	100%	100%

The asset allocations for AEP's OPEB plans at the end of 2008 and 2007, and target allocation for 2009, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2009	2008	2007
Asset Category			
Equity Securities	65%	53%	62%
Debt Securities	34%	43%	35%
Cash and Cash Equivalents	1%	4%	3%
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. AEP's investment policies prohibit the benefit trust funds from purchasing AEP securities (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, AEP's investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law, including the Employee Retirement Income Security Act (ERISA).

The value of the pension plans' assets decreased substantially to $3.2 billion at December 31, 2008 from $4.5 billion at December 31, 2007. The qualified plans paid $289 million in benefits to plan participants during 2008 (nonqualified plans paid $7 million in benefits). The value of AEP's OPEB plans' assets decreased substantially to $1 billion at December 31, 2008 from $1.4 billion at December 31, 2007. The OPEB plans paid $120 million in benefits to plan participants during 2008.

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,	
	2008	2007
Accumulated Benefit Obligation	(in millions)	
Qualified Pension Plans	$ 4,119	$ 3,914
Nonqualified Pension Plans	80	77
Total	$ 4,199	$ 3,991

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, 2008 and 2007 were as follows:

	Underfunded Pension Plans	
	December 31,	
	2008	2007
	(in millions)	
Projected Benefit Obligation	$ 4,301	$ 81
Accumulated Benefit Obligation	$ 4,199	$ 77
Fair Value of Plan Assets	3,161	-
Underfunded Accumulated Benefit Obligation	$ 1,038	$ 77

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	**2008**	**2007**	**2008**	**2007**
Discount Rate	6.00%	6.00%	6.10%	6.20%
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 2008, 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 2009 expected cash flows for the pension (qualified and nonqualified) and OPEB plans is as follows:

Employer Contributions	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Required Contributions (a)	$ 9	$ 4
Additional Discretionary Contributions	-	158

(a) Contribution required to meet minimum funding requirement under ERISA plus direct payments for unfunded benefits.

The contribution to the pension plans is based on the minimum amount required by ERISA plus the amount to pay unfunded nonqualified benefits. The contribution to the OPEB plans is generally based on the amount of the OPEB 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 OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2009	$ 378	$ 116	$ (10)
2010	379	126	(11)
2011	377	136	(12)
2012	378	143	(13)
2013	384	151	(14)
Years 2014 to 2018, in Total	1,920	876	(87)

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost for the plans for the years ended December 31, 2008, 2007 and 2006:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2008	2007	2006	2008	2007	2006
			(in millions)			
Service Cost	$ 100	$ 96	$ 97	$ 42	$ 42	$ 39
Interest Cost	249	235	231	113	104	102
Expected Return on Plan Assets	(336)	(340)	(335)	(111)	(104)	(94)
Amortization of Transition Obligation	-	-	-	27	27	27
Amortization of Prior Service Cost (Credit)	1	-	(1)	-	-	-
Amortization of Net Actuarial Loss	37	59	79	9	12	22
Net Periodic Benefit Cost	51	50	71	80	81	96
Capitalized Portion	(16)	(14)	(21)	(25)	(25)	(27)
Net Periodic Benefit Cost Recognized as Expense	$ 35	$ 36	$ 50	$ 55	$ 56	$ 69

Estimated amounts expected to be amortized to net periodic benefit costs for AEP's plans during 2009 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 56	$ 46
Prior Service Cost	1	1
Transition Obligation	-	27
Total Estimated 2009 Pretax AOCI Amortization	$ 57	$ 74
Expected to be Recorded as		
Regulatory Asset	$ 46	$ 48
Deferred Income Taxes	4	9
Net of Tax AOCI	7	17
Total	$ 57	$ 74

The following table provides KPCo's net periodic benefit cost for the plans for the years ended December 31, 2008, 2007 and 2006:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2008	2007	2006	2008	2007	2006
	(in thousands)					
Benefit Costs	$ 995	$ 1,018	$ 1,435	$ 1,618	$ 1,706	$ 2,050

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		
	2008	2007	2006	2008	2007	2006
Discount Rate	6.00%	5.75%	5.50%	6.20%	5.85%	5.65%
Expected Return on Plan Assets	8.00%	8.50%	8.50%	8.00%	8.00%	8.00%
Rate of Compensation Increase	5.90%	5.90%	5.90%	N/A	N/A	N/A

N/A = Not Applicable

The expected return on plan assets for 2008 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 OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2008	2007
Initial	7.0%	7.5%
Ultimate	5.0%	5.0%
Year Ultimate Reached	2012	2012

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

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 20	$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	196	(163)

American Electric Power System Retirement Savings Plan

KPCo participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan was 75% of the first 6% of eligible compensation contributed by the employee in 2008. Effective January 1, 2009, the match is 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for contributions to the plan totaled $1.6 million in 2008, $1.4 million in 2007 and $1.3 million in 2006.

7. BUSINESS SEGMENTS

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

8. <u>DERIVATIVES, HEDGING AND FAIR VALUE MEASUREMENTS</u>

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 risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events 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 net income and cash flows if market prices are not consistent with management's 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 net income during the period of change. 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 net income during the period of change. 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 existing fixed 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 2008, 2007 and 2006, 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. 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, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on the Statements of Income, depending on the specific nature of the risk being hedged. KPCo does not hedge all variable price risk exposure related to energy commodities. At various times during 2008, 2007 and 2006, KPCo designated cash flow hedge relationships using these commodities and 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. 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. At various times during 2007 and 2006, KPCo designated interest rate derivatives as cash flow hedges and 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 at December 31, 2008:

	(in thousands)
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)
Effective Portion of Changes in Fair Value	553
Reclasses from AOCI to Net Income	320
Balance at December 31, 2008	$ 59

The following table approximates net loss (gain) from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2008 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.

Portion Expected to be Reclassified to Net Income During the Next Twelve Months	Maximum Term for Exposure to Variability of Future Cash Flows
(in thousands)	(in months)
$ 502	$ 24

Credit Risk

Credit risk is the risk of financial loss if counterparties fail to perform their contractual obligations. KPCo limits its credit risk by maintaining stringent credit policies whereby KPCo assesses a counterparty's creditworthiness prior to transacting with them and continue to assess their creditworthiness on an ongoing basis. KPCo employees the use of standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit, and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure is exceeded in excess of an established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, collateral agreements also provide that the failure or inability to post collateral is sufficient cause for termination and liquidation of all positions.

FAIR VALUE MEASUREMENTS

SFAS 107 Fair Value Measurements

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 Long-term Debt for KPCo at December 31, 2008 and 2007 are summarized in the following table:

	December 31,			
	2008		2007	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 418,555	$ 366,108	$ 448,373	$ 442,090

SFAS 157 Fair Value Measurements

As described in Note 2, KPCo completed the adoption of SFAS 157 effective January 1, 2009. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. The adoption of SFAS 157 had an immaterial impact on the financial statements. 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 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), 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.

In accordance with SFAS 157, assets and liabilities are classified based on the inputs utilized in the fair value measurement. SFAS 157 provides definitions for two types of inputs: observable and unobservable. Observable inputs are valuation inputs that reflect the assumptions market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the reporting entity. Unobservable inputs are valuation inputs that reflect the reporting entity's own assumptions about the assumptions market participants would use in pricing the asset or liability developed based on the best information in the circumstances.

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts, listed equities and U.S. government treasury securities that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in level 1, OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market and certain non-exchange-traded debt securities.

Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

Risk Management Contracts include exchange traded, OTC and bilaterally executed derivative contracts. Exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified within level 1. Other actively traded derivative fair values are verified using broker or dealer quotations, similar observable market transactions in either the listed or OTC markets, or valued using pricing models where significant valuation inputs are directly or indirectly observable in active markets. Derivative instruments, primarily swaps, forwards, and options that meet these characteristics are classified within level 2. Bilaterally executed agreements are derivative contracts entered into directly with third parties, and at times these instruments may be complex structured transactions that are tailored to meet the specific customer’s energy requirements. Structured transactions utilize pricing models that are widely accepted in the energy industry to measure fair value. Management uses a consistent modeling approach to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data), and other observable inputs for the asset or liability. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in level 2. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. In addition, long-dated and illiquid complex or structured transactions or FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in level 3. In certain instances, the fair values of the transactions included in level 3 that use internally developed model inputs are offset partially or in full, by transactions included in level 2 where observable market data exists for the offsetting transaction.

The following table sets forth by level within the fair value hierarchy KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 3,443	$ 140,387	$ 2,561	$ (125,636)	$ 20,755
Cash Flow and Fair Value Hedges (a)	-	1,418	-	(302)	1,116
Dedesignated Risk Management Contracts (b)	-	-	-	2,749	2,749
Total Risk Management Assets	$ 3,443	$ 141,805	$ 2,561	$ (123,189)	$ 24,620
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 4,021	$ 132,087	$ 848	$ (126,370)	$ 10,586
Cash Flow and Fair Value Hedges (a)	-	544	-	(302)	242
DETM Assignment (c)	-	-	-	1,118	1,118
Total Risk Management Liabilities	$ 4,021	$ 132,631	$ 848	$ (125,554)	$ 11,946

(a) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(b) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into revenues over the remaining life of the contract.

(c) See "Natural Gas Contracts with DETM" section of Note 12.

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

	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of January 1, 2008	$ (157)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	95
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements	-
Transfers in and/or out of Level 3 (b)	(192)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	1,967
Balance as of December 31, 2008	$ 1,713

(a) Included in revenues on KPCo's Statements of Income.

(b) "Transfers in and/or out of Level 3" represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.

(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

9. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31,		
	2008	2007	2006
		(in thousands)	
Income Tax Expense (Credit):			
Current	$ 4,674	$ 11,258	$ 17,203
Deferred	4,097	5,691	2,596
Deferred Investment Tax Credits	(875)	(962)	(1,144)
Total Income Tax	$ 7,896	$ 15,987	$ 18,655

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,		
	2008	2007	2006
		(in thousands)	
Net Income	$ 24,531	$ 32,470	$ 35,035
Income Taxes	7,896	15,987	18,655
Pretax Income	$ 32,427	$ 48,457	$ 53,690
Income Tax on Pretax Income at Statutory Rate (35%)	$ 11,349	$ 16,960	$ 18,791
Increase (Decrease) in Income Tax resulting from the following items:			
Depreciation	1,169	1,223	1,669
Allowance for Funds Used During Construction	(872)	(661)	(606)
Removal Costs	(4,110)	(1,766)	(1,361)
Investment Tax Credits, Net	(875)	(962)	(1,144)
State and Local Income Taxes	1,072	736	1,070
Other	163	457	236
Total Income Taxes	$ 7,896	$ 15,987	$ 18,655
Effective Income Tax Rate	24.4%	33.0%	34.7%

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

	December 31, 2008	December 31, 2007
	(in thousands)	
Deferred Tax Assets	$ 56,519	$ 35,037
Deferred Tax Liabilities	(312,433)	(280,667)
Net Deferred Tax Liabilities	$ (255,914)	$ (245,630)
Property Related Temporary Differences	$ (203,951)	$ (188,213)
Amounts Due From Customers For Future Federal Income Taxes	(27,299)	(25,794)
Deferred State Income Taxes	(29,694)	(27,325)
Deferred Income Taxes on Other Comprehensive Loss	(32)	438
Deferred Fuel and Purchased Power	54	(1,617)
Accrued Pensions	8,959	(3,521)
All Other, Net	(3,951)	402
Net Deferred Tax Liabilities	$ (255,914)	$ (245,630)

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. KPCo and other AEP Subsidiaries have completed the exam for the years 2001 through 2003 and have issues that are being 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 net income.

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 net income. 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 on January 1, 2007, KPCo began recognizing interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation. The impact of this interpretation was an unfavorable adjustment to the 2007 opening balance of retained earnings of $786 thousand. In 2008, KPCo reported $303 thousand of interest expense and $1.9 million of interest income. In 2007, KPCo reported $55 thousand of interest expense and reversed $926 thousand of prior period interest expense. KPCo had approximately $1.7 million for the receipt of interest accrued at December 31, 2008 and $788 thousand and $1.3 million for the payment of interest and penalties accrued at December 31, 2008 and 2007, respectively.

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

	2008	2007
	(in thousands)	
Balance at January 1,	$ 2,205	$ 3,413
Increase - Tax Positions Taken During a Prior Period	-	1
Decrease - Tax Positions Taken During a Prior Period	(113)	(1,796)
Increase - Tax Positions Taken During the Current Year	1,301	587
Decrease - Tax Positions Taken During the Current Year	(144)	-
Increase - Settlements with Taxing Authorities	96	-
Decrease - Lapse of the Applicable Statute of Limitations	-	-
Balance at December 31,	$ 3,345	$ 2,205

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $881 thousand and $936 thousand in 2008 and 2007, respectively. 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

Several tax bills and other legislation with tax-related sections were enacted in 2006 and 2007, including the Pension Protection Act of 2006, the Tax Relief and Health Care Act of 2006, 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 2006 and 2007 did not materially affect KPCo's net income, cash flows or financial condition.

The Economic Stimulus Act of 2008 was signed into law by the President in February 2008. It provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision similar to the one in effect in 2003 through 2004 for assets placed in service in 2008. The enacted provisions did not have a material impact on net income or financial condition, but provided a material favorable cash flow benefit of approximately $8 million.

In October 2008, the Emergency Economic Stabilization Act of 2008 (the 2008 Act) was signed into law. The 2008 Act extended several expiring tax provisions and added new energy incentive provisions. The legislation impacted the availability of research credits, accelerated depreciation of smart meters, production tax credits, and energy efficient commercial building deductions. Management has evaluated the impact of the law change and the application of the law change will not materially impact KPCo's net income, cash flows or financial condition.

In February 2009, the American Recovery and Reinvestment Tax Act of 2009 (the 2009 Act) was signed into law. The 2009 Act extended the bonus depreciation deduction for one year and provides for a long-term extension of the renewable production tax credit for wind energy and other properties. The 2009 Act also establishes a new investment tax credit for the manufacture of advanced energy property as well as appropriations for advanced energy research projects, carbon capture and storage and gridSMART technology. Management has evaluated the impact of the law change and the application of the law change will not materially impact net income or financial condition, but is expected to have a positive material impact on cash flows.

State Tax Legislation

In July 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.

In September 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 differences 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. Management has evaluated the impact of the MBT Act and the application of the MBT Act will not materially affect KPCo's net income, cash flows or financial condition.

In March 2008, the Governor of West Virginia signed legislation providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. Management has evaluated the impact of the law change and the application of the law change will not materially impact KPCo's net income, cash flows or financial condition.

10. 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,		
	2008	2007	2006
Lease Rental Costs		(in thousands)	
Net Lease Expense on Operating Leases	$ 2,250	$ 2,405	$ 2,079
Amortization of Capital Leases	971	1,141	1,207
Interest on Capital Leases	102	140	116
Total Lease Rental Costs	$ 3,323	$ 3,686	$ 3,402

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,	
	2008	2007
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ -	$ 22
Other	3,974	5,261
Total Property, Plant and Equipment Under Capital Leases	3,974	5,283
Accumulated Amortization	2,152	3,039
Net Property, Plant and Equipment Under Capital Leases	$ 1,822	$ 2,244
Obligations Under Capital Leases		
Noncurrent Liability	$ 1,045	$ 1,272
Liability Due Within One Year	777	972
Total Obligations Under Capital Leases	$ 1,822	$ 2,244

Future minimum lease payments consisted of the following at December 31, 2008:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2009	$ 804	$ 2,032
2010	588	1,803
2011	446	7,451
2012	15	98
2013	15	98
Later Years	18	432
Total Future Minimum Lease Payments	$ 1,886	$ 11,914
Less Estimated Interest Element	64	
Estimated Present Value of Future Minimum Lease Payments	$ 1,822	

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified management in November 2008 that they elected to terminate the Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, KPCo will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. As a result, the unamortized value of this equipment of $6 million is reflected in KPCo's future minimum lease payments for 2011. In December 2008, management signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years. Management expects to enter into replacement leasing arrangements for the equipment affected by this notification prior to the termination date of 2011.

For equipment under the GE master lease agreements that expire prior to 2011, the lessor is guaranteed receipt of 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 is 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. Under the new master lease agreements, the lessor is guaranteed receipt of up to 68% of the unamortized balance at the end of the lease term. If the actual fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the actual fair market value and unamortized balance, with the total guarantee not to exceed 68% of the unamortized balance. At December 31, 2008, the maximum potential loss for these lease agreements was approximately $613 thousand assuming the fair market value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

11. 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, 2008 and 2007:

Type of Debt	Maturity	Weighted Average Interest Rate at December 31, 2008	Interest Rate Ranges at December 31, 2008	Interest Rate Ranges at December 31, 2007	Outstanding at December 31, 2008	Outstanding at December 31, 2007
					(in thousands)	
Senior Unsecured Notes	2008-2032	5.93%	5.625%-6.00%	5.625%-6.45%	$ 400,000	$ 430,000
Notes Payable – Affiliated	2015	5.25%	5.25%	5.25%	20,000	20,000
Unamortized Discount					(1,445)	(1,627)
Total Long-term Debt					418,555	448,373
Less: Long-term Debt Due Within One Year					-	30,000
Long-term Debt					$ 418,555	$ 418,373

At December 31, 2008 future annual long-term debt payments are as follows:

	2009	2010	2011	2012	2013	After 2013	Total
				(in thousands)			
Principal Amount	$ -	$ -	$ -	$ -	$ -	$ 420,000	$ 420,000
Unamortized Discount							(1,445)
Total Long-term Debt							$ 418,555

Utility Money Pool – 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 borrowings from the Utility Money Pool as of December 31, 2008 and 2007 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2008 and 2007 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)			
2008	$ 142,416	$ -	$ 54,536	$ -	$ 131,399	$ 250,000
2007	164,913	181,970	59,104	115,727	19,153	250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the years ended December 31, 2008, 2007 and 2006 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
2008	5.47%	2.28%	-%	-%	3.42%	-%
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%

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, 2008, 2007 and 2006:

	Years Ended December 31, 2008	2007	2006
		(in thousands)	
Interest Expense	$ 1,893	$ 2,494	$ 1,065
Interest Income	-	1,614	30

Dividend Restrictions

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

Credit Facilities

In April 2008, KPCo and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, letters of credit may be issued. As of December 31, 2008, there were no outstanding amounts for KPCo under either facility.

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 2008, AEP renewed AEP Credit's sale of receivables agreement. The sale of receivables agreement provides a commitment of $700 million from banks and commercial paper conduits to purchase receivables from AEP Credit. This agreement will expire in October 2009. AEP intends to extend or replace the sale of receivables agreement. The previous sale of receivables agreement, which expired in October 2008 and was extended until October 2009, provided a commitment of $650 million from banks and commercial paper conduits to purchase receivables from AEP Credit. Under the previous sale of receivable agreement, the commitment increased to $700 million for the months of August and September to accommodate seasonal demand. At December 31, 2008, $650 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,		
	2008	2007	2006
	($ in millions)		
Proceeds from Sale of Accounts Receivable	$ 7,717	$ 6,970	$ 6,849
Loss on Sale of Accounts Receivable	$ 20	$ 33	$ 31
Average Variable Discount Rate	3.19%	5.39%	5.02%

	December 31,	
	2008	2007
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 118	$ 71
Deferred Revenue from Servicing Accounts Receivable	1	1
Retained Interest if 10% Adverse Change in Uncollectible Accounts	116	68
Retained Interest if 20% Adverse Change in Uncollectible Accounts	114	66

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

	December 31,	
	2008	2007
	(in millions)	
Customer Accounts Receivable Retained	$ 569	$ 730
Accrued Unbilled Revenues Retained	449	379
Miscellaneous Accounts Receivable Retained	90	60
Allowance for Uncollectible Accounts Retained	(42)	(52)
Total Net Balance Sheet Accounts Receivable	1,066	1,117
Customer Accounts Receivable Securitized	650	507
Total Accounts Receivable Managed	$ 1,716	$ 1,624
Net Uncollectible Accounts Written Off	$ 37	$ 24

Customer accounts receivable retained and securitized for the 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 $22 million and $30 million at December 31, 2008 and 2007, 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 $55.8 million and $41.4 million as of December 31, 2008 and 2007, respectively.

KPCo paid fees to AEP Credit for factoring customer accounts receivable of $3.2 million, $3.8 million and $3.4 million for the years ended December 31, 2008, 2007 and 2006, respectively.

12. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Utility Money Pool – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 11.

AEP 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 AEPSC and profits/losses are allocated under the SIA to AEP Power Pool members, PSO and SWEPCo. 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 OTC 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, AEPSC 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)

The SIA provides for the integration and coordination of AEP East companies and AEP West companies zones. This includes joint dispatch of generation within the AEP System, and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). 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 a 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, 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, 2008, 2007 and 2006:

	Years Ended December 31,		
	2008	**2007**	**2006**
Related Party Revenues		**(in thousands)**	
Sales to AEP Power Pool	$ 62,642	$ 56,708	$ 57,921
Direct Sales to West Affiliates	3,521	3,738	4,801
Natural Gas Contracts with AEPES	(133)	(197)	(4,698)
Other	219	302	263
Total Revenues	$ 66,249	$ 60,551	$ 58,287

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31,		
	2008	2007	2006
Related Party Purchases	(in thousands)		
Purchases from AEP Power Pool	$ 127,669	$ 96,997	$ 99,166
Direct Purchases from East Affiliates	106,256	88,051	92,881
Direct Purchases from West Affiliates	454	351	33
Total Purchases	$ 234,379	$ 185,399	$ 192,080

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

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 East companies and AEP West companies zones. Similar to the SIA, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the Transmission 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, 2008, 2007 and 2006 were $2 million, $800 thousand and $2 million, respectively, and were recorded in Other Operation on KPCo's Statements of Income.

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. KPCo's risk management liabilities related to DETM at December 31, 2008 and 2007 were $1.1 million and $1.9 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 $257 thousand, $930 thousand and $398 thousand for the years ended December 31, 2008, 2007 and 2006, respectively. These purchases are reflected in Purchased Electricity for Resale on KPCo's Statements of Income.

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) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a 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 $9 thousand, $80 thousand and $68 thousand in 2008, 2007 and 2006, 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 $1.2 million, $167 thousand and $181 thousand for the years ended December 31, 2008, 2007 and 2006, 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 its Balance Sheets and such costs are recoverable from customers. The following table shows the net effect of the railcar agreement on KPCo's Balance Sheets:

	December 31,	
	2008	**2007**
Billing Company	**(in thousands)**	
APCo	$ 274	$ 90
OPCo	332	183

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 agreement expired in May 2008 and subsequently ended in December 2008. KPCo recorded $4 million and $2 million for the years ended December 31, 2008 and 2007, 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, 2008, 2007 and 2006 as shown in the following table:

	Years Ended December 31,		
Companies	**2008**	**2007** (in thousands)	**2006**
I&M to KPCo	$ 444	$ -	$ -
KPCo to APCo	-	-	191
OPCo to KPCo	-	133	-

In addition, KPCo had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2008, 2007 and 2006 as shown in the following table:

	APCO	**CSPCo**	**I&M**	**KGPCo**	**OPCo**	**PSO**	**SWEPCo**	**TCC**	**WPCo**	**Total**
Sales					(in thousands)					
2008	$ 354	$ 11	$ 16	$ 6	$ 121	$ -	$ 2	$ 33	$ -	$ 543
2007	345	38	21	10	124	85	7	-	66	696
2006	2,178	75	40	11	254	28	-	3	9	2,598
Purchases										
2008	$ 112	$ -	$ 15	$ -	$ 95	$ -	$ -	$ -	$ -	$ 222
2007	518	6	4	1	197	-	-	-	5	731
2006	3,206	1	18	-	504	-	-	-	3	3,732

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.

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.

Variable Interest Entities

FIN 46R is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by FIN 46R. In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of variability of the VIE KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE and other factors. Management believes that the significant assumptions and judgments were applied consistently and that there are no other reasonable judgments or assumptions that would result in a different conclusion. There have been no changes to the reporting of VIEs in the financial statements where it is concluded that KPCo is the primary beneficiary. In addition, KPCo has not provided financial or other support that was not previously contractually required to any VIE.

As of December 31, 2008, KPCo holds a significant variable interest in AEPSC and AEGCo. AEPSC provides certain managerial and professional services to KPCo. AEP is the sole equity owner of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to KPCo at AEPSC's cost. KPCo has not provided financial or other support outside the reimbursement of costs for services rendered. The cost reimbursement nature of AEPSC finances its operations. There are no other terms or arrangements between AEPSC and KPCo that could require additional financial support from KPCo or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. KPCo is exposed to losses to the extent it cannot recover the costs of AEPSC through its normal business operations. KPCo is considered to have a significant interest in the variability of AEPSC due to its activity in AEPSC's cost reimbursement structure. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. Total billings from AEPSC for the years ended December 31, 2008 and 2007 were $46.4 million and $35.3 million, respectively. The carrying amount of liabilities associated with AEPSC for the years ended December 31, 2008 and 2007 were $4.7 million and $5.1 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. KPCo has no involvement with AEGCo's interest in the Lawrenceburg Generating Station. AEP guarantees all the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to the nature of the AEP Power Pool, there is a sharing of the cost of Rockport Plant such that no member of the AEP Power Pool is the primary beneficiary of AEGCo's Rockport Plant. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the years ended December 31, 2008 and 2007 were $106.3 million and $88.8 million, respectively. The carrying amount of liabilities associated with AEGCo for the years ended December 31, 2008 and 2007 were $9.4 million and $7.7 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

13. 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:

2008	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	$ 533,998	$ 177,679	3.5%	40-50	$ -	$ -	-	-
Transmission	431,835	135,955	1.6%	25-75	-	-	-	-
Distribution	528,711	146,009	3.4%	11-75	-	-	-	-
CWIP	46,650	(7,936)	N.M.	N.M.	-	-	-	-
Other	59,994	24,684	8.1%	N.M.	5,491	177	N.M.	N.M.
Total	$ 1,601,188	$ 476,391			$ 5,491	$ 177		

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	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
		(in years)		(in years)
Production	3.8%	40-50	-	-
Transmission	1.7%	25-75	-	-
Distribution	3.4%	11-75	-	-
Other	9.6%	N.M.	N.M.	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 records ARO in accordance with SFAS 143 "Accounting for Asset Retirement Obligations" and FIN 47 "Accounting for Conditional Asset Retirement Obligations" for the retirement of ash ponds and asbestos removal. KPCo has identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since KPCo plans to use its facilities indefinitely. The retirement obligation would only be recognized if and when KPCo abandons or ceases the use of specific easements, which is not expected.

The following is a reconciliation of the 2008 and 2007 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)			
2008	$ 944	$ 52	$ -	$ (590)	$ 2,869	$ 3,275
2007	1,175	63	-	(294)	-	944

Allowance for Funds Used During Construction (AFUDC)

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

	Years Ended December 31, 2008	2007	2006
		(in thousands)	
Allowance for Equity Funds Used During Construction	$ 1,012	$ 260	$ 241
Allowance for Borrowed Funds Used During Construction	1,701	595	656

14. 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:

	2008 Quarterly Periods Ended March 31	June 30	September 30	December 31
		(in thousands)		
Revenues	$ 167,290	$ 147,051	$ 188,872	$ 162,347 (a)
Operating Income	21,557	21,528	16,770	3,992 (a)
Net Income (Loss)	11,144	10,930	7,451	(4,994)(a)

	2007 Quarterly Periods Ended March 31	June 30	September 30	December 31
		(in thousands)		
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

(a) See "Allocation of Off-system Sales Margins" section of Note 3 for discussion of the financial statement impact of the FERC's November 2008 order related to the SIA.

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